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December 14, 2017

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Mr. Patrick Wruck, Commission Secretary and Manager, Regulatory Support

Dear Mr. Wruck:

Re: FortisBC Energy Inc. (FEI)

2017 Long Term Gas Resource Plan

On December 3, 2014, the British Columbia Utilities Commission (the Commission) issued Order No. G-189-14 accepting the FEI[1] 2014 Long Term Resource Plan. By Order G-99-17, the Commission approved FEI's request to extend the submission deadline for its next Long Term Gas Resource Plan to November 30, 2017.

In accordance with the Commission's Resource Planning Guidelines and Section 44.1(2) of the *Utilities Commission Act* (UCA), FEI respectfully submits the attached 2017 Long Term Gas Resource Plan (LTGRP) for the Commission's review.

There are no approvals being sought by FEI as part of this LTGRP submission. The LTGRP presents a 20-year view of the demand- and supply-side resources identified to meet expected and future natural gas demand and reliability requirements at the lowest reasonable cost to FEI's customers. The LTGRP includes an action plan that identifies the activities that FEI intends to take during the first four years of the 20-year planning horizon. FEI will file separate applications for Certificates of Public Convenience and Necessity, if and as necessary, for any of the identified activities in accordance with the Commission's guidelines.

[1] The FortisBC Energy Utilities (comprised of FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc.) were amalgamated into FortisBC Energy Inc. as of January 1, 2015 per Commission Order G-21-14 approving FortisBC Energy Utilities' Common Rate, Amalgamation and Rate Design Application.

FEI seeks acceptance of this LTGRP in accordance with Section 44.1(2) of the UCA. A discussion of how the LTGRP addresses the requirements of the UCA is included in various sections throughout.

If further information is required, please contact Ken Ross at (604) 576-7343 or ken.ross@fortisbc.com.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): FortisBC Energy Utilities 2014 Long Term Resource Plan Registered Parties

Energy at work FORTIS BC

FortisBC 2017 Long Term Gas Resource Plan

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EXECUTIVE SUMMARY

1. Introduction

This 2017 Long Term Gas Resource Plan (LTGRP) is FortisBC Energy Inc.'s (FEI, the Company or the Utility) long-term resource plan as required by the *Utilities Commission Act* (*UCA*). The 2017 LTGRP presents a long term view of the demand- and supply-side resources[1] identified to meet expected future natural gas demand and reliability requirements at the lowest reasonable cost to FEI's customers over the 20-year planning horizon (2017-2036). Table ES-1 provides a summary of FEI customer, demand and pipeline characteristics.

Table ES-1: FEI Service Statistics

	2015	2016
Number of Customers	979,000	994,000
Annual Demand (TJ)	186,000	197,000
Peak Day Demand (TJ/d)	1,074	1,334
Length of Transmission Pipeline (km)	2,958	2,959
Length of Distribution Pipeline* (km)	45,242	45,741

** Includes both low and intermediate pressure pipelines*

The resource planning process begins by closely examining the planning environment in which the Company operates and by identifying expectations for future customer and demand growth. The demand- and supply-side resource alternatives for meeting future demand are then assessed, and actions recommended to ensure that the proper resources are in place to deliver the preferred energy solutions to meet future customer needs. Finally, a four-year action plan, which identifies the near term activities needed to meet the long term resource requirements identified in the LTGRP is prepared. FEI's LTGRP objectives are to: ensure cost effective, secure and reliable energy for customers; provide cost effective Demand Side Management (DSM) initiatives; and ensure consistency with provincial energy objectives.

FEI submits this 2017 LTGRP under Section 44.1(2) of the UCA and is **not seeking approval of any particular elements of the plan**. Any requests for approval of specific resource needs that are identified within this plan will be further evaluated and brought forward through a separate application to the British Columbia (BC) Utilities Commission (the Commission or BCUC) if warranted in the future.

[1] The British Columbia Utilities Commission Resource Planning Guidelines define resources as indivisible investments or actions by the utility to modify energy and/or capacity supply, or modify (decrease, shift, increase) energy and/or capacity demand. Within the context of FEI, such resources typically refer to FEI's own infrastructure (pipelines, natural gas compression equipment, natural gas storage equipment), natural gas supply arrangements, and demand side management initiatives.

2. Planning Environment

A wide range of factors influence FEI's long term analysis and planning decisions. FEI is submitting this 2017 LTGRP during a time of continued change and uncertainty in market forces, energy technology and government policy.

Price: The North American natural gas market remains in a low commodity pricing environment which is expected to continue for several years to come. These low commodity prices have created opportunities for increased natural gas use, particularly in power generation, liquefied natural gas (LNG) export potential, and the use of natural gas by the transportation and industrial sectors.

Supply: Improvements have been made to two essential technologies, horizontal drilling and hydraulic fracturing[2], that are used to unlock natural gas trapped in shale formations. These technological achievements have resulted in major production cost reductions, allowing producers to continue to drill despite the lower natural gas price environment. Market analysts believe a rig operating in 2016 delivers over two times as much gas as a rig operating in 2013. Not only is gas supply abundant, shale gas supplies are located throughout North America, providing cost effective supply within close proximity to many major load centres. However, due to increasing industrial demand for natural gas in the Pacific Northwest (PNW), upstream infrastructure on which FEI relies to get natural gas onto its distribution system is becoming fully contracted.

Demand: Over the past several years in North America, growth in industrial demand, specifically from the petrochemical sectors and United States (US) gas exports to Mexico, has been increasing demand for natural gas. The market is also seeing increased natural gas demand from the power sector due to more switching from coal to natural gas electricity production, as well as from the retirement of coal plants. Furthermore, new incremental demand from US LNG being exported overseas will continue to increase in the coming years.

Competition: Low commodity costs have improved the price competitiveness of using natural gas over electricity on an operating cost basis, though natural gas direct use applications (such as space and water heating) typically require higher capital, installation and maintenance costs than electric appliances. A multitude of factors beyond those relating to commodity cost influence consumer, builder and developer preferences relating to the use of natural gas versus other sources of energy. Capital costs, installation requirements, operating and maintenance costs, government policies and public perception all play a role in this regard.

Policy: The energy and emissions policy environment throughout North America and in BC remains uncertain and changing. In the US, federal policies are shifting away from carbon regulation under the current administration, while many states, including those on the west coast are continuing to strengthen carbon emission policies and initiatives. The Canadian government has set Greenhouse Gas (GHG) emissions targets and introduced a number of emissions reduction initiatives, including a carbon tax to be implemented where provinces fail to

[2] Appendix D-1: https://www.eia.gov/todayinenergy/detail.php?id=2170.

do so. Yet there is continued federal support for natural gas production, exporting and domestic use where doing so displaces higher emitting fossil fuels. A new BC government is likely to make amendments to existing energy and emissions policies and may be weighing many factors including the challenge of reducing GHG emissions against cost and employment issues. Finally, municipalities across the Province are considering initiatives like enacting the voluntary step codes put forth by the Province to increase efficiency requirements for new residential and commercial buildings.

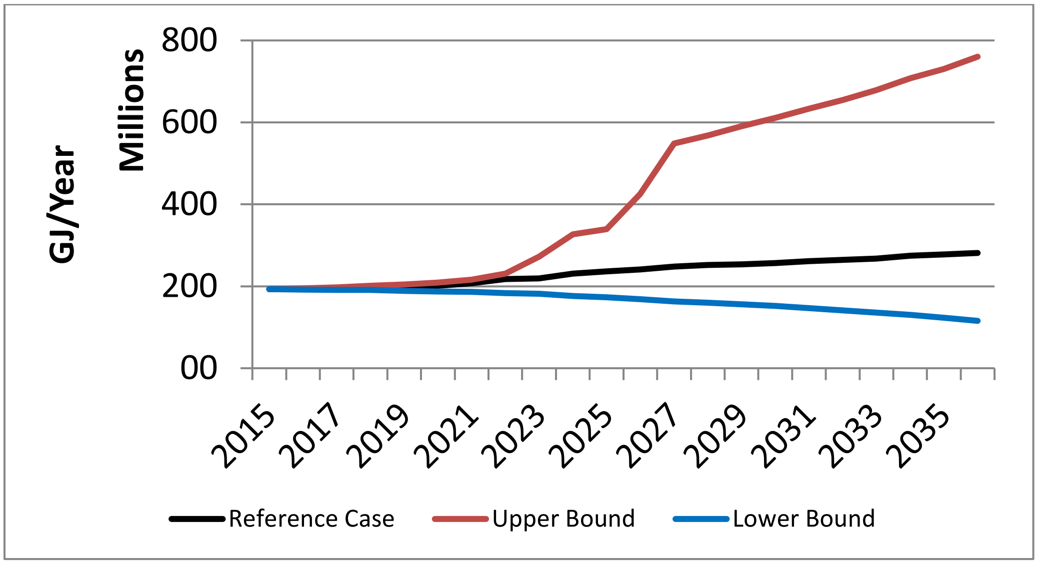
Customer Solutions: FEI believes that developing innovative and integrated customer solutions is an important part of positioning natural gas services competitively within BC's energy marketplace for the benefit of all customers. Using the right fuel effectively for the right end use and developing customer-driven energy services remain a key focus of FEI's customer solutions activities. Natural Gas for Transportation (NGT), Renewable Natural Gas (RNG) and Conservation and Energy Management (C&EM) are initiatives that FEI is currently undertaking toward this goal while helping to meet provincial goals for emissions reductions. FEI is also working with other entities to examine the potential for new technologies to reduce carbon emissions from the natural gas stream in order to help to meet provincial emission targets while maintaining throughput on the natural gas system and allowing customers to continue taking advantage of lower cost natural gas.

3. Annual Energy Demand Forecasting

Two key elements that underpin FEI's resource planning activities are the forecasts of annual demand and peak demand for natural gas. The annual demand forecast represents annual consumption by Rate Schedule and allows the Company to determine directional rate impacts and annual gas supply needs in the Company's long term planning efforts. The peak demand forecast provides an estimate of the maximum daily natural gas demand that expected under extreme weather conditions. The annual demand forecast is presented in Section 3 and discussed in Section 5 as it relates to securing gas supply. System-wide peak demand and its implications for securing supply resources to meet peak demand is discussed in the gas supply planning section, while regional peak demand forecasts are presented in Section 6 (System Resource Needs and Alternatives) where FEI's own infrastructure requirements for meeting regional peak demand are discussed.

FEI recognizes that its customers are using natural gas in different ways and amounts than they did in the past. Heating equipment installed in new buildings and in retrofit situations is more efficient and, in some cases, results in a different demand profile than the older equipment it replaces. FEI now uses an end-use, bottom up approach to demand forecasting for these customers in order to address these changing trends. New demand from the transportation sector will also impact the Company's overall demand profile. Figure ES-1 shows the total range of annual demand forecast for all customer groups, including NGT customers, for the Reference Case demand forecast as well as the highest (Upper Bound) and lowest (Lower Bound) of the various alternate future scenarios examined.

Figure ES-1: End-Use Total Annual Demand Forecast



FEI plans for the Reference Case demand, but will remain vigilant for indicators that suggest demand requirements might be unfolding more toward the Upper Bound scenario (driven largely by higher than expected NGT demand) or the Lower Bound scenario (driven largely by climate policy and regulation that favours displacing natural gas with other fuels for space heating and hot water). FEI does not assign probabilities to any particular forecast outcome.

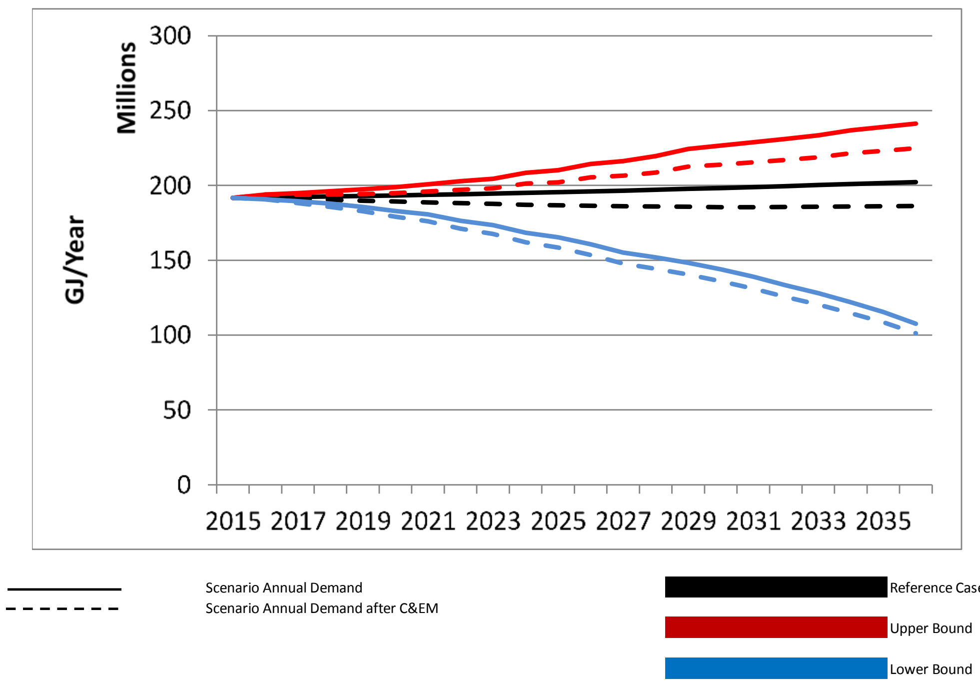
FEI also recognizes the potential for the addition of one or more large industrial customers over the planning horizon. If such large point source load additions were to occur in addition to demand in the Upper Bound scenario, demand could be pushed higher than that shown in Figure ES-1. Because the nature, size and location of such large industrial customer additions could vary widely and are subject to uncertainty, FEI generally does not plan for these load additions until a firm decision and a commitment by the customer for natural gas service is in place. Instead, in its 2017 LTGRP, FEI presents the Woodfibre LNG Project as an example to describe how it addresses such load additions while maintaining safe and reliable service to all customers.

4. Demand-Side Resources

Once an estimate of the demand for natural gas in FEI's territory is developed, the next step in long-term resource planning is to assess the impact of DSM activities on the demand forecast. In its LTGRP, FEI discusses both those DSM activities that fall strictly under the definition of demand-side measure under BC's Demand-Side Measures Regulation (DSM Regulation) as well as other demand side measures that do not fall under this strict definition. Yet these other demand side activities are recognized, industry-accepted utility practices important for FEI and its customers as well as for helping to meet BC Government energy and emissions objectives.

Under DSM activities defined by the DSM Regulation, FEI has estimated C&EM expenditures and energy savings from all cost effective measures identified through the Company's results from the BC Conservation Potential Review (BC CPR) study (undertaken between 2015 and 2017). This analysis was applied under FEI's Reference Case, Upper Bound and Lower Bound scenarios. The Upper Bound and Lower Bound scenario analyses ensure that FEI is considering its planning needs under the highest and lowest demand scenarios it reasonably expects could occur after energy savings from cost effective demand-side measures. Figure ES-2 presents energy savings for each of these scenarios before and after estimated C&EM savings amongst its residential, commercial and industrial customers. Reference Case incentive expenditures are estimated to reach a high of $46 million in 2023 based on cost effective measures known today.

Figure ES-2: Annual Natural Gas Demand Before and After Estimated C&EM Program Savings (Excluding NGT)



Since both the BC CPR and the 2017 LTGRP C&EM analysis investigate all cost effective C&EM measures already, FEI also conducted a sensitivity analysis to determine how the assumed level of incentive spending impacts forecast portfolio level C&EM expenditures and energy savings. The analysis, based on the BC CPR results, shows that as the level of incentives is increased, the portfolio expenditures rise much more quickly than do the portfolio energy savings. Conversely, as incentive levels are lowered, energy savings do not fall as quickly as portfolio expenditures.

Other demand side activities being undertaken by FEI include fuel switching to natural gas for space heating and hot water, NGT to shift fleets, heavy duty vehicles, marine and other vessels from higher carbon, petroleum based fuels to natural gas, and seeking to add new, large industrial customers. While these activities are not included in the DSM Regulation definition of a demand-side measure and are therefore not included in the C&EM activities described above, they are important for customers by adding throughput to the natural gas system and thereby reducing rates while also helping to achieve government energy and emissions policy objectives.

5. Gas Supply Portfolio Planning and Price Risk Management

FEI's gas supply planning activities ensure that the forecast normal and peak day demand of core market (Core) customers is appropriately planned for. FEI addresses how it plans to meet customer demand for natural gas over the long term via its gas supply arrangements. These arrangements encompass FEI's activities and means to contract for both the natural gas supply as well as the resources needed to bring this gas to the FEI pipeline system.

Key factors in FEI's gas portfolio planning include resource cost and availability, which are determined in the competitive natural gas marketplace. Consequently, gas supply portfolio planning activities must also consider marketplace developments throughout North America and particularly in the PNW that will affect traditional gas flows, supply and demand in the region, as well as the cost and availability of regional market resources for FEI. FEI has two primary means of managing these gas supply market dynamics in the medium and short term - the Annual Contracting Plan (ACP) and the Price Risk Management Plan (PRMP). Basic elements of the gas supply portfolio include the purchasing of gas commodity volumes, contracting on third party transportation pipelines that connect supply to market, and contracting for third party storage resources. Gas supply is also provided via FEI's own on-system LNG storage facilities.

It is critical that FEI's supply and resource portfolio incorporate a flexible variety of resources ranging from purchased term and spot gas supply, seasonal and short duration third party storage contracts, and high volume on-system resources. Accessing gas supply from a variety of locations and sources also provides FEI with a diverse pool of resources that is essential to help mitigate locational supply disruptions and price risk.

Gas supplies are plentiful throughout North America. This fact has caused western market prices to drop as producers seek to get supply from Northeast BC (NEBC) and Alberta onto a market that continues to develop more access to more producing regions. Although natural gas commodity prices are expected to remain low, interest from industrial users in natural gas is growing, as is the demand for regional storage and transmission resources to move gas from the producing areas to the demand areas.

Available capacity on these regional resources is becoming constrained. In today's competitive environment for regional gas supply resources, there is more risk of and a higher impact from FEI not having sufficient resources to meet forecast demand than from FEI finding itself long on supply resources. In the latter case, FEI's flexible portfolio will allow it to shed resources relatively quickly, whereas current trends in regional market factors may make it more difficult or even impossible to contract for critical additional resources on a firm basis should FEI find itself in need of more. For this reason, FEI's strategy is to be proactive in securing reliable and diversified gas supply cost effectively over the long term.[3] On behalf of its customers, FEI also closely monitors and participates in regulatory filings that could affect the availability of and costs for these resources, continues to establish key relationships with producers in the region and continues to evaluate opportunities within its own operating region to improve diversity and reliability within the gas supply portfolio.

Managing price risk in a marketplace with price volatility and competition for resources is also essential in helping to maintain affordable, competitive and stable rates for customers. FEI's price risk management objectives include mitigating market price volatility to support rate stability and capturing favourable prices to provide customers with more affordable rates. To meet these objectives, FEI has developed diversified procurement strategies through its PRMP to manage commodity price risk. FEI applies a range of price risk management strategies including various physical resource procurement strategies, managing locational basis risk and employing financial hedging tools. Today's low commodity price environment also provides opportunities for longer term strategies to meet PRMP objectives. FEI plans to continue to investigate longer term strategies such as investing in reserves and, if warranted, will bring forward any requests to the Commission for approval in the future.

6. System Resource Needs and Alternatives

A key aspect of ensuring safe, reliable and secure supply of natural gas to customers is identifying when and where any capacity constraints may appear and planning for the facilities that FEI needs to construct over the planning horizon to enable unrestrained delivery of natural gas to consumers. Growth in peak demand is among the most significant challenges for FEI's long term planning. When forecast peak demand exceeds available capacity, a gas system expansion is required.

There are three resource options to evaluate when planning system expansions: pipelines, compression and storage. To solve capacity constraints, each alternative is analysed with respect to overall cost, difficulty of implementation, operational flexibility, implementation time, and other factors within the overall philosophy of system sustainment and reliability. Often, some combination of the three resource options leads to an optimal solution.

Infrastructure projects on transmission systems to address system capacity constraints are often large and take many years to plan and execute. The location of customer demand on the system is a significant factor in determining the ability (capacity) of the system to deliver gas. To address the specific local and regional requirements, FEI builds regional peak demand forecasts from the bottom up, assembling the peak demand from the recent consumption and regional weather history of each customer within the system. The Company conducts this analysis for each of the three main transmission systems: Vancouver Island Transmission System (VITS); Coastal Transmission System (CTS); and Interior Transmission System (ITS).

[3] FEI has started to contract for some resources in excess of what Core customers are forecast to require in the short term. This approach is reasonable because the costs and ability to manage contract renewals within the portfolio of resources help to reduce the risk to Core customers.

Currently, FEI expects that capacity on the VITS will be exceeded in 2028 under expected load growth. Two primary options are identified to overcome this constraint. Option 1 involves adding compression along the transmission pipeline system near Squamish, while Option 2 includes some operational changes – increasing send-out and storage allotments from the Mt. Hayes storage facility to delay the need for additional compression near Squamish until 2030.

System expansion requirements on the CTS are highly dependent on the amount and nature of natural gas demand for use as a transportation fuel in either liquefied or compressed form. Compressed Natural Gas (CNG) demand could occur in many different locations across the CTS, while LNG demand would appear as a point source, industrial scale demand, most likely served by the Tilbury liquefaction and storage facility in Delta, BC. In the expected demand scenario, further expansion of the CTS (in addition to that currently under construction) would be needed at the end of the 20-year planning horizon (in approximately 2036).

The ITS peak demand will reach pipeline capacity when the system cannot maintain minimum system pressures near the high load centres in the Central Okanagan region. Expected load growth will cause an expansion requirement to address this constraint in 2022. FEI identified four reinforcement alternatives to meet the Traditional case demand forecast. Option 1 involves installing a 28 km transmission pipeline loop just north of Penticton and adding compression facilities at an existing station to move gas through the expanded pipe. Option 2 involves replacing a 9 km section of transmission pipeline between Penticton and Kelowna and adding the same compression as in Option 1. Option 3 entails approximately 52 km of transmission pipeline looping installed near Kamloops, BC. Option 4 is the installation of an LNG storage facility near Vernon BC, close to the load centre to bolster system delivery during times of high demand.

For each regional system, higher or lower than expected load growth could shift the timing of system expansion requirements either ahead or further out in time. The potential for additional new, large industrial demand could create a step change in load delivery requirements and a corresponding advancement of system expansion requirements. Because the location, size and nature of such potential new loads are often speculative, a myriad of potential impacts could occur, making it difficult to model these loads. FEI has used examples of potential loads to describe the impacts on system capacity that could result. For the VITS and CTS, the proposed Woodfibre LNG export facility near Squamish and potential additional demand at the Tilbury LNG facility to serve large increases in NGT demand, respectively, provide such examples. Based on these examples, expansion requirements on the VITS could be advanced to as early as 2021, and the CTS expansion could be advanced to as soon as 2024. The high and low demand scenarios, along with the large industrial customer addition examples presented in the LTGRP are used to identify contingency plans by advancing or delaying the timing of system constraints and resulting infrastructure needs.

In addition to the transmission pipeline expansion analysis, a number of other sizable expansion requirements on FEI's distribution and lateral transmission systems have been identified. FEI continues to examine the needs of the Revelstoke satellite propane distribution system and the potential to convert it to a natural gas system via a satellite LNG station. On the Cache

Creek/Ashcroft Transmission Lateral, FEI works closely with a firm transportation customer to manage peak demand and avoid the need for a pipeline loop. The company also explores several other significant projects that address needs other than system capacity. While these projects are not driven by capacity needs, FEI strives to ensure any projects integrate effectively with system capacity requirements of each system.

FEI plans to:

- Continue monitoring and studying the system capacity constraints identified to occur in 2028 on the VI Transmission System and complete the analysis of system reinforcement and load or supply reallocation alternatives;
- Identify system reinforcements that would be required to maintain system reliability and resilience for Core customers as LNG expansion or other large industrial loads are added on the CTS system;
- Continue to monitor and study the system capacity constraints identified to occur in 2022 in the Okanagan region of the ITS and complete the analysis of system reinforcement alternatives in anticipation of a Certificate of Public Convenience and Necessity (CPCN) application to the BCUC in the next two to three years; and
- Continue evaluating other major system projects and submit CPCN applications for these projects if required.

7. Stakeholder Consultation

Connecting with customers, communities and other stakeholders on long range planning issues is of critical importance to FEI. FEI undertook a number of initiatives to offer stakeholders the opportunity to participate in discussions to inform the 2017 LTGRP. These activities continued until the third quarter of 2017 and included:

- Workshops with the dedicated Resource Planning Advisory Group (RPAG) - the RPAG engages strategic representatives of municipalities, government, First Nations, customers, associations and organizations with interest, experience and/or significant industry knowledge in energy planning in the development of the LTGRP.
- Community Engagement workshops in communities served by FEI - recognizing the importance of considering diverse community perspectives when planning for the future, FEI has established resource planning Community Engagement workshops to gather feedback from stakeholders throughout FEI's service territories.
- Other activities that indirectly inform the resource planning process, including dialogue with First Nations, advisory groups, industry associations and other stakeholders.

Through the RPAG workshop sessions, stakeholders have been able to provide FEI with input on areas, such as demand forecasting and scenario analysis methods as well as annual demand drivers and scenarios. The Community Engagement workshops assisted FEI in identifying energy issues or planning opportunities in municipalities and communities throughout BC. The information gained through these activities informs FEI's market research and analysis, identifying long term planning issues of concern to a number of stakeholder groups, and identifying interested stakeholders who may become more engaged in the LTGRP process.

8. 20-Year Vision

FEI's long term vision is to continue to strive to be BC's trusted energy provider for safe, reliable and cost effective natural gas delivery services to its customers, and to be a healthy, growing contributor to the BC economy and to the well-being of communities in BC. Sustainability represents a key component of this vision and FEI considers all three pillars of this concept: social, environmental, and economic sustainability. FEI has developed the current 2017 LTGRP within a planning environment characterized by continued high policy uncertainty and rapid technological change. A long term vision thus cannot be made so specific that it does not allow for changes in the planning environment.

FEI discusses four key areas in which Market Transformation is occurring or may occur over the next 20 years, which could impact FEI's traditional business: NGT, C&EM technologies, low carbon thermal energy technologies, and RNG.

FEI examined NGT market capture scenarios of between 1 and 15 percent of the heavy duty and return to base fleet vehicles, and uses a Reference Case expectation of 4 percent market capture. All market sectors of potential NGT future demand - land transportation CNG and LNG vehicles as well as coastal freight vessels, domestic passenger ferries, locomotives, mine haul trucks and stationary power generation for industrial applications - are important in helping the Province meet its carbon emission reduction targets. The trans-Pacific marine segment, however, has the most significant potential impact on increased natural gas demand combined with reduced carbon emissions.

FEI expects to increase its C&EM activities with the overall goal of transforming the market from lower to higher efficiency technologies for use in the built environment. While FEI has not identified the extent of market transformation that will occur for each measure or technology via specific C&EM programs, the analysis results do represent an estimate of the amount of energy efficiency that can be achieved by the Company over the planning horizon.

Low carbon thermal energy solutions such as geo-exchange systems, waste heat recovery systems and solar thermal systems can displace both existing and future expected demand for natural gas. While FEI does not offer these services to its customers, the potential for other third party service providers to do so creates a risk to FEI's annual demand profile. This highlights the need for FEI to invest in other load building initiatives such as NGT and to support development of its RNG program and other technologies that enable FEI to meet market preferences while also helping to meet BC energy objectives.

Even annual demand forecast scenarios that assume a high level of RNG demand result in RNG accounting for a small proportion of FEI's total annual demand (less than three million GJ) by the end of the planning horizon. However, this analysis assumes current RNG supply technologies. If cellulosic biogas technologies become commercially scalable at reasonable cost, RNG demand may account for a significant share of FEI's demand within 20 years.

Table ES-2 compares forecast 2036 emissions reductions of FEI's initiatives with a 2036 target calculated by linear regression from the Government of Canada's 2017 Nationally Determined Contribution under the Paris Agreement (reducing GHG emissions by 30 percent from 2005 until 2030), and BC's legislated sector-agnostic 2050 emissions reduction target.[4,5]

Table ES-2: Comparison of FEI's Emissions Reduction Activities with the Calculated Emissions Reduction Target

GHG Reductions Required to Meet the Calculated 2036 Target ($MtCO_2e$, 2014 Base)	Forecast Emissions Reductions in 2036 ($MtCO_2e$, 2015 Base)		
29.3	**Reference Case**	**Upper Bound**	**Lower Bound**
RNG	0.04	0.14	0.01
C&EM	0.8	0.8	0.3
NGT	2.3	14.9	0.2

Note: Some forecast NGT emissions reductions are realized outside the current boundaries of the BC emissions inventory

Other technologies exist or are under development that may decarbonize the natural gas stream and enable the natural gas infrastructure to store electric energy (indirectly by injecting into the pipeline system hydrogen derived via electrolysis), decarbonize natural gas end-use appliances or increase beyond 100 percent the efficiency of natural gas appliances. FEI is monitoring and, where applicable, supporting the evolution of such technologies. If such technologies become commercially scalable at reasonable cost, they may mitigate policy-driven risks of downward pressure on natural gas demand (identified in Section 2) and create an investment opportunity for the Company. Within the context of a 20-year vision, FEI examined potential pathways through which emerging initiatives and technologies could help FEI lead efforts to pursue long term GHG emissions abatement. Please see Appendix E for this examination.

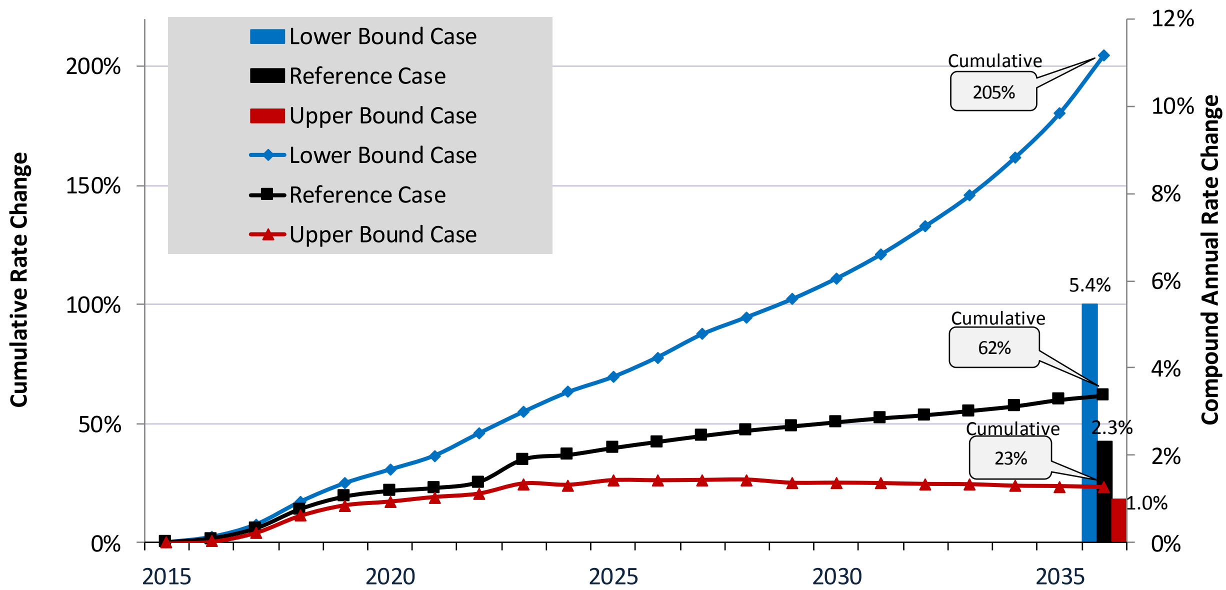
FEI also analyzes how variations in demand over the planning period can influence customer rates. Figure ES-3 shows that, holding all else constant, increasing delivery volumes (as demonstrated by the Upper Bound Case) has a downward impact on rates. This figure includes the impact of expenditures and demand impact for both the C&EM and the NGT initiatives,

4 FEI's RNG, C&EM and NGT initiatives each have their own merits and run under separate regulatory approval processes.

5 FEI received stakeholder support for using the Government of Canada's 2030 percentage reduction target as a reasonable alternative to the GGRA's 2020 target as part of a trajectory towards the GGRA's ultimate 2050 target.

however, FEI's analysis shows that individually, the C&EM initiative puts upward pressure on rates while the NGT initiative reduces rate pressure. Expanding the NGT market is an important opportunity for growth on the delivery system and underscores the importance for the Company to explore other opportunities for growth that will assist in mitigating upward pressure on delivery rates.

Figure ES-3: Delivery Rate Direction – All Rate Schedules with C&EM and NGT



9. Action Plan

The actions that FEI intends to pursue over the next four years based on the information and analyses provided in this LTGRP are to:

- Continue monitoring and analysing the energy planning environment including any market, policy and/or technology developments that may impact regional gas flows, supply, demand and pricing, or offer opportunities to improve on the secure, reliable and cost effective energy services that the Company provides to its customers.
- Continue exploring the application of projected changes across end-use patterns to peak demand forecasting and examining potential metering solutions that may allow FEI to field-validate the potential impact of end-use trends on peak demand.
- Protect and promote the interests of the Utility's customers by securing a reliable, cost effective long term gas supply. This includes participating in regional pipeline proceedings, evaluating opportunities within FEI's operating region to improve infrastructure, and exploring opportunities for longer term price risk management

strategies such as using fixed price purchases, building key relationships with producers, investing in natural gas reserves and continued financial hedging.

- Continue monitoring and evaluating system expansion needs in the Okanagan and Vancouver Island areas to maintain reliable and cost effective gas delivery to FEI's customers. Under the expected peak demand trajectory, FEI identifies a capacity constraint in the Okanagan occurring in 2022, for which four potential reinforcement options will be examined in more detail. A capacity constraint on the VITS is identified to occur in 2028 for which two reinforcement options will be examined in more detail if necessary. If peak demand trends are seen to be changing over the near to medium term, the timing of these constraints may change.
- Plan for and prepare CPCN applications for near-term system requirements to support safe, reliable and cost effective gas delivery to FEI's customers. The Company identifies a number of high priority projects on the CTS (including the Lower Mainland Intermediate Pressure System) and FEI's interior region infrastructure for which the Utility intends to submit CPCN applications. FEI will integrate its examination of these system upgrade requirements with the study of reinforcement options under consideration to meet FEI's capacity needs.
- Continue implementing the Company's NGT initiatives to meet market needs while capturing an important opportunity for load growth and GHG emissions reductions. This includes implementing any required expansions to the Tilbury LNG facility and FEI's CTS for meeting NGT and non-NGT LNG demand.
- Pursue approval of C&EM funding for the period beyond 2018 by submitting for BCUC approval a C&EM expenditure schedule in 2018. FEI will continue to examine the potential for all forms of DSM activity to optimize the use of BC's energy infrastructure by implementing programs that help meet customer energy needs while working toward BC energy objectives.
- Pursue approvals as necessary of a funding envelope dedicated to enabling FEI to further monitor and, where applicable, support the development of innovative natural gas technologies that have potential to help FEI meet market preferences while also supporting solutions for BC's emissions policy objectives.

1. INTRODUCTION

Long-term resource planning[6] is a tool for identifying long-range infrastructure requirements and resource acquisition strategies and for sharing this information with stakeholders; it is also a requirement of the UCA. This 2017 LTGRP[7] is FEI's[8] long-term resource plan as required by the UCA. The 2017 LTGRP presents a long term view of the demand- and supply-side resources[9] identified to meet expected future natural gas demand and reliability requirements at the lowest reasonable cost to FEI's customers over the 20-year planning horizon (2017-2036).[10]

The 2017 LTGRP analyzes the external regulatory, policy and planning environment within which FEI operates, compares annual and peak energy demand forecasts against current resource capabilities, and evaluates the potential for demand reduction with Demand Side Management (DSM) initiatives. This serves as a foundation for further evaluating gas supply and system infrastructure options for meeting forecast customer needs under different scenarios. This 2017 LTGRP includes an action plan that identifies the activities that FEI intends to take during the first four years of the 20-year planning horizon. This 2017 LTGRP will enable FEI to achieve its primary objective of providing cost effective, secure and reliable energy for its customers. The 2017 LTGRP is consistent with the applicable sections of the UCA and the British Columbia Utility Commission's Resource Planning Guidelines, and complies with directives from the Commission arising from the acceptance of FEI's 2014 Long Term Resource Plan (LTRP). These requirements are discussed further in Section 1.4.

FEI submits this 2017 LTGRP for acceptance under Section 44.1(2) of the UCA and is **not seeking approval of any particular elements of the plan**. Any requests for approval of specific resource needs that are identified within this plan will be further evaluated and brought forward through a separate application to the BCUC if warranted in the future. The LTGRP is not a substitute for the analysis done to support specific resource acquisitions or projects in the future but rather it helps to inform the acquisition process.

1.1 *RESOURCE PLANNING PROCESS*

The resource planning process begins by closely examining the planning environment in which the Company operates and by identifying expectations for future customer and demand growth.

6 The terms 'integrated resource planning,' 'long-term resource planning' and 'resource planning' are used interchangeably in this document.

7 FEI referred to the LTGRP as Long Term Resource Plan (LTRP) in previous filings but has updated this term to reflect the difference to FortisBC Inc.'s Long Term Electric Resource Plan (LTERP).

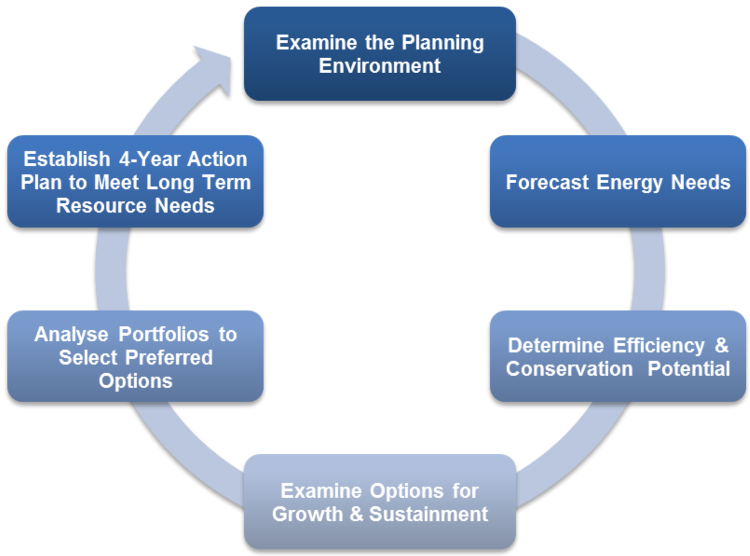
8 Where applicable, FEI's LTGRP analysis includes data for Fort Nelson. FEI does not expect any system capacity constraints in Fort Nelson during the 2017 LTGRP forecast horizon. FEI's gas supply portfolio planning and DSM activities do include Fort Nelson customers.

9 The British Columbia Utilities Commission Resource Planning Guidelines define resources as indivisible investments or actions by the utility to modify energy and/or capacity supply, or modify (decrease, shift, increase) energy and/or capacity demand. Within the context of FEI, such resources typically refer to FEI's own infrastructure (pipelines, natural gas compression equipment, natural gas storage equipment), natural gas supply arrangements, and DSM initiatives.

10 FEI submitted the 2014 LTRP as FortisBC Energy Utilities (FEU) which includes the now amalgamated FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc., and FortisBC Energy (Whistler) Inc.

The demand- and supply-side resource alternatives for meeting future demand are then assessed, and actions are recommended to ensure that the proper resources are in place to deliver the preferred energy solutions to meet future customer needs. The final stage of the process is developing a four-year action plan which identifies the near term activities needed to meet the long term resource requirements identified in the LTGRP. Figure 1-1 below outlines FEI's resource planning process:

Figure 1-1: FEI Long Term Resource Planning Process



The Company continues to engage customers and stakeholders as a critical part of the LTGRP process. Furthermore, FEI believes that, as part of the planning process, it is important to also understand the planning issues, competitive environment and resource requirements for other utilities in the PNW region, due to common regional infrastructure used to serve both electricity and natural gas demand. As such, FEI actively participates as a stakeholder in the resource planning efforts of other gas and electric utilities in the region, such as British Columbia Hydro and Power Authority (BC Hydro), FortisBC Inc. (FBC), Puget Sound Energy (PSE), Avista and Northwest Natural Gas Company (NW Natural). To facilitate understanding and response to regional resource issues, FEI also participates in planning, resource assessment activities and events conducted by regional organizations including the Northwest Gas Association (NWGA), the Northwest Power and Conservation Council (NWPCC) and the Pacific Northwest Economic Region (PNWER). The regional outlooks provided by these organizations also inform the analyses and recommendations in this LTGRP.

1.2 *FORTISBC ENERGY INC.*

FEI is a subsidiary of Fortis Inc., the largest investor-owned gas and electric distribution utility company in Canada. FBC, which provides electric service in the British Columbia (BC) interior, is a separate Fortis Inc. subsidiary and sister company to FEI. The long term planning considerations and business activities of FBC are not included in this LTGRP.

FEI provides natural gas services to approximately one million residential, commercial, and industrial customers in more than 135 communities throughout BC. This puts FEI among the largest gas utilities in Canada and in the PNW. Table 1-1 provides a summary of FEI customer, demand and pipeline characteristics. Figure 1-2 shows the Company's service area locations.

Table 1-1: FEI Service Statistics

	2015	2016
Number of Customers	982,000	994,000
Annual Demand (TJ)	186,000	197,000
Peak Day Demand (TJ/d)	1,074	1,334
Length of Transmission Pipeline (km)	2,958	2,959
Length of Distribution Pipeline* (km)	45,242	45,741

** Includes both low and intermediate pressure pipelines*

Figure 1-2: Map of FortisBC Service Areas by Fuel Source

1.3 LONG TERM RESOURCE PLANNING OBJECTIVES

FEI's resource planning objectives form the basis for identifying and evaluating potential resources in the LTGRP, including major infrastructure projects, gas supply alternatives and demand side programs. These objectives reflect the Utility's commitment to providing customers with the highest level of quality energy services. FEI's key resource planning objectives are to:

1.3.1 Ensure Cost Effective, Secure and Reliable Energy for Customers

A secure energy supply is essential for all FEI customers. Ensuring a sufficient supply of gas and the capacity to deliver gas to customers during anticipated peak demand periods is an ongoing objective for the Utility. Acquiring resources that improve the reliability and security of supply will also help to reduce rate volatility and protect customers from potential outages.

1.3.2 Provide Cost Effective DSM Initiatives

Customers and regulators expect the Utility to procure and deliver energy in a cost effective and efficient manner. The most desirable resource options will provide cost effective service solutions and help to manage rate volatility both in the near term and into the future. Cost effective DSM strategies can add value to customers through more effective use of the gas delivery infrastructure and more efficient use at the burner tip. In addition to cost effective energy efficiency and conservation programming, FEI also delivers innovative energy solutions through natural gas initiatives for the transportation sector and carbon neutral biomethane for residential and commercial customers.

1.3.3 Ensure Consistency with Provincial Energy Objectives

FEI provides natural gas distribution service to 994,000 customers[11] across 135 communities in BC. This wide reach enables FEI to play a role in assisting customers to understand and reduce their energy consumption and GHG emissions. FEI's DSM activities, NGT[12] and RNG initiatives are key avenues through which FEI contributes to advancing BC's energy and GHG emission goals; the Company continues to examine and, where applicable, support potential programs, technologies and initiatives that will contribute to BC's energy and GHG emissions goals.

1.4 REGULATORY CONTEXT

In addition to being good utility practice, FEI has a regulatory obligation to file long-term resource plans under Section 44.1 of the UCA. The UCA and any directives from the Commission related to FEI's previously filed resource plans establish the requirements for what must be included in the plans. Additionally, the Commission has issued Resource Planning

[11] FEI 2016 customer count.
[12] NGT includes CNG and LNG supply for heavy duty on-road trucks, locomotives, marine vessels, mine haul trucks and remote power generation for industrial applications.

Guidelines which provide general guidance as to the BCUC's expectations of FEI's process and methods for developing the LTGRP.

1.4.1 *Utilities Commission Act*

The UCA provides the BCUC with the jurisdiction to regulate public utilities in BC and requires utilities to submit a long-term resource plan. Section 44.1(2) of the UCA, "Long-Term Resource and Conservation Planning," outlines the specific elements that are to be included in resource plans. Table identifies where each specific requirement is addressed.

Table 1-2: UCA Requirements and Areas Addressed in the 2017 LTGRP

Requirement of UCA Section 44.1(2)	Addressed in the 2017 LTGRP
a. An estimate of the demand for energy the public utility would expect to serve if the public utility does not take new demand-side measures during the period addressed by the plan;	See Sections 3.4.8 and 3.4.9
b. A plan of how the public utility intends to reduce the demand referred to in paragraph (a) by taking cost-effective demand-side measures;	See Section 4.2.4
c. An estimate of the demand for energy that the public utility expects to serve after it has taken cost-effective demand-side measures;	See Section 4.2.3
d. A description of the facilities that the public utility intends to construct or extend in order to serve the estimated demand referred to in paragraph (c);	See Section 6
e. Information regarding the energy purchases from other persons that the public utility intends to make in order to serve the estimated demand referred to in paragraph (c);	See Section 5
f. An explanation of why the demand for energy to be served by the facilities referred to in paragraph (d) and the purchases referred to in paragraph (e) are not planned to be replaced by demand-side measures; and	See Sections 6.2.1.3 and 6.3
g. Any other information required by the Commission.	Recent BCUC Directives from the 2014 LTRP Decision have been incorporated throughout this 2017 LTGRP. Directives relating to GHG reduction targets, DSM planning/funding scenarios and impacts of new initiatives are addressed in Sections 3, 4, and 8. Details of FEI's approach to demand forecasting are provided in Section 3; and Discussion of FEI's guiding principles for Price Risk Management is provided in Section 5.

In determining whether to accept a long-term resource plan, Section 44.1(8) of the UCA requires the Commission to consider:

- The applicable of BC's energy objectives (addressed in Section 8);
- The extent to which the plan is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act* (*CEA*) (addressed Section 1.4.2 below);
- Whether the plan shows that the public utility intends to pursue adequate, cost effective demand-side measures (addressed Sections 4 and 6); and
- The interests of persons in BC who receive or may receive service from the public utility (addressed throughout the 2017 LTGRP but primarily in Section 8).

The 2017 LTGRP meets the requirements of the UCA.

1.4.2 CEA Objectives

As set out in Section 1.4.1 above, two of the considerations in section 44.1(8) of the UCA relate to the CEA. This section provides background and discussion of the CEA and its relationship to the LTGRP.

In 2010 the Government of BC enacted the CEA. The CEA contains a set of sixteen specific energy objectives for the Province of BC. It provides a guide to help the Province meet its self-sufficiency goals and to reduce GHG emissions.

Table 1-3 below lists the CEA objectives that are directly applicable to the LTGRP and describes which section of the 2017 LTGRP supports them. It is important to note that these are provincial objectives and some of the objectives are specific to BC Hydro, as referenced in the CEA by the term 'the authority':

Table 1-3: Applicable CEA Objectives Directly Relevant to the LTGRP

CEA Section	CEA Objective	Supported in the 2017 LTGRP
2(b)	To take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%.	The 66 percent target applies to BC Hydro. Section 4 addresses FEI's DSM analysis.
2(d)	To use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources.	Sections 2, 3 and 8 address FEI's actions to support innovative and clean or renewable energy technologies. Section 4 addresses FEI's DSM analysis.

CEA Section	CEA Objective	Supported in the 2017 LTGRP
2(g)	To reduce BC GHG emissions: (i) By 2012 and for each subsequent year to at least 6% less than the level of those emissions in 2007, (ii) By 2016 and each subsequent calendar year to at least 18% less than the level of those emissions in 2007, (iii) By 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007, (iv) By 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and (v) By such other amounts as determined under the *Greenhouse Gas Reduction Targets Act*.	Section 8 addresses GHG emissions and emissions reductions from FEI's forecast energy demand and initiatives.
2(h)	To encourage the switching from one kind of energy source to another that decreases greenhouse gases in British Columbia.	Sections 2, 3, 4 and 8 address FEI's fuel switching initiatives within the umbrella definition of DSM.
2(i)	To encourage communities to reduce greenhouse gas emissions and use energy efficiently.	Section 4 addresses FEI's DSM analysis. Section 8 addresses GHG emissions and emissions reductions from FEI's forecast energy demand and initiatives.
2(j)	To reduce waste by encouraging the use of waste heat, biogas and biomass	Sections 2, 3, 5 and 8 discuss FEI's RNG initiative.
2(k)	To encourage economic development and the creation and retention of jobs	Section 8 summarizes FEI's 2017 LTGRP analysis results in light of BC's energy objectives.

1.4.3 Commission Resource Planning Guidelines and Directives

1.4.3.1 Resource Planning Guidelines

In 2003, the BCUC issued Resource Planning Guidelines which outline a process to assist in the development of resource plans to be filed with the Commission.[13] According to the guidelines, "resource planning is intended to facilitate the selection of cost-effective resources that yield the best overall outcome of expected impacts and risks for ratepayers over the long run." The guidelines do not distinguish between utilities that provide generation, transmission or

[13] http://www.bcuc.com/Documents/Guidelines/RPGuidelines_12-2003.pdf.

distribution services; therefore, some items (such as supply-side portfolio analysis[14]) apply more readily to integrated electric utilities. The BCUC reviews resource plans in the context of the unique circumstances of the utility in question. FEI adheres to the BCUC's planning guidelines where relevant and applicable to the Company's operating context. Table 1-4 below outlines the key elements of the Resource Planning Guidelines and the sections of the 2017 LTGRP in which they are addressed:

Table 1-4: Commission Resource Planning Guidelines

Resource Planning Guideline	Addressed in the 2017 LTGRP
1. Identification of the planning context and the objectives of a resource plan	See Sections 1.3, 1.4 and 2
2. Development of a range of gross (pre-DSM) demand forecasts	See Section 3
3. Identification of supply and demand resources	See Sections 2, 3, 4 and 5
4. Measurement of supply and demand resources	See Sections 3, 4, and 5
5. Development of multiple resource portfolios	As FEI is not a vertically integrated electric utility, it does not develop and compare multiple integrated resource portfolios. Rather, FEI plans to its forecast Reference Case but also prepares contingency plans. See Section 4 for the 2017 LTGRP's DSM analysis, Section 5 for the gas supply analysis, and Section 6 for FEI's system requirements and options.
6. Evaluation and selection of resource portfolios	As FEI is not a vertically integrated electric utility, it does not develop and compare multiple integrated resource portfolios. Rather, FEI plans to its forecast Reference Case but also prepares contingency plans. See Section 4 for the 2017 LTGRP's DSM analysis, Section 5 for the gas supply analysis, and Section 6 for FEI's system requirements and options.
7. Development of a four-year action plan, including contingency plans	See Section 9
8. Solicit stakeholder input during the planning process	See Section 7
9. Seek regulatory input from Commission staff	FEI met with Commission staff to discuss the resource planning process as well as some scope issues. Commission staff also attended FEI's external advisory group workshops (see Section 7) throughout the process.
10. Consideration of government policy	See Section 2.3
11. Regulatory review once a resource plan is filed	See Section 1.6

14 Supply-side portfolio analyses are conducted outside of FEI's LTGRP planning process and are submitted for approval to the BCUC through the Annual Contracting Plan (ACP) and Price Risk Management Plan (PRMP).

Where applicable, the 2017 LTGRP is consistent with the Resource Planning Guidelines.

1.4.3.2 Commission Directives

In the BCUC's acceptance of the 2014 LTRP (Order G-189-14), the Commission provided a number of directives and suggestions for FEI to integrate in future resource plans. These directives and related FEI actions are outlined in Table 1-5 below:

Table 1-5: List of Commission Directives and FEI Action Pursuant to Order G-189-14

Directive #	Commission Directive	FEI Action
5.	Therefore, the Commission Panel directs the FEU, to: • In its next LTRP filing, provide a detailed analysis of the relative benefits/shortcomings of their particular End-Use Method as compared to other end-use methods, and • Continue use of the Traditional Method as a parallel approach until such time as the Commission approves a new end-use method as a substitute.	Addressed in Section 3.4, report by an independent consultant in Appendix B-2, and further discussion in Appendix B-3. FEI continues using both the Traditional method as well as the end-use method for forecasting annual energy demand. Section 3.4.3 shows a comparison between both methods.

8.	The Panel therefore directs the FEU to include, in its next LTRP, the following information:
	• The development of DSM funding scenarios, reflecting the results of the most recent CPR. At a minimum, this should include a 'reference' DSM funding scenario with 'high DSM' and 'low DSM' scenarios that are relative to the reference scenario;
	• Analysis of each DSM scenario, at a portfolio level and for each DSM category (residential, low-income, commercial etc.), including:
	  ○ Total Resource Cost/Modified Total Resource Cost test results;
	  ○ Utility Cost Test result, expressed as a ratio and $/GJ
	  ○ Delivery rate impact;
	  ○ Estimated total bill impact
		Section 4.2 addresses FEI's forecast of C&EM activity, funding scenarios, and cost effectiveness test results.
		
		Sections 8.3 and 8.6 address the GHG emissions and projected delivery rate impact of the 2017 LTGRP analysis.
		
		FEI notes that the 2017 LTGRP provides a long term forecast of C&EM activity and that its next C&EM expenditure schedule (which FEI plans to submit after submission of the 2017 LTGRP), will determine and request approval for its specific program activity across the short and/or medium term.

Directive #	Commission Directive	FEI Action
	(including delivery and commodity), $ and %, with residential split between high and low use gas customers; and ○ Estimated gas (GJ) and GHG emission reductions.	
9.	Accordingly, in the next LTRP the FEU are directed to provide a more fulsome analysis of opportunities for DSM to be cost-effectively used to replace or defer infrastructure investments.	Section 6.2 addresses the potential impact of DSM as part of the 2017 LTGRP's discussion of system requirements and options.
11.	To ensure regulatory efficiency in the review of CPCN applications, the Panel directs that the FEU include in their next LTRP, a contingency plan(s) that outlines the impact(s) to FEU's System Resource Needs and Alternatives based on potential changes in supply, demand, market conditions and significant new developments in the industry that were not identified in the LTRP as being associated with the Reference Case or most-likely forecast.	Addressed in Section 6 by modulating FEI's Traditional peak demand forecast method and also reviewing results from a new exploratory peak demand forecast method.
12.	The Panel therefore directs FEU to include in the next LTRP a description of its long term vision for price risk management and provide broad principles which can be used to inform the PRMP.	Addressed in Section 5.5.
13.	the Commission Panel finds that (i) the FEU's objective of maintaining the competitiveness of natural gas with other energy sources is inappropriate and should not be included in a future PRMP, and (ii) while the Panel has no desire to close the door on the consideration of all future hedging options, the PRMP must show that this is the most cost effective approach or solution to moderating the volatility of natural gas prices or reducing risks related to price disconnects.	This directive relates to FEI's PRMPs specifically and is thus addressed in FEI's PRMPs when FEI submits these to the Commission for review and approval.

Directive #	Commission Directive	FEI Action
15.	The Panel determines that the FEU provided sufficient information in the LTRP to meet the 2010 LTRP requirements to provide: (i) an analysis of the GHG targets as set out in British Columbia's energy objectives and an estimate of the portion of the required reduction that the Company believes it can reasonably attain over time; and (ii) an outline of the impact of the implementation of new initiatives on the demand forecast and GHG emission reductions. The Panel directs the FEU to also provide this GHG related information in the next LTRP.	Section 8.3 continues to provide this information in the 2017 LTGRP. Based on current trends in the discourse on energy use and emissions policy (see Section 2.3) and with stakeholder support, Appendix E expands this analysis with an examination of possible wider GHG emissions abatement pathways.
17.	If, in the next LTRP, the FEU provides a demand forecast that includes the possibility of there being insufficient supply for both NGT BC customers and non-BC LNG export customers, then the Panel directs the FEU to address how it will insure compliance with section 44.1(8)(d) of the UCA.	Addressed in Section 5. Gas supply is abundant. Risk would arise related to ensuring sufficient storage and transportation infrastructure is available. For large LNG export projects, this relates to regional non-FEI infrastructure and may impact FEI indirectly only via price signals.
18.	The Commission Panel directs the FEU to file their next LTRP on or before June 30, 2017.	The Commission granted FEI an extension to this filing date to November 30, 2017 in Order G-99-17.

Please refer to Appendix D for excerpts of online sources referenced in footnotes throughout the 2017 LTGRP.

1.5 *STATUS OF THE 2014 LTRP ACTION PLAN*

In each successive resource plan, FEI presents a list of actions to implement the recommendations outlined throughout the plan. Table 1-6 below provides an update of the items identified in the Four-Year Action Plan of the 2014 LTRP.

Table 1-6: 2014 LTRP Action Items

Action Item	Status
1. Continue to monitor and analyze the energy planning environment.	FEI has continued monitoring and analysing the planning environment. To support its analysis of the policy planning environment, FEI, since the 2014 LTRP, has dedicated resources specifically to public policy analysis. Section 2 presents a snapshot of FEI's current analysis of the planning environment.

Action Item	Status
2. Continue to implement the Companies' NGT initiatives.	FEI has consolidated its NGT initiatives under a Director, NGT and Regional LNG. To date, FEI has invested $90.2 million in its NGT initiatives. From 2014 until 2016, FEI's annual NGT energy demand has increased by 53 percent.
3. Discontinue using the traditional annual demand forecasting method for residential, commercial and industrial customers.	In its decision on the 2014 LTRP, the Commission directed FEI to continue use of the Traditional method as a parallel approach until such time as the Commission approves a new end-use method as a substitute. FEI continues using both methods for forecasting annual energy demand; Section 3.4.3 shows a comparison between them.
4. Pursue approval of EEC[15] funding for the 2014-2018 period through the FEI 2014-2018 PBR application.	The Commission approved FEI's 2014-2018 expenditure schedule via its decision on FEI's 2014-2019 Performance Based Ratemaking Plan, as the application contained FEI's 2014-2018 DSM Plan.[16] [17,18] FEI is implementing this portfolio and delivers annual performance reports to the Commission.
5. Plan for and prepare CPCN applications for near-term system requirements identified in the FEU Five-Year Capital Plans.	Order C-11-15 approved the Lower Mainland Intermediate Pressure (IP) System Upgrade (LMIPSU) projects, which included two of the projects identified in the Action Plan: • Coquitlam Gate IP pipeline replacement; and • Fraser Gate IP pipeline replacement. Both projects are in progress. The remaining three projects which are components of the Coastal Transmission System (CTS), were authorized by Orders in Council[19] and are expected to be completed during 2017: • Nichol to Port Mann TP pipeline loop; • Cape Horn to Coquitlam TP pipeline loop; and • Nichol to Roebuck TP pipeline loop.
6. Expand the Tilbury LNG facility.	In accordance with the BC Government Special Direction No. 5, FEI implemented its first-stage expansion of the Tilbury LNG facility. This stage will be completed in 2017.
7. Continue monitoring and evaluating system expansion needs in the Okanagan area.	FEI continues to monitor and evaluate the Interior Transmission system and expects a system capacity constraint to occur in 2023, with contingency planning for 2021 and 2027. Section 6.3.3 discusses this analysis.

15 In 2014, FEI used the term Energy Efficiency and Conservation (EEC) to specifically refer to FEI programs whose expenditures fall under the BC Demand-Side Measures Regulation (DSM Regulation). FEI has updated this name to C&EM. Please see Section 4.1 for further details.

16 The 2017 LTGRP refers to FEI's future applications to the BCUC for approval of C&EM expenditures simply as the C&EM expenditure schedule.

17 FEI Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018 ~ Project No.3698715. http://www.bcuc.com/ApplicationView.aspx?ApplicationId=400.

18 http://www.ordersdecisions.bcuc.com/bcuc/orders/en/item/119195/index.do.

19 OIC 557 (BC Reg. 245/2013, Direction No. 5 to the Commission);
OIC 749 (BC Reg. 265/2014, amendment to Direction No. 5 to the Commission);
OIC 162 (BC Reg. 115/2017, amendment to Direction No. 5 to the Commission).

Action Item	Status
8. Protect and promote the interests of the Utility’s customers by securing a reliable, cost-effective long term gas supply.	• FEI has begun to secure the basis differential between the Station 2 and AECO/NIT price for term supply delivered at Station 2, for a period not exceeding three years, and within a confidential target pricing level. FEI’s strategy to layer in its monthly indexed gas over a period of time is important because the Station 2 to AECO/NIT monthly discount/premium can change significantly over the course of a few months, which is reflective of ongoing changes in the marketplace. • FEI actively participated as an intervener in a number of facilities applications proposed by NOVA Gas Transmission Ltd. (NGTL) for construction in Northeast BC (NEBC). After reviewing the North Montney Project and the Towerbirch Expansion Project, FEI raised concerns with the National Energy Board (NEB) about the lack of cost accountability by shippers requesting these facilities and the risk that supply could shift away from the Westcoast Energy Inc. (Westcoast) T-North system if these facilities were constructed. In the North Montney Project report, the NEB agreed with FEI, and other opposing interveners, that NGTL’s toll method does not properly price some new facilities. The NEB ordered NGTL to either develop and seek approval for a new toll method for the facilities or to toll these facilities on a stand-alone basis. Although the NEB did not agree with FEI’s objections to the Towerbirch Expansion project, it indicated that it was considering the potential for an inquiry into toll and competition matters in NEBC. If such an inquiry is held, FEI will be an active participant in that process. FEI continues to monitor developments in NEBC in order to identify issues with new proposed infrastructure and is working with regional stakeholders to develop suitable solutions. • The landscape of producers that are developing natural gas production in NEBC is continually changing. Many of the traditional gas producers that FEI had established relationships with have either sold their assets or reduced their development in NEBC. Over time, they were replaced by an influx of companies that acquired assets, specifically in the Montney Region. FEI has developed relationships with many of these companies and has successfully established multiple gas purchasing agreements with them. • FEI on a continuous basis evaluates the regional infrastructure that delivers natural gas to FEI’s system. This assessment of infrastructure in the regional marketplace has gained prominence over recent years as major industrial project proponents evaluate the south coast of BC and the US states of the PNW to set up plants to develop products such as LNG and methanol. Please see Sections 5.2 and 5.3 for FEI’s discussion of the potential regional impact of such projects.

The actionable items that FEI intends to pursue over the next four years are provided in Section 9 of this 2017 LTGRP.

1.6 *ORDER SOUGHT AND PROPOSED REGULATORY PROCESS*

FEI submits this 2017 LTGRP under Section 44.1(2) of the UCA. FEI is not seeking approval of any particular elements identified within the plan—any future requests for approval will be submitted under a different section of the *Act*. FEI submits that this 2017 LTGRP demonstrates that FEI has met the requirements of the UCA and the Commission's directives provided in the 2014 LTRP Decision and has followed the BCUC Resource Planning Guidelines. The Commission should accept this 2017 LTGRP under Section 44.1(6) of the UCA. A draft Order is attached as Appendix G-1.

The Company submits that a written hearing is appropriate for the review of the 2017 LTGRP and proposes the following regulatory timetable, which includes two rounds of Information Requests. An alternate timeline is also proposed in the event that interveners in the review of the 2017 LTGRP wish to file evidence. A draft Procedural Order is attached as Appendix G-2.

Table 1-7: Proposed Regulatory Timetable

ACTION	DATE	
	2018	
Commission Issues Procedural Order	Friday, January 5	
FEI Publishes Notice of Filing by	Friday, January 26	
Registration of Interveners and Interested Parties	Thursday, February 1	
Commission Information Request No. 1	Thursday, February 8	
Intervener Information Request No. 1	Thursday, February 15	
FEI Responses to Information Requests No. 1	Thursday, March 22	
Commission and Intervener Information Request No. 2	Thursday, April 5	
Notification by Interveners of Intent to file Evidence	Thursday, April 26	
FEI Responses to Information Requests No. 2	Thursday, May 3	
	No Intervener Evidence	If Intervener Evidence
Intervener Evidence	n/a	Thursday, May 24
Commission and Intervener Information Request No. 1 on Intervener Evidence	n/a	Thursday, June 7
Intervener Responses to Information Requests No. 1	n/a	Thursday, July 5
FEI Final Submission	Thursday, May 17	Thursday, July 19
Intervener Final Submissions	Thursday, May 31	Thursday, August 2
FEI Reply Submission	Thursday, June 14	Thursday, August 16

2. PLANNING ENVIRONMENT

2.1 INTRODUCTION

Like the 2014 LTRP, FEI is submitting this 2017 LTGRP during a time of continued change and uncertainty in market forces, energy technology and government policy. A wide range of factors influence FEI's long term analysis and planning decisions. This section discusses a number of the factors that the Company believes are among the most important. It provides relevant context for the analysis, results and recommendations that are made throughout the LTGRP to address the requirements for resource planning within the UCA. The remainder of this section is organized as follows:

- Section 2.2 discusses the competitive environment for natural gas which is influenced not only by regional energy markets and commodity pricing but also by supply infrastructure availability and end-use equipment installation and operations;
- Section 2.3 discusses the policy and regulatory context which provides the framework through which FEI's customers' energy needs are delivered and which can heavily influence the energy choices that consumers make.
- Section 2.4 discusses FEI's customer solutions.

The natural gas supply outlook looks different than it did even a few years ago. Horizontal drilling and hydraulic fracturing technologies have unlocked the potential of North America's vast shale gas deposits, which has led to a significant growth in supply and lower commodity prices than in recent years. As a result of the supply growth, governments across Canada, the PNW and North America more broadly, are looking to take advantage of the environmental, social and economic benefits of using natural gas. Natural gas is increasingly viewed as a fuel that can be used to help reduce GHG emissions by displacing more carbon-intensive coal-fired power generation, providing firm backup for renewable energy, and more recently, by displacing dirtier fuels such as diesel and gasoline in transport applications.

While governments across North America were keen to introduce climate and green energy policies in recent years, today's setting is more uncertain in light of a changed administration in the US. Uncertainty also exists about long term energy policy in BC after a 2017 provincial election and resulting change in government. This uncertainty is compounded, on the one hand, by discussions in various North American jurisdictions about energy affordability and potential negative economic impacts of stringent energy and emissions policies. On the other hand, this discussion also includes voices which support initiatives to mitigate emissions from natural gas upstream activities and which express concern about the long term climate impacts of methane emissions. Actions to address these latter issues pose the risk of upward pressure on natural gas prices.

New energy technologies and gains in energy efficiency have led the way to changing natural gas use, particularly as customers look for innovative solutions and improved information about energy and consumption patterns. Energy consumers are increasingly faced with numerous energy services and equipment choices, often with conflicting information with which to make decisions that have a long term impact on energy consumption. New energy technologies and energy production at or near the end use are also beginning to create challenges for the traditional utility model. These new, efficient technologies are changing energy use patterns, making it difficult to accurately predict how such factors may influence the demand for natural gas or its competitive position in the long term. To help maintain the competitiveness of natural gas rates for customers, FEI continues to focus on growing its customer base, adding efficient load to the natural gas system, and delivering energy solutions which address customers' GHG emissions concerns, such as through FEI's NGT and RNG initiatives.

2.2 *COMPETITIVE ENVIRONMENT FOR NATURAL GAS*

The competitive environment for natural gas is influenced by factors that affect the full value chain for energy services. Section 2.2.1 discusses issues that affect natural gas production and supply (upstream), infrastructure (midstream) and end uses (downstream). While technological advancements have contributed to a supply boom and low price environment, a number of other factors beyond commodity cost influence the competitive position of natural gas relative to other forms of energy.

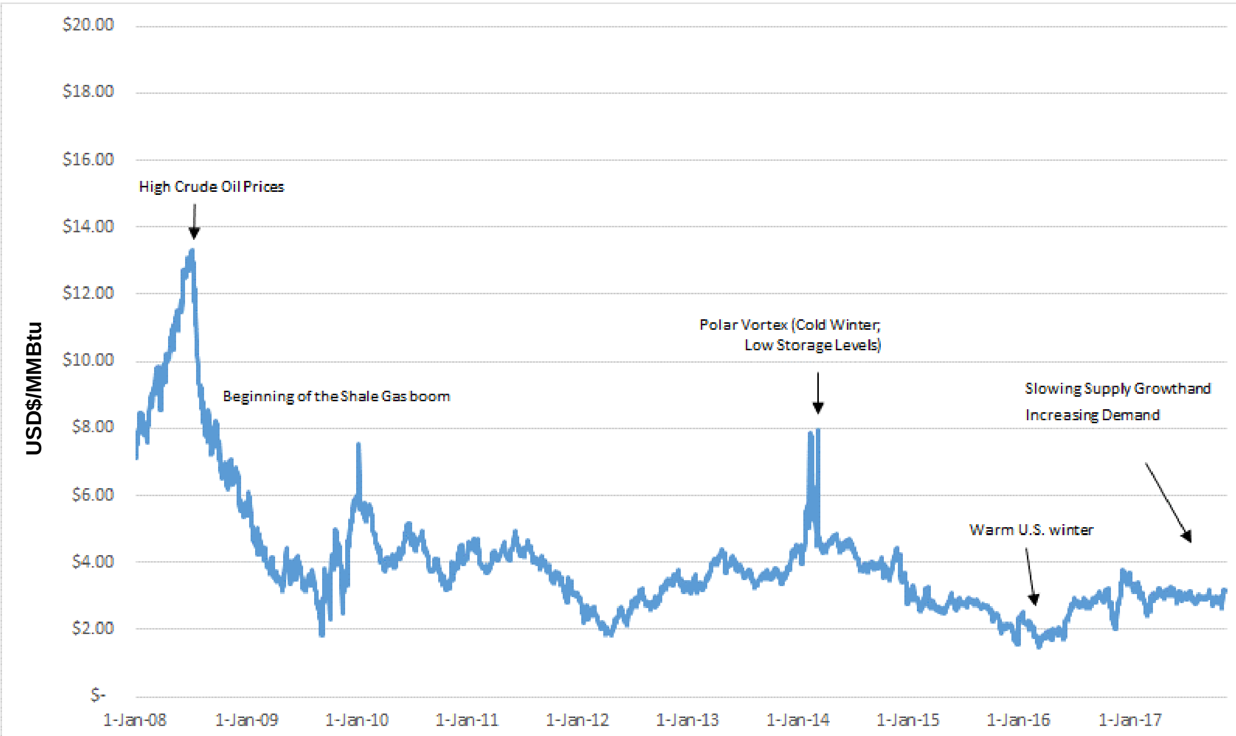
2.2.1 Market Dynamics and Commodity Pricing

The North American natural gas market remains in a low commodity pricing environment which is expected to continue for several years to come. These low commodity prices are attributed to significant changes that have occurred in the North American natural gas market since the temporary high market natural gas prices experienced in 2008. The advancement in drilling technology, specifically the use of hydraulic fracturing in conjunction with horizontal drilling, sparked an 'unconventional natural gas revolution' in the production of natural gas that has unlocked an abundance of gas supply. The surge in associated gas from liquids and oil production has also contributed to this gas supply growth. The dramatic increase in North American production has outpaced consumption, causing natural gas commodity prices to decline. Advancement in drilling technology has redrawn the North American supply map by increasing production in the US Northeast (e.g. in the Marcellus play), effectively decreasing demand for Canadian supply. The low commodity prices have created significant opportunities for increased natural gas use, particularly in power generation, LNG export potential, and the use of natural gas by the transportation and industrial sectors. In 2017, prices are rising due to some increased demand from these and other drivers as well as slowing supply growth.

Henry Hub is the official pricing point for natural gas futures on the New York Mercantile Exchange (NYMEX) and is used as the benchmark for the North American natural gas market. The significant growth of shale gas supply in recent years has resulted in a significant drop in natural gas prices. Prior to the shale gas revolution, NYMEX prices were typically trading above

USD$6.00 per MMBtu[20], however since then prices have dropped back down, currently trading around USD$3.00 per MMBtu as of June 1, 2017. This is illustrated in Figure 2-1.

Figure 2-1: Henry Hub Historical Natural Gas Spot Prices[21]



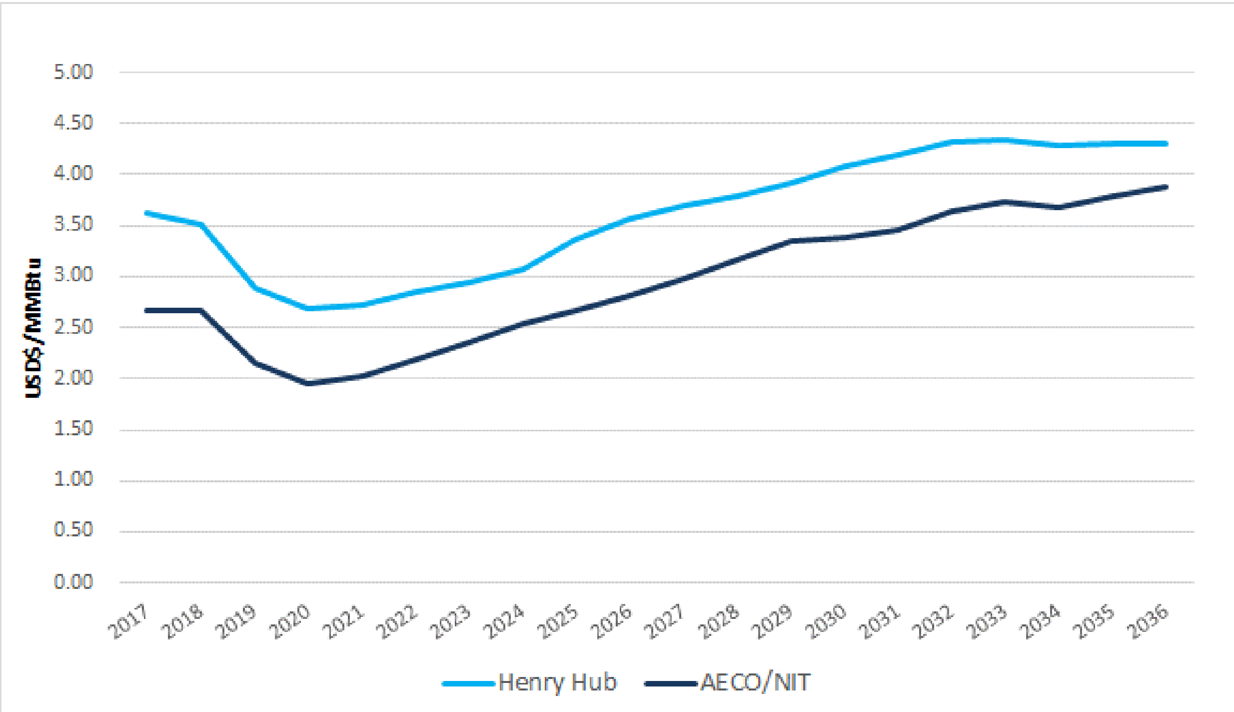
As Figure 2-1 shows, since the 2013/14 polar vortex, natural gas prices dropped to historically low levels, due to a significant imbalance in the supply/demand fundamentals. Gas production in North America increased significantly at a time when demand was relatively flat, resulting in an oversupply of gas. Natural gas prices dropped to as low as USD$1.48 per MMBtu on March 5, 2016, the lowest daily settlement price for NYMEX since 1998.[22] This oversupply of gas continued throughout the summer and fall of 2016, testing the limits of gas storage inventories in North America. The US Energy Information Administration (EIA) reported on November 17, 2016, that total US gas in storage reached a record high of 4,047 billion cubic feet (Bcf) for the week ending November 11, 2016.[23] However since that report, prices have recovered somewhat, as a slowdown in supply growth and increasing industrial demand, US LNG exports, and exports to Mexico, have started to re-balance the market.

NYMEX natural gas prices are expected to remain low over the medium to long term, ranging between USD$3.00 to USD$4.00 per MMbtu until 2025.[24] Regional prices may likely be even lower as Alberta (AECO/NIT) and BC (Station 2) prices are forecasted to continue to trade at a

[20] MMBtu is defined as one million British Thermal Units.
[21] Platts. “Platts Gas Daily Market Fundamentals”. https://www.platts.com/products/gas-daily.
[22] Ibid.
[23] EIA (March 16, 2017). “Weekly Natural Gas Storage Report – EIA”.
[24] Wood Mackenzie (Jan 2017). “United States gas long-term outlook H2 2016”.

significant discount to the Henry Hub price. One of the major reasons that prices are lower in Western Canada relative to the NYMEX is due to increasing supply coming from the US Northeast, which continues to displace traditional gas markets served by Western Canadian supply. (Regional gas market developments are discussed in more detail in Section 5.2). Figure 2-2 shows Wood Mackenzie's long term price forecast for natural gas based on the NYMEX and AECO/NIT market in nominal dollars.

Figure 2-2: Natural Gas Price Forecast (2016 USD$)[25]



With an abundance of gas supply, North American natural gas became more economically attractive relative to other fuel sources as it was significantly disconnected from other competing fuels, such as heating and fuel oil. This was particularly evident in 2012 when natural gas prices traded around USD$2.80 per MMBtu, while crude oil prices were trading over USD$100 per Barrel, which is equivalent to around USD$17.00 per MMBtu. However, a few years later this disconnect from other competing fuels decreased, as oil prices collapsed, dropping below USD$30 per Barrel (approximately USD$5.00 per MMBtu) in early 2016.[26] This narrowing spread between natural gas and competing fuels has had a major impact on both North American natural gas supply and demand.

Figure 2-3 sets out prices (historical prompt month and futures, on a USD$/MMBtu equivalent basis)[27] for various fuels that compete with natural gas, as of June 1, 2017. As Figure 2-3

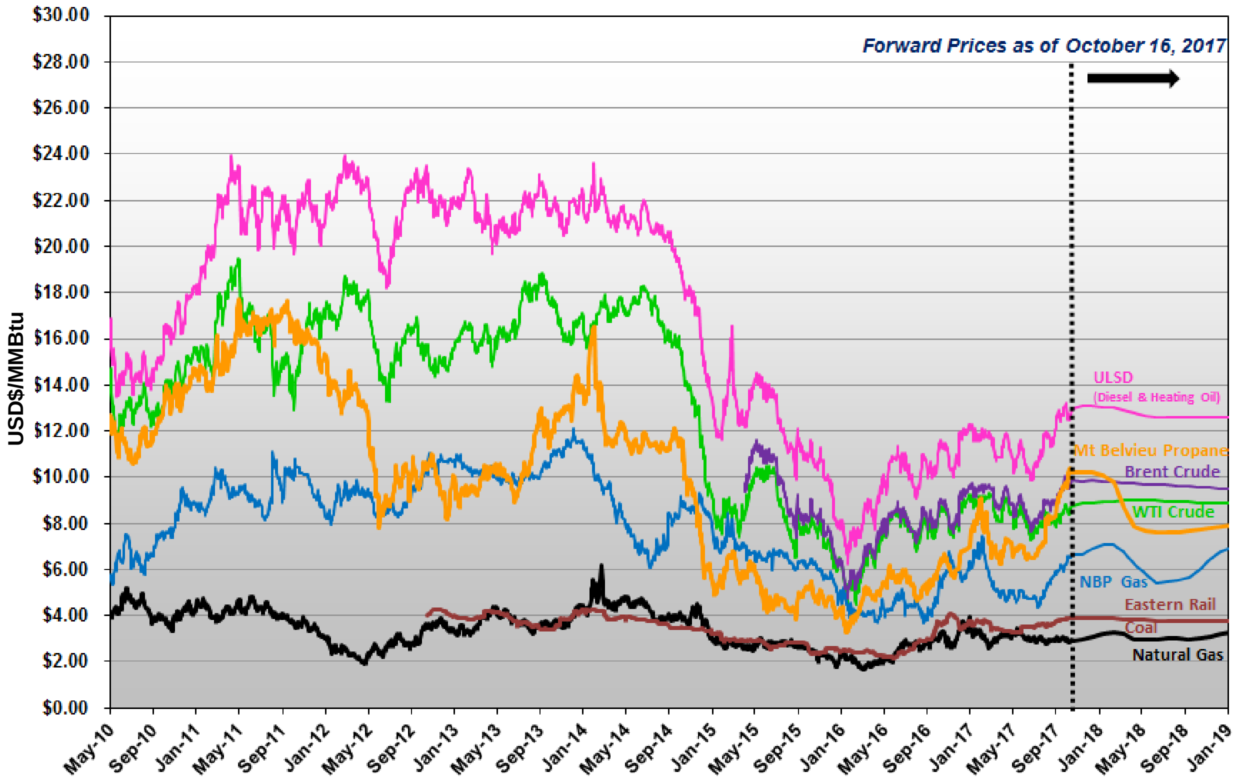
25 Wood Mackenzie (November 30, 2016). "United States gas long-term outlook 2016".

26 CME. http://www.cmegroup.com/trading/energy/.

27 Commodities futures are agreements to buy or sell a raw material at a specific date in the future at a particular price. Prompt-month prices refer to prices of the futures contract that is closest to expiration and is usually for

shows, prices have recovered somewhat since the winter of 2016. The increase in crude oil prices since early 2016 has been due to attempts by OPEC to re-balance the global supply and demand fundamentals by limiting production but recent US inventory levels continue to rise and mitigate the impact of OPEC production cuts. Due to the surge in North American oil production, it is not expected that oil prices will rise back to 2012 levels in the next five years.

Figure 2-3: Competing Fuel Prices[28]



2.2.1.1 Natural Gas Supply

The North American natural gas market continues to be influenced by the abundance of shale gas supply due to the rapid development of unconventional natural gas reserves. The rapid increase in domestic supply is a result of efficient drilling technologies and associated gas from oil and natural gas liquid plays. Significant improvements have been made to two essential technologies, horizontal drilling and hydraulic fracturing[29], that are used to unlock natural gas trapped in shale formations. These technological achievements have resulted in major production cost reductions, allowing producers to continue to drill despite the lower natural gas price environment. Market analysts believe a rig operating in 2016 delivers over two times as much gas as a rig operating in 2013. The use of horizontal drilling and hydraulic fracturing will

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delivery in the next calendar month; historical prompt-month data thus records the actual historical prices of these prompt-month contracts.

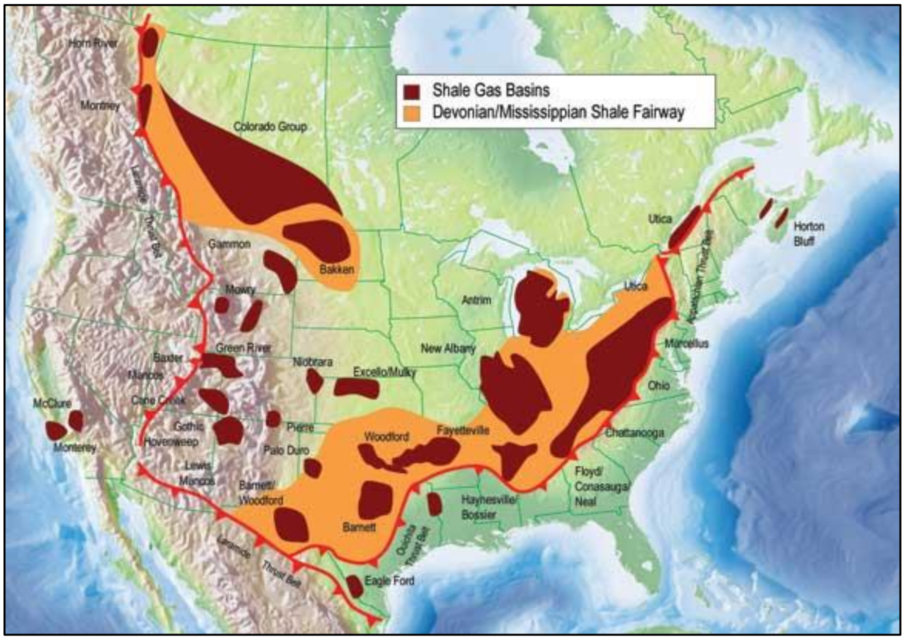
[28] US EIA & CME Group. (March 31, 2017).

[29] Appendix D-1: https://www.eia.gov/todayinenergy/detail.php?id=2170.

be increasingly critical in the future for accessing the natural gas potential of North America's shale basins. The potential resource in these basins will be needed in order to continue maintaining production growth in the future.

The shale gas potential in North America is significant. Not only is gas supply abundant, shale gas supplies are located throughout North America, providing cost effective supply within close proximity to many major load centres. Figure 2-4 shows the key North American shale gas regions.

Figure 2-4: North American Shale Gas Plays[30]



There is tremendous shale gas potential in Canada and it ranks globally in the top five countries with recoverable shale gas reserves. The majority of it is located in the Western Canadian Sedimentary Basin (WCSB), which extends from NEBC to southwest Manitoba. This area includes Horn River, Montney, Liard, Cordova, and Duvernay gas plays. In a joint study conducted by Canada's National Energy Board (NEB), Yukon Geological Survey, the Northwest Territories Geological Survey, and the British Columbia Ministry of Natural Gas Development it was reported that the estimated total potential of marketable gas in the WCSB (discovered and undiscovered) is now 1,051 trillion cubic feet (Tcf).[31] This estimation is 230 Tcf higher than the NEB's previous estimate in 2013 of 821 Tcf.[32] This number could continue to climb, as additional unconventional potential may be found in other formations over time.

In the US, the supply increase will be driven by the Mid-Atlantic's Marcellus shale formation. Output from the Marcellus continues to grow and will likely continue to increase as new and

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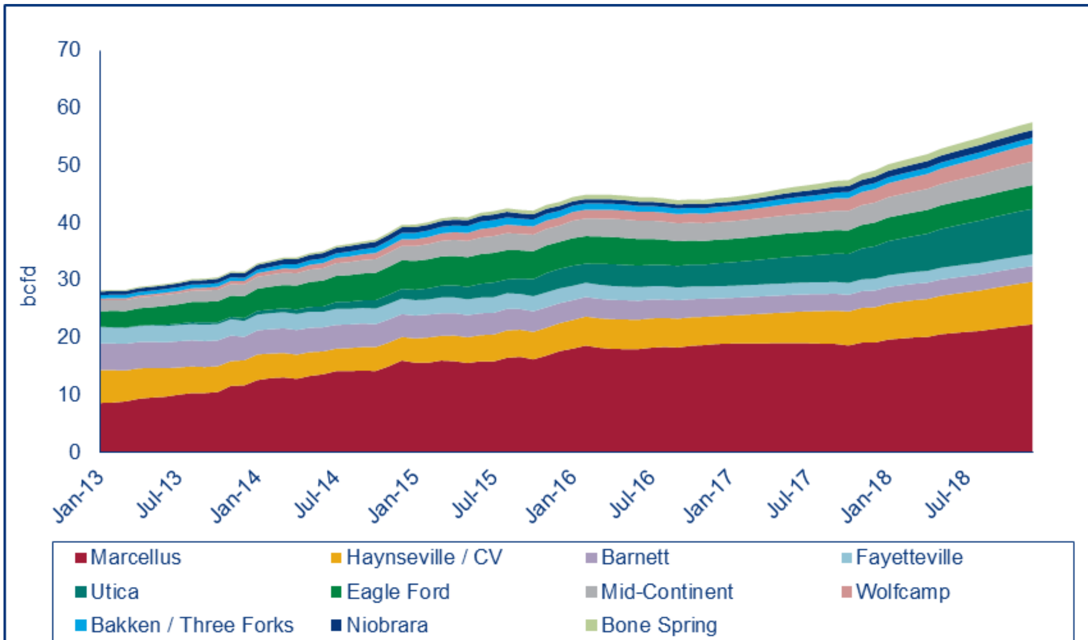
[30] NEB (November 2009). "Understanding Canadian Shale Gas - Energy Brief".

[31] Appendix D-2: https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/ltmtptntlbcnwtkn2016/index-eng.html.

[32] Appendix D-3: https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/ltmtptntlmntnyfrmtn2013/ltmtptntlmntnyfrmtn2013-eng.pdf.

planned pipeline transport capacity and processing plants allow for more Marcellus gas to come online. Figure 2-5 shows how quickly the Marcellus production capacity has expanded since 2013.

Figure 2-5: US Natural Gas Production[33]

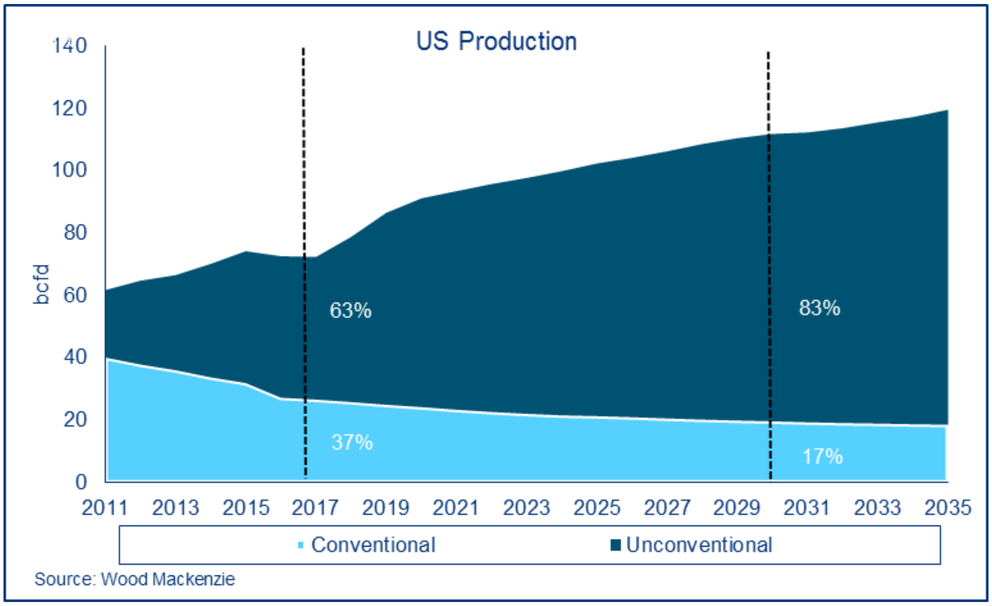


Source: Wood Mackenzie

Supplies from unconventional resources, specifically shale gas, have quickly become the most significant contributor to growth in production. As illustrated in Figure 2-6 below, unconventional gas, which accounted for 35 percent of US natural gas production in 2011, now accounts for 63 percent and is forecasted to account for 83 percent of US natural gas production by 2030. Contributions from conventional gas plays are expected to decline from 37 percent in 2016, to less than 17 percent by 2030.

[33] Wood Mackenzie (Jan 2017). “North American Gas Short Term Energy Outlook”.

Figure 2-6: US Production by Type[34]



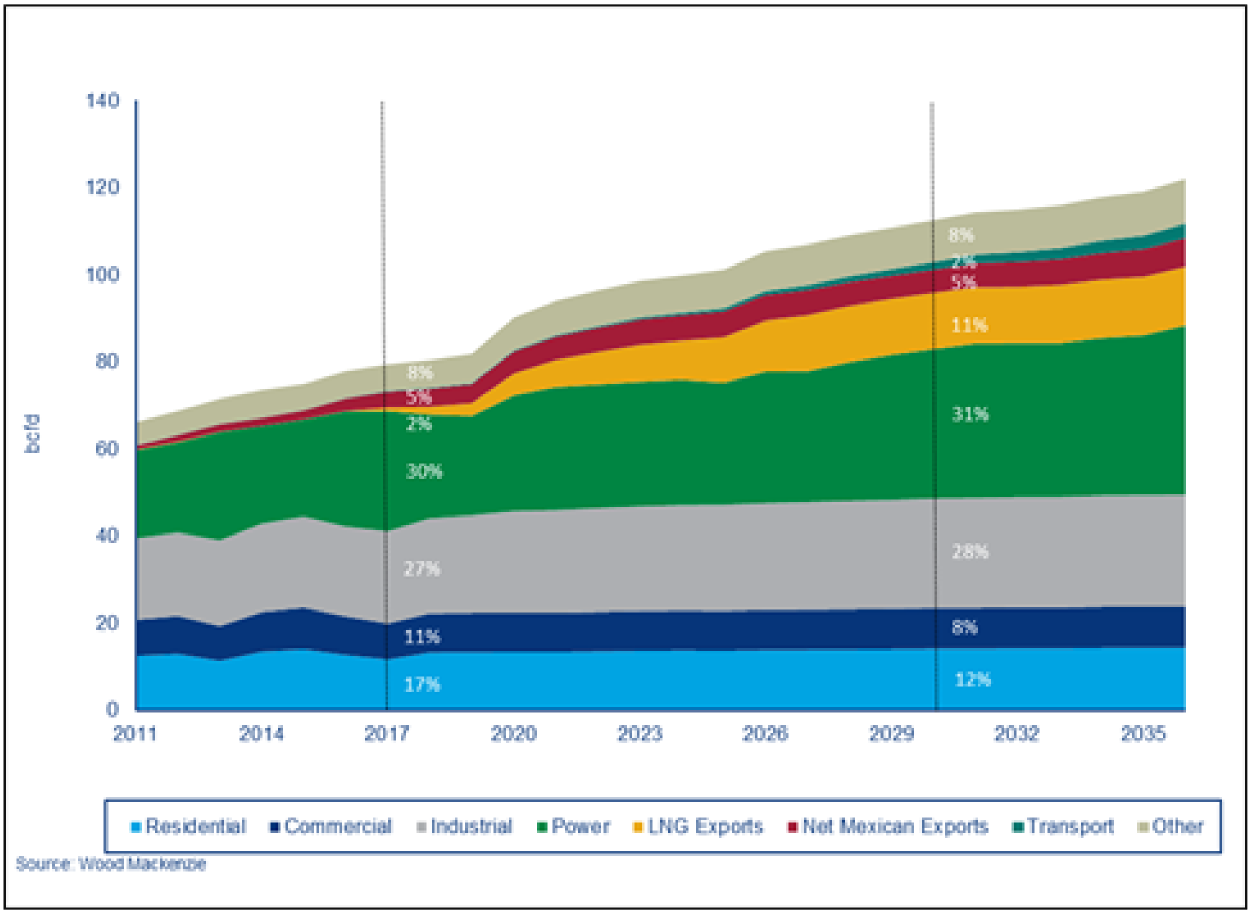
2.2.1.2 Natural Gas Demand

The low price of natural gas in recent years has been a key driver for its increased usage across North America. Over the past several years, industrial demand, specifically from the petrochemical sectors and US gas exports to Mexico, has been increasing the demand for natural gas. The market is also seeing increased natural gas demand from the power sector due to more switching from coal to natural gas electricity production, as well as from the retirement of coal plants. Furthermore, new incremental demand from US LNG being exported overseas will continue to increase in the coming years.

Figure 2-7 provides a demand forecast for US residential, commercial, industrial, power, NGT, other demand components (including lease, plant, and pipeline fuel), and LNG export demand out to 2035. Demand in the longer term is expected to grow steadily, with gas demand for power generation expected to be the largest contributor by 2030. In addition, the development of the LNG export sector is expected to eventually account for about 11 percent of total US gas demand by 2030. The overall increase in US gas demand is being met with supply from the US Northeast and is resulting in less demand for Canadian regional market exports to the US. This pushback of supply in Canada has resulted in lower natural gas prices for BC and Alberta, relative to most market prices in the US, which is discussed further in Section 5.1 (Regional Market Developments).

[34] Wood Mackenzie (Nov 2016). “North America gas long-term outlook data 2016”.

Figure 2-7: US Natural Gas Demand[35]



2.2.2 Competitive Environment in BC for Energy End Uses

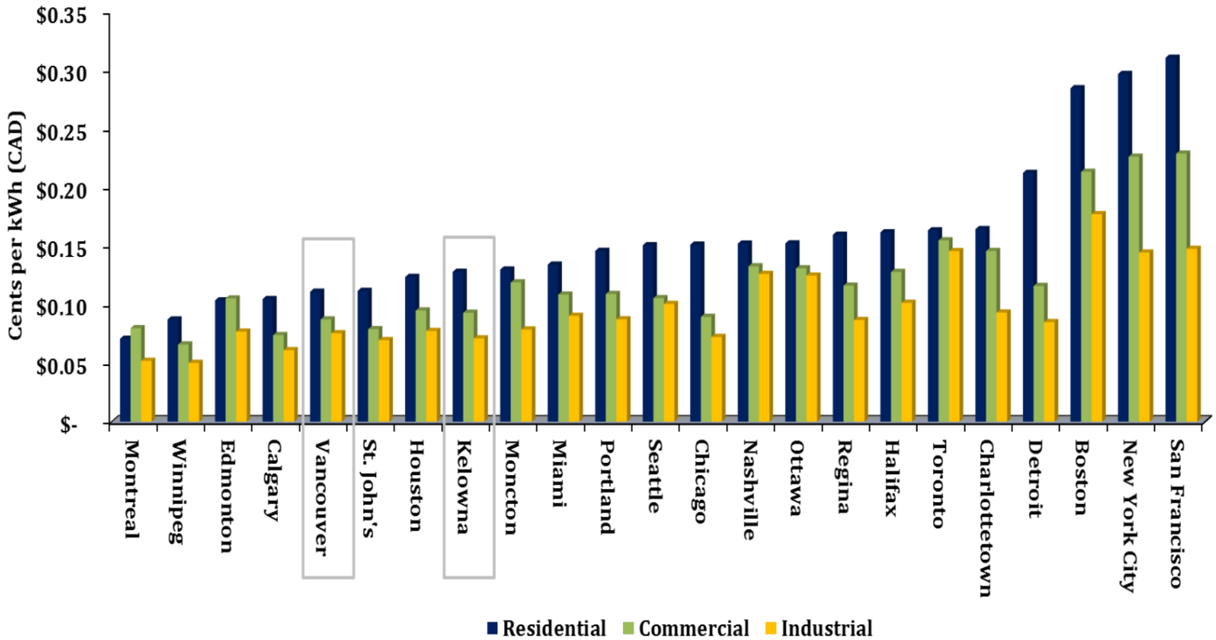
The relatively new abundance of natural gas supply in North America and recent low price levels have positively impacted the commodity's competitiveness with other sources of energy. The low price environment has improved the price competitiveness of using natural gas on an operating cost basis, though natural gas direct use applications (such as space and water heating) typically require higher capital, installation and maintenance costs than electric appliances. Since the competitiveness of low carbon thermal energy systems is determined on a case-specific basis as explained in Section 2.2.2.3, FEI needs to better understand how these new end-use technologies are impacting natural gas demand and use patterns (Section 3 provides information on how FEI is incorporating changing end-use trends into long term demand forecasts). A multitude of factors beyond those relating to commodity cost influence consumer, builder and developer preferences relating to the use of natural gas versus other sources of energy. Capital costs, installation requirements, operating and maintenance costs, government policies (outlined in Section 2.3) and public perception all play a role in this regard.

35 Wood Mackenzie (November 2016). "North America Natural Gas Long-Term View".

2.2.2.1 Natural Gas and Electricity Rates

Electricity rates in BC are among the lowest in North America (illustrated in Figure 2-8) and since 2010, the province's CEA has defined a provincial objective to "ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America."

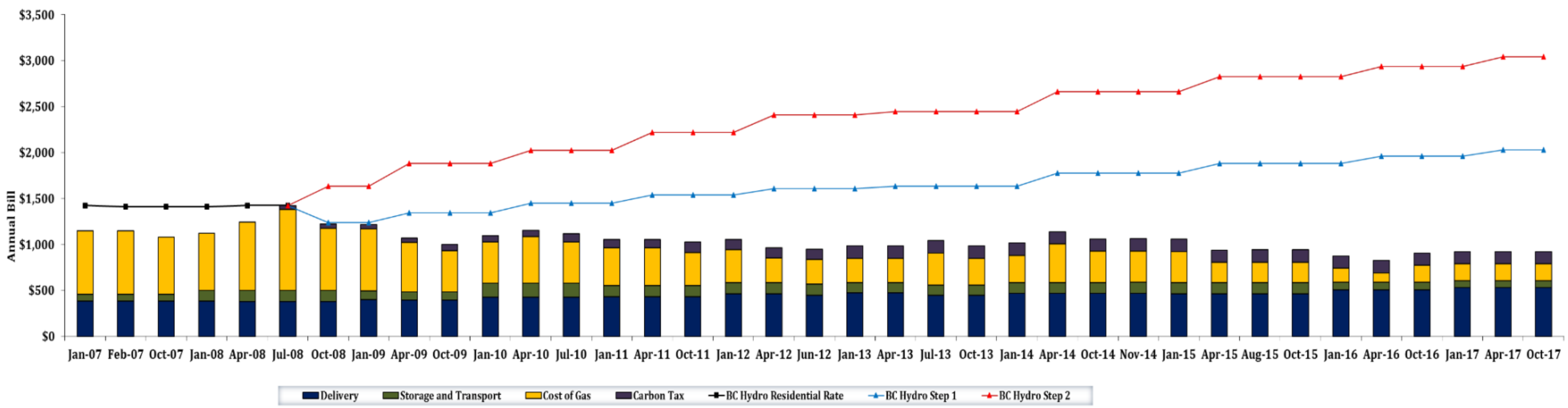
Figure 2-8: Electricity Rate Comparison Across Jurisdictions in North America[36]



In the past, low electricity rates have contributed to a competitive challenge for natural gas in BC, but the decline in gas commodity cost and increases to electricity rates in BC in recent years has helped to improve the competitiveness of natural gas. Figure 2-9 provides a historical comparison of the cost for space heating and domestic hot water for natural gas (based on consumption of 90 gigajoules (GJ) per year and 90 percent efficiency) versus electricity (assuming 100 percent efficiency) for an FEI residential customer in the Lower Mainland. This chart demonstrates that today's natural gas rates are cost competitive with electricity rates.

36 Hydro-Québec's Comparison of Electricity Prices in Major North American Cities, effective April 1, 2017; FEI added comparable Kelowna (FBC) rates.

Figure 2-9: FEI Lower Mainland Residential Natural Gas Cost for Space Heating and Domestic Hot Water[37]



37 This illustration assumes natural gas use of 90 GJ and the efficiency of gas equipment is 90 percent relative to 100 percent for electric equipment. FEI amount includes the basic charge; BC Hydro amount does not include basic charge since a household already pays the basic electric charge for non-heating use. The annual amounts include only space heating and water heating load. For the BC Hydro Step 1 annual amount, all natural gas-equivalent electricity consumption is assumed to be accounted for under Step 1; similarly, the BC Hydro Step 2 annual amount assumes all natural gas-equivalent electricity consumption to be accounted for under Step 2. Pleas note that households may actually experience a blended rate, depending on their total electricity consumption.

Figures 2-10 and 2-11 below illustrate the price difference per kilowatt hour energy unit between FEI natural gas, a 100 percent blend of FEI RNG, and BC Hydro's commercial general service and residential Step 1 and Step 2 electricity rates, respectively. RNG is more costly than conventional natural gas but it is also a clean and renewable fuel type that is less expensive than the electric alternative.

Figure 2-10: Lower Mainland Residential Energy Cost Comparison ($/kWh)

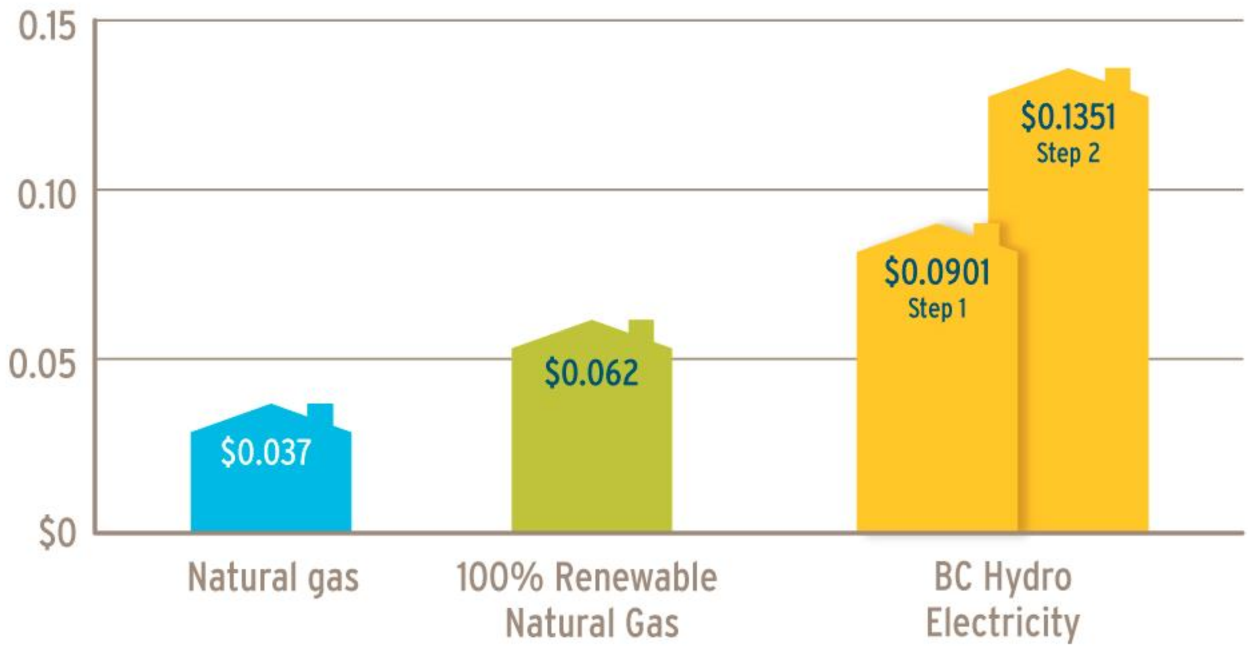
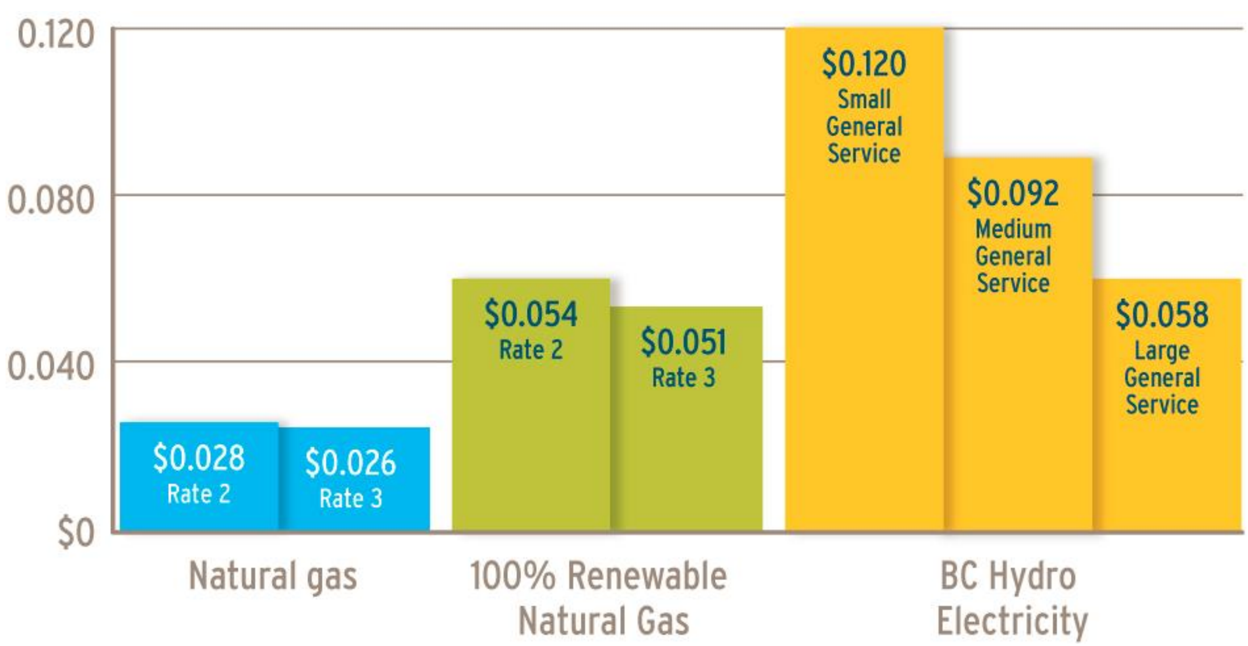


Figure 2-11: Lower Mainland Commercial Energy Cost Comparison ($/kWh)



While today's low natural gas rates contribute to a natural gas operating cost advantage relative to electricity, FEI believes that commodity price is only one factor that impacts the price competitiveness of natural gas in BC relative to electricity. Other factors include natural gas price volatility (discussed in the Regional Market Overview, Appendix A) and the installation costs of natural gas appliances relative to electric appliances.

2.2.2.2 Installation and Operation

Capital costs related to natural gas equipment (such as furnaces, ducting and hot water tanks) tend to be costlier than those relating to electric resistance heating equipment (such as electric baseboard heaters and hot water tanks). In retrofit situations, ducting requirements for high efficiency equipment are making the installation of natural gas equipment more difficult and costly. In both retrofit and new construction situations, venting requirements may also increase the difficulty and cost of installing high efficiency natural gas equipment. In addition, it is often not the end user that makes decisions regarding energy sources installed in the home: builders and developers are the primary decision makers regarding the choice of energy and equipment used in new construction. As builders and developers do not ultimately pay operating costs, they tend to be more influenced by capital costs alone. In addition, builders and developers typically aim to maximize the useable square footage available in a development to maximize the return on investment, particularly for multi-unit residential developments. Thus, capital cost savings and the ability to sell more useable living space incents developers and builders to install electricity equipment over natural gas equipment in new developments. The upfront capital cost difference for installing natural gas equipment has been identified by the American Gas Association as the "primary impediment to natural gas use in residential and commercial buildings if service can be made available."[38]

Table 2-1 provides an example of the upfront installation (capital) cost difference associated with natural gas versus electricity for a space heating furnace and hot water tank in new construction for FEI residential customers. The difference in upfront capital costs between gas and electricity means that over the life of the appliance, the operating cost advantage of natural gas over electricity must be significant ($13.84/GJ for space heating and $5.25/GJ for water heating) for the equipment to be economic to the consumer. As outlined in Figure 2-10 above, the current price differential between natural gas and BC Hydro Step 1 is $14.75 per GJ; this differential increases to $27.85 per GJ when compared to BC Hydro Step 2. When comparing a 100 percent nominal blend of RNG to BC Hydro Step 1, the differential declines to $7.81 per GJ but increases to $20.31 per GJ when compared to BC Hydro Step 2.

[38] American Gas Association (2012). "Squeezing Every BTU: Natural Gas Direct Use Opportunities and Challenges". p. 32.

Table 2-1: Capital Cost Difference for Space and Water Heating – Natural Gas vs. Electricity[39][40]

	Space Heating	Water Heating
Capital costs for natural gas	$9,000	$2,000
Capital costs for electricity	$4,435	$1,000
Upfront capital cost premium for natural gas compared to electricity	**$4,565**	**$1,000**
Annual difference in capital costs[41]	$422	$116
Annual difference in maintenance costs	$100	$0
Total annual difference in capital and maintenance costs	**$522**	**$116**
Energy consumption per year (GJ)	38	22
Difference in capital and maintenance costs over measurable life ($/GJ)	**$13.84/GJ**	**$5.25/GJ**

The higher upfront capital cost of natural gas end-use applications reduces the cost advantage of natural gas compared to electricity and plays an important role in influencing customer energy choice. FEI recognizes that factors other than pure economics can influence customer decisions. Nevertheless, FEI expects the capital cost difference between natural gas and electricity to continue into the foreseeable future, which highlights the need to develop solutions (such as working with key energy influencers and contributing to the commercialization of innovative natural gas use technologies, discussed in Section 2.4) to address this challenge.

2.2.2.3 Competition from Low Carbon Thermal Energy Systems

Numerous new end-use technologies have entered the energy services marketplace in recent years and will likely continue to do so throughout the 20-year planning horizon of this LTGRP. In addition to advancements on both natural gas- and electricity-based heating equipment, advancements in low carbon thermal energy solutions have emerged to take a small but growing slice of the market. Examples of low carbon thermal solutions include air and ground source heat pumps for single family residences; geo-exchange and biomass energy systems that can serve one or more multi-family developments; and district energy systems that can employ one or more renewable energy systems such as waste heat from industrial processes, geo-exchange technologies, or biomass solutions often in combination with natural gas-fired heating solutions. FEI needs to continue to monitor how these low carbon thermal solutions are impacting natural gas demand (outlined in Sections 3 and 8) and how they are

39 Assumptions based on the new construction of a 3,000 sq. ft. home in the Lower Mainland.

40 FEI explored expanding this comparison to include electric heat pumps. It is important to note that the performance of heat pumps greatly varies depending on the manufacturer, especially over a seasonal profile. This also explains why a simple comparison using the printed chart is not an appropriate comparison and shall not be used to draw conclusions as to how a natural gas based system performs against a heat pump system.

41 Represents the difference in capital costs per year, assuming a stream of equal annual payments with an interest rate of 6 percent and measurable life of 18 years for a space heating furnace and 13 years for a hot water tank.

changing the way FEI's customers are using natural gas. These growing changes indicate that the traditional utility model may potentially shift over the long term.

The competitiveness of any given low carbon thermal energy system with that of a natural gas only system is case-specific. In some cases, high quality renewable energy sources are readily available and in close proximity and match the needs of a residential or commercial development. In other cases, the low carbon thermal energy source may not be as well-matched or close to the energy plant, which increases the costs of installation and operation. Generally speaking, capital costs for low carbon thermal systems are higher than capital costs of non-renewable systems, while the commodity cost can range from zero for heat extracted from the ground, to much higher for biomass, depending on market conditions. These and other factors can result in a low carbon thermal solution being more cost effective than a natural gas system in some cases, and less so in other cases. Adding to the difficulty in understanding how these solutions will impact natural gas demand over time, the decision to choose a low carbon thermal energy solution is often not purely based on cost of the system. A homeowner or developer might choose to invest in such a system based on air emission reductions, perceived impact on resale value, municipal development requirements or other reasons. The willingness of the system owner to incur higher capital costs at the outset versus potentially lower operating costs over the long run can also impact the decision to install these systems.

How these factors will affect the rate at which low carbon thermal systems enter the BC end-use energy market place remains unknown. This LTGRP has therefore incorporated a range of market penetration assumptions into the forecast scenarios for annual demand (described in Section 3).

2.2.3 Summary

The proliferation of shale gas development in North America and recent low price levels continue to influence the competitiveness of natural gas with other sources of energy. Changing market dynamics are likely to impact regional gas flows and prices, particularly as new industrial, power generation and oil sands demand have the potential to affect the availability and cost to obtain gas supply for BC and PNW markets. Although market developments have improved the competitiveness of natural gas on an operating cost basis, the higher upfront capital costs of natural gas installations and appliances can negatively influence the competitive position of natural gas relative to other energy forms, such as oil, propane, electricity and possibly low carbon thermal energy. These factors combine with government policy (discussed below) to influence customer perception, energy choice and energy technology adoption.

2.3 ENERGY AND EMISSIONS POLICY

2.3.1 Canada

Overall, the Government of Canada supports using natural gas for export markets but support for continued growth in domestic use is limited to market segments where natural gas can displace higher emitting fossil fuels. This creates risks of a downward pressure on demand in buildings but also generates opportunities for natural gas demand to grow in exports and other sectors such as transportation, where natural gas can displace more carbon intensive fuels.

The government's policy frameworks, budget documents and public statements reflect this approach. On January 19, 2017, in a response to the interim report of the Standing Committee on Natural Resources, the government notes:

> Resource industries have, and must continue to make vital contributions to the prosperity of Canadians. Today, Canada is among the world's largest oil and gas producers and exporters and we expect to continue to play a significant role in meeting global demand for energy. Accessing strategic markets ensures Canadians receive full value for our resources; resources which can fund the next generation of renewable energy. The Government believes that resource development and environmental protections must go hand in hand, and that collaboration with stakeholders is essential to developing resources in a manner that maintains public trust.[42]

In March 2016 at a First Ministers' Meeting, the government started developing the Pan-Canadian Framework on Clean Growth and Climate Change (the Framework). This Framework intends to support a path for Canada to reduce its GHG emissions by 30 percent below 2005 levels by 2030 (in May 2017, the Government of Canada reaffirmed its commitment to this reduction path under the Paris Agreement).[43] The Government of Canada and Canadian provinces (apart from Saskatchewan) formally adopted the Framework in October 2016.[44] The framework itself represents a planning document rather than mandatory regulation or statute.

The government expects emissions reductions within the Framework to break down as follows:

- 41 percent will derive from federal regulations and provincial measures that were announced by November 1, 2016, as well as international cap-and-trade credits. These include federal regulations for hydrofluorocarbons, heavy duty vehicles, and methane emissions as well as provincial renewables targets and climate action plans;

[42] Appendix D-4: http://www.parl.gc.ca/Content/HOC/Committee/421/RNNR/GovResponse/RP8710641/421_RNNR_Rpt02_GR/421_RNNR_Rpt02_GR-e.pdf.

[43] http://www4.unfccc.int/ndcregistry/PublishedDocuments/Canada%20First/Canada%20First%20NDC-Revised%20submission%202017-05-11.pdf

[44] Appendix D-5: https://www.canada.ca/en/services/environment/weather/climatechange/pan-canadian-framework.html.

- 39 percent will derive from measures in the Framework, such as phasing out coal-fired electric power generation by 2030, supporting building efficiency and transitions to electricity, and developing a federal clean fuel standard[45]; and
- The final 20 percent will derive from additional measures, such as investments in public transit, technology innovation and carbon stored in forests, soils and wetlands.

The Canadian government reinforced the Framework via its 2016 Mid-Century Long-Term Low-Greenhouse Gas Development Strategy.[46] This strategy includes the following substantiated actions:

- Enhancing inter-provincial interties to support decarbonisation of the electricity supply;
- Shifting end users, such as diesel-powered remote communities, to non-fossil energy sources;
- Encouraging building retrofits and behavioural changes; and
- Supporting development of cellulosic biogas as part of initiatives that target emissions reductions from land use and forestry.[47]

The Government of Canada's 2017 budget, tabled in the House of Commons on March 22, 2017,[48] provides further clarity on emissions reduction initiatives and reinforces the government's commitment to emissions reductions via electrification. This creates risk of downward pressure on natural gas demand. However, highlights from the budget also suggest opportunities for FEI's C&EM as well as CNG and LNG for Transportation programs:

- $182 million for advancing building codes and expanding Natural Resources Canada's mandate to support energy efficiency in buildings;
- Simplified and realigned technology innovation support programs, including re-capitalization of Sustainable Development Technology Canada with $400 million over five years and an additional $300 million in funding for renewable energy commercialization and demonstration;
- Doubled funding (from $60 million in 2016 to $120 million in 2017) for deploying alternative fuelling technologies;

[45] On December 13, 2017, the Government of Canada published a regulatory framework on the proposed clean fuel standard. The framework outlines the proposed scope, regulated parties, compliance options and regulation timing. The framework proposes for natural gas distribution utilities to be covered by the regulation. The framework proposes to select carbon intensity reduction targets after establishing baseline values. The Government of Canada plans to conduct additional consultations and aims for the regulation to come into force in mid-2019.

[46] Appendix D-6: http://unfccc.int/files/focus/long-term_strategies/application/pdf/canadas_mid-century_long-term_strategy.pdf.

[47] Appendix D-7: https://www.canada.ca/en/natural-resources-canada/news/2017/03/government_of_canadainvestsinrenewablenaturalgas.html?_ga=1.147080181.372773754.1489585450.

[48] https://www.budget.gc.ca/2017/docs/plan/budget-2017-en.pdf

- Approximately $60 million for Transport Canada to address GHG regulations in the marine, rail, aviation and vehicles sectors; and
- Approximately $18 million for Environment and Climate Change Canada and Transport Canada to develop heavy duty vehicle retrofit and off-road regulations as well as a clean fuel standard for reducing emissions.
- $160 million allocated to BC from the $2 billion Low Carbon Economy Fund to generate clean growth and reduce GHG emissions towards meeting or exceeding commitments under the Paris Agreement.

2.3.1.1 Canadian Carbon Price

As part of the Framework, the Government of Canada plans to implement a carbon pricing backstop mechanism. This mechanism sets the floor price of carbon at $10 per metric tonne in 2017 and increases to $50 per metric tonne by 2022. The backstop mechanism will be reviewed by 2022 (with a preliminary review by 2020) to confirm its path.

The backstop mechanism will apply to a common and broad set of sources which are substantively identical to the sources covered under BC's 2016 carbon tax. Provinces with existing cap-and-trade systems must set their 2030 target at least equal to the Canadian federal target from the Framework and their 2018-2022 emissions reductions trajectories must at least align with the reductions expected from the federal carbon price increases between 2018 and 2022.

On May 18, 2017 the Government of Canada released a technical paper on the backstop mechanism and invited commentary by June 30, 2017.[49] In addition to the backstop mechanism, the paper outlines an output-based pricing system for carbon intensive industries with annual emissions over 50 kilotonnes of CO_2 equivalent. The technical paper plans for this system to become effective in 2018.

At the time of writing, the federal backstop mechanism and the output-based pricing system have not been passed into law.

Outside of BC, six Canadian provinces have developed and implemented energy and emissions policy actions.

Section 2.3.3 discusses BC policy actions while Section 2.3.2 discusses the US and PNW policy context.

2.3.2 United States

The US policy context impacts the BC natural gas use environment in two ways. First, upstream natural gas resources in BC and Alberta serve US demand for natural gas for electricity

[49] Appendix D-8: https://www.canada.ca/en/services/environment/weather/climatechange/technical-paper-federal-carbon-pricing-backstop.html.

generation. However, increasing supply of natural gas from the US Northeast is expected to decrease demand for Canadian exports to the US as further discussed in Section 5.2. Second, US policy may influence Canadian policy due to potential impacts on the relative economic competitiveness of each jurisdiction.

Historically, US energy and emissions policy has influenced policy implementation in Canada. Canada signed the Kyoto Protocol but did not implement strong policy actions in pursuit of its Kyoto emissions reduction target during a time when the US withdrew from the Protocol.

Some uncertainty still exists about the direction of US energy and emissions policy under the current administration. The US administration has declared that it will facilitate energy infrastructure projects and reduce environmental regulations but has, at times, taken contradictory positions on energy and emissions policy. Some actions of the US administration indicate that the US intends to implement its declared goals on energy infrastructure projects and environment regulations. Such implementation will be intermediated by US states (e.g. in the case of infrastructure projects), federal regulatory bodies (e.g. the Federal Energy Regulatory Commission), and the US judiciary.

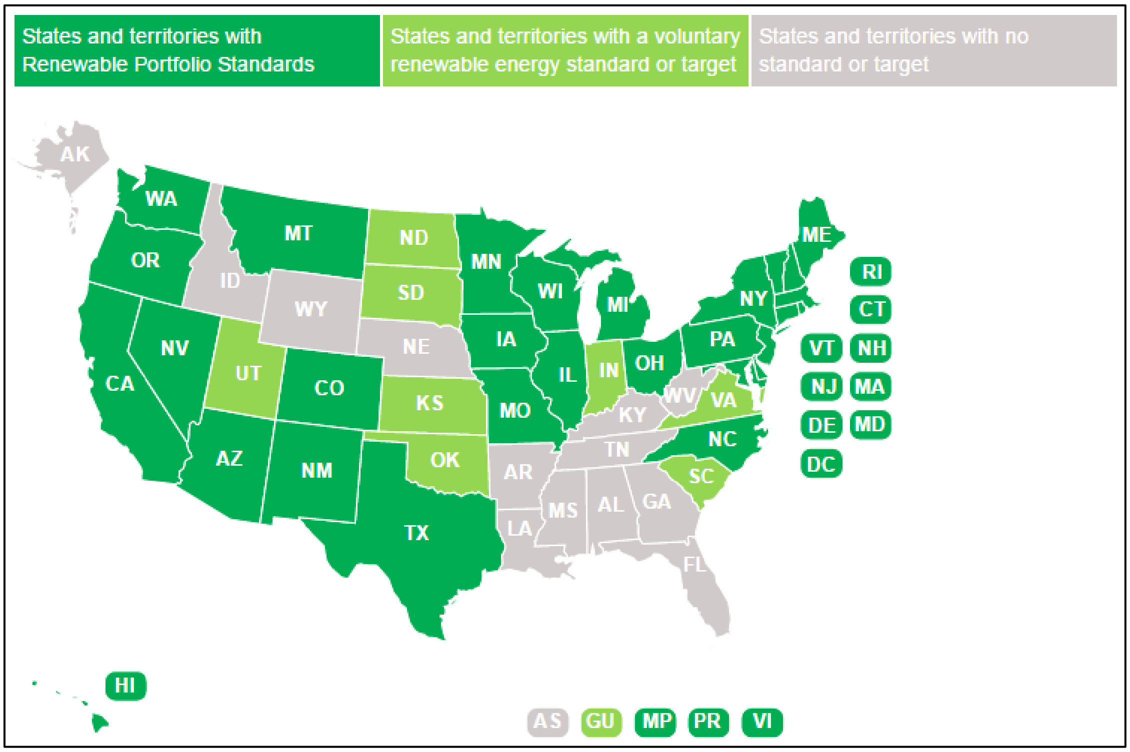
Sections 2.3.2.1 to 2.3.2.3 discuss the State-level Renewable Portfolio Standards (RPS) and Energy Efficiency Resource Standards (EERS) and the Clean Power Plan. Section 2.3.2.4 discusses energy and emissions policy action in the PNW as federal US policy uncertainty may leave regional and state entities leading these policy actions in the US.

2.3.2.1 Renewable Portfolio Standards

Renewable Portfolio Standards (RPS) are policies designed to increase generation of electricity from renewable resources. These policies require or encourage electricity producers within a given jurisdiction to generate and supply a minimum share of their electricity from designated renewable resources. Generally, these resources include wind, solar, geothermal, biomass, and some types of hydro-electricity. Some RPS policies may also include other resources such as landfill gas, municipal solid waste, and tidal energy.[50] Thirty states and the District of Columbia have enforceable RPS or Alternative Energy Portfolio Standards, and eight states have a voluntary Renewable or Alternative Energy Goal.[51] These programs vary widely in terms of program structure, enforcement mechanisms, size, and application. Figure 2-12 below shows the states with RPS or voluntary targets versus those without any standard or target.

50 Appendix D-9: http://www.eia.gov/todayinenergy/detail.cfm?id=4850.
51 Appendix D-10: http://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx.

Figure 2-12: State RPS or Voluntary Targets[52]



According to the NWPCC's 7th Power Plan, 250 to 400 megawatts (MW) of installed capacity is expected to be required by 2035 to fulfil existing RPS.[53] Renewable development in the region has historically consisted primarily of wind resources. Implementing the RPS will impact natural gas demand for power generation in the US and PNW, which, in turn, impacts demand for Canadian (primarily BC and Alberta to serve the PNW) natural gas imports to the US. At the same time, the declining cost of utility-scale solar means that future increases in US renewable electricity generation may increasingly come from solar power sources. Although renewable generation resources will make a material contribution to the total installed generation capacity in the future, their contribution to the electricity system's ability to meet its peak demand is modest given the intermittent nature of wind and solar resources.

2.3.2.2 Energy Efficiency Resource Standards

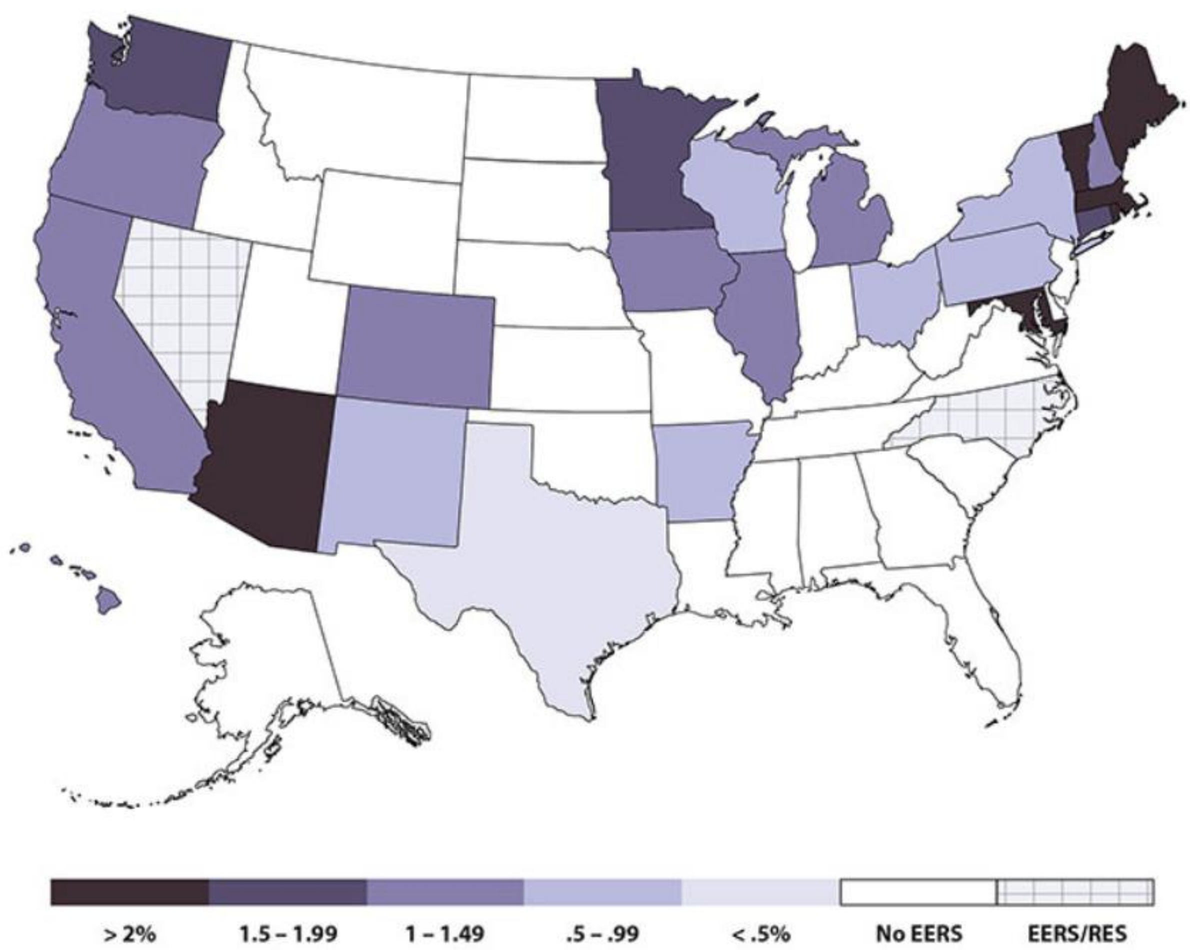
Energy Efficiency Resource Standards (EERS) aim to increase utility investment in energy efficiency measures to meet a share of their total load. Under an EERS, electric and gas utilities are regulated to demonstrate annual energy savings as a percentage of their total load. These savings are achieved through investment in utility energy efficiency programs. Annual savings targets range from 0.5 percent to 3 percent of total utility sales depending on the state. As of the end of 2016, 26 and 16 states in the US had implemented EERS for electricity and natural gas

[52] Ibid.

[53] Appendix D-11: Northwest Power and Conservation Council (2016). "7th Power Plan". p. 3-5. https://www.nwcouncil.org/media/7149940/7thplanfinal_allchapters.pdf.

utilities, respectively. States with an EERS achieved energy savings that were four times greater than states without this policy.[54] The scale of the savings from EERS on energy markets is currently small. Averaged over all state programs, EERS are saving an estimated 1.2 percent of utility load. However, should this annual savings rate persist, it would lead to a 15 percent reduction in utility energy demand by 2030, all else remaining equal. Figure 2-13 below shows the states with EERS targets versus those without any target.

Figure 2-13: State EERS Arranged By Annual Electric Savings Target[55]



2.3.2.3 Clean Power Plan

The US Environmental Protection Agency's (EPA) Clean Power Plan aims to reduce carbon dioxide emissions from power plants by 32 percent below its 2005 levels by 2030.[56] The Clean Power Plan sets emissions standards for electric generating units and provides a number of

54 Appendix D-12: http://aceee.org/sites/default/files/state-eers-0117.pdf.
55 Appendix D-13: http://aceee.org/topics/energy-efficiency-resource-standard-eers.
56 Appendix D-14: http://www2.epa.gov/sites/production/files/2015-08/documents/cpp-final-rule.pdf.

options for states to meet these standards, including inter-state collaboration to demonstrate emissions performance. This recognizes that electricity is transmitted across state lines.

As such, individual power plants can use out-of-state reductions (in the form of credits or allowances, depending on the plan type) to achieve required CO_2 reductions. This will provide a structural incentive for increased carbon trading activity. Renewable energy generated by sources outside of the US, such as hydropower from Canada, can qualify for emission reduction credits to be used to adjust a CO_2 emissions rate of a US generator, provided that they meet the eligibility requirements. This could provide opportunities for renewable energy projects in BC, or impact the prices and rates of electricity in BC.

One likely outcome of the Clean Power Plan, if it is implemented, includes less reliance on coal and more development of natural gas-fired generation. It could also provide states and developers additional incentives to rapidly expand their non-hydro renewable capacity to displace existing coal generation. The incremental increases in renewable generation would consist primarily of new wind and solar capacity.[57] This adoption of intermittent renewables could produce vulnerability to the power system through reliability issues. It could also provide market opportunities for exporters of renewable generation such as Canadian wind and hydro-electric generation.

However, a number of legal challenges are underway after the release of the final Clean Power Plan rule. Twenty-seven states and dozens of industry groups comprising almost 150 total identified parties have sued the EPA[58] to suspend the rule and ultimately have it invalidated. It will likely be several years before all the legal challenges and appeals are exhausted. Furthermore, additional uncertainty now exists over the future of climate action, including the Clean Power Plan rule, in the US as a result of the current administration's proposal to repeal the Clean Power Plan. On October 10, 2017, the EPA formally proposed to repeal the Clean Power Plan, will accept comment on the proposal for 60 days after publication in the Federal Register, and will hold a public hearing if one is requested.[59]

2.3.2.4 Pacific Northwest

Policymakers and utilities in the PNW region consider natural gas to be a viable solution to meet growing energy demands; due to high generation efficiency, relatively low carbon content and operational flexibility, natural gas provides an ideal source of base load and peaking electric power supply. Therefore, policies are aimed at moving away from coal-based electricity generation to natural gas and other renewable energy.

The NWPCC adopted its Seventh Power Plan (NWPCC Plan) on February 10, 2016. The NWPCC Plan indicates that natural gas-fired electricity generation is the lowest cost option for reducing regional carbon emissions. The NWPCC Plan also forecasts that, even without additional policy actions, aggressive pursuit of energy efficiency opportunities and expanded

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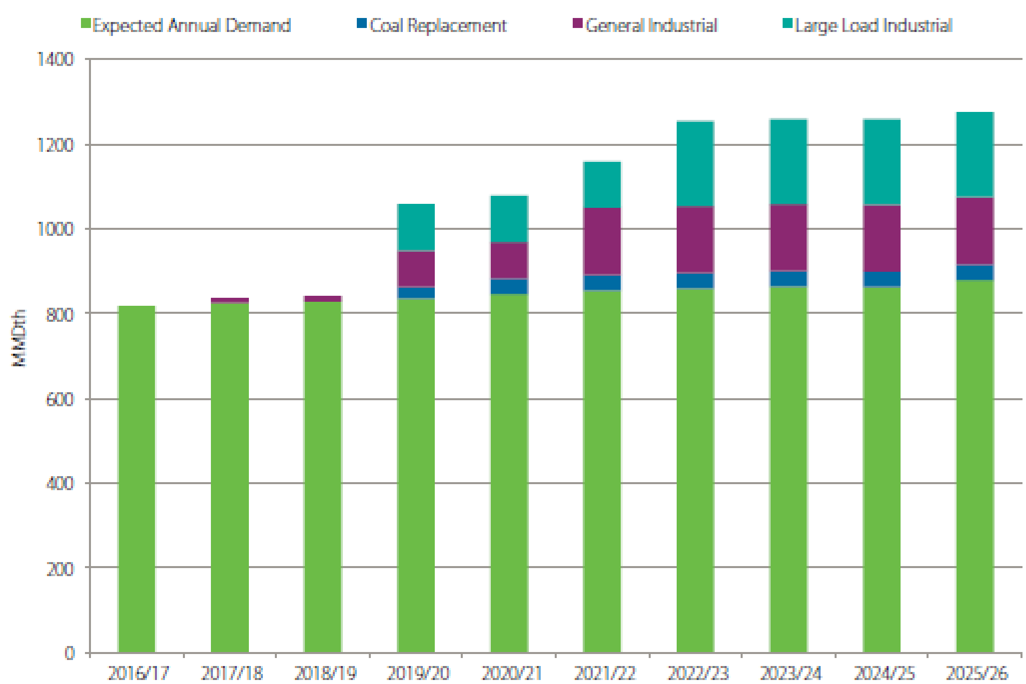
[57] Appendix D-15: https://www.epa.gov/cleanpowerplan/fact-sheet-clean-power-plan-clean-energy-now-and-future.
[58] Appendix D-16: http://www.eenews.net/interactive/clean_power_plan/fact_sheets/legal.
[59] https://www.epa.gov/sites/production/files/2017-10/documents/fs-proposed-repeal-cpp-final_oct10.pdf

natural gas-fired electricity generation (by retiring existing coal-fired power plants) would reduce PNW power system carbon emissions nearly 40 percent by 2035. This drop would meet the goals of the Clean Power Plan but uncertainty surrounding the Clean Power Plan or the replacement plan put forth by the current US administration remains a question going forward.[60]

New gas-fired generation demand continues to account for forecast load growth in the region, though at a slower pace than in years past. Figure 2-14 from the NWGA's 2016 Gas Outlook displays how replacing coal-fired electricity generation as well as additional industrial projects (including large methanol or LNG export plants) may drive regional demand for natural gas.

Figure 2-14: PNW Expected and Incremental Annual Natural Gas Demand[61]



At the same time, with the exception of Idaho, PNW states use RPS to promote renewable energy generation. Wind power is considered the most available and cost effective resource to meet these mandates; thus, electricity generation from wind energy has also grown in the PNW.

Within this context, Oregon's Clean Air and Coal Transition Plan commits to phase out coal-fired electricity generation and meet half of customer electricity demand with renewables by 2040. High penetrations of renewables electricity generation may require natural gas power plants as backup.[62]

The Washington Department of Ecology is implementing a binding carbon cap on major stationary emissions sources (factories, power plants, oil refineries) and residential households

[60] Appendix D-11: https://www.nwcouncil.org/media/7149940/7thplanfinal_allchapters.pdf.
[61] Appendix D-17: http://www.nwga.org/wp-content/uploads/2016/10/2016NWGA-Gas-Outlook.pdf.
[62] Ibid.

as well as businesses. In a fall 2016 referendum, Washington voters defeated proposals for a carbon tax to start at USD$ 15 per metric tonne and escalate to USD$ 100 per metric tonne across 40 years.[63]

The growing use of renewable, intermittent resources may change the way that the region's gas infrastructure will be called upon to meet the region's future energy needs – a possibility for which FEI must be prepared.

Natural gas in the PNW is also promoted for direct use applications. Direct use refers to natural gas consumed directly in appliances for space and water heating, cooking and clothes drying. Direct use of natural gas avoids the significant energy losses incurred in gas-fired generation of electricity; in total, electricity generation, transmission and distribution losses amount to nearly half the energy used in homes and commercial businesses.[64] Since using natural gas for space heating and thermal applications is more efficient than using it to generate electricity for use in these same applications, utilities such as PSE (which provide both electricity and natural gas), promote the direct use of natural gas to avoid new electricity demand—even in service territories where other utilities may benefit from increased natural gas demand.[65] The NWGA also advocates policies to promote the direct use of natural gas. Like other entities in the region, the NWGA sees gas as a pillar of the region's electricity resource strategy to reduce the use of coal-fired generation and to allow integration of a growing fleet of intermittent renewable resources.[66]

In BC, natural gas is gaining traction as a transportation and power generation fuel where diesel is the displaced incumbent fuel. FEI has seen continued growth in this market segment since the inception of FEI's NGT program for CNG and LNG supply for heavy duty vehicles, marine vessels and power generation applications.[67]

In the Port of Tacoma in Washington, PSE is developing an LNG production facility that will enable LNG supply for marine and transportation markets in the region. This LNG facility will incorporate LNG liquefaction, storage and bunkering (i.e. fuelling) to the marine market. PSE would provide LNG as a marine fuel to local vessels and could potentially also provide regional natural gas system peak support to gas customers of PSE. The project is scheduled to be completed in late 2019 and would compete with FEI's supply of LNG for over-the-road, rail and the marine transportation sectors.[68] An anticipated increase in natural gas demand within the PNW region will provide BC with an opportunity to leverage its natural gas supply resources to fulfill this anticipated market demand.

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63 Ibid.

64 For additional information on the opportunities and challenges of the direct use of natural gas, refer to American Gas Association (2012). "Squeezing Every BTU: Natural Gas Direct Use Opportunities and Challenges".

65 Appendix D-18: https://pse.com/savingsandenergycenter/tips-tools-ideas/Pages/Choosing-natural-gas.aspx.

66 NWGA, "Natural Gas and Climate Change in the Pacific Northwest". Volume 5, Issue 1. p. 3-5.

68 Appendix D-19: http://tacomacleanlng.com/project-summary.

2.3.3 British Columbia

In the years between 2007 and 2010, the Government of BC stated its desire to become a leader of North America's GHG emissions reduction efforts with a number of key energy and emissions policy initiatives.

BC crystallized its comprehensive approach in the BC Energy Plan of 2007. This plan was followed by a number of legislative and regulatory acts which include the following:

- The 2007 *Greenhouse Gas Reduction Targets Act* (GGRA) sets a legislated target for BC to reduce its emissions by 33 percent below 2007 levels by 2020 and 80 percent by 2050;
- The 2008 *Carbon Tax Act* established a carbon tax rate of $10 per metric tonne of CO_2 for all fuels at the point of consumption. This tax increased by $5 per metric tonne until it reached $30 per metric tonne in 2012;
- The 2008 *Utilities Commission Amendment Act* encourages utilities to reduce GHG emissions and to promote energy efficiency and renewable energy sources;
- The 2008 Demand-Side Measures Regulation (DSM Regulation) sets the framework for the Commission to evaluate utility energy efficiency activities;
- The 2008 Emissions Offset Regulation and the Carbon Neutral Government Regulation set the foundation for public sector organizations' GHG emissions reduction targets and reporting on these targets;
- The 2008 Renewable and Low-Carbon Fuel Requirements Regulation established a schedule of reductions that will reduce the carbon intensity of the transportation fuel mix in BC by 10 percent by 2020 relative to 2010. This has helped stimulate the adoption of natural gas as a transportation fuel;[69] and
- The 2010 CEA focuses on exporting electricity, increases from 50 to 60 percent the goal of meeting new electricity demand from energy efficiency, increases from 90 to 93 percent to goal of electric power generation from clean resources, and encourages fuel switching that reduces GHG emissions. Excluding electricity-to-gas fuel switching as a demand-side measure may cloud customer and public perception of natural gas as an efficient fuel. This, combined with heavy government and media emphasis on BC's electricity as a clean, renewable energy source, may contribute to customer and stakeholder confusion regarding the role of natural gas as an efficient, affordable and reliable energy source. The Act also requires the BC Hydro to submit its integrated resource plan (IRP) to the Government of BC rather than the BCUC. This may diminish independent regulatory oversight of major energy projects and policies.

[69] Ministry of Energy, Mines and Petroleum Resources, 2017, Renewable and Low-Carbon Fuel Requirements Regulation Summary: 2010-2016. http://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/rlcf-007-2016.pdf.

In March 2011, BC experienced a change in government which caused a further calibration of provincial energy and emissions policy. This calibration resulted in a further focus on NGT, natural gas exports, energy efficiency in buildings, RNG, and efficient electrification. This creates the risk of a downward pressure on natural gas demand from buildings in BC but also provides an opportunity for FEI's NGT, C&EM and RNG initiatives.

Figure 2-15 shows BC's transport-related GHG emissions and highlights the relative contribution of road transportation emissions. Transport emissions (37 percent of BC's total emissions), and road transportation emissions in particular (26 percent of BC's total emissions), make the largest contribution to BC's GHG emissions profile and emphasize a need to target emission reduction strategies in these areas in order to address the province's climate change goals.

Figure 2-15: 2014 Transport and Road Transportation GHG Emissions in BC[70]

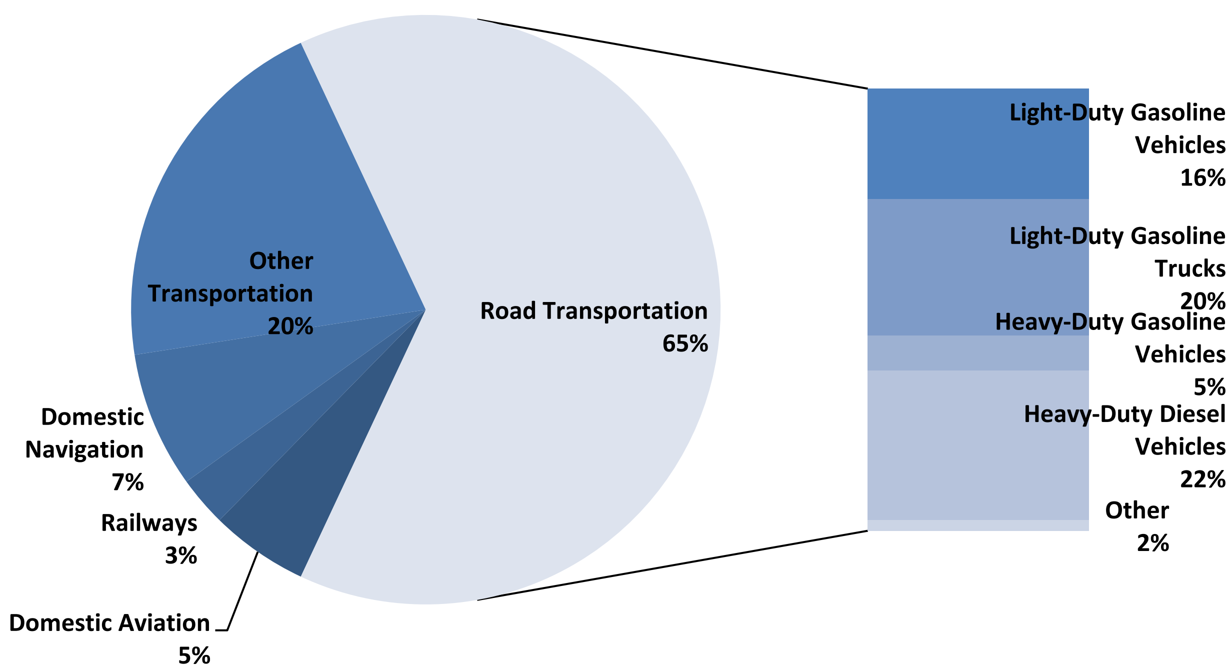
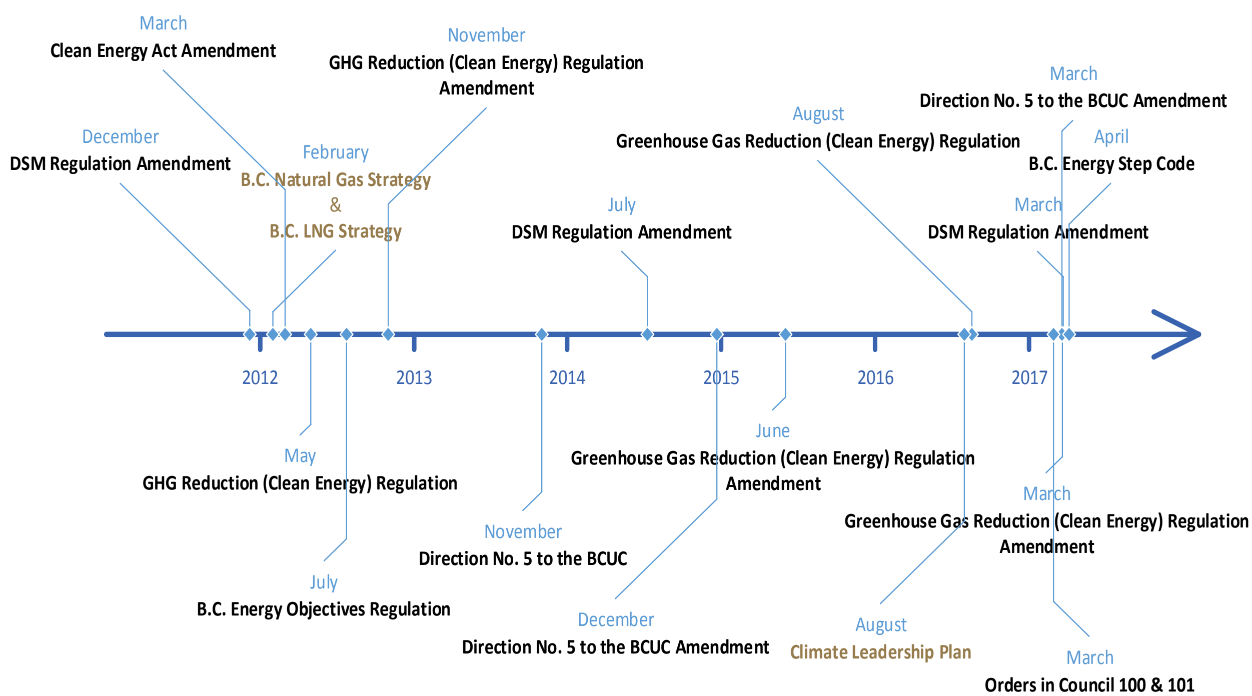


Figure 2-16 outlines the chronological development of BC's energy and emissions policy since the 2011 change in government. Black font denotes regulation or legislation whereas brown font denotes plans and general policy documents:

[70] FEI from "2014 BC GHG Inventory Report". BC Climate Action Secretariat.

Figure 2-16: BC Energy and Emissions Policy and Legislative Timeline



Sections 2.3.3.1 to 2.3.3.5 discuss the BC Climate Leadership Plan (CLP), the BC Natural Gas and LNG Strategies, the BC Energy Objectives Regulation, the Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR), Government of BC Directions to the BCUC, and amendments to the DSM Regulation.

2.3.3.1 BC Climate Leadership Plan

The BC Government has signalled intent to remain committed to reducing GHG emissions and, in 2015, formed a Climate Leadership Team (CLT) comprised of leaders from the business, academic and environmental communities, including First Nations, to provide advice and recommendations to government on how to maintain BC's climate leadership.

In October 2015, the CLT released a report to the BC Government calling for increased action to reduce provincial GHG emissions with 32 policy recommendations. A key recommendation was to increase the carbon tax by $10 per year commencing in 2018 and to expand the application of the carbon tax to all sources of GHG emissions in the province including fugitive, flared and vented emissions from upstream oil and gas extraction and processing. The CLT report noted that with an increasing carbon tax, special consideration should be given to emission-intensive, trade-exposed industries. Additionally, the CLT recommended that if the majority of Canadian provinces opt for carbon pricing via emissions trading, a review should be undertaken of potential mechanisms to integrate a carbon tax with a cap and trade framework for the BC context and that BC should work closely with other jurisdictions in North America to achieve parity with BC's climate action policies. The CLT report also recommended the development of a low carbon transportation strategy, including establishing Zero Emission Vehicle targets to encourage greater adoption of electric vehicles.

In August 2016, the BC government released the CLP, which adopted some of the recommendations from the CLT's report. The CLP affirmed existing policy directions but also outlined goals for additional policy activity. The CLP included 21 action items intended to help put BC on course to meet the target of an 80 percent reduction in GHG emissions from 2007 levels by 2050. The CLP stated that the carbon tax rate could be increased from the current level ($30 per tonne) in the future but only once other jurisdictions catch up.[71]

The CLP included the following actions which, if implemented, may impact FEI and provincial natural gas use patterns:

- Encouraging commercial vehicle fleets to switch from diesel to natural gas and RNG, and amending the applicable regulations to enable utilities to double incentives for switching vehicles if such vehicles will use 100 percent RNG after their switch;
- Affirming existing amendments to the BC GGRR to enable utilities to provide incentives for marine, mining, and remote power generation to switch from higher emitting fuels to natural gas;
- Supporting energy efficiency initiatives via multiple actions:
  - Updating the DSM Regulation to support FEI with expanding its energy efficiency incentives by at least 100 percent;
  - Expanding the mandate for BC public utilities to meet demand growth via DSM and supporting GHG emissions reduction by advancing efficient electrification;
  - Introducing energy performance regulations for natural gas industrial package boilers in 2020;
  - Introducing updated energy performance regulations for heat pumps and natural gas fireplaces in 2018;
  - Introducing high efficiency energy performance regulations for natural gas space heating equipment in 2020 and 2025;
  - Allocating budget from the provincial Innovative Clean Energy Fund to support innovation and training;
  - Aiming for newly constructed buildings to be net zero ready in 2032;
- Pursuing multiple pathways for reducing the emissions intensity of natural gas:
  - Introducing regulation and an incentive program to reduce upstream vented and fugitive methane emissions by 45 percent by 2025;

[71] https://climate.gov.bc.ca/app/uploads/sites/13/2016/10/4030_CLP_Booklet_web.pdf

- Potentially supporting electricity capital projects to power upstream infrastructure in the Montney region; and
- Completing a review of the Low Carbon Fuel Standard.

The CLP's transportation and innovation actions provide an opportunity for FEI's NGT and RNG programs. The CLP's building sector actions present the risk of downward pressure on natural gas demand but also provide an opportunity for FEI's C&EM programs. The CLP's actions for reducing the emissions intensity of natural gas also provide an opportunity to increase the attractiveness of natural gas as a clean energy option.

2.3.3.2 BC's Natural Gas and LNG Strategies

On February 3, 2012, the Government of BC unveiled its Natural Gas Strategy[72] and LNG Strategy[73], which outlined a vision to become an international leader in LNG development and recognize the role of natural gas as a transition fuel to a low carbon global economy. BC's LNG Strategy committed the province to having three LNG facilities in operation by 2020 and represented an attempt to create a new industry that was intended to bring significant job creation and economic benefits to the province. Critical priorities that guide the strategies included: maintaining BC's competitiveness in global LNG markets; promoting natural gas as a transportation fuel; developing new markets for gas-related industries such as a gas-to-liquids, methanol and fertilizer production; and ensuring a reliable supply, available infrastructure and effective royalty regime to encourage investment in BC's natural gas sector. The current BC Government has affirmed its conditional support for the BC LNG industry; however some uncertainty exists on how the strategy will be implemented. The current BC Government's mandate to the BC Minister of Energy and Mines now requires that LNG project proposals should expressly guarantee jobs and training opportunities for BC residents, provide BC a fair return on its resources, respect and partner with First Nations, and protect BC's climate commitments.[74]

The Natural Gas Strategy also continues to build on BC's Bioenergy Strategy by reinforcing a commitment to encourage biomethane opportunities and offering consumers low carbon natural gas (Section 2.4.2 discusses FEI's initiatives to provide its customers with RNG).

As such, the province's energy demand and energy infrastructure needs are also set to expand. FEI is well-positioned to assist in meeting the government's objectives in BC's Natural Gas and LNG Strategies.

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72 http://www.gov.bc.ca/ener/popt/down/natural_gas_strategy.pdf
73 http://www.gov.bc.ca/ener/popt/down/liquefied_natural_gas_strategy.pdf
74 Appendix D-20: https://www.bcndp.ca/latest/read-premier-john-horgans-mandate-letters-new-bc-ndp-government-ministers.

2.3.3.3 BC's Energy Objectives Regulation

Building on momentum from the BC Natural Gas and LNG Strategies, in June 2012, the Government of BC declared natural gas as a 'clean' fuel when used to generate power for BC's LNG export market (Appendix A provides further information on expected LNG projects, pipeline routes and implications for the regional gas marketplace). Using the Government's rationale that natural gas can be used to reduce global GHG emissions, FEI believes the efficient use of natural gas for heating applications in BC can provide a similar benefit for global emissions when displaced electricity load results in clean electricity supply available for export to offset coal and gas fired generation in neighbouring jurisdictions, or reduces the need to import electricity from neighbouring jurisdictions.[75]

The change to the designation of natural gas as a source of clean energy, made through BC's Energy Objectives Regulation, enabled production of relatively cheap and abundant electricity to fuel the LNG export market without compromising the requirements of the CEA. As a result, natural gas can be used for both liquefaction and as a power-generating fuel, and demand for natural gas in BC may increase.

2.3.3.4 Greenhouse Gas Reduction (Clean Energy) Regulation

As part of the province's strategy to encourage the use of natural gas as a transportation fuel, on May 14, 2012, the Provincial government introduced the GGRR through a "prescribed undertaking" under sections 18 and 35(n) of the CEA.

Through subsequent amendments to the GGRR, the regulation authorizes a utility to invest up to $331.500 million in NGT programs, with commitments for funding to be made by March 31, 2022 (when the GGRR expires), including[76]:

- Offering capital incentives to transportation fleets that use natural gas as a fuel in place of diesel (or other higher carbon emitting fuels) such as marine vessels, heavy duty trucks, locomotives, mine haul trucks, busses, or natural gas used to produce power for remote industrial applications;
  - Capital incentives are available to either CNG or LNG transportation fleets that consume gas supply that is derived entirely from biogas or biomass;
- Providing LNG bunkering infrastructure such as shoreside fuelling assets to the marine market;
- Building, owning and operating CNG and LNG fuelling stations; and

[75] This assertion is supported by comprehensive analysis conducted by the Center for Climate and Energy Solutions in its June 2013 report, "Leveraging Natural Gas to Reduce GHG Emissions". Appendix D-21: http://www.c2es.org/publications/leveraging-natural-gas-reduce-greenhouse-gas-emissions.

[76] First amendment to the GGRR was through OIC 297 on June 3, 2015, the second GGRR amendment was approved through OIC 609 dated August 19, 2016, and the third GGRR amendment was approved through OIC 161 dated March 21, 2017.

- Providing grants to meet safety guidelines for operating and maintaining natural gas vehicles.

The GGRR is designed to facilitate certain market segments to adopt natural gas as a transportation (or power generation) fuel to displace higher carbon emitting fuels such as diesel and heavy marine oil. For NGT customers, there are immediate benefits from adopting natural gas into their fleets, such as reduced fuel and operating costs, better air quality due to reduced emissions, and minimizing environmental hazards associated with diesel/oil storage tanks.

FEI's NGT efforts will assist BC in achieving its GHG reduction goals by converting the province's transportation fleet from more carbon intensive fuels, such as diesel and gasoline, to relatively cleaner burning natural gas. Further, the broader adoption of natural gas fuel in the transportation sector will also reduce air contaminants such as particulate matter (PM), sulfur oxides (SOx) and nitrous oxides (NOx).

For FEI's customers, CNG and LNG demand also adds value by increasing the year-round load on the gas distribution system, thereby reducing upward pressure on delivery rates for all natural gas customers.

In its March 22, 2017, amendment to the Regulation, the BC government also increased to $30/GJ the maximum rate at which FEI may acquire RNG. The amendment also enables FEI to acquire sufficient RNG to meet up to 5 percent of FEI's 2015 non-bypass annual demand (this equals approximately 8.9 million GJ).

2.3.3.5 BC Government Directions to BCUC

On November 27, 2013 through Order in Council 557/2013 (OIC 557), the BC Government issued Direction No. 5 to the BCUC under Section 3 of the UCA. This direction exempts from CPCN review expenditures on an expansion of the Tilbury LNG facility up to $400 million. OIC 557 also established the Rate Schedule 46 LNG Sales, Dispensing and Transportation Service tariff.

On December 19, 2014 the BC Government issued OIC 749/2014 (OIC 749) amending Direction No. 5, which established, among other things, investment parameters for an additional expansion of the Tilbury LNG facility beyond that approved in OIC 557 (i.e. Phase 1A permitted under OIC 557).[77] Specifically, OIC 749 permitted additional expenditures, exempt from CPCN review by the BCUC, of up to $400 million for Phase 1B expansions of the Tilbury LNG facility subject to overall contracting levels averaging 70 percent of the facilities production capacity over a period of 15 years. Additionally, OIC 749 also established a new Rate Schedule 50 Large Volume Industrial Transportation tariff. OIC 749 also exempted several transmission system projects from the requirement to undergo a CPCN review, including the Eagle Mountain

[77] OIC 749 also established spending limit exemptions for the FEI CTS and Eagle Mountain Gas Pipeline (EGP) project in addition to the LNG-related expenditure limits as referenced above.

to Woodfibre Gas Pipeline (EGP) project and three Coastal Transmission System (CTS) projects.

Subsequently, on March 21, 2017, the BC Government further amended Direction No. 5 through OIC 162/2017. The key amendments under OIC 162 were an increase to the Tilbury Phase 1A capital expenditure limit from $400 million to $425 million, removing the 70 percent average contracting requirement over 15 years pertaining to the Phase 1B expansion facility and removing the two lower priced tiers from Rate Schedule 46.

On March 1, 2017, the BC Government issued OICs 100/2017 and 101/2017. These orders enable BC public utilities to conduct efficient electrification programs and BC Hydro to charge the costs of these programs to its DSM deferral account.

In July 2014 and March 2017, the BC Government also amended the DSM Regulation to further encourage the efficient use of natural gas in BC and to enable a broader set of utility customers to participate in energy efficiency programs. These updates present an opportunity for FEI's C&EM programs. Please see Section 4.2.1.1 for further details.

2.3.3.6 2017 BC Election and Change in Government

BC conducted provincial elections in May 2017 which resulted in a new minority government forming in July 2017. The BC government's mandate letters to cabinet include the following key instructions that may impact the government's energy and emissions policy:

- Create a roadmap for the future of BC energy to drive innovation, energy efficiency, responsible and sustainable generation of new energy and create durable good jobs across the province;
- Boost investments in new energy technologies and climate solutions by reinvigorating the Innovative Clean Energy Fund;
- Implement a comprehensive climate action strategy that includes a new legislated 2030 reduction target and separate sectoral reduction targets and plans;
- Implement an increase of the carbon tax by $5 per year beginning in April 2018 to meet the federal carbon-pricing mandate and take measures to expand the carbon tax to fugitive emissions;[78] and
- Revitalize the Environmental Assessment process to ensure a transparent public process and that legal rights of First Nations are met.[79]

[78] In its September 11, 2017, BC budget update, the BC Government proposes a $5 per metric tonne annual increase to the carbon price, starting in 2018 and lasting four years. If this increase is maintained each year, as proposed in the updated budget, carbon tax will increase to $50 per tonne in 2021. Specific tax rates vary for each type of fuel, depending on the amount of CO_2 equivalent emissions released as a result of its combustion. At the current $30 per metric tonne level the tax adds $1.50 per GJ of natural gas, which is approximately half the price of the commodity itself. At $50 per tonne of CO_2 the additional cost will increase to $2.48 per GJ.

[79] Appendix D-20: https://www.bcndp.ca/latest/read-premier-john-horgans-mandate-letters-new-bc-ndp-government-ministers.

On October 23, 2017, the BC Government introduced the Climate Solutions and Clean Growth Advisory Council whose work will provide strategic advice to the BC Government on carbon pollution reductions as well as optimizing opportunities for sustainable economic development and job creation.[80]

The minority government status creates uncertainty as to what extent, how specifically, and the time frame that the BC Government will implement these mandates. The thrust of these mandates presents the risk of downward pressure on natural gas demand but also provides opportunities for FEI's C&EM, RNG and NGT initiatives.

2.3.4 Municipalities

Many municipalities in BC and across Canada are using their municipal powers to take policy actions aimed at reducing GHG emissions. This can range from building code and zoning by-laws placing restrictions around building energy use, to municipalities investing in energy efficiency and conservation programs, or municipal investments in renewable energy generation.

In order to support municipal energy efficiency and emissions reductions goals, the BC government enacted the BC Energy Step Code in April 2017. The step code represents a fuel-neutral voluntary set of energy performance variances from the prevailing *BC Building Code*. Under the 2015 *Building Act* and effective December 15, 2017, BC municipalities will be unable to pass bylaws that create variances in energy performance requirements from the prevailing BC Building Code, unless these variances enact specific steps from the BC Energy Step Code.[81] Under the *Act*, BC municipalities will still able to enact actions outside their bylaws as long as the Province has not already regulated the areas which are impacted by such actions. The BC Energy Step Code contains multiple steps for residential and commercial buildings that range from enhanced compliance with the prevailing provincial building code to net zero ready building performance. The BC Energy Step Code provides a consistent provincial standard for energy efficiency and replaces the various existing policies that various municipal governments had enacted previously. As such, the BC Energy Step Code poses a risk of downward pressure on natural gas demand but also provides an opportunity for FEI's C&EM programs.

Uncertainty exists regarding which municipalities will adopt what steps of the BC Energy Step Code and how quickly. While municipalities are cognizant of their legislated emissions reduction goals, they are cautious about their implementation approach. Some municipalities profess that they prefer to move in regional or economic groups in order to prevent economic leakage to other municipalities.[82]

Some municipalities are setting goals to supply 100 percent of their energy needs via clean and renewable sources by 2050. These goals focus on buildings, transport and municipal waste but are aspirational in nature as implementation pathways and municipal policy levers for achieving

[80] https://news.gov.bc.ca/releases/2017ENV0057-001797
[81] http://www.bclaws.ca/civix/document/id/complete/statreg/15002
[82] FEI received this feedback during its 2017 LTGRP stakeholder engagement efforts.

such goals are not clear yet. These municipalities include the City of Vancouver (COV), the City of Victoria, the District of Saanich, and various municipalities in the BC Kootenays. These municipal targets present a risk of downward pressure on natural gas demand but also provide an opportunity for FEI's RNG program and the Company's other initiatives for increasing the renewables portion of its energy supply.

The COV represents a special case among BC municipalities since COV has its own charter which confers regulatory powers that other BC municipalities do not have access to. The COV is moving forward with the Renewable Cities Strategy which includes the aspirational goal of consuming 100 percent renewable energy in all sectors by 2050 and reducing GHG emissions by 80 percent below 2007 levels by 2050. The COV's Greenest City Action Plan includes specific goals to reduce energy use and GHG emissions in existing buildings by 20 percent below 2007 levels, and require all buildings constructed from 2020 onward to be carbon neutral in operations. The COV also aims to increase public transit rideshare, expand the public transit system, and transition light-duty vehicles (cars and light trucks) to predominantly battery electric, plug-in electric, or sustainable biofuel powered models. On March 23, 2015, Vancouver City Council voted unanimously to support a shift toward the city deriving 100 percent of its energy from renewable sources, including energy for transportation and buildings.

In July 2016, the COV released the Zero Emissions Building Plan that aims for all new buildings to achieve zero operational GHG emissions by 2030.[83] The plan features GHG intensity (GHGI) targets for each major building type, complemented by Thermal Energy Demand Intensity (TEDI) targets to focus on building envelope performance improvements for all buildings. Section 2.2 of the plan states that its focus is on "reducing the demand for fossil fuel-based natural gas used primarily for space heating and hot water, and transitioning these functions to renewable sources such as electricity (including heat pumps), biogas and neighborhood renewable energy systems (NRES)."[84] The COV and FEI announced an agreement in November 2017, whereby the COV would amend the Zero Emissions Building Plan to include alternate compliance pathways that align with the BC Energy Step Code. This pathway does not require new buildings to achieve the GHGI target if they, instead, comply with a step of the BC Energy Step Code that achieves similar reductions in GHGs. Significantly reducing GHG emissions from new developments and new housing builds, and implementing an electrified transportation system, poses the risk of downward pressure on natural gas demand and could result in increased electricity demand in the COV.

2.3.5 Summary

Energy and emissions policy in Canada and the US is constantly evolving. While current legislation and the actions of municipalities to reduce the use of gas create risks for FEI as a result of potential residential, commercial and/or industrial demand reductions, natural gas is also increasingly recognized as playing an important role in BC's overall energy portfolio, resulting in the potential for demand growth. These countervailing forces create a measure of

[83] Appendix D-22: http://council.vancouver.ca/20160712/documents/rr2.pdf.
[84] Ibid.

uncertainty in the market and thus FEI must be prepared for a range of possible outcomes. Section 3 discusses how FEI's long term analysis accounts for these countervailing forces and resulting uncertainty

2.4 CUSTOMER SOLUTIONS

FEI believes that developing innovative and integrated customer solutions is an important part of positioning natural gas services competitively within BC's energy marketplace for the benefit of all customers. Using the right fuel effectively for the right end use and developing customer-driven energy services remain a key focus of FEI's customer solutions activities.

Following the BCUC Alternative Energy Solutions Inquiry in 2011-2012, FEI's new initiatives in thermal energy service projects are being undertaken by a separate FEI affiliate.[85] Some customers continue to seek out efficient, low carbon, integrated end-use energy solutions.

Although FEI is no longer delivering low carbon thermal energy alternatives, the Company is:

- Providing natural gas as a transportation fuel alternative and capturing carbon neutral biomethane sources to displace conventional natural gas;
- Exploring advanced metering and natural gas utilization solutions; and
- Improving the competitive position of natural gas service to better meet the needs of builders, developers and end-use customers.

The initiatives discussed below are provided to illustrate the types of activities that FEI continues to explore, implement and expand where there are benefits to customers and where they create an opportunity for the Company to assist in meeting government energy and GHG emission goals. Section 4 also discusses how the Company is enabling a number of customer solutions through programs to promote energy efficiency and conservation. There are no approvals sought by FEI within this LTGRP related to any new initiatives; such approvals, where required, will be sought prior to program implementation.

2.4.1 Natural Gas for Transportation

NGT and remote power generation are key opportunities for the Company to serve the energy needs of customers and help reach the ambitious GHG reduction targets legislated by the Province. In the NGT and remote power generation sectors, FEI is looking to displace petroleum fuels such as diesel with cleaner-burning natural gas. Natural gas is a lower carbon alternative to conventional transportation and remote power generation fuels and can play a significant role in reducing emissions, reducing reliance on petroleum-based fuels and supporting technology development in BC.

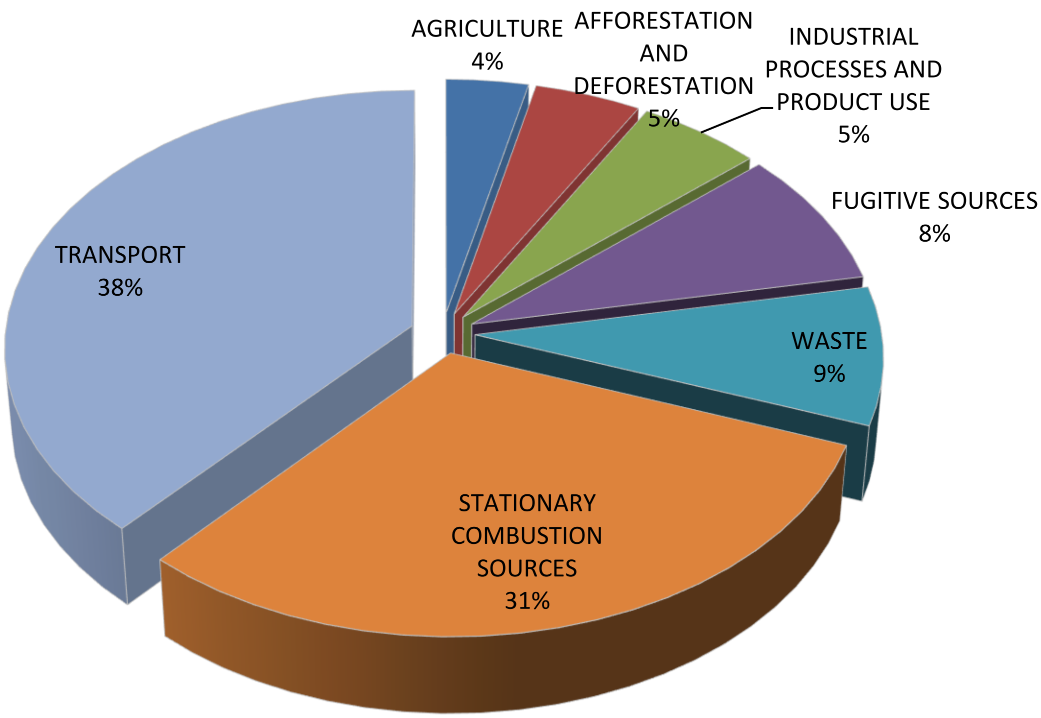
[85] BCUC report, "Inquiry into the Offering of Products and Services in Alternative Energy Solutions and Other New Initiatives". Dec. 27, 2012. http://www.bcuc.com/Documents/Arguments/2012/DOC_33032_12-27-2012-G-201-12_FEI-AES-Inquiry-Report_WEB.pdf.

To capture the NGT benefit, customers must make significant investments in vehicles, equipment and marine vessels designed to use natural gas. Given the significant investment dollars at stake for early adopters of natural gas as a transportation fuel, customers view FEI as a partner that can be depended upon to deliver the natural gas energy they need to facilitate the shift from conventional petroleum fuel to natural gas.

The GGRR is one mechanism that utilities in the Province can use to begin the market transformation process of converting applicable transportation and power generation applications to natural gas as a feedstock fuel.

The Company sees the development of natural gas use for these types of applications, programs and markets as a key part of its low carbon strategy to help meet changing customer needs and the GHG reduction targets legislated by the province. Shown in Figure 2-17, the on road and off road transportation sectors are responsible for more GHG emissions than any other sector. As such, these sectors provide BC's biggest opportunity to contribute to a reduction of GHG emissions and other air pollutants over the next 20 years. Note that the GHG emissions presented in the figure below include emissions for marine traffic operating in Provincial intercoastal waterways (i.e. such as domestic tug boats, BC Ferries and Seaspan vessels operating in domestic waterways). The data in Figure 2-17 is using the most current available information up to the end of 2014 from the Province of BC's GHG emissions inventory.

Figure 2-17: 2014 GHG Emissions by Sector in BC[86]



As discussed in greater detail in Section 3, natural gas is expected to emerge as a viable fuel for the global marine vessel market. As further discussed in Sections 2.4.1.1 to 2.4.1.3, there are global environmental regulations that are scheduled to be implemented in the next couple of years that are expected to materially impact the current mix of fuels that have traditionally been consumed by the global marine market. Due to these tighter restrictions on marine vessel emissions, natural gas in the form of LNG is expected to emerge as a choice alternative fuel for vessel operators to comply with these tighter restrictions.

2.4.1.1 Marine Bunkering Overview

Bunkering is the act of supplying a ship with fuel while vessels are berthed at port. Various incumbent fuels are used in marine transportation, including marine gas oil (MGO), marine diesel oil (MDO), intermediate fuel oil (IFO) and heavy fuel oil (HFO).[87] Currently, HFO accounts for the majority of the fuel used for tankers, bulk carriers and container ships globally. LNG is a relatively new fuel in the marine bunkering market whose adoption is being driven by its environmental and operating cost advantages compared to incumbent fuels.

[86] FEI from 2014 BC GHG Inventory Report, Climate Action Secretariat.

[87] These four marine fuels are ordered from lightest to heaviest in terms of density and weight (i.e. least emitting to highest emitting).

Capitalizing on the LNG marine bunkering opportunity is a key part of FEI's strategy to leverage pre-existing Company-owned assets and operational expertise to drive growth in new markets. While the Tilbury LNG facility primarily serves as a winter peaking facility, over time, the facility has also evolved to serve a variety of new LNG markets. Tilbury is a scalable LNG facility that, subject to any required regulatory approvals and the lead time for obtaining them, provides FEI with the flexibility to invest in new infrastructure in order to capitalize on load growth opportunities such as the marine bunkering market.

Due to the complexity of global ports, ships and fuelling (i.e. bunkering) requirements, numerous marine bunkering scenarios could unfold. In general, the ship requiring bunkering is either at the cargo loading/unloading berth or anchored at the port. LNG marine bunkering is performed by transporting LNG by a truck, through shoreside storage, or via an LNG ship to the marine vessel requiring refuelling. These three bunker delivery methods vary in complexity and the more complex bunkering solutions would involve the use of a LNG bunker barge or vessel whereby the bunker barge or vessel would be filled with LNG at a terminal (such as Tilbury) and then transported on the water to alongside the ship that requires LNG bunkering fuel.

FEI has had initial success advancing the LNG marine bunkering market in BC as evidenced in the milestones listed below:

- Tilbury Phase 1A expansion to be completed by the end of 2017 as a prerequisite to enable demand growth from LNG markets, such as marine bunkering;
- The GGRR supporting FEI's activity in developing the LNG marine bunkering market by providing capital cost incentives and bunkering/fuelling infrastructure for vessels to operate on LNG;
- LNG supply and delivery contracts are in place for three BC Ferries and two Seaspan Ferries vessels, with two more BC Ferries Spirit-class vessels expected to begin operational service, beginning mid-2018 for the first vessel and mid-2019 for the second vessel[88]; and
- The first ever global instance of an LNG tanker providing LNG bunkering by driving on-board the ship to refuel.

FEI will continue to advance its interests in the LNG marine bunkering market as an LNG fuel and logistics provider. The Company's early progress in this market, coupled with recent supportive market conditions, create a favourable environment for the Company.

2.4.1.2 Marine Market Overview

The International Maritime Organization (IMO) is scheduled to implement a global cap on sulfur emissions from the shipping industry to take effect on January 1, 2020. Vessels that operate in designated Emission Control Areas (ECA), which are 200 mile zones extending from all coasts

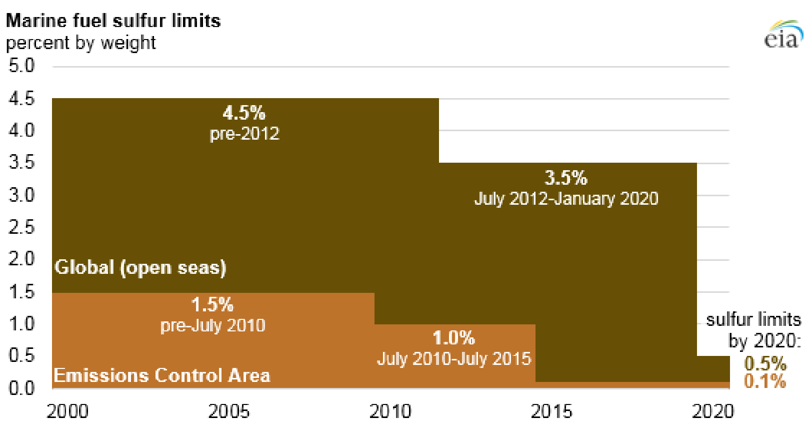
[88] Appendix D-23: http://www.timescolonist.com/news/local/b-c-ferries-will-head-to-poland-for-refits-1.2217288.

in North America and in Europe, are currently required to burn ultra-low sulfur MGO in order to comply with the current sulfur limit on emissions of 0.1 percent. Globally (outside of the ECA), the current limit is 3.5 percent. In 2020, this global sulfur limit will drop to 0.5 percent.

Figure 2-18 below illustrates the current ECAs. Figure 2-19 graphically outlines current and future legislated limits on sulfur for marine vessels operating within and outside of the designated ECA zones.

Figure 2-18: Designated ECA in North America and Europe

Figure 2-19: Designated ECA in North America and Europe



The global cap on sulfur in marine fuels is expected to have a material impact on marine vessel operators as they must weigh a number of options in order to comply with these emission limits.

For example, operators using higher-sulfur marine fuels such as IFO or HFO could install exhaust scrubbers that essentially scrub out the sulfur from the flue gas from a ship's exhaust. This is expected to be a temporary solution as the scrubbers do not remove other harmful emissions such as NOx and PM. Another option is for marine operators to consume more expensive low-sulfur MGO, which is what most vessels operating in the current ECAs are consuming today. Lastly, marine vessels could consume LNG, which is a cheaper fuel on a commodity cost basis, but the engines, on-board storage tanks and fuel delivery systems that are capable of consuming natural gas, are more costly than traditional marine petroleum fuelled engines. LNG would help vessel operators to comply not only with sulfur emission limits, but would also help dramatically reduce NOx and PM emissions.

2.4.1.3 GHG Emissions from the Global Marine Sector

The Provincial GHG emissions inventory (in Section 2.4.1) includes only marine emissions for vessels transiting intercostal provincial waterways. Marine vessels that regularly call BC ports that originate from ports of other countries (i.e. container ships, chemical tankers, car carriers, etc.) are not included in the Provincial emissions inventory, although these vessels emit large amounts of GHGs into the Province's atmosphere when in transit, and when berthed in domestic ports. It is FEI's view that these emissions should be considered as part of a global GHG reduction strategy through fuel switching from the incumbent petroleum marine fuels to natural gas.

For example, coastal freight vessels (which operate entirely within the currently-designated ECA zones) and trans-Pacific marine vessels (which operate a small portion of the total journey in the currently-designated ECA zones) are not included in the BC GHG inventory numbers. Specifically, emissions from shipping activities not included in the provincial GHG inventory amount to about 70 million metric tonnes of CO_2e per year, which is greater than the combined 64 million metric tonnes of CO_2e per year that the entire Province of BC emits per year.[89] It is FEI's view that emissions from the marine segment which are not currently included in the provincial GHG inventory numbers should also be considered in the context of global GHG emission reduction opportunities through the development of natural gas use for this market segment.[90]

Within the context of the planning environment of the LTGRP, a strategic focus on developing LNG for the marine segment is expected to have an impact in terms of total demand on FEI's distribution system as the marine market for LNG develops over time. The potential total LNG demand (as discussed in Section 3.4.7 of the LTGRP) that could materialize could be significant in the region and FEI will pay close attention to this demand as it develops over time to ensure that adequate resources are developed to continue to serve this key market segment.

The Company's CNG and LNG solutions are designed to capture the opportunity for emission reductions in the transportation and remote power generation sectors and provide an important source of load growth on FEI's systems. The Company is not asking for approval of any natural gas for transport programs as part of this LTGRP.

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89 Stx Canada Marine: West Coast Marine LNG Supply Chain Project; prepared for Transportation Development Centre of Transport Canada; October 2013; Table 5-11.

90 The Provincial GHG emissions inventory only includes marine emissions for vessels transiting intercoastal waterways. Marine vessels that regularly call BC Provincial ports that originate from ports from other countries are not included in the Provincial emissions inventory and should be considered as a GHG reduction strategy through the use of natural gas.

2.4.2 RNG

In response to customer demand for sustainable energy options and to support the Province's energy and climate change goals,[91] FEI was the first utility in North America to offer an end-to-end RNG supply and service program. FEI initiated development of a low carbon natural gas product offering in June 2010 and today, the RNG Offering gives customers the means to support low carbon energy initiatives. Customers that elect to purchase RNG continue to receive natural gas supply from the FEI distribution system but notionally replace a percentage of their traditional gas supply with biomethane,[92] or RNG. Because the BC Government considers biomethane to be carbon neutral, customers with GHG emission reduction targets (such as public sector organizations or municipalities) can purchase a portion of their natural gas supply through the RNG Offering to offset their climate emissions. FEI customers that participate in the RNG Offering can elect to designate 5, 10, 25, 50 or 100 percent of the natural gas they use as RNG. These customers pay a premium on their natural gas bill dependent on the percentage level of RNG that they select (please see Figures 2-10 and 2-11 for an energy cost comparison of 100 percent FEI RNG with FEI natural gas and BC Hydro electricity). Participants in the RNG Offering also receive a credit on the BC carbon tax on their bill.

Though supply and demand for the RNG Offering is small when compared against FEI's traditional gas service, the program remains an important part of the Utility's customer offering. The 2017 LTGRP's RNG annual demand forecasts assume current RNG supply technologies. FEI is aware that pilot projects exist for expanding the base of RNG supply technologies. One example is a project that seeks to prove the commercial scalability of RNG from wood waste. If such cellulosic biogas does become available at reasonable prices, it would dramatically increase RNG supply and thus potentially enable FEI to substantially increase RNG annual demand via its RNG program. FEI will continue monitoring the progress of cellulosic biogas pilot projects.

The LTGRP does not contain any requests in relation to the RNG program. Section 3 discusses RNG impact on annual demand. Section 5 references RNG in relation to FEI's gas supply considerations. Section 8 outlines the RNG program's impact on FEI GHG emissions.

2.4.3 Others

The Company is improving customer engagement through education and awareness of the benefits of natural gas use, along with providing customers with energy management tools facilitated through multiple communication channels. As such, FEI continues to explore ways to engage a wider network of builders and developers along with other influencers of residential gas use including architects, engineers, contractors, manufacturers, dealers and homeowners.

[91] The BC Bioenergy Strategy aims to "launch British Columbia as a carbon-neutral energy powerhouse in North America [and] help BC achieve its targets for zero net greenhouse gas emissions from energy generation, improved air quality, electricity self-sufficiency and increased use of biofuels." BC Bioenergy Strategy, 2009.

[92] Biomethane is derived from biogas, which is produced from decomposing organic waste from landfills or agricultural waste. When captured and cleaned, biomethane is interchangeable with conventional natural gas and can be injected into the existing natural gas pipeline system. Biogas is readily available in BC and most importantly, it is a renewable fuel. Once upgraded, biogas is called biomethane or RNG.

This activity is aimed at building natural gas load, mitigating declining market share in some sectors, and improving customer and stakeholder engagement through opportunities to promote natural gas education, awareness and training.

To support the above goals, FEI is contributing to various projects that support commercializing innovative natural gas utilization technologies that will help FEI meet its customers' preferences for natural gas while also addressing societal plans for reducing GHG emissions. Such technologies achieve this goal by raising the efficiency of natural gas end uses and also reducing the GHG emissions intensity of both the natural gas stream as well as individual end uses. The initiatives include:

- Work with the Canadian Gas Association (CGA) and its member companies to explore injection of hydrogen into the natural gas pipeline system (hydrogen combusts without generating GHG emissions and can be derived via electrolysis which makes it a candidate for decarbonizing the natural gas stream while serving as a potential storage medium for electricity generated from renewable sources);
- Support for a project to capture and make commercially usable carbon emissions from commercial natural gas end-use appliances, such as commercial furnaces;
- Research into commercialization of gas-driven heat pumps which could help natural gas appliances exceed 100 percent end-use efficiency;
- Research into combined heat and power appliances that increase the aggregate energy use efficiency of natural gas end-use appliances by generating heat and power from the natural gas stream; and
- Support for commercializing small-scale residential natural gas end-use appliances that are designed to meet the reduced heating requirements of more energy efficient newly constructed buildings.

2.5 *CONCLUSION*

The development of unconventional natural gas supply has opened up vast reserves of natural gas throughout North America. Advances in drilling and well productivity have led to record high production and as natural gas supplies have grown, commodity prices have fallen. A low price environment is generating new sources of natural gas demand. The availability and cost to supply gas to traditional BC and PNW markets may change in the future as the commodity moves from production areas to areas of high demand growth.

Although the decline of natural gas commodity rates has improved the fuel's price competitiveness against electricity on an operating cost basis, this decline has been offset by the relatively higher capital, installation and maintenance costs for natural gas equipment and increasing end-use efficiency of electric appliances. Furthermore, the role of natural gas in its traditional use of space and water heating, which makes up over 80 percent of residential natural gas throughput, continues to be challenged by changing energy and emissions policies, appliance standards and regulations. These declining trends negatively impact throughput and load growth, and increase the importance of FEI's actions to mitigate this pressure. Though the evolving natural gas marketplace presents a number of utility challenges, FEI is also presented with opportunities to capitalize on new areas to add new system load.

To help maintain the competitiveness of natural gas rates, FEI is focusing on growing the customer base and increasing throughput on the natural gas system by developing new markets for natural gas use. FEI continues to develop sustainable energy solutions, such as NGT, RNG and C&EM programs, as well as to pursue innovative technologies, such as thermal metering or commercial appliance carbon capture, to help satisfy customer and stakeholder demand for new, innovative solutions while simultaneously reducing customers' energy costs and environmental impact. The Company continues to remain flexible in its service offerings in order to overcome the challenges presented by an evolving energy marketplace while capitalizing on opportunities to serve customer needs for safe, reliable, efficient and cost effective energy.

This LTGRP addresses the evolving elements of the planning environment discussed in this section by examining a range of possible scenarios in the Utility's analysis for annual and peak demand forecasting, DSM activities, system resource needs and gas supply portfolio planning:

- Section 3 provides a range of annual demand forecasts based on a number of future scenarios that incorporate a variety of outcomes based on these planning environment uncertainties;
- Section 4 examines a range of potential energy savings for FEI's C&EM programs based on consideration of the same potential outcomes that are used to examine demand forecasts;
- Section 5 includes consideration of how these planning environment uncertainties may impact resource cost and availability for FEI to secure a stable, reliable and cost effective source of gas supply; and
- Section 6 examines how a range of potential future peak demand scenarios could be influenced by these planning environment uncertainties and the effect that these could have on the timing to address future constraints on FEI's gas delivery system.

3. ANNUAL ENERGY DEMAND FORECASTING

3.1 *INTRODUCTION AND BACKGROUND*

Two key elements that underpin FEI's resource planning activities are the forecasts of annual demand and peak demand for natural gas. FEI's demand forecasts are used to ensure adequate system capacity, to plan gas supply resources, and also to provide a baseline against which to analyse the impact of proposed or potential future initiatives such as expanded energy efficiency and conservation activities or growth in natural gas sales for fuelling transportation.

The annual demand forecast discussed in this Section represents annual consumption by region and customer class, and allows the Company to determine directional rate impacts and annual gas supply needs in the Company's long term planning efforts. In contrast, the peak demand forecast provides an estimate of the maximum daily natural gas demand that would be expected under extreme weather conditions. Gas supply planning (discussed in Section 5) uses system-wide daily peak demand and also relies on the annual shape of the load curve to model prolonged periods of high demand throughout the year. In contrast, system capacity planning (discussed in Section 6), relies on regional peak day and, in certain cases, peak hour demand to design FEI's regional system infrastructure to be able to meet that peak day or peak hour demand.

The current planning environment is uncertain. The Company recognizes that its customers are using natural gas in different ways and amounts than they did in the past. Heating equipment installed in new buildings and in retrofit situations is more efficient and, in some cases, results in a different demand profile than the older equipment it replaces. Potential new demand from the transportation and industrial sectors may also impact the Company's overall demand profile. While recent demand history is appropriate for short term demand forecasting, a method which relies on modelling long range changes in energy end uses is more appropriate for longer forecast horizons.

This section of the 2017 LTGRP addresses Section 44.1(2)(a) of the UCA, which requires utilities to include an estimate of the demand for energy the utility expects to serve in the absence of taking new demand-side measures. This section is organized as follows:

- Sections 3.2 and 3.3 set the stage by outlining FEI's base year customer distribution and annual demand and by discussing FEI's customer forecast which serves as the basis for both of the 2017 LTGRP's two annual demand forecast methods;
- Sections 3.4.1 to 3.4.5 explain and compare FEI's traditional annual demand forecast method (Traditional Annual Method) with its end-use annual demand forecast method and outline FEI's end-use annual demand forecast scenario analysis (FEI uses the Traditional Annual Method to ground its end-use annual demand forecast method and uses the end-use annual demand forecast method to plan its resources across the 2017 LTGRP long term forecast horizon);

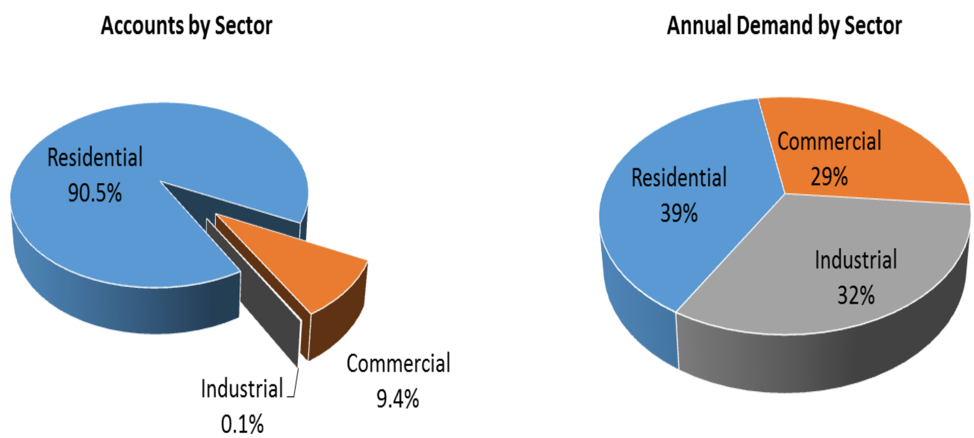
- Sections 3.4.6 and 3.4.7 discuss the annual demand impact of FEI's NGT and RNG initiatives; and
- Section 3.4.8 outlines FEI's total annual demand forecast while Section 3.4.9 discusses the impact of potential new large industrial point loads on this annual demand.

3.2 *EXISTING RESIDENTIAL, COMMERCIAL, & INDUSTRIAL CUSTOMER DEMAND*

The 2017 LTGRP uses a 2015 base year, starts its forecast in 2016 and ends the forecast horizon in 2036. The 2017 LTGRP selected the 2015 base year because FEI had not finalized its 2016 actuals in time for the 2017 LTGRP analysis to import this data while also being able to conclude in the 2017 submission year.

FEI's customer base includes approximately one million customers, consisting predominantly of residential customers that account for approximately 90 percent of the overall customer base (see **Error! Reference source not found.** below). However, on an annual demand basis, there is a more even split between the residential, commercial, and industrial groups. The makeup of the Company's customer base and demand patterns has implications for infrastructure requirements and conservation goals as discussed throughout this LTGRP.

Figure 3-1: FEI Customer Base and Demand Overview, 2015



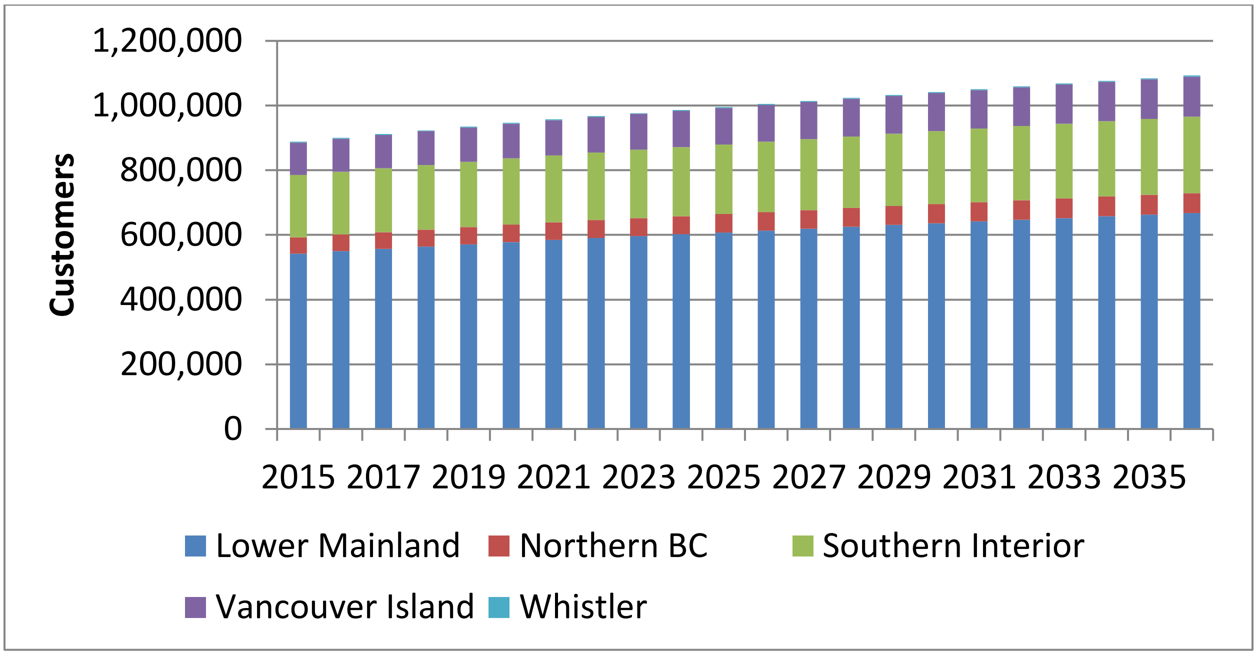
3.3 *CUSTOMER ADDITIONS FORECAST*

FEI uses a well-established method to forecast customer additions that remains consistent with previous LTRP filings. The forecast of residential customer additions is grounded in the Conference Board of Canada housing starts forecast for BC, while commercial customer additions are forecast based on recent trends in growth for the commercial customer group. In its decision on FEI's 2014 LTRP, the BCUC noted that it expects FEI's future LTRP filings to show "forecast variability in new customer additions for all scenarios based on different economic growth assumptions".[93] The 2017 LTGRP relies on a statistical method for altering the Reference Case customer forecast across the various scenarios such that the individual scenarios use different customer forecasts. Please refer to Appendix B-1 for an explanation of this method and illustrations of its impact on the Reference Case account forecast. Section 3.4.4 explains how the LTGRP treats different account growth trajectories as one of the critical uncertainties for its scenario analysis. Section 3.4.5 details the scenario analysis results.

3.3.1.1 Residential

Figure 3-2 shows the Reference Case forecast of residential customers for each of the Company's service areas, as defined for the purpose of this LTGRP. The Reference Case predicts growth of 23 percent across the 20-year planning period with regional distribution remaining relatively unchanged.

Figure 3-2: Long Term Customer Forecast by Region – Residential[94],[95],[96]



3.3.1.2 Commercial

Recent trends in commercial customer additions are used to forecast future additions. The net customer additions are estimated based on actual additions in the latest three years. Recent additions are stronger than in the period between 2010 and 2014 with annual new attachments averaging in the range of 1,400.

93 Decision and Order G-189-14, dated December 3, 2014. p. 16.

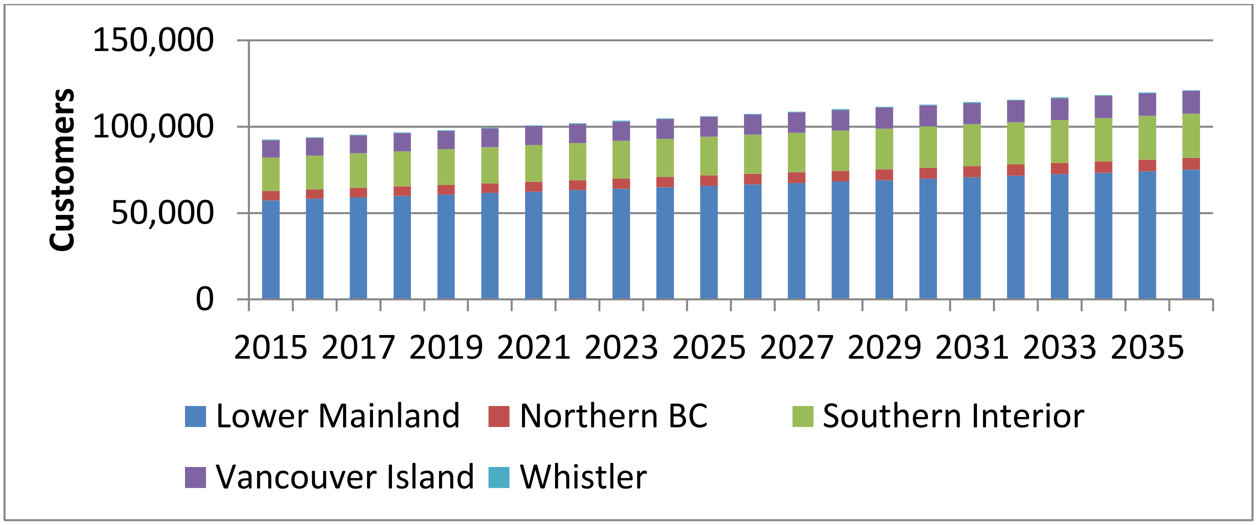
94 All 2017 LTGRP annual demand, customer, GHG, and rate impact graphs, tables, and results exclude data for Vancouver Island Joint Venture, BC Hydro Island Generation, and Company Use.

95 In the 2017 LTGRP analysis customer counts represent the number of FEI accounts.

96 The region names specified in FEI's end-use annual demand forecast method are independent from FEI's internal service areas that may appear in other regulatory submissions or short term forecasts.

Figure 3-3 shows the Reference Case long term account forecast for commercial rate schedule customers for each of FEI's service regions. The Reference Case predicts continued growth of 31 percent across the planning horizon with regional distribution remaining relatively unchanged.

Figure 3-3: Long Term Customer Forecast by Region – Commercial (Excluding NGT)



3.3.1.3 Industrial

The Company had 979 industrial customers in 2015. At the time the long term forecast was prepared, there were no firm commitments for new industrial customers to take natural gas service or for existing customers to close their accounts. Hence, no material growth or decline in industrial customers has been forecasted.

3.4 *FORECAST METHODS*

The amount of natural gas that the Company expects its customers to use over the course of a year determines both the amount of gas that FEI needs to acquire and transport on behalf of its customers on an annual basis, and the number of units of energy per year over which the Company is able to recover its cost of service. Hence, the forecast of annual demand is a key early step in identifying the resources the Company needs to put into place in order to meet customers' future energy needs.

Using historical data to prepare short term time series forecasts of future consumption is a common and accepted industry practice. This method provides a high level of confidence for near-term business and operational decision making. All short-term demand forecasts for revenue requirements at FEI rely on historical data and the short-term Forecast Information System (FIS), which has been in use for over a decade.

However, as described in Section 2, on-going changes in the end-use energy solutions available to customers and the way in which customers are using energy means that historical trends are not robust enough to provide the best basis on which to forecast the long term potential range of future demand. For this reason, the Company used an approach to demand forecasting in the 2014 LTRP that involved examining different ways that end-use trends in energy utilization could potentially impact future demand for natural gas. FEI refers to this newer method as the "end-use method" of demand forecasting. This method produces a Reference Case annual demand forecast but also enables FEI to examine alternate future scenarios. In contrast FEI's Traditional Annual Method provides one forecast trajectory only.

In its review of the 2014 LTRP, the BCUC and interveners recognized the value of the end-use method. The BCUC directed FEI to continue using its Traditional Annual Method as a parallel approach until such time as the BCUC finds the end-use method acceptable as a substitute.[97]

In its decision on the 2014 LTRP, the BCUC also directed FEI to provide a detailed analysis of the relative benefits and shortcomings of its particular end-use method as compared to other end-use methods. FEI commissioned Boreas Consulting Ltd. (Boreas) to prepare this analysis. Boreas concludes that almost half of the 30 surveyed North American entities use end-use models for all or part their long term forecasts. Entities that run DSM programs or exist within an uncertain or changing planning environment are more likely to use an end-use method. Boreas completed its review before FEI updated its end-use model for the 2017 LTGRP and at that time concluded that FEI's end-use model compares well with other North American end-use methods. Please refer to Appendix B-2 for the Boreas report.

In this 2017 LTGRP, FEI continues to improve on its end-use method as well as to use its Traditional Annual Method. Improvements for the 2017 LTGRP not only enhance FEI's ability to examine the end-use method Reference Case annual demand forecast but also to analyse how annual demand behaves across alternate future scenarios.

Section 3.4.1 below outlines FEI's approach to the end-use method. Section 3.4.2 discusses the end-use method Reference Case annual demand forecast results. Section 3.4.3 compares the end-use method Reference Case forecast results to the Traditional Annual Method forecast results. Based on this foundation, Section 3.4.4 subsequently discusses how end-use method annual demand behaves across alternate future scenarios.

Please refer to Appendix B-3 for more detailed results from the Traditional Annual Method.

3.4.1 End-Use Annual Demand Method – Residential, Commercial and Industrial

To prepare the 2017 LTGRP end-use forecast, the Company used the following data sources to calibrate[98] the forecast model to FEI's 2015 base year actuals and to identify Reference Case end-use changes across the forecast horizon:

[97] Decision and Order G-189-14, dated December 3, 2014.

[98] The calibration process ensures that the sum total annual natural gas demand of all base year end uses in the end-use demand forecast model matches FEI's base year actuals.

- The BC Conservation Potential Review (BC CPR) which represents a collaborative provincial forecast (sponsored by FEI, FBC, BC Hydro, and Pacific Northern Gas) of energy conservation potential and thus benefits from data supplied by all sponsors as well as the rigour of multiple entities acting as reviewers;
- FEI's 2012 Residential End-use Survey (REUS); FEI's 2017 REUS is not complete at the time of filing the 2017 LTGRP;
- FEI's 2015 Commercial End-use Survey (CEUS) which represents FEI's most recent study of its commercial customers; and
- Research and data analysis from the 2014 LTGRP which FEI included to utilize and build upon work that had already been completed for the 2014 LTRP.

FEI engaged Posterity Group (Posterity) to support FEI in preparing the end-use forecast for the 2017 LTGRP. Members of Posterity's team were instrumental in preparing FEI's 2010 CPR and 2014 LTRP end-use demand forecast. Posterity prepared an updated end-use forecast model for FEI based on lessons learned from the 2014 LTRP. As in the 2014 LTRP, the current end-use model provides raw data outputs to FEI which FEI further processes with the database infrastructure that it created for the 2014 LTRP.

The end-use forecast process starts with developing a Reference Case forecast. The Reference Case is based on end-use patterns observed in the base year and keeps these patterns constant throughout the planning period. The impact of C&EM programs up to and including 2015 are thus implicitly included in the end-use characteristics identified for the base year, but the existing program activity is assumed not to have any incremental impact through the planning period for the purpose of demand forecasting. Section 4 separately discusses the impact of FEI's forecast future C&EM activities.

3.4.2 Development of the Reference Case for Annual Demand

The Reference Case began with the development of a base year, in this case 2015. FEI provided Posterity with a database of accounts and weather normalized consumption data, categorized by region, rate schedule, and industry (for industrial and commercial customers). To further subdivide natural gas consumption by end-use, Posterity drew on the detailed customer knowledge assembled by the BC CPR and the 2014 LTRP, including end-use consumption, market saturation[99] and gas share.[100] As described in Section 3.4.1 above, some

[99] Market saturation is a percentage indicating what portion of the population of buildings has a given end-use. For end-uses such as space heating and water heating, this is assumed to be 100 percent of dwellings. For an end-use such as clothes drying, where the logical unit of analysis is the appliance, the percentage is the number of clothes dryers divided by the number of dwellings. Market saturation in the commercial sector is based on the percentage of building floor space with a given end-use, instead of percentage of dwellings. Market saturation is not employed in the industrial model – saturation is taken into account in the overall end-use consumption for a given plant type.

[100] Gas share is the percentage of the energy end-use that is supplied by natural gas. For clothes dryers, for example, this translates into the percentage of dryers that are natural gas-fired. Note that that gas share is based

of this information has been derived from end-use surveys commissioned by the Company, while other aspects emerged from detailed building modeling. The resulting model, calibrated to FEI's actual normalized sales of natural gas, is subdivided as follows:

- By region: Lower Mainland, Vancouver Island, Whistler, Southern Interior, Northern BC;[101]
- By sector: Residential, Commercial and Industrial;
- By segment (i.e. sub-sector):
    - In residential — three dwelling types, detachment type, dominant heating fuel, and vintage;
    - In commercial — seventeen building types, by predominant use and building size (office, retail, school, hospital, etc.);
    - In industrial — ten plant types;
- By rate schedule: one rate schedule in residential, six rate schedules in commercial, and nine rate schedules in industrial; and
- By end-use: twelve residential, five commercial and seventeen industrial gas end-uses.

Beginning with the calibrated base year, the Reference Case forecast was built using the Company's 20-year account forecast (discussed in Section 3.3), with new residential dwellings, commercial floor area and industrial facilities added based on the account growth rates. Anticipated efficiency improvements, such as the natural replacement of furnaces, were incorporated in both existing buildings and new construction. Anticipated changes in the saturation and gas shares for specific end-uses were also included. The end-use forecast model provides the forecast consumption values for each forecast year at the same level of granularity as the base year.

Figures 3-4 and 3-5 below display end-use demand forecast annual demand by sector and by region. Overall, Reference Case demand is expected to grow slightly, motivated by growth in the commercial and residential sectors.

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on the percentage of useful energy supplied to accomplish the end-use (i.e. the tertiary load); actual energy consumption equals tertiary load divided by the efficiency of the appliance that meets this load.

[101] The region names specified in FEI's end-use annual demand forecast method are independent from FEI's internal service areas that may appear in other regulatory submissions or short term forecasts.

Figure 3-4: Reference Case Annual Demand Forecast by Rate Schedule – End-Use Method (Excluding NGT)[102]

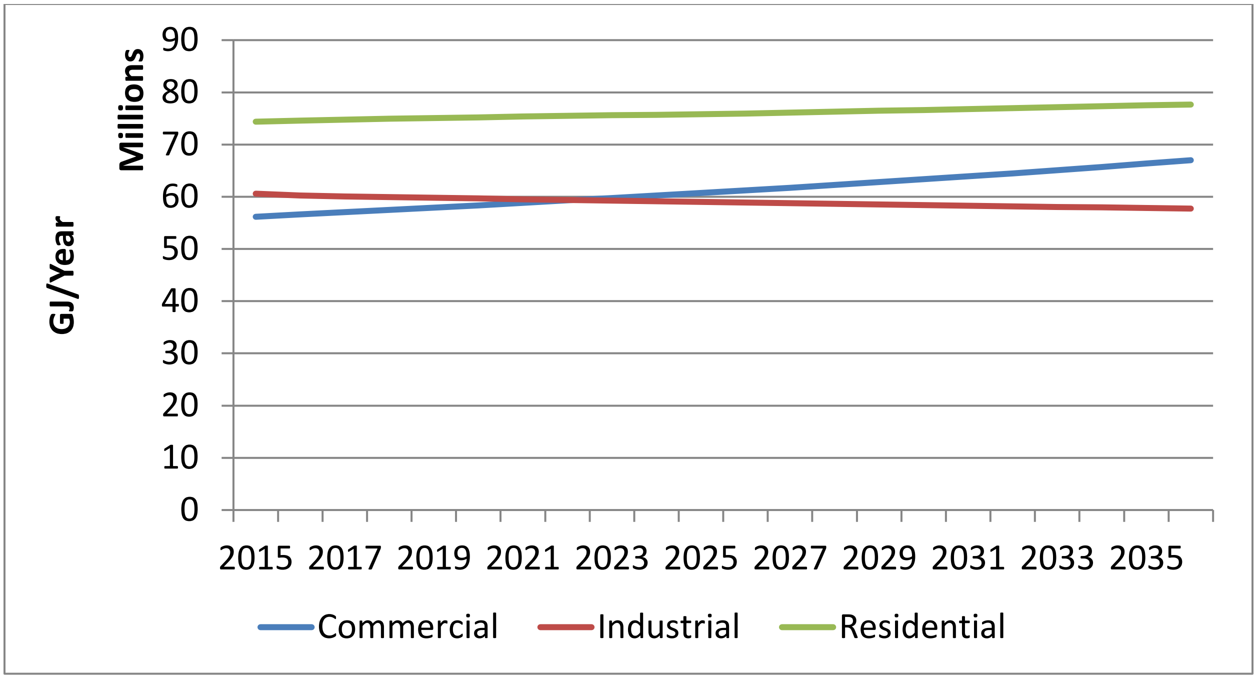
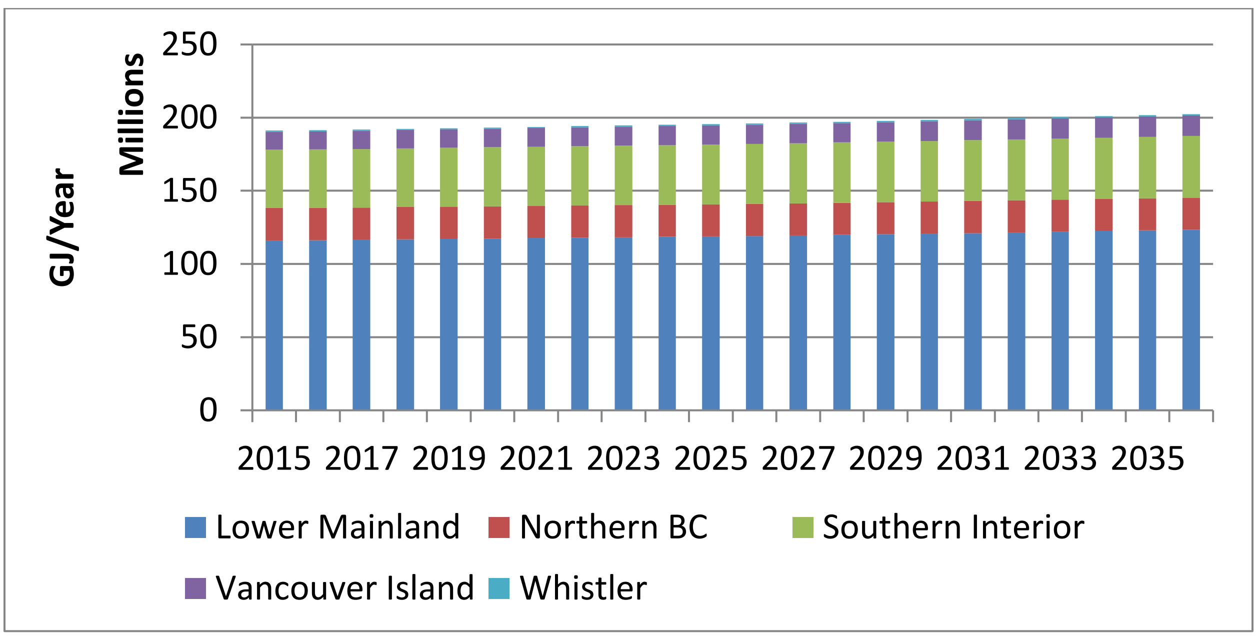


Figure 3-5: Reference Case Annual Demand Forecast by Region – End-Use Method (Excluding NGT)



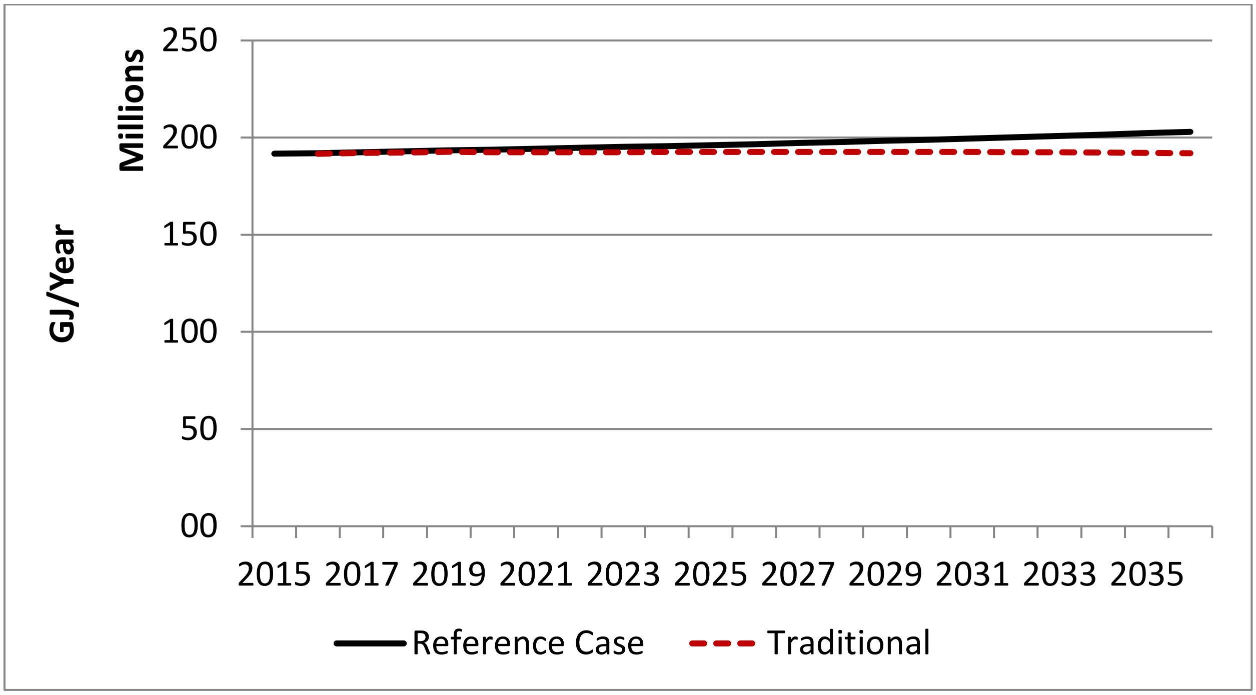
[102] This and the following figure exclude consumption of FEI's LNG customers.

3.4.3 Comparing the Traditional and End-Use Methods For Forecasting Annual Demand

As discussed above, FEI's end-use method differs in a number of ways from its time-series based Traditional Annual Method. Comparing the end-use method Reference Case results with the results of the Traditional Annual Method grounds the results of the end-use method before FEI proceeds to use this method for examining the impact on annual demand of alternate future scenarios. If the results of the Traditional Annual Method demand forecast and the end-use method Reference Case annual demand are reasonably aligned, then the end-use method provides a reasonable basis for developing alternate future scenarios.

Figure 3-6 below compares the annual demand results of the Traditional Annual Method with the results of the end-use method Reference Case. By the end of the planning period the two forecast methods differ by less than six percent. This variance is due to the various differences between the two methods. One of these differences is that the Traditional Annual Method includes intrinsic historical end-use trends, whereas the end-use method Reference Case limits itself to fully known, legally enshrined, and mandatory data. For example, the Traditional Annual Method includes historical change trends of energy performance codes and standards while the end-use method Reference Case only accounts for such changes that are already legally enshrined and are or will be mandatory during the forecast horizon. By the same token, the Traditional Annual Method includes historical C&EM program participation trends whereas the end-use method Reference Case relies on specific assumptions regarding future changes in equipment characteristics and adoption but not C&EM programs. Across the LTGRP planning horizon, FEI uses the end-use method Reference Case to plan for its forecast long term annual demand.

Figure 3-6: Comparison of Annual Demand Forecasts



3.4.4 Alternate Future Scenarios

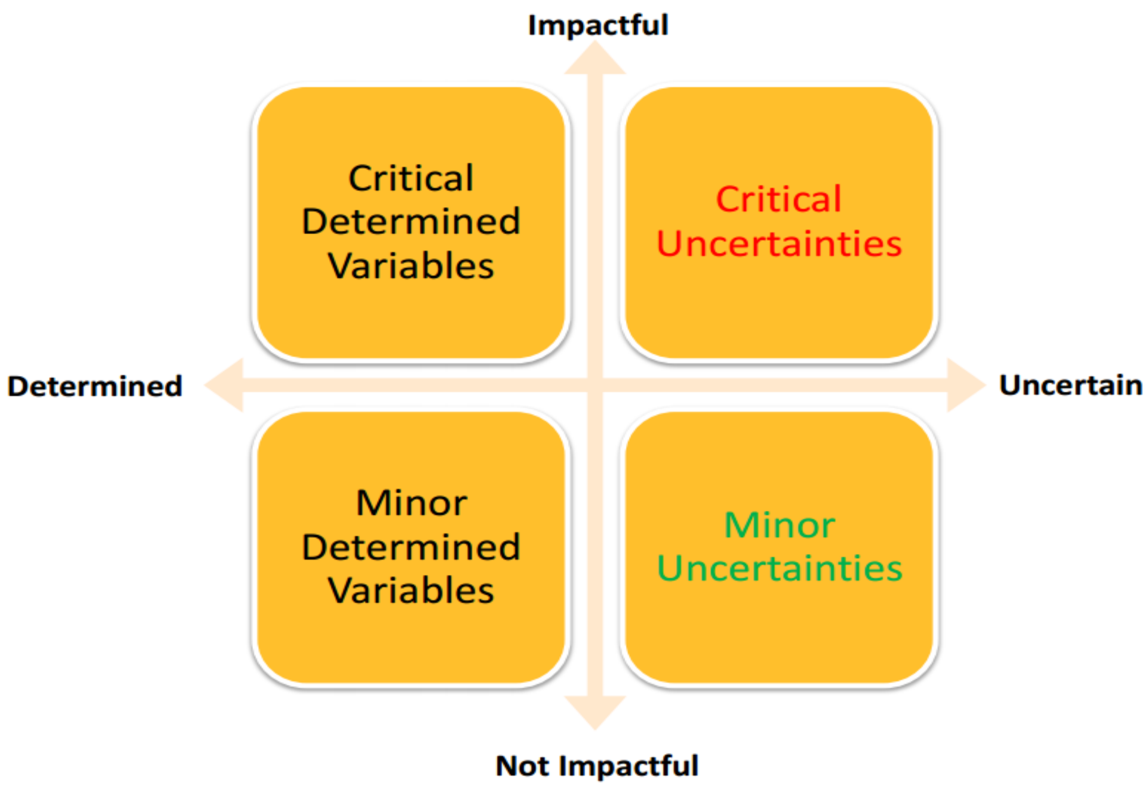
The Reference Case provides a baseline against which forecast demand under five different alternative future scenarios is examined. The five future scenarios are intended to provide insight into the impact on demand of a broader range of potential future conditions than has been examined in previous LTRPs. These five scenarios were developed based on critical uncertainties identified with input from the scenario analysis work for the 2014 LTRP, both internal FEI stakeholders and members of the external Resource Planning Advisory Group (RPAG), as well as themes that emerged from the 2017 LTGRP's community engagement workshops. The critical uncertainties represent those future conditions that FEI and stakeholders felt could have the biggest impact on FEI's business.

Following a standard scenario planning approach, FEI's scenario analysis proceeds in four steps:

1. Evaluating planning environment variables and identifying critical uncertainties;
2. Determining the number of outcomes and their broad qualitative boundaries for each selected critical uncertainty;
3. Determining plausible combinations of outcomes for each critical uncertainty and creating reasonable scenario plotlines; and
4. Populating quantitative data into the outcomes for each critical uncertainty and iterating with internal and external stakeholder feedback.

The first step in the above list intends to focus the scenario analysis by determining which of the manifold variables in the planning environment should be used to alter the Reference Case into various alternate future scenarios. This involves selecting the most impactful and most uncertain variables. Figure 3-7 below illustrates how FEI classified planning environment variables for this first step:

Figure 3-7: Classification of Planning Environment Variables



FEI intentionally held each step separate from the other steps. Selecting critical uncertainties first and then determining their qualitative boundaries before generating the plotlines and populating quantitative data guards against inadvertently favoring certain visions of the future over others by presupposing scenario results rather than focusing on inputs.

The 2017 LTGRP's critical uncertainties break down as follows:

- Economic variables:
  - Economic growth, represented by account growth values in the forecast model;
  - Natural gas commodity price, based on a multitude of third-party forecasts (this accounts for price changes motivated by various factors, such as demand-supply balance or upstream regulatory changes);

- Policy variables:
  - Carbon price, which accounts for provincial and federal carbon pricing actions and is agnostic to the specific pricing mechanism (the forecast model simply assumes a stream of price values without identifying, for example, whether these are the result of a carbon tax or a cap and trade system);
  - Non-price policy levers, which account for changes in the building code, energy performance standards, and any requirements for switching from one fuel type to another (e.g. district energy systems[103]); and
- The extraneous variables of RNG demand, NGT demand, and demand from large industrial point loads (FEI's scenario analysis assumes that the RNG and NGT markets are still emerging and thus primarily depend on policy and stakeholder action rather than other macroeconomic factors).

Table 3-1 below summarizes the five alternate future scenarios, their descriptions and input settings, and includes a brief discussion of each scenario's specific attributes. This table does not include the Reference Case because the Reference Case sets the baseline for the scenario analysis by using the Reference input setting for all critical uncertainties. Based on the Reference Case, the scenario analysis alters the outcomes of each critical uncertainty to be higher and lower, respectively, than their Reference outcome. Please see Appendix B-1 for a description of the scenario analysis method and the critical uncertainty parameters:

Table 3-1: Alternate Future Scenario Summary

Scenario	Description	Input Settings		Discussion
A (Upper Bound)	The BC economy experiences higher-than-average growth. Infrastructure development in other regions, coupled with extraction infrastructure development in BC, keep regional gas supply abundant. Continued political opposition to carbon pricing and non-price carbon policy action cause governments to focus on issues other than carbon policy but the BC government keeps supporting NGT and RNG as cost effective existing carbon solutions.	Economic Growth	High	In general, the outcomes of the multiple critical uncertainties can offset each other's impact on annual demand but this scenario combines all outcomes that would increase annual demand. As such, this scenario represents one of two boundary scenarios that frame the scenario analysis. The combination of outcomes on each critical uncertainty is plausible and has occurred in the past.
		Natural Gas Price	Low	
		Carbon Price	Low	
		Non-Price Carbon Policy Action	Delayed	

[103] As noted in Section 2.3.4, some BC municipalities are pursuing goals to supply 100 percent of their energy needs via clean and renewable sources by 2050. Some of these municipalities are encouraging deployment of district energy systems. In the near term, such district energy systems may rely on natural gas but municipalities may intend to shift these to other fuel sources in the long term.

Scenario	Description	Input Settings		Discussion
B (Local Growth & Constricted Supply)	The BC economy experiences higher-than-average growth. This is paralleled by moderate growth elsewhere which continues fuelling existing demand for natural gas and constricts BC's natural gas demand balance. High natural gas prices and continued political opposition to carbon pricing and non-price carbon policy action cause government policy to implement energy performance standards upgrades published in their existing vision documents but to avoid imposing carbon costs that exceed annual increases of $5 per metric tonne.	Economic Growth	High	This represents one of the three intermediate scenarios in which outcomes of the multiple critical uncertainties do offset each other's impact on annual demand. Economic growth creates upward pressure on annual demand which is more strongly felt in the commercial and industrial sectors than in the residential sector. Price signals counteract this upward pressure on annual demand (these signals, again, more strongly impact the commercial and industrial sector in relation to the residential sector). Carbon policy action also dampens annual demand. Non-price carbon policy levers more significantly impact residential sector demand than commercial and industrial sector demand.
		Natural Gas Price	High	
		Carbon Price	Medium Increase	
		Non-Price Carbon Policy Action	Accelerated	
C (Global Growth & Carbon Step Change)	The BC economy experiences higher-than-average growth as part of a global economic upturn. Infrastructure development in other regions (such as a strong focus on renewable fuel sources which reduces natural gas export opportunities), coupled with extraction infrastructure development in BC, keep BC's gas demand balance abundant. Global economic performance contributes to a political climate that is favourable to carbon pricing and non-price carbon policy action. This provides governments confidence to strongly focus on carbon policy.	Economic Growth	High	This represents the second of the three intermediate scenarios. This scenario differs from Scenario B in the natural gas and carbon price settings. The annual demand impacts in this scenario versus Scenario B show the trade-off between the natural gas and carbon price trajectories. The directional implications of each critical uncertainty on annual demand in this scenario are identical to Scenario B.
		Natural Gas Price	Low	
		Carbon Price	High Increase	
		Non-Price Carbon Policy Action	Accelerated	

Scenario	Description	Input Settings		Discussion
D (Global Economic Stagnation)	The BC economy experiences lower-than-average growth as part of global economic stagnation which also reduces excess regional demand for natural gas and keeps BC's gas demand balance abundant. Global economic performance contributes to a political climate that is not favourable to carbon pricing and non-price carbon policy action. This causes governments to focus on areas other than carbon policy.	Economic Growth	Low	This represents the third of the three intermediate scenarios and examines the possible impact of further economic stagnation. The annual demand impact of low economic growth is offset by low natural gas and carbon pricing and delayed carbon policy action. As in Scenarios B and C, price signals and the economy are more impactful for the commercial and industrial sector, whereas carbon policy action more significantly impacts the residential sector.
		Natural Gas Price	Low	
		Carbon Price	Low	
		Non-Price Carbon Policy Action	Delayed	
E (Lower Bound)	The BC economy experiences lower-than average growth as part of global economic stagnation. This reduces investment in regional gas supply so much that BC's demand balance becomes constricted. Global economic performance contributes to a political climate that is not favourable to carbon pricing and non-price carbon policy action in other jurisdictions but causes a counter-movement in BC. This causes the BC government to focus on carbon policy and electrification without support for NGT and RNG.	Economic Growth	Low	This represents the second of the two boundary scenarios. This combination of outcomes across the critical uncertainties is plausible but has not been prevalent in the past. Governments have typically been reluctant to impose taxes and other restrictions, including carbon pricing and carbon policy actions, during periods of economic stagnation.
		Natural Gas Price	High	
		Carbon Price	High Increase	
		Non-Price Carbon Policy Action	Accelerated	

The modeling process involved turning each of these assumptions into concrete changes to the input values for buildings in the three sectors. For example, in response to higher or lower gas prices, adjustments were made to the number of new buildings using natural gas for specific end-uses, or to the number of existing buildings whose owners might opt to change fuels when equipment needs replacement. The policy environment affects assumptions about the number of customers who would opt to install energy efficient equipment naturally, without influence from utility programs. Assumptions for developing district energy systems resulted in adjustments to the fuel shares for those options: increases in those fuel shares would generally displace the demand for natural gas. Renewable energy systems include systems such as geo-exchange, waste heat recovery, and solar thermal energy. This has the effect of displacing natural gas consumption, particularly for space and water heating in commercial buildings and apartments. With limited but growing market penetration of low carbon thermal energy systems, the Company must continue to monitor this growth to gauge its impact over time on the Utility's natural gas infrastructure, annual and peak day demand, system capacity needs and rate design.

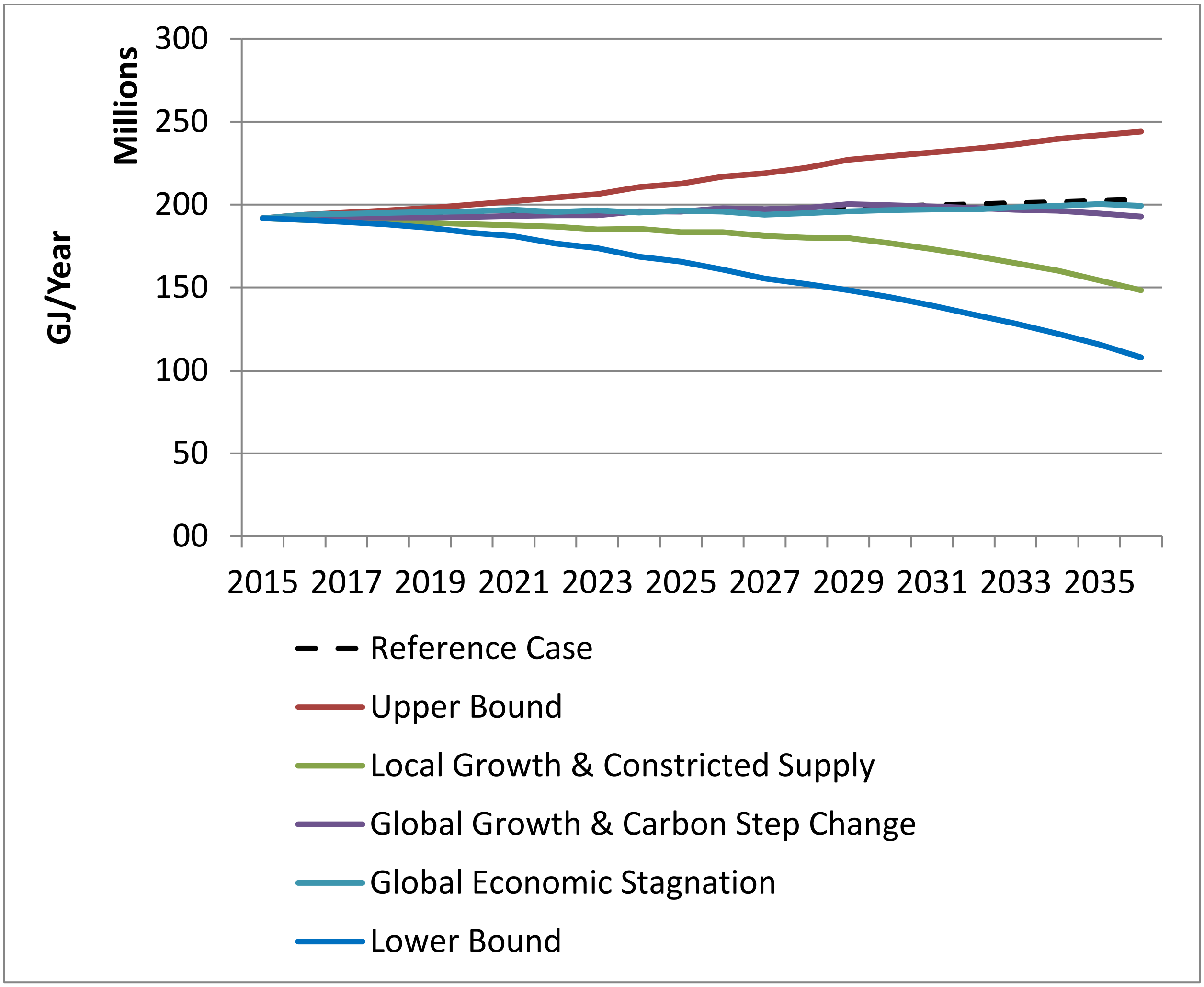
The model results for Scenarios A through E have the same level of granularity as the Reference Case. FEI does not predict which scenario will unfold in the future and does not assign probabilities to the scenarios. Rather, the five scenarios (considered together) provide a reasonable range of possible future demand that the Company will need to serve over the next 20 years.

Please refer to Appendix B-1 for a detailed explanation of the end-use demand forecast scenario parameters.

3.4.5 End-Use Demand Forecast Results by Scenario

Figure 3-8 below displays the end-use annual demand Reference Case and scenario results for all sectors and regions.

Figure 3-8: Annual Demand Scenarios – All Sectors (Excluding NGT)



As can be seen in Figure 3-8, the Upper and Lower Bound scenarios denote the range of the forecast. By the end of the planning period, this range accounts for a variation of 67 percent around the Reference Case. This range has widened since the 2014 LTRP due to increased policy uncertainty and FEI's updates to the scenario analysis inputs. Nevertheless, the majority of scenarios (and the Reference Case) cluster within a narrower annual demand range since outcomes across critical uncertainties offset each other's impact on annual demand.

Figure 3-9 below displays the same information for the residential sector.

Figure 3-9: Annual Demand Scenarios – Residential Sector

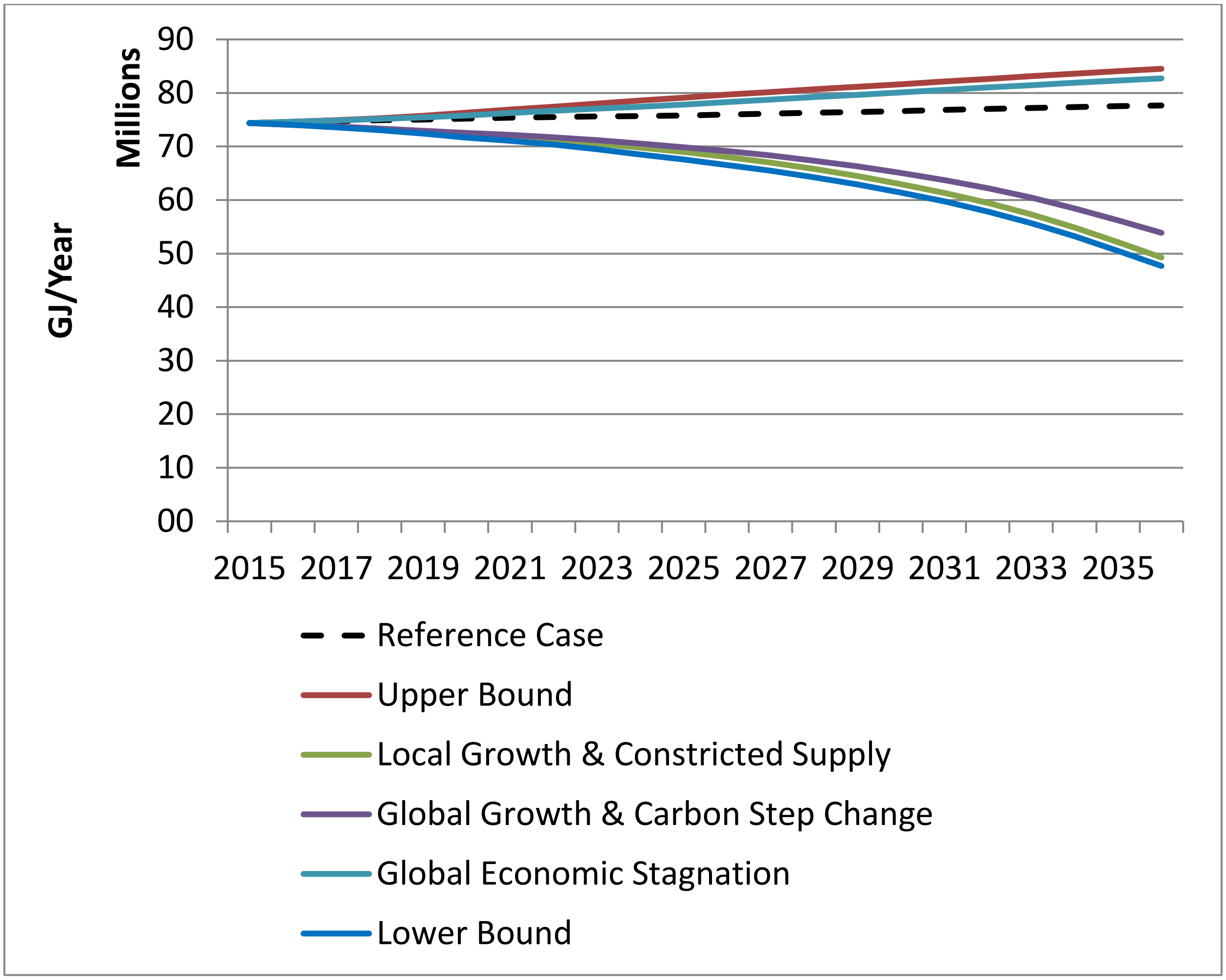


Figure 3-9 illustrates the following effects for the residential sector:

- The Upper Bound and Global Economic Stagnation scenarios differ in their economic growth assumption only. Annual demand for these two scenarios is aligned closely because, in FEI's forecast model, economic growth has a limited impact on residential sector customer numbers.
- The remaining three scenarios are also closely aligned. The difference between the Local Growth & Constricted Supply and Global Growth & Carbon Step Change scenarios highlight how the trade-off in natural gas versus carbon pricing between these scenarios impacts residential annual demand.

As illustrated for the Lower Bound scenario in Figure 3-10 below, the declining demand scenarios also involve a significant decline in space heating annual demand. Measured by annual demand, central space heating remains the top end-use until the end of the planning period. Domestic hot water end-use annual demand declines below fireplace annual demand near the middle of the planning period (this does not apply to the Reference Case and Upper Bound scenario). This observation represents one of the interesting results that can be extracted by utilizing the end-use method (in contrast to the Traditional Annual Method).

Figure 3-10: Lower Bound Annual Demand – Residential Sector (Excluding NGT) Top End Uses

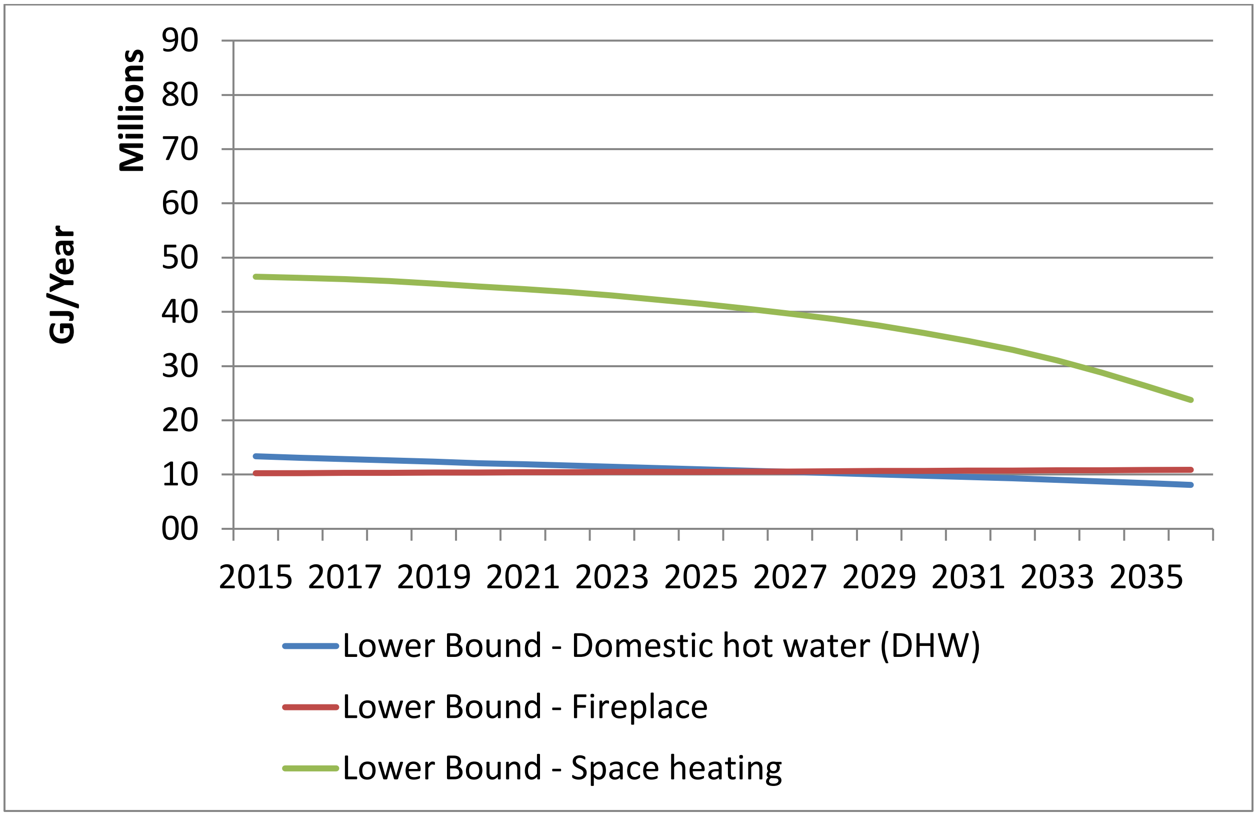


Figure 3-11 below displays the same information for the commercial sector in all regions.

Figure 3-11: Annual Demand Scenarios – Commercial Sector (Excluding NGT)

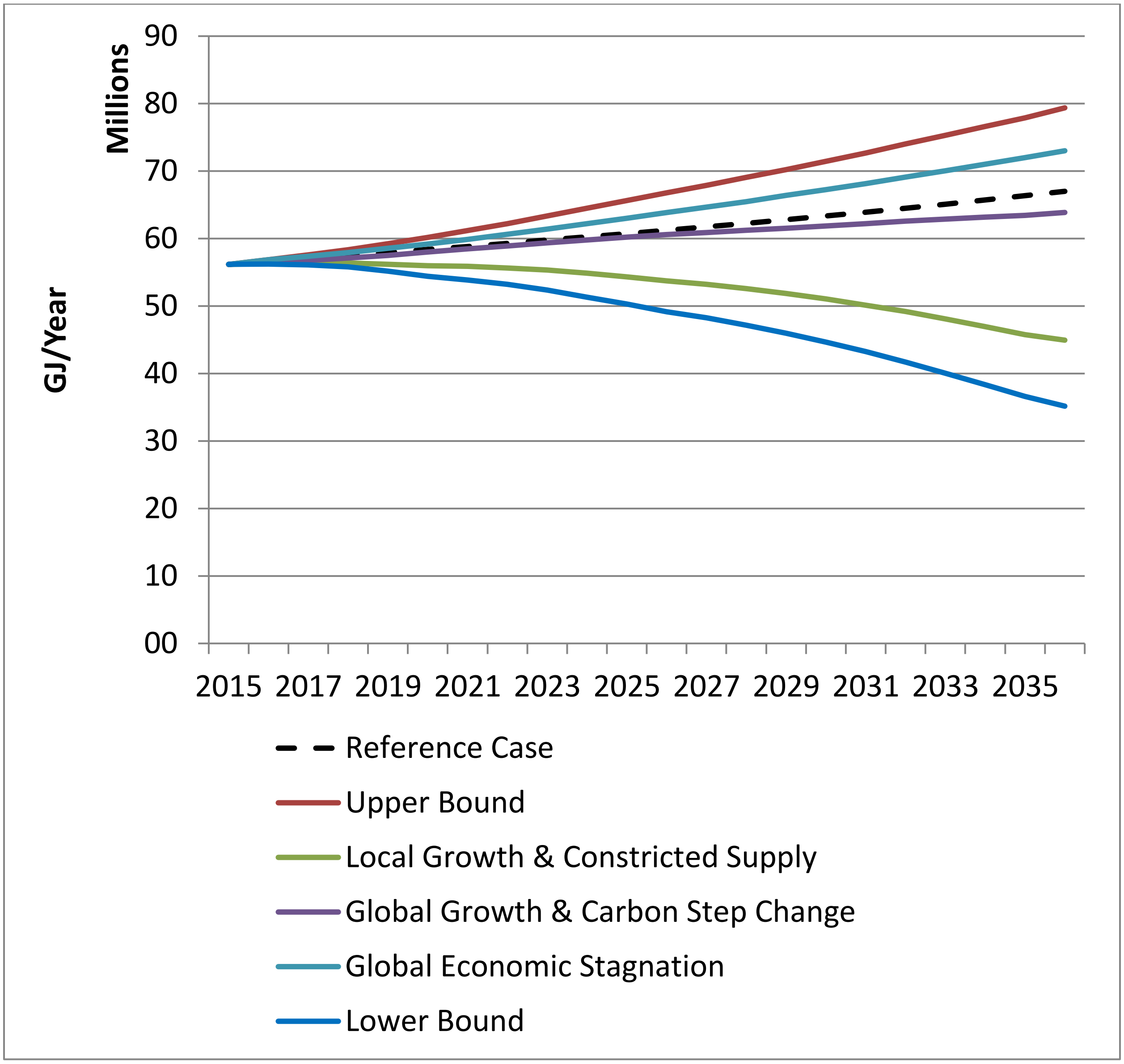


Figure 3-11 illustrates the following effects for the commercial sector:

- The annual demand difference between the Upper Bound and the Global Economic Stagnation scenarios illustrates the annual demand impact of the economic growth critical uncertainty on the commercial sector.
- The widened difference between the Local Growth & Constricted Supply and the Global Growth & Carbon Step Change scenarios highlights the increased annual demand impact of prices for the commercial in relation to the residential sector (price changes

are the result of the trade-off between natural gas and carbon pricing across the two scenarios).

- In the commercial sector, the Global Growth & Carbon Step Change scenario displays annual demand growth since the impact of high economic growth outweighs the impact of price signals and non-price carbon policy action.

Figure 3-12 below displays the same information for the industrial sector in all regions.

Figure 3-12: Annual Demand Scenarios – Industrial Sector (Excluding NGT)

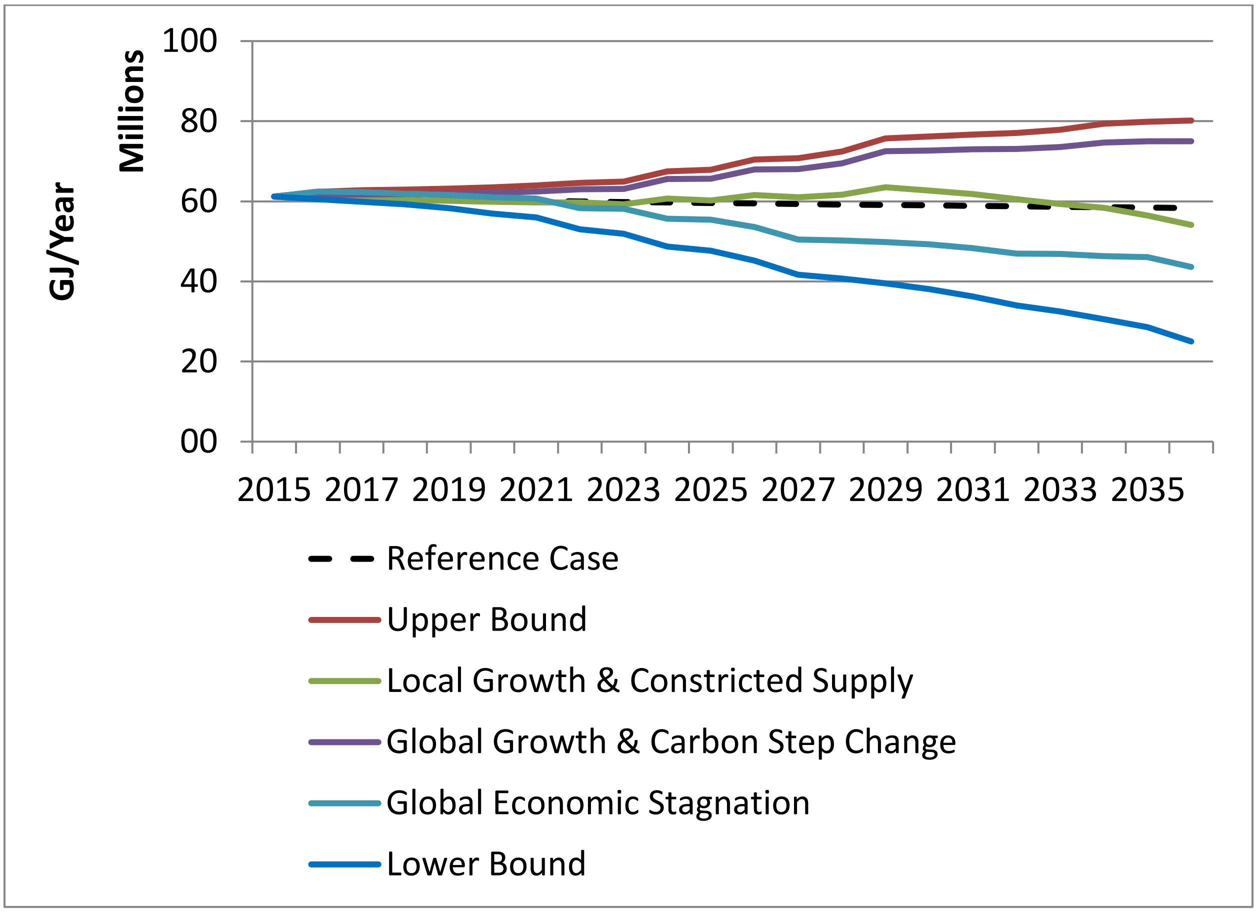


Figure 3-12 illustrates the following effects for the industrial sector:

- The annual demand trajectories are jagged because the economic growth critical uncertainty causes additions/removals of individual customers, and industrial customers typically have high annual demand.
- The annual demand difference between the Upper Bound and the Global Economic Stagnation scenarios illustrates the significant annual demand impact of the economic growth critical uncertainty on the industrial sector (in relation to the residential and commercial sectors).

- Again, the widened difference between the Local Growth & Constricted Supply and the Global Growth & Carbon Step Change scenarios highlights the increased annual demand impact of prices for the industrial in relation to the residential sector (price changes are the result of the trade-off between natural gas and carbon pricing across the two scenarios).
- Annual demand for the Global Growth & Carbon Step Change scenario is closely aligned with the Upper Bound scenario. These two scenarios differ in their carbon price and non-price carbon policy action critical uncertainties only. Since non-price carbon policy action has a limited impact on the industrial sector, this alignment illustrates the influence of carbon pricing on the industrial sector.
- Annual demand for the Global Economic Stagnation scenario initially exceeds the Local Growth & Constricted Supply scenario but falls below this over time. In the Global Economic Stagnation scenario, low natural gas and carbon pricing initially compensate for low economic growth but fail to do so throughout the remainder of the planning period.

3.4.6 RNG Demand

Based on the historical performance of the RNG program, FEI anticipated that the annual demand impact of this program across the planning period would be limited. FEI included a full quantitative RNG annual demand forecast in the 2017 LTGRP because of stakeholder interest in seeing this data. Stakeholders in both the RPAG and FEI's Community Engagement workshops voiced this opinion.

Figure 3-13 below displays the Reference Case share of RNG annual demand in relation to total natural gas demand. Customers that use RNG still utilize FEI's infrastructure. RNG annual demand displacing conventional natural gas demand for individual customers does not change the total volume of annual demand that FEI's infrastructure provides to such customers.

Figure 3-13: Reference Case Annual Demand – All Sectors (Excluding NGT), Data Labels Denote RNG Demand

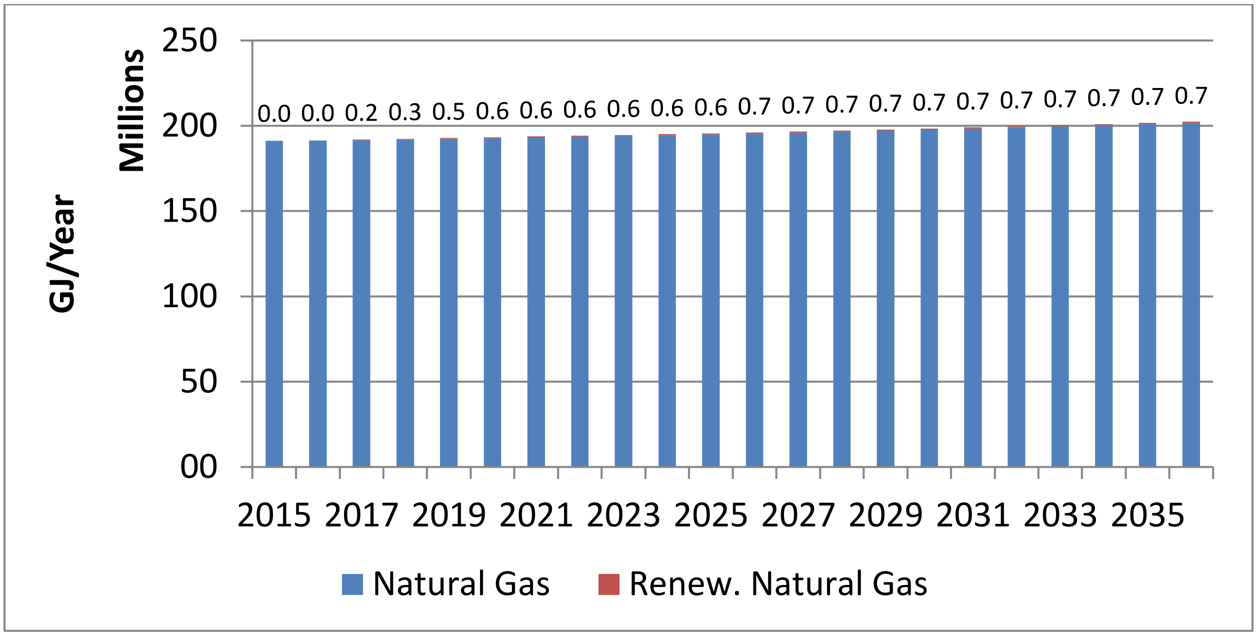
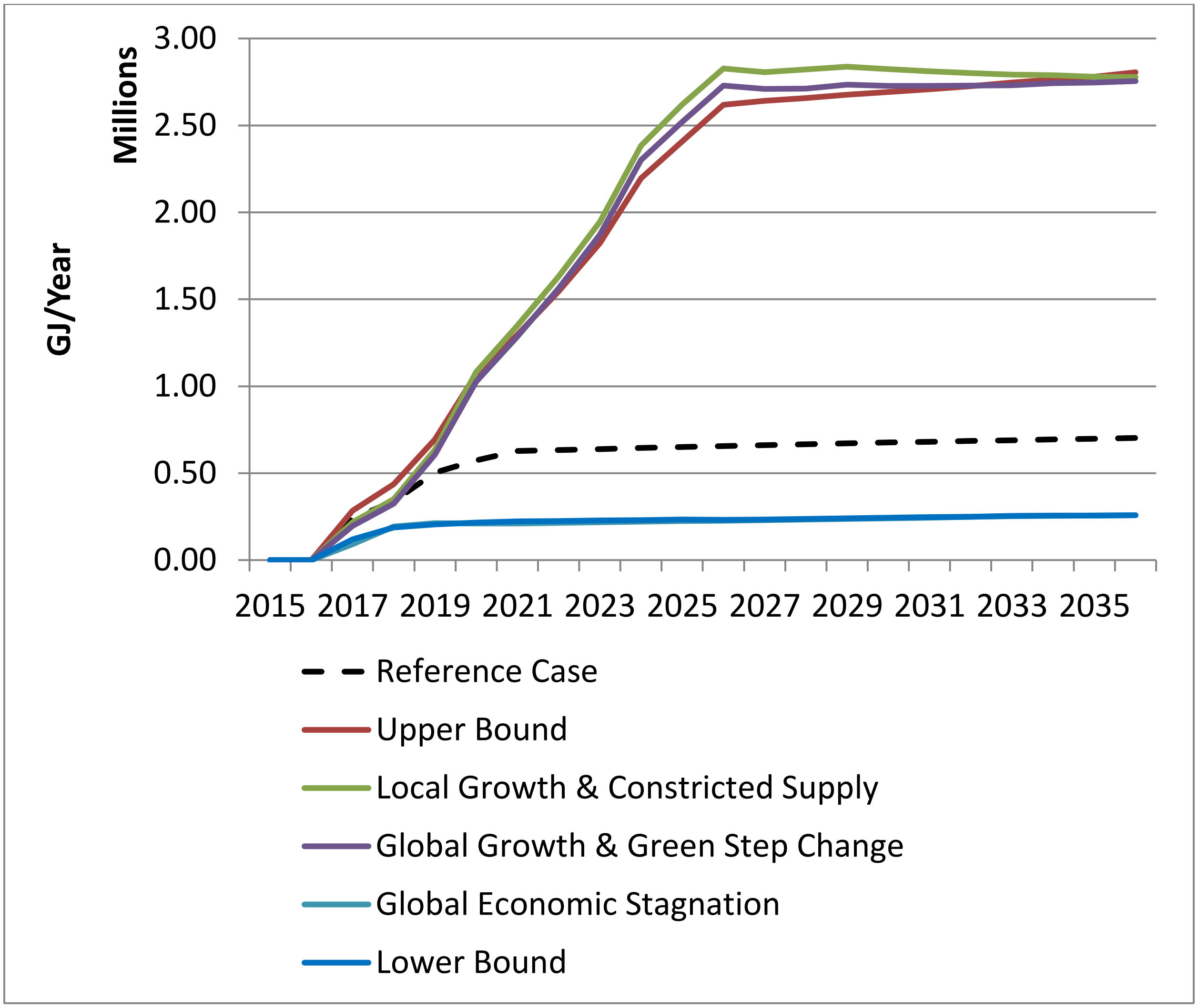


Figure 3-14 below displays how RNG annual demand changes across the 2017 LTGRP scenarios. In the Reference Case, RNG annual demand grows by 195 percent by 2036. This growth rate changes to 888 percent and 117 percent in the Upper and Lower Bound scenarios, respectively. The links between the core end-use forecast and the RNG annual demand forecast are qualitative only because RNG represents an emerging market. FEI provided the core end-use forecast scenario parameters to its RNG program team and requested this team to prepare three forecast trajectories (Reference Case, Low, High) based on these scenario parameters. FEI's RNG program team prepared the three forecast trajectories by altering expectations about committed projects, projects under negotiation, and assumptions about plausible future capture rates. FEI's RNG program team also shaped the resulting RNG annual demand forecast trajectories to align with expectations about RNG supply availability within the currently approved pricing model.[104] FEI's forecast trajectories assume current RNG supply technologies. FEI is aware that pilot projects exist for proving the commercial scalability of RNG from wood waste. If such cellulosic biogas does become available at reasonable prices, it could dramatically increase RNG supply and thus potentially enable FEI to substantially increase RNG annual demand via its RNG program. FEI will continue monitoring the progress of cellulosic biogas pilot projects.

[104] RNG forecasts account for regulatory decisions up to the end of March 2017.

In the scenario analysis, shifts to RNG displace some fuel switching away from conventional natural gas to non-gas fuel types. For example, in the Global Growth & Carbon Step Change scenario, policy impels some customers to switch away from conventional natural gas. Across FEI's customer sectors, this switch away from natural gas is offset by the difference between the Reference Case RNG annual demand and the Global Growth & Carbon Step Change RNG demand.

Figure 3-14: RNG Annual Demand Scenarios – All Sectors



3.4.7 Forecast of Annual CNG and LNG Demand

Natural gas as a transportation fuel has emerged as a growing market in BC, both for CNG and LNG customers. As discussed in Section 2, the Company has established programs (incentive and infrastructure investment opportunities) that are enabled through the BC government's GGRR to assist customers with:

- Incentives toward the incremental cost of new natural gas vehicles (which includes marine vessels, mine haul trucks, on-road trucks, buses and locomotives) and remote power generation applications;
- Incentives toward upgrading maintenance shop facilities to service natural gas vehicles; and
- The construction of fuelling infrastructure that would service these natural gas applications.

The long term CNG and LNG demand forecasts presented in this section are based on three factors: (1) FEI's experience in the GGRR vehicle incentive applications that FEI conducts quarterly to solicit incentive funding interest from NGT customers, (2) industry research, and (3) policy changes that are expected to impact the demand for natural gas as a transport fuel in the future. Some other considerations are the allowed funding period permitted under the GGRR, actual NGT customer additions to date and the relative price of competing or incumbent fuels such as diesel fuel. Sections 3.4.7.1 and 3.4.7.2 further elaborate on these factors.

The natural gas demand forecasts were completed separately for CNG and LNG applications as each segment, utilizing natural gas in either CNG or LNG form, has distinct characteristics and different considerations. CNG is positioned as a fuel for on-road transport applications such as transit buses, waste haulers and heavy duty on-road trucks. LNG is positioned to emerge as a fuel for off-road and high horsepower applications such as marine vessels, locomotives, mine haul trucks and remote industrial power and heat generation applications.

Similar to the RNG forecast, the links between the core end-use forecast and the NGT annual demand forecast are qualitative only because NGT represents an emerging market. FEI provided the core end-use forecast scenario parameters to its NGT programs department and requested three forecast demand trajectories (Base, High, Low) based on these scenario parameters. Section 3.4.8 outlines how these NGT scenarios are incorporated into the 2017 LTGRP annual demand forecast.

3.4.7.1 CNG Demand Forecast Method

To formulate the different demand curves, FEI determined the eligible market size by first quantifying the size of the diesel fuel market for transportation in BC. This data was obtained from Natural Resource Canada's (NRCan) Transportation Sector – British Columbia and Territories database, which displays the 2014 fuel consumption for the transportation sector by fuel type[105]. This fuel consumption database provided the basis for the 2014 market size, which was then escalated by a forecasted growth rate.

The sectors included in the market size were passenger light trucks, freight light trucks, medium duty trucks, heavy duty trucks, school buses, urban transit, and inter-city buses. The forecasted

[105] Appendix D-24: http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive/trends_tran_bct.cfm.

growth rate per year was derived from the NEB's report "An Energy Market Assessment – Canada's Energy Future 2016 Update"[106]. This report is a forecast of Canada's energy supply and demand projections to 2040.

Using the 2014 market size determined by the NRCan database, the growth rates of natural gas and diesel fuel consumption were used from the NEB's report to extrapolate out to 2036; utilizing the NEB and NRCan reports, the potential market in 2036 is approximately 76 million GJ.

Utilizing the above information, FEI developed a Base, Low, and High case scenario, described below.

3.4.7.1.1 CNG BASE SCENARIO DEMAND FORECAST

The CNG Base case forecast was derived in two parts: the number of vehicles that are expected to be in-service based on the GGRR incentive program,[107] and the estimated number of vehicles to come in-service after the GGRR program expires on March 31, 2022.

For the period of 2017 to 2020, the forecast includes incremental load growth based on known and expected customer commitments that FEI has made under the GGRR incentive program (current and expected). From 2021 and beyond, the forecast contains assumptions regarding incremental load generated per year. FEI has assumed an annual growth in vehicles of about 85 additional CNG vehicles to the road per year. These additional CNG vehicles translate to an approximate net incremental growth of 100 thousand GJ per year.

This method for the Base case assumes actual load from existing CNG customers in 2016 will continue throughout the term of the forecast period. This assumes that the existing customers are not retiring their CNG vehicles and will continue to renew or replace their CNG vehicles with a natural gas equivalent.

For the Base case scenario, based on the growth of CNG demand, FEI assumes that it will capture about 4 percent of the eligible market by the end of the forecast period of 2036. This level of market capture constitutes a growth rate of approximately 6 percent per year.

3.4.7.1.2 CNG LOW SCENARIO DEMAND FORECAST

The CNG Low case scenario is based on no expansion or advancements on natural gas engines, the spread between diesel prices and natural gas prices decreasing in favour of diesel, policies becoming unfavourable to natural gas adoption and the availability and efficiency of alternative energy engines increasing (i.e. electric vehicles).

This scenario assumes that minimal growth occurs and existing customers continue to renew their natural gas fleet vehicles with minimal additions to their natural gas fleet. As a result, the

[106] NEB (2016). "Canada's Energy Future 2016: Update – Energy Supply and Demand Projections to 2040 - Figure Data [EXCEL 651 KB]". Appendix D-25: https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/index-eng.html.

[107] This represents FEI's initiative that seeks to engage customers in adopting natural gas as a transportation fuel. Please see Sections 2.3.3.4 and 2.4.1 for further details on the GGRR mechanism and regulatory context.

market share for the Low case scenario forecasts a market share of about 1 percent of the eligible market size by 2036, which results in an annual growth rate of about 1 percent per year or an average demand addition of approximately 8,000 GJ per year.

3.4.7.1.3 CNG HIGH SCENARIO DEMAND FORECAST

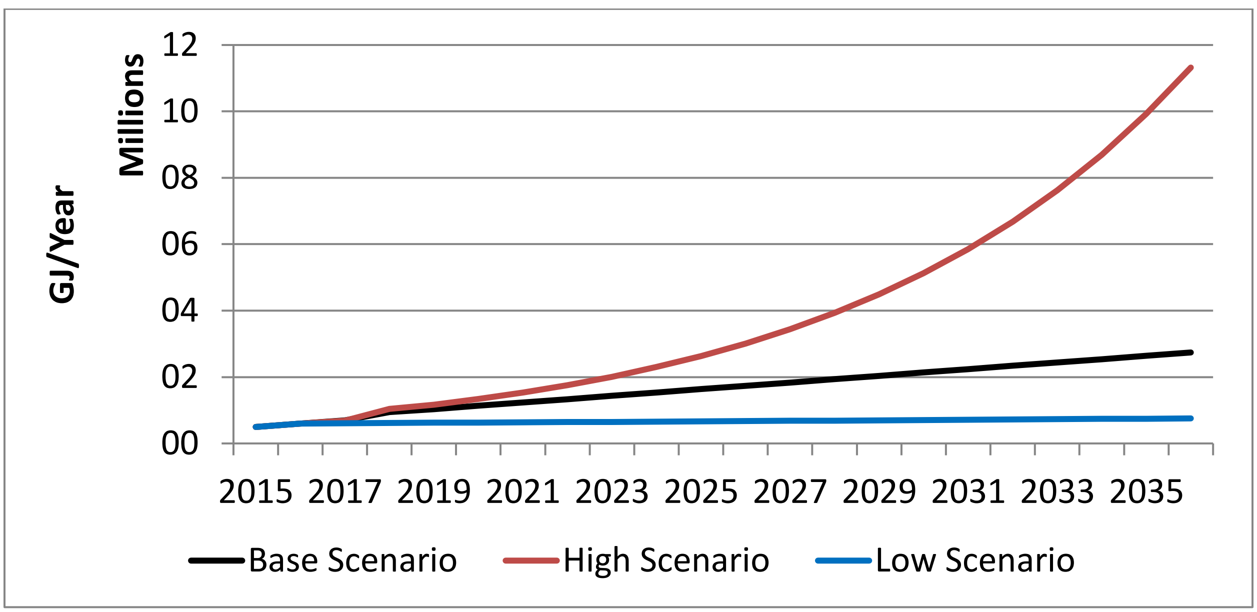
The High case scenario is predicated on expansion or advancements in natural gas engines (better efficiencies and availability), the spread between diesel prices and natural gas prices increasing in favour of natural gas, an increased spread in carbon pricing between diesel and natural gas, and policies favouring natural gas adoption.

It assumes the popularity of NGT vehicles will increase dramatically due to operating advantages over diesel and that the natural gas refuelling infrastructure is constructed over time, providing better access to fuel for CNG customers.

By 2036, for the High case scenario forecast, FEI expects to capture approximately 15 percent of the potential eligible market in BC, which equates to an average annual growth rate of about 16 percent per year or an average demand addition of approximately 532 thousand GJ per year from 2017 to 2036.

Figure 3-15 below displays a forecast of CNG demand growth on FEI's system over the planning period (2017 to 2036) across the three scenarios.

Figure 3-15: Forecast Annual Demand from Long Term CNG Adoption Scenarios (2017-2036)



3.4.7.2 LNG Demand Forecast Method

LNG is supplied under FEI's Rate Schedule 46 LNG Supply tariff (RS46). The LNG is provided by FEI from two LNG facilities: Tilbury in the Lower Mainland and Mt. Hayes on Vancouver Island.

The key early adopters of LNG in BC were on-road heavy duty trucking customers. However, after the preferred high horsepower Cummins-Westport 15 litre high pressure direct injection (HPDI) engine was discontinued in 2013, causing a technology gap in the market, LNG adoption for on-road trucking essentially halted. The key markets that have emerged over the past number of years as consumers of LNG fuel have been high horsepower applications such as marine vessels, mine haul trucks, locomotives, and remote power generation for industrial applications. Similar to the CNG demand forecasts, FEI formulated the LNG demand forecasts by accounting for commitments that have been made by customers to take LNG supply under RS46, then applying inflation and forecasting the impacts of a variety of factors. These factors include the availability of Original Equipment Manufacturer (OEM) technology capable of adopting natural gas, regulatory changes that are expected to drive natural gas adoption and assumptions regarding market size and adoption rates based on past experience for some of the market segments.

The LNG demand scenarios presented below include demand from a number of different market segments that are suited to adopt natural gas as a fuel.

LNG for the marine market could be the largest share of the overall demand if this market segment adopts natural gas over the forecast period. As such, any changes in these marine markets in terms of suitability of adopting natural gas will have a larger impact on the overall LNG demand forecasts as this market segment makes up a large share of the overall demand forecast.

3.4.7.2.1 LNG LOW SCENARIO DEMAND FORECAST

For the Low demand forecast scenario, FEI assumed that LNG demand would grow to about 13 million GJ per year by about 2025 through the capture of key LNG markets such as coastal freight vessels, domestic passenger ferries, locomotives, mine haul trucks and stationary power generation for industrial applications. Under this scenario, no growth is expected beyond this initial capture of 13 million GJ per year through to the end of the forecast period of 2036. This scenario also assumes that no trans-Pacific marine vessels adopt LNG as a marine fuel in response to the tighter emissions regulations that are expected to be imposed on the marine industry by the IMO beginning in 2020 (see Section 2).

3.4.7.2.2 LNG BASE SCENARIO DEMAND FORECAST

In the Base forecast scenario, FEI built upon the Low scenario but included some capture rate of trans-Pacific marine vessels as LNG fuel adopters. Through market intelligence and industry research, FEI has identified a certain segment of the trans-Pacific marine segment (international car and vehicle carriers) that would be ideal early adopters of LNG as a marine fuel. Over the forecast horizon to 2036, FEI assumed an annual growth rate of about 5 percent per year beyond 2028 as a Base case demand growth scenario.

3.4.7.2.3 LNG HIGH SCENARIO DEMAND FORECAST

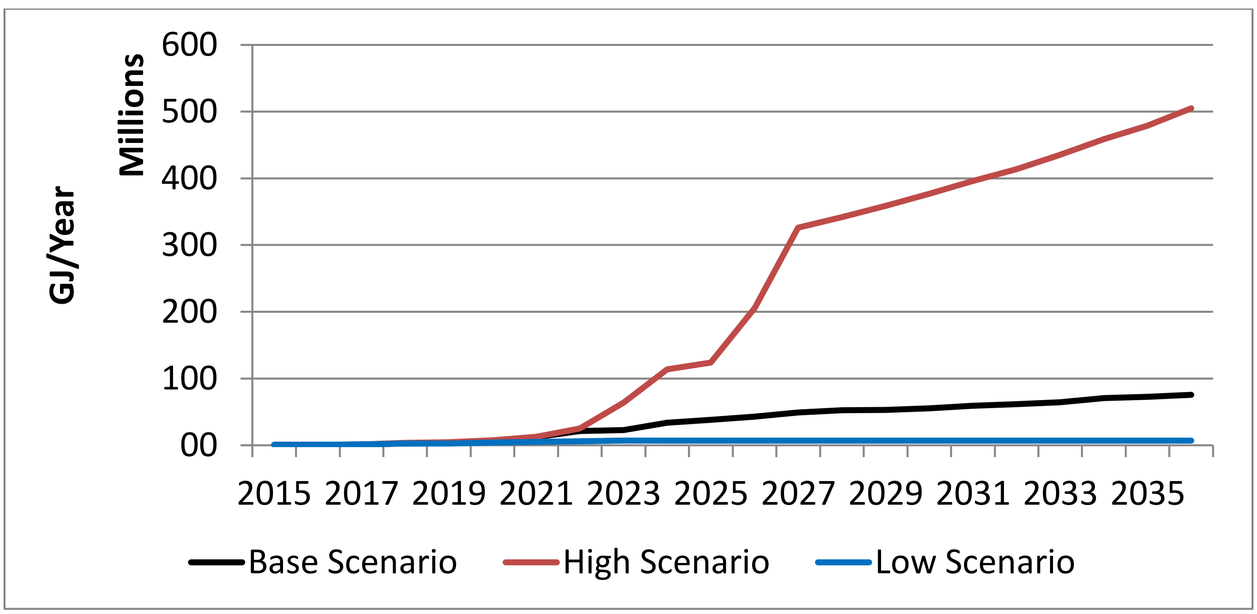
For the High forecast scenario, FEI further built upon the Base scenario but incorporated a more aggressive LNG adoption scenario, particularly from the trans-Pacific deep sea marine segment. In both the Base and High scenarios, the marine segment plays a crucial role in developing LNG demand on a material scale, beyond the capacity of the Tilbury Phase 1A Expansion.

For example, if LNG gains prominence as a maritime fuel and vessels begin to request LNG bunkers from West Coast ports, the High scenario assumes that in addition to the key marine segment identified in the Base case, other marine segments would also adopt LNG on a larger scale. For instance, LNG adoption for container marine vessels was not included in the Base scenario but is included in the High scenario.

The High scenario begins to diverge dramatically from the Base scenario beginning around the 2022/2023 time period due to the impacts from the imposition of the IMO sulfur cap on marine industry emissions beginning to be addressed by the market. This regulation is set to take effect in 2020, which is expected to favourably position natural gas as an alternative fuel to meet these tighter emissions restrictions. Although the IMO sulfur cap will take effect on January 1, 2020, there is much uncertainty as to whether this will be a 'soft cap' to allow marine vessel operators sufficient time to assess and adopt technologies or alternative fuels to meet the 0.5 percent sulfur emissions limit. Due to this uncertainty, FEI assumed that there would be a gradual ramp up in LNG adoption from 2020 to about 2025, at which time LNG adoption could accelerate as the full effects of the IMO sulfur regulation are realized by the maritime industry.

Figure 3-16 below provides a combined illustration of the three LNG adoption scenarios to the end of the forecast period of 2036.

Figure 3-16: Forecast Annual Demand from Long Term LNG Adoption Scenarios (2017-2036)



3.4.7.3 Combined CNG and LNG Demand Forecast

Figure 3-17 below illustrates the combined natural gas demand forecasts by scenario for both CNG and LNG, presented in the two sections above (Sections 3.4.7.1 and 3.4.7.2). FEI combines forecast annual demand from CNG and LNG since FEI's long term planning considers cumulative annual demand of FEI's customers and initiatives. While each fuel type has its own merit in the BC market, LNG accounts for a larger portion of forecast NGT annual demand than CNG and thus shapes the appearance of the combined annual demand graph.

Figure 3-17: Forecast Annual Demand from Long Term CNG and LNG Adoption Scenarios (2017-2036)

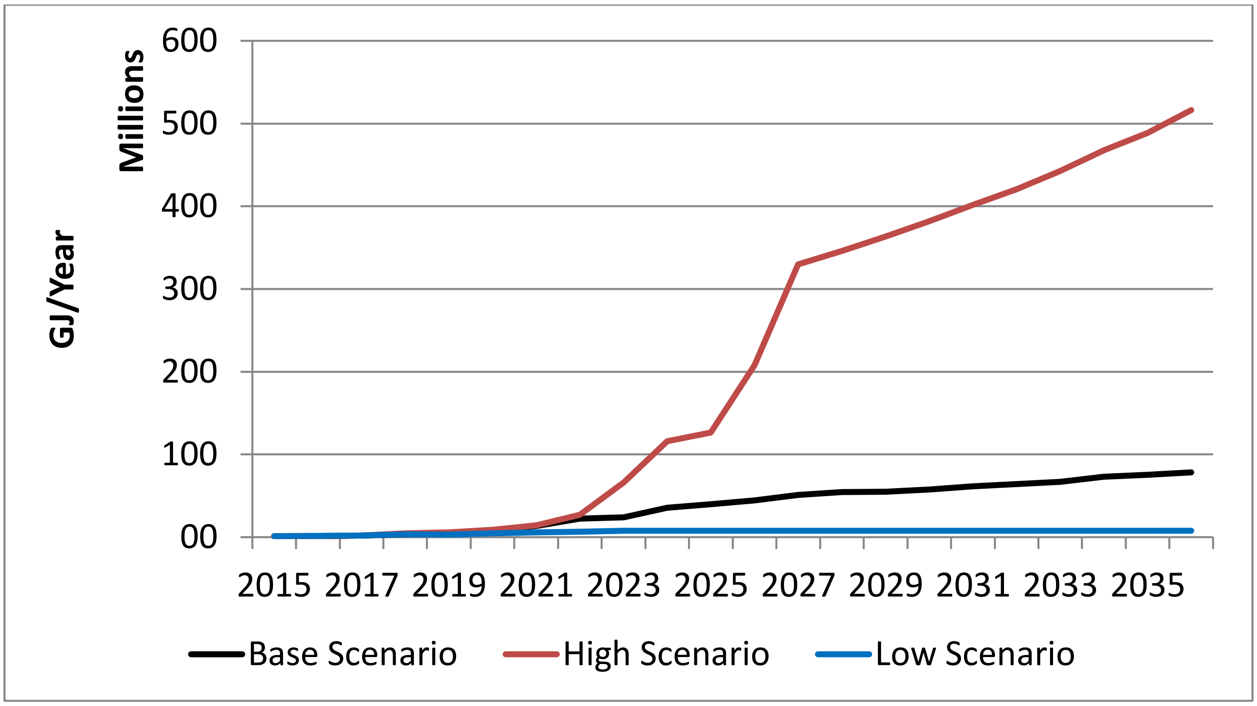
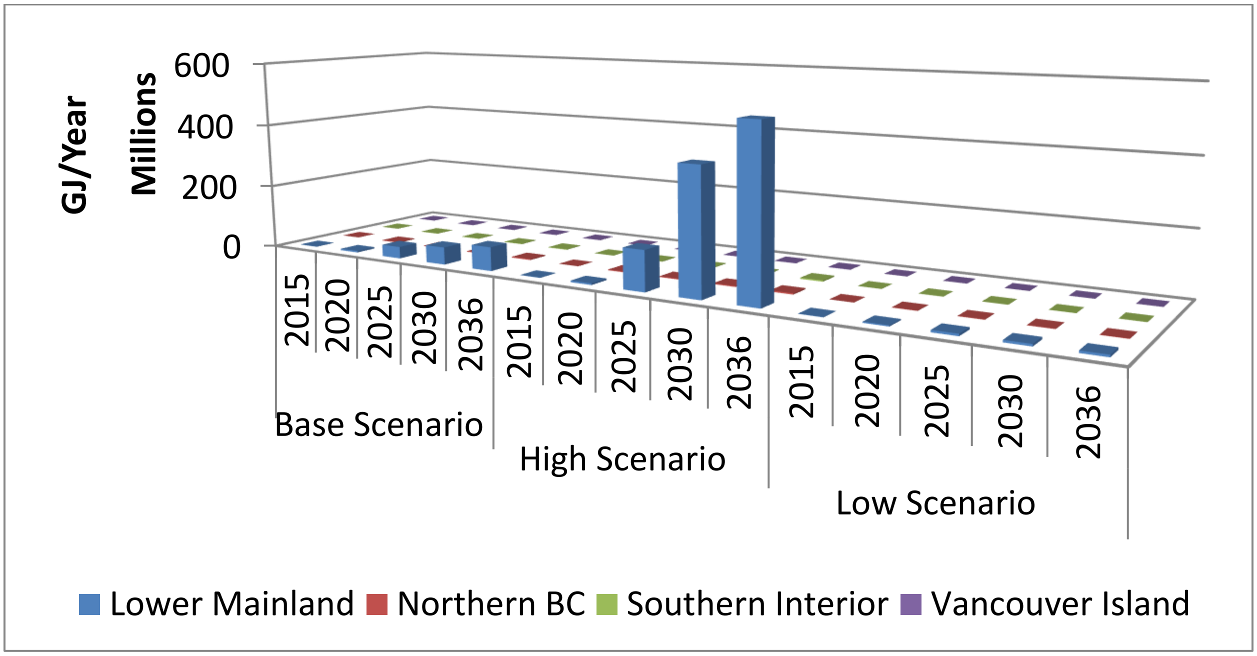


Figure 3-18 below provides a regional look at the CNG and LNG annual demand for natural gas. This graph depicts the effect of adding NGT load to the distribution system and reveals that the majority of NGT load is expected to come onto the system in the Lower Mainland.

Figure 3-18: Forecast NGT Annual Demand (CNG & LNG) – by Scenario and Region

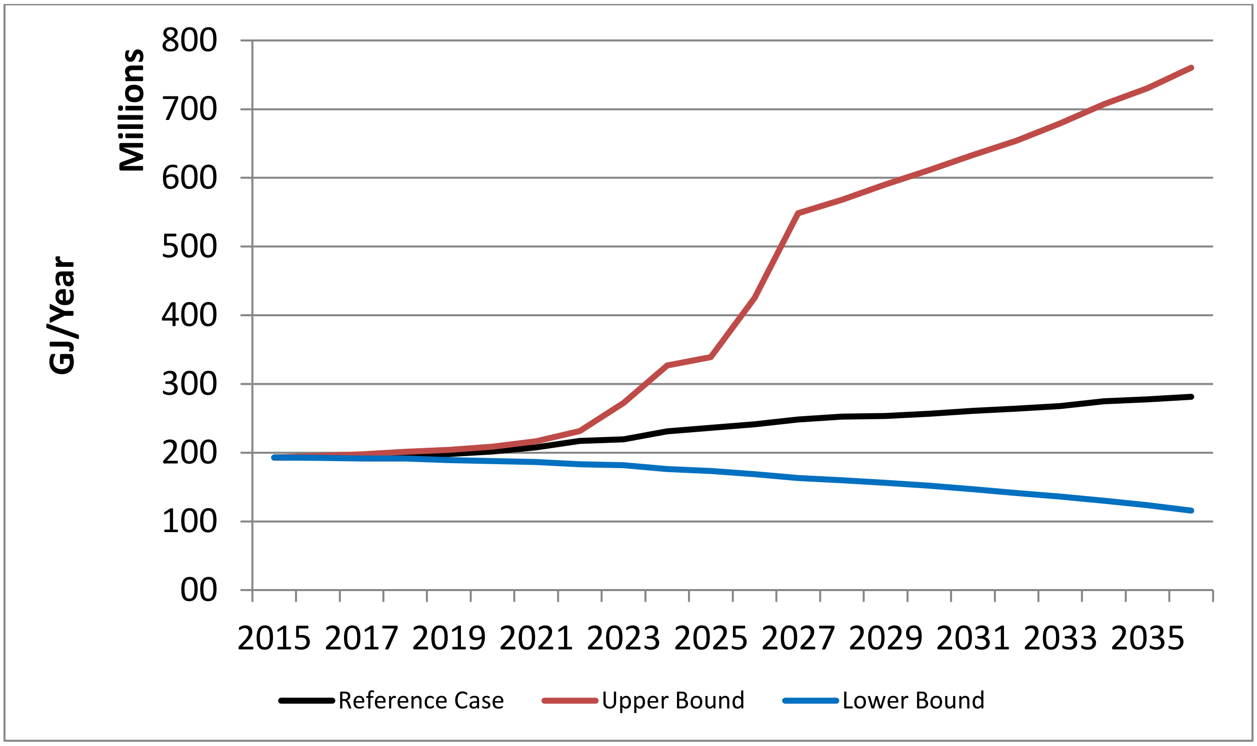


Note: Figure 3-18 displays milestones every five years only in order to fit the information to the report page; the forecast model contains information for all years of the planning period.

3.4.8 Total Annual Demand

FEI serves demand from the residential, commercial and industrial customer base as well as the CNG and LNG customer base. Therefore, to determine the lower limit to the total annual demand forecast, the Company summed the lowest demand scenario for residential, commercial and industrial customers (Scenario E) with the lowest CNG/LNG demand scenario. The same summation was conducted for the highest residential, commercial and industrial demand scenario (Scenario A) and the highest CNG/LNG demand scenario to establish the total annual demand upper limit. The Reference Case residential, commercial and industrial demand was added to the Base CNG/LNG demand to create an overall Reference Case annual demand forecast. Scenarios B, C and D were not examined further as these additional scenarios would result in a demand forecast that lies somewhere between the upper and lower demand forecast limits created by the other scenarios. Figure 3-19 shows the sum of total annual demand for the Reference Case, Upper Bound (Scenario A) and Lower Bound (Scenario E), plus the total annual NGT demand (Base, Low and High cases), and shows the range of total demand that may occur over the planning period. In the Reference Case, total annual demand grows by 46 percent across the planning horizon. This rate changes to a growth of 294 percent and a decline of 40 percent in the Upper and the Lower Bound scenarios, respectively.

Figure 3-19: Total Annual Demand Including NGT – All Sectors



Please see Appendix B-4 for tables that summarize the end-use method annual demand results and Appendix B-5 for a working MS Excel data file which contains annual demand results (sheet tab 1) and the critical uncertainty inputs (sheet tab 2) for natural gas and carbon prices.

3.4.9 Potential Large New Industrial Annual Demand

This section discusses the potential for large industrial point loads, outside of the impacts of CNG and LNG demand as articulated above, in relation to FEI's NGT programs. Customers of this nature which tend to consume more natural gas than FEI's existing industrial customers (e.g. pulp mills) could include LNG export terminals or other large industrial point loads, such as fertilizer or methanol plants.

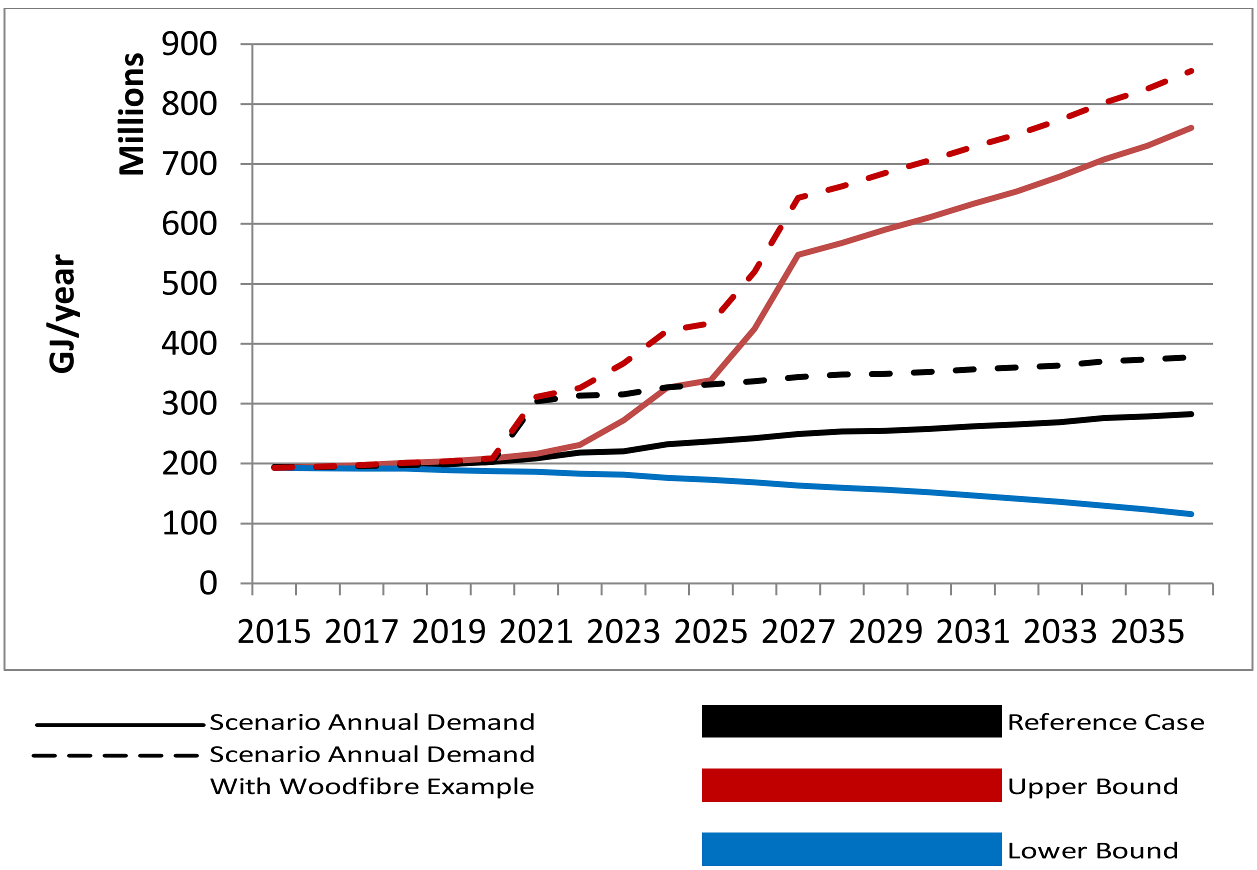
The 2017 LTGRP's results for and discussion of these customers is limited by three factors:

1. Significant uncertainty about when and where such demand would materialize in absence of FEI having firm commitments from prospective customers;
2. FEI must protect the confidentiality of negotiations with prospective large point load customers as a result of contractual obligations; and
3. The uniqueness of each such industrial point load customer, which makes extrapolating potential average impacts of such customers across the planning period difficult.

FEI's current experience indicates that most large scale industrial point loads that are proposed in the PNW will likely have their own pipeline connections to upstream/midstream resources rather than using FEI's pipeline network. In this case, such large industrial point loads would raise questions for regional gas supply and pipeline capacity rather than for FEI's annual demand and the capacity on FEI's system. Sections 5 and 6, respectively, discuss regional pipeline capacity and gas supply considerations as well as FEI's system capacity planning.

Figure 3-20 below displays the impact of the proposed Pacific Energy Corporation (PEC) small scale LNG export and processing facility located on the former Woodfibre pulp mill site near Squamish (Woodfibre LNG Project) on the 2017 LTGRP's total Reference Case and total Upper Bound scenario annual demand. The proposed Woodfibre LNG Project serves as an example to illustrate the potential impact on FEI's annual demand of large industrial point loads that are small enough to still be connected to FEI's system rather than having their own pipeline connection to midstream and upstream resources. For illustration purposes, FEI assumes that the Woodfibre LNG Project will come into service no sooner than 2021[108] and approximates that it will consume 95 million GJ annually[109].

Figure 3-20: Total Annual Demand Including NGT and Woodfibre LNG Project Example



[108] Appendix D-26: https://fortisinc.com/docs/default-source/investor-presentations/presentation-barclays-ceo-8-24-17.pdf.

[109] Woodfibre LNG Project annual demand represents an FEI estimate for illustration purposes rather than a firm commitment by the customer.

3.5 *CONCLUSION*

FEI has provided an estimate of the annual demand for natural gas that it expects to serve over the 20-year planning period, as required under Section 44.1(2)(a) of the UCA. This estimate is presented in Figures 3-19 and 3-20 as a potential range of future demand that can reasonably be expected to occur under differing potential future conditions impacting residential, commercial and industrial customers, as well as customers using natural gas as a transportation fuel. Since the likelihood of predicting actual future conditions is low, probabilities are not assigned to the different scenario outcomes; rather, the Company identifies and implements a set of cost effective resources to meet the Reference Case and establishes contingency plans for meeting the scenario range of potential future annual demand. FEI has based these estimates on the best available information at the time the forecast was prepared. Sections 5 and 6, respectively, of this LTGRP discusses the natural gas supply and FEI infrastructure physical resources required to meet this range of demand, including the timing of peak capacity requirements under higher or lower demand growth. The 2017 LTGRP presents the influence of different annual demand scenarios on customer rates in Section 8.

The end-use approach to annual demand forecasting, based on a plausible but varied range of potential future scenarios, provides an improved view of the way long term demand for natural gas could potentially unfold. FEI has examined future scenarios in which annual demand could dwindle considerably over the planning period, better capturing the risks that the Company is facing in the current planning environment, particularly with respect to carbon policy action and competition from other end-use energy types. At the same time, there are significant opportunities for demand growth while helping to meet provincial energy and economic objectives by facilitating the development of the natural gas for transportation market and by being responsive to potential new industrial demand.

In addition, FEI provides a comparative analysis of the end-use method with the Traditional Annual Method (Section 3.4.3), and includes an analysis of the impact of established new initiatives on demand and GHG emissions by including RNG and NGT in the demand forecast (Sections 3.4.6 and 3.4.7, respectively). The Company presents the GHG emissions from gas use in each scenario and emission reductions from RNG and NGT demand in Section 8.

4. DEMAND SIDE RESOURCES

4.1 INTRODUCTION

Once an estimate of the demand for natural gas in FEI's territory is developed (as has been presented in Section 3) the next step in long term resource planning is to determine what the impact of DSM activities will be on the demand forecast. Table 4-1 below outlines the requirements of Section 44.1(2) of the UCA for long term resource and conservation planning and indicates which items are applicable to and addressed in Section 4.

Table 4-1: UCA Requirements and Areas Addressed in Section 4

Requirement of UCA Section 44.1(2)	Addressed in Section 4
a. An estimate of the demand for energy the public utility would expect to serve if the public utility does not take new demand-side measures during the period addressed by the plan;	Not applicable to Section 4
b. A plan of how the public utility intends to reduce the demand referred to in paragraph (a) by taking cost-effective demand-side measures;	See Section 4.2.4
c. An estimate of the demand for energy that the public utility expects to serve after it has taken cost-effective demand-side measures;	See Sections 4.2.3 and 4.4
d. A description of the facilities that the public utility intends to construct or extend in order to serve the estimated demand referred to in paragraph (c);	Not applicable to Section 4
e. Information regarding the energy purchases from other persons that the public utility intends to make in order to serve the estimated demand referred to in paragraph (c);	Not applicable to Section 4
f. An explanation of why the demand for energy to be served by the facilities referred to in paragraph (d) and the purchases referred to in paragraph (e) are not planned to be replaced by demand-side measures; and	Section 4.2.3 outlines FEI's analysis and Section 4.2.2.1 explains that this incorporates all cost effective demand-side measure activity.
g. Any other information required by the commission.	As requested by Order G-189-14, dated December 3, 2014, Section 4.2 outlines multiple funding scenarios and provides utility cost effectiveness test results for these scenarios. Sections 8.3 and 8.6 address emissions as well as projected delivery rate and average bill impacts.

This section discusses FEI's long term expectations for DSM. Two distinctions are important for this discussion. First, FEI is a natural gas utility that, in contrast to electric utilities, is not vertically integrated and does not construct its own energy generation resources. As such, FEI's LTGRP DSM analysis does not weigh against the cost of DSM the need for procuring or constructing upstream energy generation resources to meet demand growth. Instead, FEI's LTGRP DSM analysis seeks to establish an adequate cost effective level of DSM activity and seeks to explore to what extent the peak demand implications of such DSM activity may defer FEI's requirements for downstream infrastructure upgrades.

Second, the term 'demand-side measure' has a statutory definition in BC in the CEA[110] that the Company must follow in developing a plan to reduce demand by taking cost effective demand-side measures as set out in Section 44.1(2)(b) of the UCA.[111] Across North America, DSM has a broader context that includes activities such as fuel substitution and load building, beyond the more limited statutory definition of demand-side measures that exists in BC. This section addresses both the statutory requirements for utilities within the narrower BC context, as well as broader types of DSM activities, within the broader North American meaning of the term, that are also important for FEI to consider for providing safe, reliable and cost effective energy to customers. A review of the energy planning environment in BC (Section 2) confirms that the Company needs to maintain a strong focus on a range of demand side activities to ensure that FEI is: providing the services that customers want, delivering demand side service offerings that help keep customers' energy costs down, helping to meet provincial emission targets, and playing a role in optimizing BC's energy infrastructure.

This section is organized as follows:

Section 4.2 addresses the utility demand-side measures as defined by the CEA that are being met through FEI's C&EM activities. A review of the statutory environment for demand-side measures in BC is followed by an analysis of the reductions in annual demand for natural gas that the Company expects to achieve under the range of future scenarios presented in Section 3. Section 4.2.3.6 specifically addresses the estimated long term impact of FEI's projected C&EM activities on peak demand and points to Section 6 for further details. Finally, the section presents the plan for how the Company will move forward to try to achieve these demand reductions over the planning horizon. Section 4.2 represents FEI's long term plan to reduce demand by taking cost effective demand-side measures as outlined in the provincial definition of such measures and thus addresses Sections 44.1(2)(b), 44.1(2)(c) and 44.1(2)(f) of the UCA. This excludes fuel switching and load building initiatives. The Company is not seeking approval of the pro-forma estimated expenditures listed in Section 4.2 (FEI will develop a separate C&EM expenditure schedule and submit this in 2018 for BCUC approval).

Section 4.3 discusses DSM in the broader context of utility activities beyond BC's statutory definition of a demand-side measure. FEI's fuel switching and NGT initiatives and exploration of new, large industrial customer demand are examples of activities that, though they do not meet

[110] http://www.bclaws.ca/civix/document/id/consol24/consol24/00_10022_01.
[111] http://www.bclaws.ca/civix/document/id/complete/statreg/96473_01.

the provincial definition of demand-side measure and are therefore not eligible for C&EM funding, are nevertheless important DSM activities for the Company. The FEI activities discussed in Section 4.3 have been approved by the Commission through other regulatory proceedings and the Company is not seeking approval for any new initiatives or changes to any existing initiatives as part of this LTGRP. The Company believes that these types of initiatives are vital components of FEI's efforts to provide customers with the energy they are seeking while adding cost effective, efficient new load to the system that will help to optimize use of the natural gas infrastructure and put downward pressure on customer rates. The Company is not seeking approval of the activities listed in Section 4.3.

Section 4.4 draws conclusions about FEI's DSM activities and recommends actions to be taken in the near term.

Although there are no specific, government-mandated GHG targets for FEI or the Company's customers to meet, Section 8 presents the emissions reduction estimates for each of the C&EM scenarios outlined in Section 4.2, alongside further discussion of GHG emissions from non-C&EM FEI activities. Section 8 also discusses C&EM rate impacts alongside rate impacts from non-C&EM FEI activities.

4.2 *CONSERVATION AND ENERGY MANAGEMENT (C&EM)*

4.2.1 Background

4.2.1.1 Regulatory Framework

FEI's C&EM initiative is a portfolio of efficiency and conservation programs and activities that meets the province's DSM definition in the CEA and helps customers reduce their natural gas consumption. The Company's C&EM initiative has a range of other customer and societal benefits, such as reducing GHG emissions and water consumption, enhancing human health and comfort, creating jobs, and encouraging a culture of conservation throughout BC. The objectives of the C&EM initiative include, in no particular order, to:

- Provide programs to help customers manage their energy use;
- Educate consumers regarding energy efficiency;
- Improve the overall economic efficiency of buildings and end-use applications;
- Improve the operating characteristics of customers' energy utilization systems;
- Support government energy and emission objectives; and
- Overcome barriers to market transformation for energy efficient technologies.

In BC, the implementation of demand-side measures is governed by the UCA, the

Province's DSM Regulation made pursuant to the UCA, and by the definition of "demand-side measure" found in section 1(1) of the CEA, which provides as follows:

> A rate, measure, action or program undertaken (a) to conserve energy or promote energy efficiency, (b) to reduce the energy demand a public utility must serve, or (c) to shift the use of energy to periods of lower demand . . . but does not include (d) a rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increase greenhouse gas emissions in British Columbia, or (e) any rate, measure, action or program prescribed.

The DSM Regulation further defines what C&EM measures must be included in a public utility's plan portfolio in order for it to be "adequate" within the meaning of section 44.1(8)(c) of the UCA. Effective March 24, 2017, section 3(1) of the DSM Regulation provides that a public utility's plan portfolio is adequate when it includes all of the following:

Table 4-2: Adequacy Requirements of the DSM Regulation

Section of the DSM Regulation	Adequacy Requirement
3 (a)	A demand-side measure intended specifically (i) To assist residents of low-income households to reduce their energy consumption, or (ii) To reduce energy consumption in housing owned or operated by (A) A housing provider that is a local government, a society as defined in section 1 of the *Societies Act*, other than a member-funded society as defined in section 190 of that Act, or an association as defined in section 1 (1) of the *Cooperative Association Act*, or (B) The governing body of a first nation, If the benefits of the reduction primarily accrue to (C) The low-income households occupying the housing, (D) A housing provider referred to in clause (A), or (E) A governing body referred to in clause (B) if the households in the governing body's housing are primarily low-income households;
3(b)	If the plan portfolio is submitted on or after June 1, 2009, a demand-side measure intended specifically to improve the energy efficiency of rental accommodations;
3(c)	An education program for students enrolled in schools in the public utility's service area;
3(d)	If the plan portfolio is submitted on or after June 1, 2009, an education program for students enrolled in post-secondary institutions in the public utility's service area;
3(e)	One or more demand-side measures to provide resources as set out in paragraph (e) of the definition of "specified demand-side measure", representing no less than (i) An average of 1% of the public utility's plan portfolio's expenditures per year over the portfolio's period of expenditures, or (ii) An average of $2 million per year over the portfolio's period of expenditures;

Section of the DSM Regulation	Adequacy Requirement
3(f)	One or more demand-side measures intended to result in the adoption by local governments and first nations of a step code or more stringent requirements within a step code.

Section 4 addresses this adequacy requirement by outlining the adequacy initiatives of FEI's current C&EM portfolio (Section 4.2.1.2), confirming that its C&EM analysis includes measures that can be used for adequacy purposes (Section 4.2.1.2), and addressing how its long term plan for implementing C&EM activities will address adequacy in the future (Section 4.2.4)

As discussed in Section 2, FEI's planning environment for C&EM activities has evolved since 2014. The provincial CLP of August 2016 provides direction for FEI to increase its energy efficiency program incentives by at least 100 per cent. The BC Government also amended the DSM Regulation. In addition to any adequacy requirements reflected in Table 4-2 above, these amendments made further changes may impact the ambit of FEI's C&EM activities, such as the following:

- Effective July 10, 2014, BC Reg 141/2014 amended the DSM Regulation to exempt adequacy measures from the Modified Total Resource Cost Test (MTRC) cap and to increase from 0.5 to 1 times BC Hydro's long run marginal cost of electricity the Zero Emissions Energy Alternative (ZEEA) value that the MTRC uses as the avoided cost of gas; and
- Effective March 24, 2017, BC Reg 117/2017 increased from 33 to 40 percent the cap on the ratio of public utility DSM portfolios that may rely on the MTRC for cost effectiveness testing and enables DSM programs to incentivize new construction projects that comply with the BC Energy Step Code in support of municipalities that are implementing steps from the Code.

4.2.1.2 C&EM Portfolio

The Commission approved FEI's existing C&EM portfolio via its decision on FEI's 2014-2019 Performance Based Ratemaking Plan, as the application contained FEI's 2014-2018 DSM Plan.[112],[113],[114] FEI's existing C&EM portfolio meets the adequacy requirements that were in place at the time of approval and certain of the requirements added with the March 24, 2017 revision. The new adequacy requirements that are not met within the existing portfolio will be addressed in the upcoming expenditure schedule application to be filed after the 2017 LTGRP. The 2017 LTGRP C&EM analysis contains measures that are included in FEI's existing portfolio

[112] The 2017 LTGRP refers to FEI's future applications to the BCUC for approval of DSM expenditures simply as C&EM expenditure schedule.
[113] FEI Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018 ~ Project No.3698715. http://www.bcuc.com/ApplicationView.aspx?ApplicationId=400.
[114] http://www.ordersdecisions.bcuc.com/bcuc/orders/en/item/119195/index.do.

but also adds new measures. In general, many measures are applicable to adequacy situations but their adequacy implications depend on their specific program packaging and delivery (including marketing) which is determined during program design. Sections 4.2.1.2.1 to 4.2.1.2.6 below summarize FEI's current C&EM portfolio. Over the 2017 LTGRP's planning horizon, FEI's specific program offers will likely change to suit the evolving marketplace, legislative provisions (including future adequacy requirements) and FEI customer needs.

4.2.1.2.1 RESIDENTIAL PROGRAM AREA

Residential programs serve over 890,000 FEI customers. These customers predominantly include those living in single-family homes, rowhouses, townhomes or mobile homes.[115] Some in-suite measures, such as low flow fixtures and a small number of fireplaces and water heaters in multi-unit residential buildings are also included in this funding envelope. Residential programs serve retrofit and new home applications. In combination with the Company's education and outreach activities, these programs play an important role in driving the culture of conservation in BC. Residential programs focus on space heating (including fireplaces) and domestic hot water measures as well as insulation upgrades but also include a new construction package and a behavioral program. Typically, residential programs provide incentives towards the incremental capital cost of replacing existing end-use appliances or building envelopes with more efficient options but programs also contain incentives for home evaluations and educational components that encourage customers to optimize their energy use patterns.

4.2.1.2.2 LOW INCOME PROGRAM AREA

FEI's Low Income programs target income-qualified customers specifically via distribution of free energy saving kits and via two home retrofit package programs. The package programs target customers both broadly (via installation of generic energy savings upgrades and basic energy coaching) and also specifically (by conducting deep retrofits of homes that are identified as candidates for such retrofits during broad energy coaching). Low income programs also provide top-ups on rebates for select existing residential and commercial programs. In the residential programs, these top-ups support income-qualified customers. In the commercial programs, these top-ups support qualifying housing operators.

4.2.1.2.3 COMMERCIAL PROGRAM AREA

FEI's commercial C&EM programs focus on space and water heating as well as food service measures in commercial buildings. The Company also offers package programs for commercial new construction and commercial building retrofits. In addition, FEI's commercial program offering includes multiple programs that seek to support energy efficiency by incenting FEI customers to change their operations and maintenance practices. Finally, FEI offers a commercial program that specifically targets rental apartment buildings.

[115] Programs for Multifamily Dwellings served under Rate Schedule 2 or 3 are included in the commercial C&EM program area.

4.2.1.2.4 INNOVATIVE TECHNOLOGIES PROGRAM AREA

FEI's innovative technologies activities identify market-ready technologies that are not yet widely adopted in BC, and which are suitable for the development of or inclusion in the portfolio of ongoing C&EM programs in other program areas. This is accomplished through pilot and demonstration projects, pre-feasibility studies and the use of industry standard evaluation, measurement and verification protocols to validate manufacturers' claims related to equipment and system performance. Results from innovative technologies activities are used in making future C&EM programming decisions.

4.2.1.2.5 INDUSTRIAL PROGRAM AREA

FEI offers two industrial programs. One of these includes measures that allow industrial customers to identify, investigate, and implement natural gas energy efficiency projects in a manner that is customized for their specific facility needs. Participation in the program can span multiple years due to the timescales associated with completing an energy study, procuring and installing an energy conservation measure, and multi-year measurement and verification analysis. The other industrial program provides incentives for customers to install a more prescriptive (i.e. less customized) set of industrial energy efficiency measures.

4.2.1.2.6 CONSERVATION EDUCATION AND OUTREACH AND ENABLING ACTIVITIES

FEI's conservation education and outreach initiatives continue to support C&EM portfolio goals by fostering energy literacy and a culture of conservation among FEI's residential and commercial customers as well as students. In 2016, FEI launched its curriculum-connected online resource program called Energy Leaders for BC elementary and secondary school teachers. FEI also continues to support various training seminars and educational workshops in collaboration with such organizations as the Greater Vancouver Home Builders Association and other industry associations.

C&EM enabling activities focus on trade allies that support FEI's delivery of programming to customers, research, work to advance building codes and appliance standards, maintaining FEI's C&EM tracking system, and funding to support post-secondary energy management programs.

4.2.1.3 BC Conservation Potential Review (BC CPR)

In 2015, FEI, in collaboration with BC Hydro, FBC, and Pacific Northern Gas (PNG), initiated a province-wide BC CPR. This project uses a 2014 base year to determine the technical, economic, and market energy savings potential for natural gas and electricity until 2035. FEI received its BC CPR energy savings market potential results in 2017.

The purpose of a CPR is to examine available energy efficiency technologies, understand the inventory of energy equipment in a utility's service area, and determine the conservation potential that exists. The CPR is a tool that informs current and future C&EM expenditure applications and provides directional input into program development. FEI's 2010 CPR provided the baseline data on which FEI developed the 20-year C&EM energy savings estimates for the 2014 LTRP. Results from the 2010 CPR informed both FEI's previous 2012-2013 and also its current 2014-2018 C&EM expenditure schedule. The BC CPR represents a new study which projects energy savings opportunities between 2015 and 2035 across the service territories of each of the contributing BC utilities. Please refer to Appendix C-1 for the BC CPR report prepared for FEI which describes the study approach and methods alongside a summary of the study results. The BC CPR summary report does not recommend specific programs or targets to be implemented. However, the report does identify technology and market opportunities as well as the scope of market energy savings potential across the study period.

The range of potential C&EM measures from the BC CPR results informs the 2017 LTGRP C&EM forecast. FEI's C&EM forecast includes expenditure estimates and projected cost effectiveness test results. FEI's next C&EM expenditure schedule will be informed by the results of the BC CPR and the 2017 LTGRP's DSM analysis. FEI expects to file the next C&EM expenditure schedule after submission of the 2017 LTGRP. The BC CPR and the 2017 LTGRP represent long term forecasts that do ***not*** request approval from the Commission for specific C&EM expenditures.

Section 4.2.2 below outlines broadly how the 2017 LTGRP processed CPR results in order to apply them to its multi-scenario end-use demand forecast. Section 4.2.3 below details the 2017 LTGRP C&EM forecast analysis results.

4.2.2 Applying C&EM Potential to the Multi-Scenario, End-Use Demand Forecast

The 2017 LTGRP's C&EM analysis displays results for the Reference Case, Upper Bound and Lower Bound scenarios presented in Section 3. The C&EM analysis selected these scenarios to display the impact of forecast C&EM activity on the Reference Case but to also illustrate the potential range of this impact across the Upper Bound and Lower Bound scenarios which resulted in the lowest and highest forecast of annual demand for natural gas. This enables the Company to present the widest range of potential demand for natural gas after energy savings from cost effective demand-side measures. The Reference Case forecast assumes that conditions that are present and legally enshrined in the planning environment when the demand forecasting exercise was undertaken prevail through the planning horizon. For convenience, Table 4-3 below reproduces the descriptions of Scenarios A and E from Section 3:

Table 4-3: Descriptions of Future Scenarios A (Highest Demand) and E (Lowest Demand)

Scenario	Description	Input Settings		Discussion
A (Upper Bound)	The BC economy experiences higher-than-average growth. Infrastructure development in other regions, coupled with extraction	Economic Growth	High	In general, the outcomes of the multiple critical uncertainties can offset each other's impact on annual demand but this scenario combines all

Scenario	Description	Input Settings		Discussion
	infrastructure development in BC, keep regional gas supply abundant. Continued political opposition to carbon pricing and non-price carbon policy action cause governments to focus on issues other than carbon policy but the BC government keeps supporting NGT and RNG as cost effective existing carbon solutions.	Natural Gas Price	Low	outcomes that would increase annual demand. As such, this scenario represents one of two boundary scenarios that frame the scenario analysis. The combination of outcomes on each critical uncertainty is plausible and has occurred in the past.
		Carbon Price	Low	
		Non-Price Carbon Policy Action	Delayed	
E (Lower Bound)	The BC economy experiences lower-than average growth as part of global economic stagnation. This reduces investment in regional gas supply so much that BC's demand balance becomes constricted. Global economic performance contributes to a political climate that is not favourable to carbon pricing and non-price carbon policy action in other jurisdictions but causes a counter-movement in BC. This causes the BC government to focus on carbon policy and electrification without support for NGT and RNG.	Economic Growth	Low	This represents the second of the two boundary scenarios. This combination of outcomes across the critical uncertainties is plausible but has not been prevalent in the past. Governments have typically been reluctant to impose taxes and other restrictions, including carbon pricing and carbon policy actions, during periods of economic stagnation.
		Natural Gas Price	High	
		Carbon Price	High Increase	
		Non-Price Carbon Policy Action	Accelerated	

4.2.2.1 Method

FEI applied the C&EM potential to its multi-scenario end-use forecast via the following steps:

1. In the 2017 LTGRP forecast model, construct a separate Reference Case which matches as closely as possible the BC CPR's Reference Case;
2. Import the CPR measure assumptions into this 2017 LTGRP CPR Reference Case;
3. Produce the technical energy savings potential in the 2017 LTGRP CPR Reference Case and calibrate the measure applicability rates in light of the BC CPR technical energy savings potential results;
4. Produce the economic energy savings potential results in the 2017 LTGRP CPR Reference Case;[116]
5. In the 2017 LTGRP CPR Reference Case, run the market potential energy savings analysis and calibrate individual measure participation rates in light of the BC CPR energy savings market potential results;
6. Import into the 2017 LTGRP CPR Reference Case, the expenditure parameters (i.e. ratio of incentive to non-incentive spending by program area and ratio of incentives to incremental costs by program area) from the BC CPR market potential analysis;
7. Apply the 2017 LTGRP Reference Case and produce the market potential energy savings, benefit-cost, and expenditure results;
8. Calibrate expenditure parameters at the measure level in light of the BC CPR results and existing program experience and re-run step 7; and
9. Run the step 7 analysis for the Upper Bound and Lower Bound scenarios.

4.2.2.2 Sensitivity to the End-Use Scenarios

The availability of potential energy savings will vary from one forecasting scenario to another due to several effects, all of which were incorporated into the demand forecasts for each of the scenarios prior to analyzing the potential savings from C&EM (see scenario explanations contained in Appendix B-1):

- Higher gas pricing, due to commodity prices or a carbon price, will cause more measures to pass the Total Resource Cost (TRC) test, or will cause measures that already pass to pass with a more positive result. Conversely, lower gas pricing will cause more measures to fail the TRC test, or will cause measures that pass to fail in some situations.

[116] The 2017 LTGRP's C&EM analysis requires each measure to meet the cost effectiveness test threshold and does not package measures into programs (where individual non-cost effective measures could be rendered cost effective by other measures). This approach for pursuing all cost effective DSM is consistent with the analysis in the BC CPR. The 2017 LTGRP's C&EM analysis represents a long term directional forecast of addressable C&EM initiatives; FEI's C&EM expenditure schedules bundle measures into specific programs, consider operational program deployment factors, and request BCUC permission for specific DSM expenditures.

- Although customer demand is price inelastic over the short term, higher gas pricing over the long term, while holding all other variables constant, may cause some customers to switch away from natural gas for certain end uses. This will tend to reduce the energy potential for measures that pass the TRC test. Conversely, lower gas pricing may tend to cause some customers to switch from other fuels to gas for certain end uses, increasing the energy potential for those measures that still pass the TRC test.
- Higher economic growth tends to increase the potential for savings due to its impact on the customer forecast; lower economic growth tends to decrease it.
- A policy environment that encourages more existing adoption of energy efficiency (e.g. accelerated appliance standards) will tend to decrease the remaining potential for energy efficiency for utility programs to capture. Conversely, a policy environment that does not encourage existing adoption of energy efficiency will tend to increase the potential for utility programs.
- An environment with increased development of renewable and district energy systems will tend to decrease the remaining natural gas share and therefore the potential for natural gas savings. An environment with little development of renewable and district energy systems will tend to have more potential for natural gas savings.
- Following the BC CPR's approach, the 2017 LTGRP C&EM analysis applies the TRC test to commercial and industrial program areas but the MTRC test to the residential program area to simulate the current DSM landscape. Scenarios that are subject to accelerated non-price carbon policy action apply the MTRC test to all program areas in order to simulate the potential removal of the current MTRC cap as regulators potentially further recognize the economic and social non-energy benefits of C&EM activity.

4.2.3 Long Term C&EM Analysis Results

The 2017 LTGRP's C&EM analysis results are informed by both the BC CPR and existing program experience. The results maintain the BC CPR's segmentation into residential, commercial, and industrial program areas. These do not break out individual adequacy programs specifically (this breakdown will occur in the forthcoming 2018 and future C&EM expenditure schedule submissions). As in the BC CPR, the 2017 LTGRP's C&EM analysis reports apartment buildings in the commercial sector.

The C&EM analysis results indicate the outcome of pursuing all cost effective energy savings potential. Crucially, the BC CPR and the 2017 LTGRP C&EM analysis display a theoretical estimate of energy savings measure uptake in relation to the ratio between incentive levels and measure incremental costs. This estimate takes into account program experience and technology diffusion but does not take into account operational program delivery factors, such as staffing levels or specific program eligibility rules. This represents a critical difference to FEI's C&EM expenditure schedule which requests the Commission to approve expenditures for short or medium term C&EM activities. In contrast the BC CPR and the 2017 LTGRP C&EM analysis provide a long term forecast of estimated C&EM potential and activity.

Section 4.2.3.1 below outlines the estimated long term impact on annual demand of the 2017 LTGRP C&EM analysis. Section 4.2.3.2 details estimated long term C&EM expenditures while Section 4.2.3.3 presents estimated cost effectiveness test results. Section 4.2.3.4 compares top ten energy savings measures across scenarios. Section 4.2.3.5 explains how sensitive the Reference Case C&EM results are to changes in the level of incentive value as a proportion of incremental cost. Section 4.2 concludes with Section 4.2.3.6 referring to the peak demand impact of C&EM activities which will be further discussed in Section 6.

4.2.3.1 Estimated Long Term Impact on Annual Demand

Figure 4-1 below illustrates annual natural gas demand, excluding NGT, before and after estimated C&EM energy savings for all rate schedules. Cumulative Upper Bound energy savings across the planning horizon exceed the Reference Case by 3 percent while cumulative Lower Bound energy savings fall 60 percent below the Reference Case. Forecast 2036 Reference Case energy savings account for 7.89 percent of projected sales. This ratio changes to 6.79 percent and 5.92 percent for the Upper and Lower Bound scenarios, respectively.

Figure 4-1: Natural Gas Demand Before and After Estimated C&EM Savings (Excluding NGT) – All Sectors

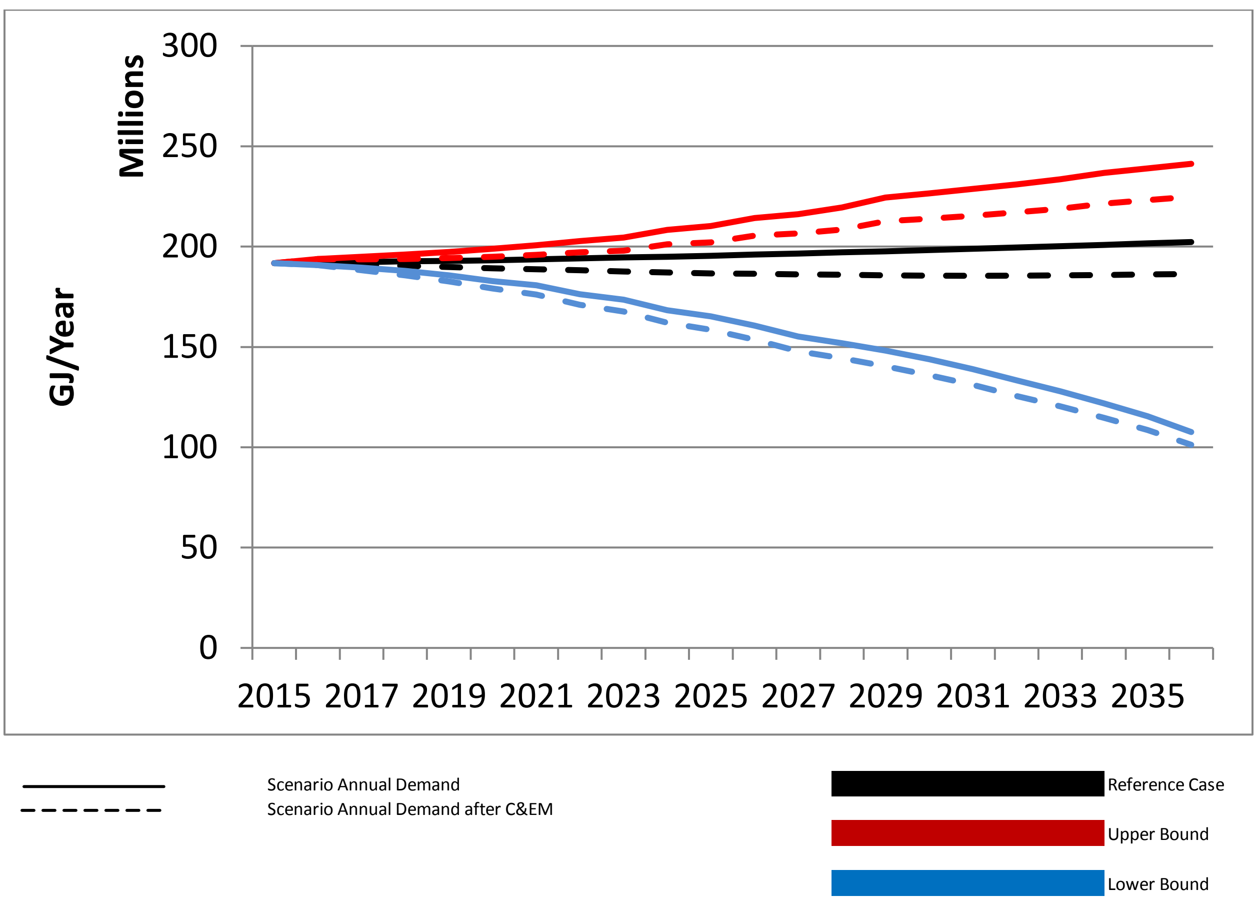


Figure 4-2 below illustrates annual natural gas demand, excluding NGT, before and after estimated C&EM energy savings for the residential rate schedules. Cumulative Upper Bound energy savings across the planning horizon exceed savings in the Reference Case by 9 percent while cumulative Lower Bound energy savings fall 47 percent below those of the Reference Case. Forecast 2036 Reference Case energy savings account for 7.16 percent of projected sales. This ratio changes to 7.19 percent and 6.18 percent for the Upper and Lower Bound scenarios, respectively.

Figure 4-2: Natural Gas Demand Before and After Estimated C&EM Savings (Excluding NGT) – Residential Sector

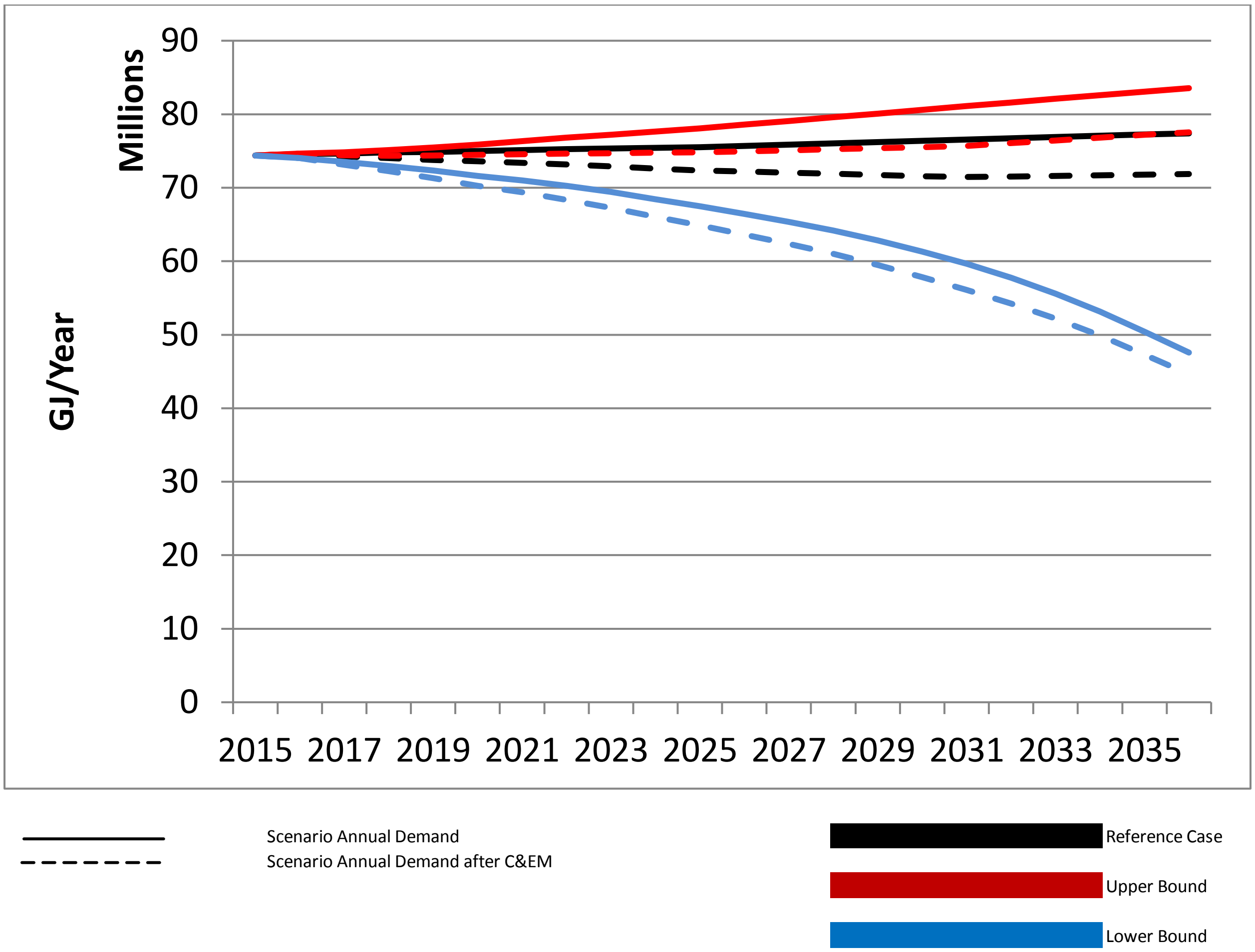


Figure 4-3 below illustrates annual natural gas demand, excluding NGT, before and after estimated C&EM energy savings for the commercial rate schedules. Cumulative Upper Bound energy savings across the planning horizon fall short of the Reference Case savings by 7 percent while cumulative Lower Bound energy savings fall 66 percent below those in the Reference Case. This departs from the pattern of cumulative Upper Bound energy savings exceeding the Reference Case. This appears to be due to low natural gas and carbon price costs in the Upper Bound depressing the avoided cost of gas in this scenario and thus rendering commercial energy efficiency measures uneconomic. This effect appears to outweigh the Upper

Bound having more technical energy savings opportunities than the Reference Case (by virtue of having more natural gas consumption than the Reference Case). Forecast 2036 Reference Case energy savings account for 9.27 percent of projected sales. This ratio changes to 7.34 percent and 6.04 percent for the Upper and Lower Bound scenarios, respectively.

Figure 4-3: Natural Gas Demand Before and After Estimated C&EM Savings (Excluding NGT) – Commercial Sector

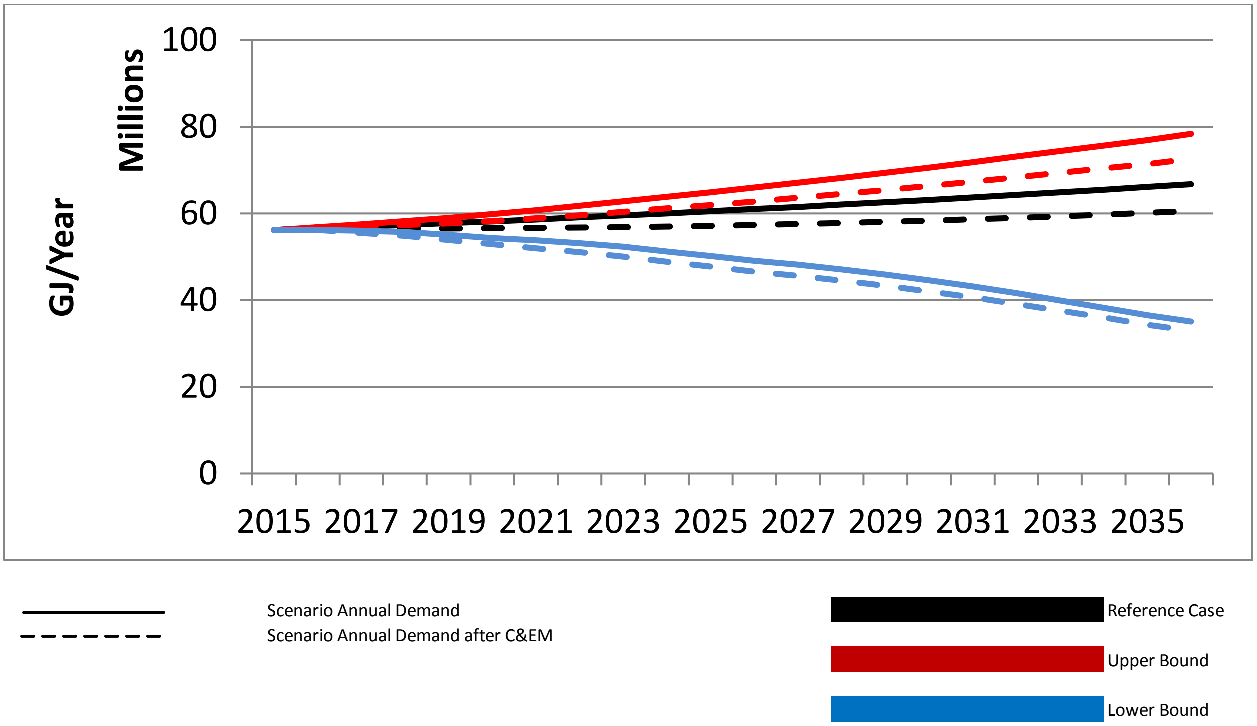
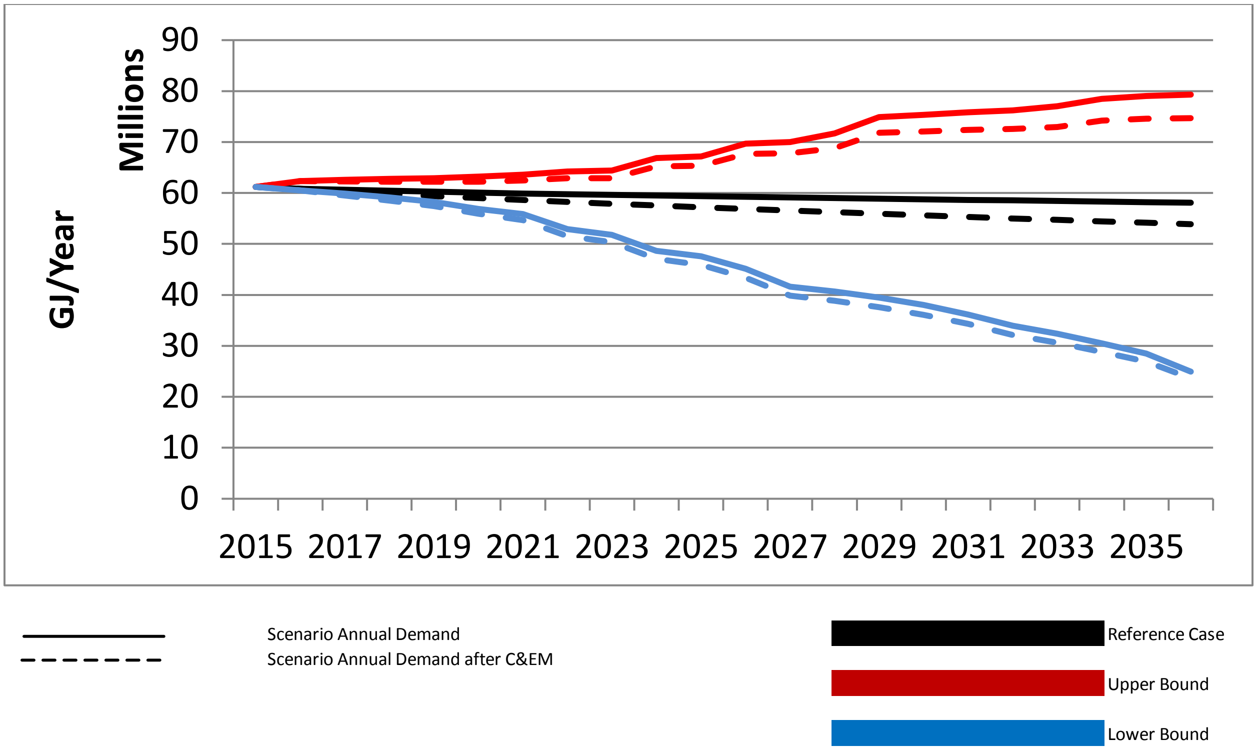


Figure 4-4 below illustrates annual natural gas demand, excluding NGT, before and after estimated C&EM energy savings for the industrial rate schedules. Cumulative Upper Bound energy savings across the planning horizon exceed the Reference Case savings by 10 percent while cumulative Lower Bound energy savings fall 69 percent below the Reference Case. Forecast 2036 Reference Case energy savings account for 7.26 percent of projected sales. This ratio changes to 5.83 percent and 5.25 percent for the Upper and Lower Bound scenarios, respectively.

Figure 4-4: Natural Gas Demand Before and After Estimated C&EM Savings (Excluding NGT) – Industrial Sector[117]



4.2.3.2 Estimated C&EM Expenditures

Results presented in this section are long term estimates only and are informed by the results of the BC CPR and program experience. These results do not take into account the following factors which flow into C&EM expenditure schedules and C&EM annual reports to the Commission:[118]

- Non-incentive expenditures that support or enable C&EM programs at the portfolio level, such as Enabling Activities and Conservation Education Outreach expenditures;[119]
- Operational program delivery considerations, such as changes in required C&EM staffing levels or program eligibility requirements; and
- Emergence of new technologies more than five years into the future or technologies which are currently unknown which may increase aggregate energy savings

[117] The 2017 LTGRP commentary for Figure 3-11 in Section 3 explains why projected industrial demand trajectories are jagged.

[118] For this reason, individual C&EM expenditure schedules may contain higher or lower energy savings and expenditures in the short and medium term than indicated in the long term C&EM analysis in the LTGRP.

[119] FEI expects these expenditures to continue but FEI's future C&EM expenditure schedules will determine their specific extent.

opportunities and thus enable greater actual C&EM program expenditures across the planning period.[120]

The base year of the 2017 LTGRP forecast is 2015 but the C&EM analysis does not include data for 2015 and 2016 since these years are in the past already.[121] FEI filed its actual program performance for these years with the Commission in its 2015 and 2016 C&EM Annual Reports.[122,123] FEI does not expect the LTGRP 2017 C&EM expenditure estimates to match its 2017 C&EM Annual Report because both filings are different in nature and methods and use different years of actuals data (2015 versus 2017, respectively).

Table 4-4 below displays estimated annual C&EM expenditures for all program areas. Estimated expenditures are expected to almost double from 2016 levels by 2023 and gradually decline after this year towards the end of the planning horizon as available energy savings opportunities are depleted.

[120] FEI does not project the actual expenditure impact of unforeseen future technologies as these depend on both their per-measure C&EM expenditure and also their total DSM participation rate.

[121] FEI used its 2015 actuals as inputs for the load forecast and C&EM analysis. Based on this 2015 input data, the C&EM analysis starts providing projected results in 2017 since 2015 and 2016 are historical years on the filing date. FEI filed annual reports on its C&EM activity with the BCUC already.

[122] Appendix D-27: https://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/160330_FEI_2015_DSM_Annual_Report_FF.PDF.

[123] Appendix D-28: https://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/170331_FEI_2016_DSM_Annual_Report_FF.PDF.

Table 4-4: Estimated Reference Case Annual Expenditures – All Program Areas

	REFERENCE CASE (MILLIONS)		
Year	Incentive Estimate	Non-Incentive Estimate	Total Estimate
2017	$ 27	$ 5	$ 31
2018	$ 30	$ 5	$ 35
2019	$ 31	$ 5	$ 36
2020	$ 33	$ 5	$ 39
2021	$ 42	$ 7	$ 49
2022	$ 41	$ 6	$ 47
2023	$ 46	$ 7	$ 52
2024	$ 43	$ 7	$ 50
2025	$ 36	$ 6	$ 42
2026	$ 35	$ 6	$ 41
2027	$ 33	$ 6	$ 39
2028	$ 32	$ 6	$ 38
2029	$ 32	$ 6	$ 37
2030	$ 33	$ 6	$ 39
2031	$ 29	$ 5	$ 34
2032	$ 25	$ 5	$ 30
2033	$ 25	$ 4	$ 29
2034	$ 25	$ 4	$ 29
2035	$ 25	$ 4	$ 29
2036	$ 25	$ 4	$ 29

Figure 4-5 below illustrates estimated annual C&EM expenditures across the Reference Case, Upper Bound and Lower Bound scenarios for all program areas. Cumulatively across the planning horizon, Upper Bound estimated expenditures fall 6 percent short of the Reference Case while Lower Bound estimated expenditures are 33 percent below the Reference Case. This departs from the intuitive expectation that cumulative Upper Bound estimated expenditures should exceed the Reference Case. This appears to be due to low natural gas and carbon price costs in the Upper Bound depressing the avoided cost of gas in this scenario and thus rendering energy efficiency measures less economic. Under such conditions, measures with lower incremental cost have a higher chance of being economic than measures with higher incremental cost. Since both the BC CPR and the 2017 LTGRP C&EM analysis conceptualize incentive levels as a proportion of incremental cost, this appears to reduce total expenditures. This effect appears to outweigh the Upper Bound having more technical energy savings opportunities and thus more opportunities for C&EM expenditures than the Reference Case (by virtue of having more natural gas consumption than the Reference Case).

1 **Figure 4-5: Estimated Annual Expenditures by Scenario – All Program Areas**

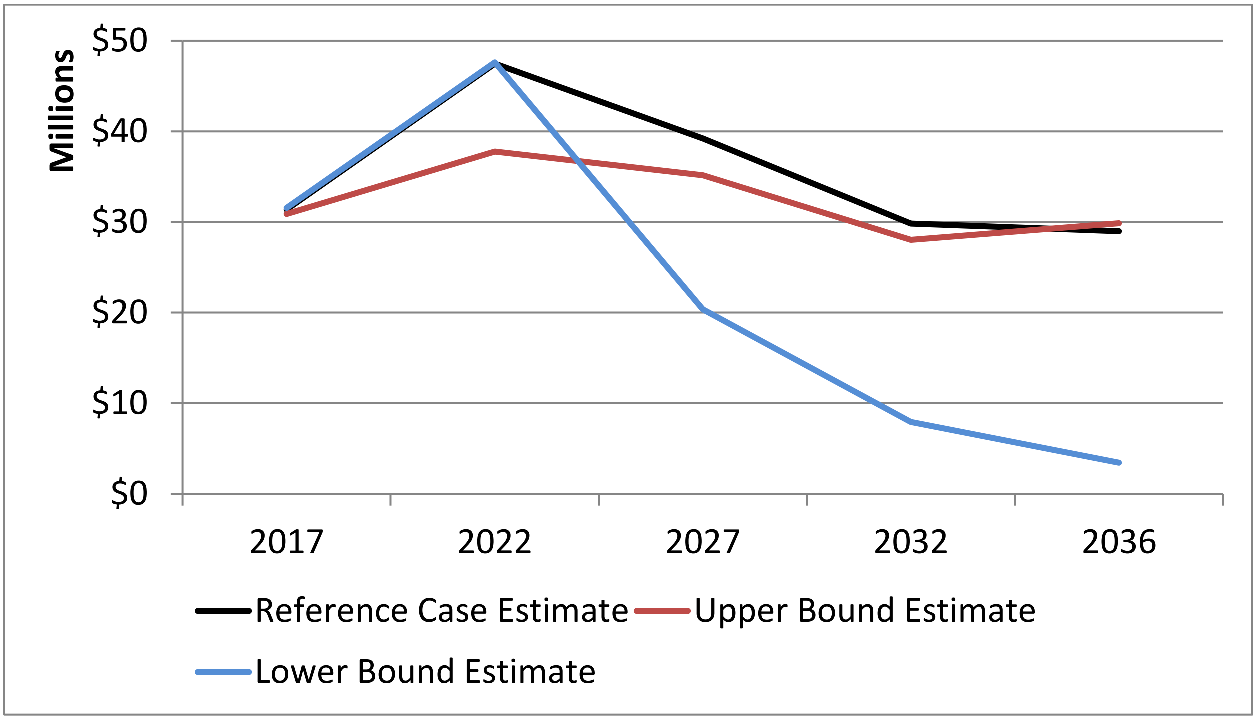


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Table 4-5 below displays estimated annual C&EM expenditures for the residential program area. Estimated expenditures are expected to almost double from 2016 levels by 2018, to remain at approximately this level until 2030, and to decline after this year towards the end of the planning horizon as available energy savings opportunities are depleted.

Table 4-5: Estimated Reference Case Annual Expenditures – Residential Program Area

	REFERENCE CASE (MILLIONS)		
Year	Incentive Estimate	Non-Incentive Estimate	Total Estimate
2017	$ 16	$ 3	$ 19
2018	$ 17	$ 4	$ 21
2019	$ 16	$ 3	$ 19
2020	$ 16	$ 3	$ 19
2021	$ 19	$ 4	$ 23
2022	$ 17	$ 4	$ 21
2023	$ 17	$ 4	$ 21
2024	$ 22	$ 5	$ 27
2025	$ 17	$ 3	$ 20
2026	$ 16	$ 3	$ 19
2027	$ 15	$ 3	$ 19
2028	$ 15	$ 3	$ 18
2029	$ 15	$ 3	$ 18
2030	$ 16	$ 3	$ 20
2031	$ 13	$ 3	$ 15
2032	$ 10	$ 2	$ 12
2033	$ 10	$ 2	$ 12
2034	$ 10	$ 2	$ 12
2035	$ 10	$ 2	$ 12
2036	$ 10	$ 2	$ 13

Figure 4-6 below illustrates estimated annual C&EM expenditures across the Reference Case, Upper Bound and Lower Bound scenarios for the residential program area. Cumulatively across the planning horizon, Upper Bound estimated expenditures exceed the Reference Case by 9 percent while Lower Bound estimated expenditures are 35 percent below the Reference Case. This departs from the portfolio level phenomenon illustrated by Figure 4-5 above. Both the BC CPR as well as the 2017 LTGRP C&EM analysis examine the residential program area under the MTRC in order to mimic the impact of the MTRC cap. The MTRC relies on the ZEEA as the avoided cost of gas. This value, which is informed by the long run marginal cost of BC Hydro electricity, does not fluctuate in response to the 2017 LTGRP scenario parameters.

Figure 4-6: Estimated Annual Expenditures by Scenario – Residential Program Area

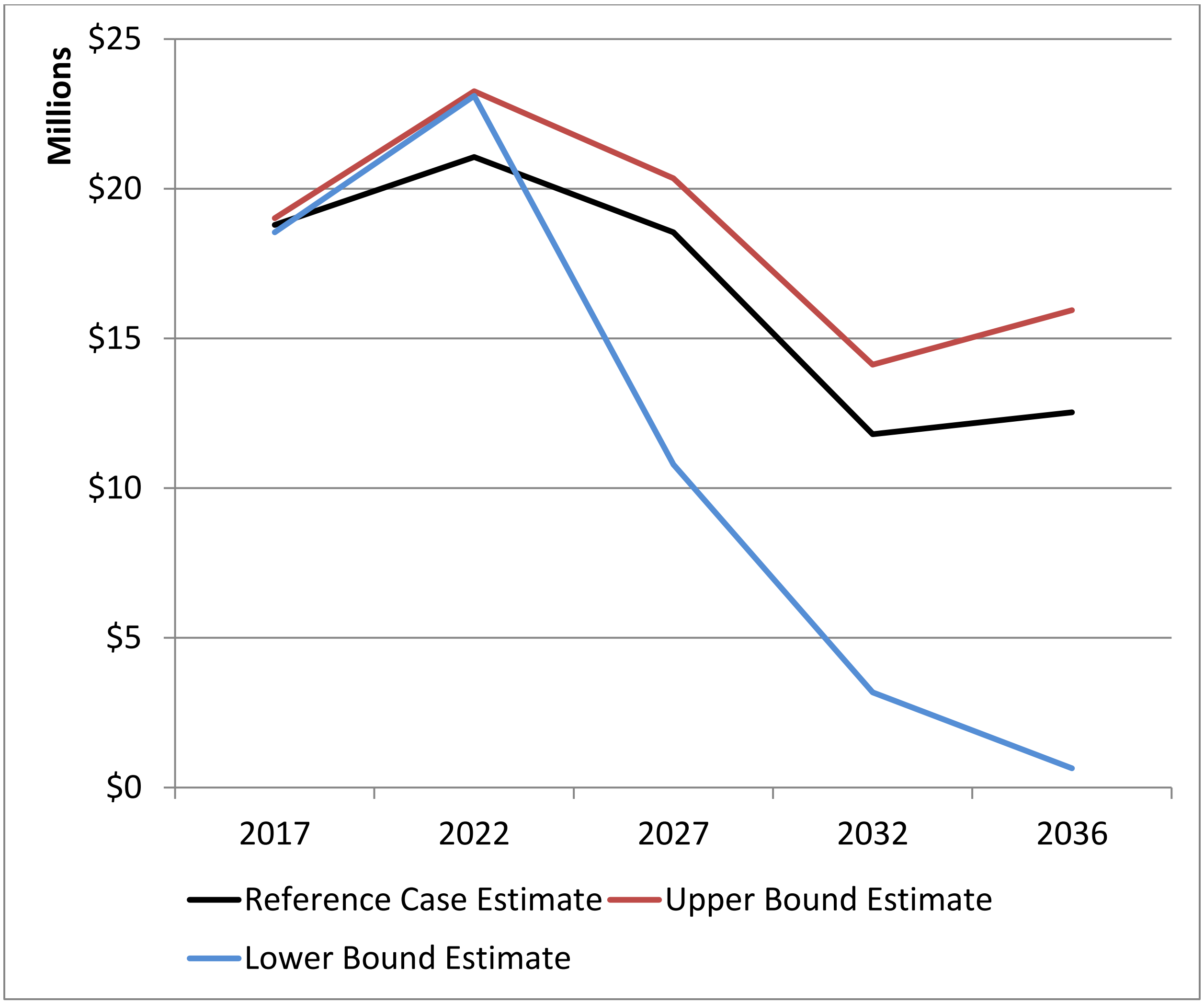


Table 4-6 below displays estimated annual C&EM expenditures for the commercial program area. Estimated expenditures are expected to almost double from 2016 levels by 2021, to increase further until 2023, and to decline after this year towards the end of the planning horizon as available energy savings opportunities are depleted.

Table 4-6: Estimated Reference Case Annual Expenditures – Commercial Program Area

	REFERENCE CASE (MILLIONS)		
Year	Incentive Estimate	Non-Incentive Estimate	Total Estimate
2017	$ 9	$ 1	$ 10
2018	$ 11	$ 1	$ 12
2019	$ 13	$ 1	$ 14
2020	$ 15	$ 1	$ 16
2021	$ 21	$ 2	$ 22
2022	$ 21	$ 2	$ 23
2023	$ 26	$ 2	$ 28
2024	$ 18	$ 1	$ 19
2025	$ 17	$ 1	$ 18
2026	$ 16	$ 1	$ 17
2027	$ 15	$ 1	$ 16
2028	$ 14	$ 1	$ 15
2029	$ 13	$ 1	$ 14
2030	$ 13	$ 1	$ 14
2031	$ 13	$ 1	$ 14
2032	$ 12	$ 1	$ 13
2033	$ 12	$ 1	$ 13
2034	$ 12	$ 1	$ 13
2035	$ 11	$ 1	$ 12
2036	$ 11	$ 1	$ 12

Figure 4-7 below illustrates estimated annual C&EM expenditures across the Reference Case, Upper Bound and Lower Bound scenarios for the commercial program area. Cumulatively across the planning horizon, Upper Bound estimated expenditures fall 18 percent short of the Reference Case while Lower Bound estimated expenditures are 44 percent below the Reference Case. This appears to be due to the same phenomenon which impacts the aggregate portfolio level results in Figure 4-5 above.

Figure 4-7: Estimated Annual Expenditures by Scenario – Commercial Program Area

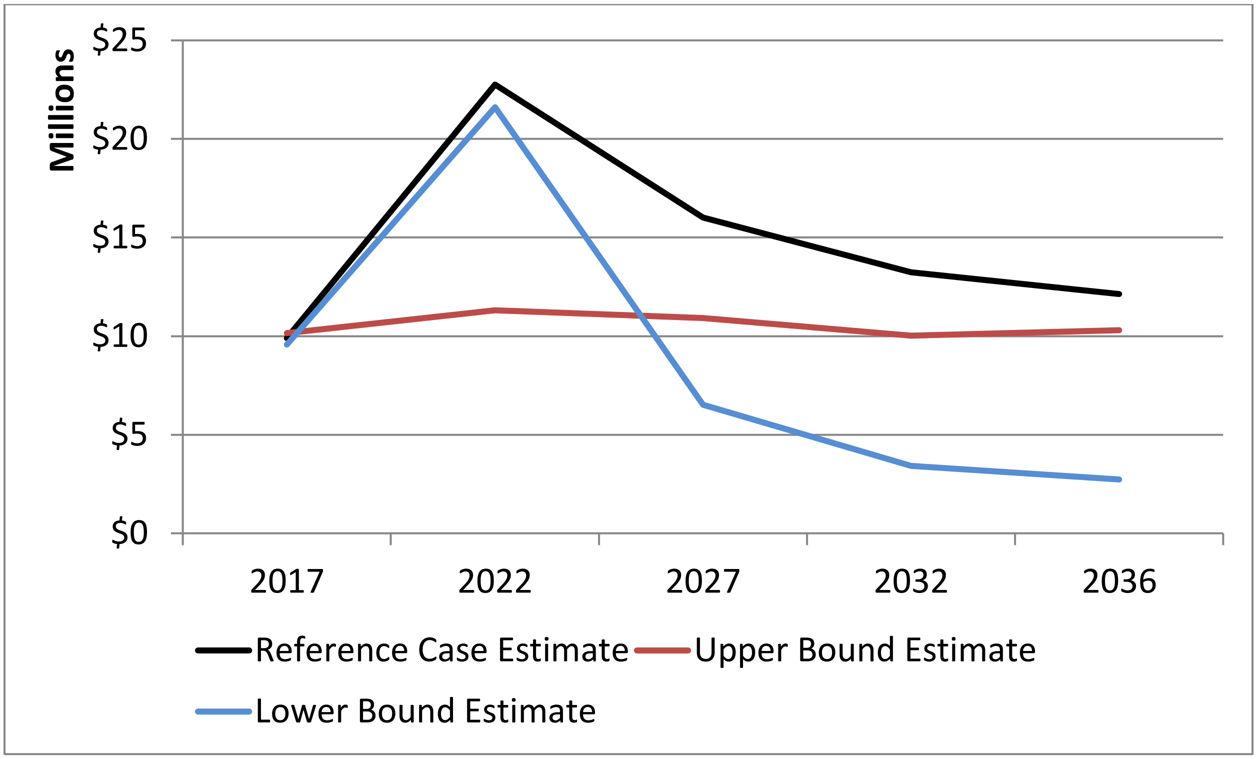


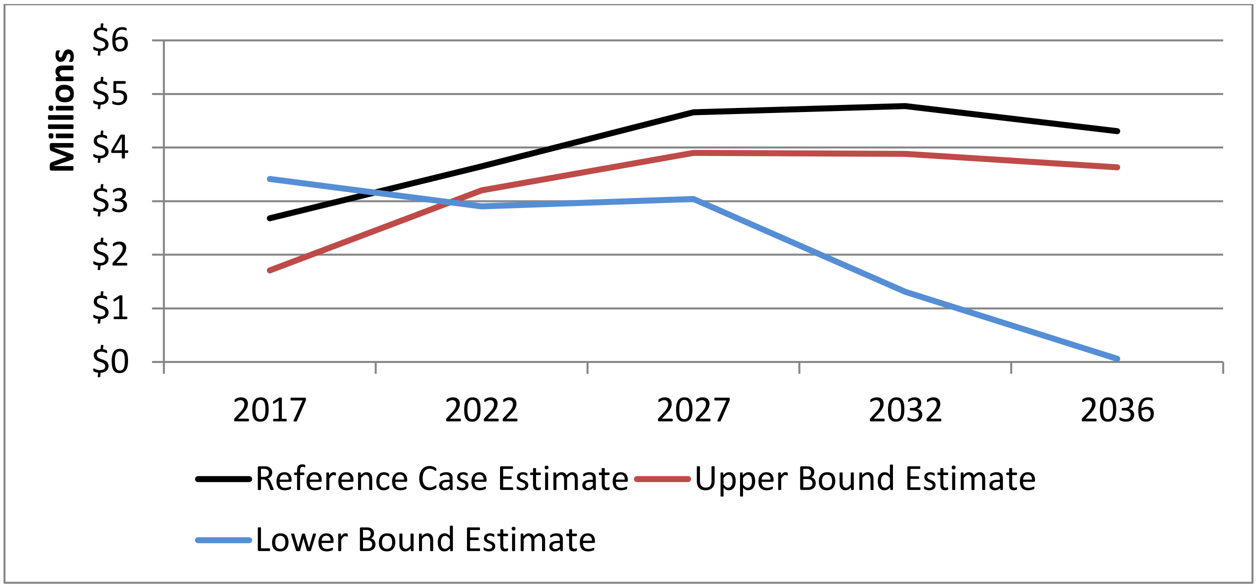
Table 4-7 below displays estimated annual C&EM expenditures for the industrial program area. Estimated expenditures are expected to almost double from 2016 levels by 2017, to increase further until 2026, to remain at approximately this level until 2034, and to decline after this year towards the end of the planning horizon as available energy savings opportunities are depleted.

Table 4-7: Estimated Reference Case Annual Expenditures – Industrial Program Area

	REFERENCE CASE (MILLIONS)		
Year	Incentive Estimate	Non-Incentive Estimate	Total Estimate
2017	$ 2	$ 1	$ 3
2018	$ 2	$ 1	$ 3
2019	$ 2	$ 1	$ 3
2020	$ 2	$ 1	$ 3
2021	$ 2	$ 1	$ 3
2022	$ 2	$ 1	$ 4
2023	$ 3	$ 1	$ 4
2024	$ 3	$ 1	$ 4
2025	$ 3	$ 1	$ 4
2026	$ 3	$ 1	$ 5
2027	$ 3	$ 2	$ 5
2028	$ 3	$ 2	$ 5
2029	$ 3	$ 2	$ 5
2030	$ 3	$ 2	$ 5
2031	$ 3	$ 2	$ 5
2032	$ 3	$ 2	$ 5
2033	$ 3	$ 2	$ 5
2034	$ 3	$ 2	$ 5
2035	$ 3	$ 1	$ 4
2036	$ 3	$ 1	$ 4

Figure 4-8 below illustrates estimated annual C&EM expenditures across the Reference Case, Upper Bound and Lower Bound scenarios for the industrial program area. Cumulatively across the planning horizon, Upper Bound estimated expenditures fall 22 percent short of the Reference Case while Lower Bound estimated expenditures are 35 percent below the Reference Case. This appears to be due to the same phenomenon which impacts the aggregate portfolio level results in Figure 4-5 above.

Figure 4-8: Estimated Annual Expenditures by Scenario – Industrial Program Area[124]



4.2.3.3 Estimated Cost Effectiveness Test Results

The base year of the 2017 LTGRP forecast is 2015 but the C&EM analysis does not include data for 2015 and 2016 since these years are in the past already. FEI filed its actual program performance for these years with the Commission in its 2015 and 2016 C&EM Annual Reports.[125,126] FEI does not expect the LTGRP 2017 cost effectiveness test results to match its 2017 C&EM Annual Report because both filings are different in nature and methods and use different years of actuals data (2015 versus 2017, respectively). In particular, the 2017 LTGRP C&EM analysis excludes the items noted in Section 4.2.3.2 above. The C&EM analysis, like the

124 The 2017 estimated expenditure variance across the scenarios appears to be due to the impact of the natural gas and carbon pricing as well as the customer forecast scenario parameters on addressable cost effective industrial energy savings opportunities.

125 Appendix D-27: https://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/160330_FEI_2015_DSM_Annual_Report_FF.PDF.

126 Appendix D-28: https://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/170331_FEI_2016_DSM_Annual_Report_FF.PDF.

BC CPR, also includes numerous energy efficiency measures which are not included in FEI's current C&EM program portfolio.[127]

All cost effectiveness test results reported below exclude data from behavioural and energy management measures (e.g. residential home energy reports or industrial strategic energy management). In alignment with the BC CPR, the 2017 LTGRP C&EM analysis assumes that these measures have negligible incremental costs which cause them to have uncharacteristically high cost effectiveness test results. Excluding data for these measures prevents their results from skewing the aggregate data reported below.

Table 4-8 below summarizes the Reference Case cost effectiveness test results for all program areas while Figures 4-9 to 4-12 illustrate how cost effectiveness test results vary across scenarios. In general, Upper Bound cost effectiveness test ratios are lower than Lower Bound ratios because the low natural gas cost and carbon cost parameters in this scenario depress the avoided cost of gas which reduces the benefits from energy efficiency measures. The MTRC represents an exception to this as this test relies on the ZEEA for its avoided cost of gas. In the 2017 LTGRP, the ZEEA is not impacted by the natural gas and carbon cost critical uncertainties. In general, cost effectiveness test ratios fall over time as the more easily realized energy savings opportunities (i.e. the low-hanging fruit) are depleted. The 2017 LTGRP C&EM cost effectiveness test results also display the Cost of Conserved Energy (CCE) in dollars per GJ. The CCE is an industry standard method for expressing the TRC results in dollars per GJ. Electric utilities use the CCE to express the net cost of saving one unit of utility-supplied energy. The CCE can be used to express Utility Cost Test (UCT) results in dollars per GJ by applying the UCT benefit and cost inputs.[128] CCE results increase over time:

Table 4-8: Estimated Reference Case Cost Effectiveness Test Results – All Program Areas

Year	TRC	MTRC	UCT	CCE ($/GJ)
Aggregate	**2.2**	**11.3**	**2.2**	**4.7**
2017	4.8	25.4	4.4	2.8
2018	4.1	21.3	3.7	3.4
2019	3.5	18.2	3.2	3.7
2020	3.1	16.2	2.9	4.0
2021	2.8	14.5	2.7	4.3
2022	2.6	13.5	2.5	4.5
2023	2.4	12.6	2.4	4.6
2024	2.3	12.0	2.3	4.8

[127] FEI will consider these measures when it prepares its C&EM expenditure schedule for submission to the BCUC in 2018.

[128] In this case, the CCE represents the annualized and, where applicable, discounted UCT net costs (i.e. sum of UCT costs minus sum of UCT benefits, excluding cost savings for utility fuel sales) divided by annual energy savings.

Year	TRC	MTRC	UCT	CCE ($/GJ)
2025	2.3	11.6	2.2	4.8
2026	2.2	11.3	2.2	4.8
2027	2.1	11.1	2.1	4.9
2028	2.1	10.8	2.1	4.9
2029	2.0	10.6	2.1	4.9
2030	2.0	10.5	2.1	4.9
2031	2.0	10.3	2.0	4.8
2032	2.0	10.3	2.0	4.8
2033	2.0	10.3	2.0	4.8
2034	2.0	10.4	2.0	4.7
2035	2.0	10.4	2.0	4.7
2036	2.0	10.4	2.0	4.7

Figure 4-9: Estimated TRC Results by Scenario – All Program Areas

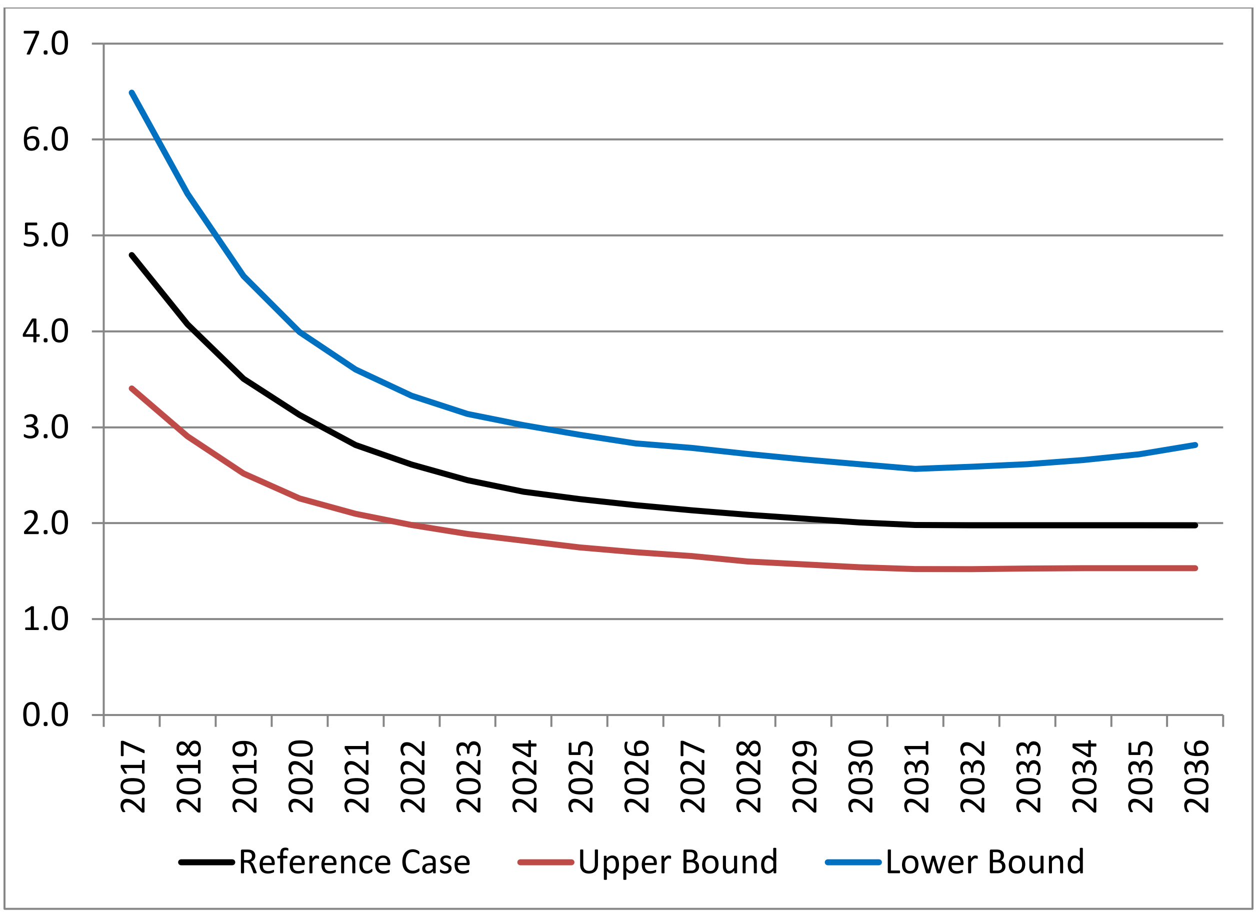


Figure 4-10: Estimated MTRC Results by Scenario – All Program Areas

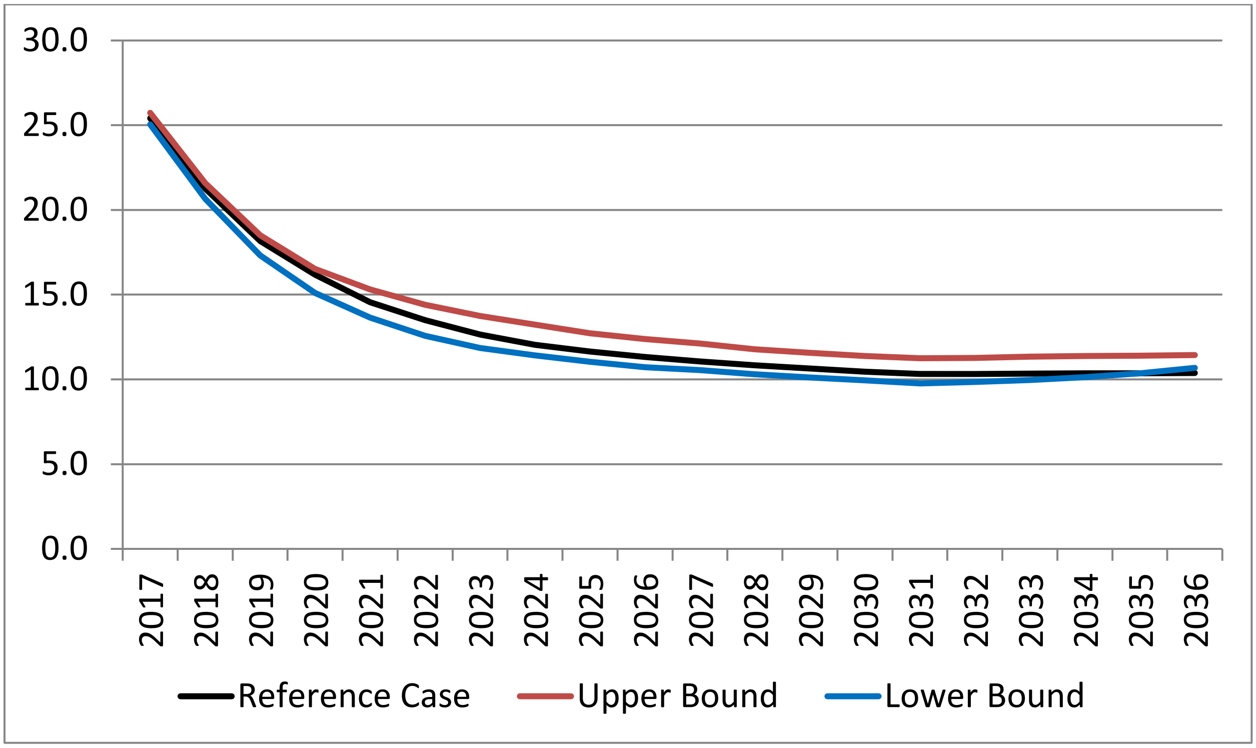


Figure 4-11: Estimated UCT Results by Scenario – All Program Areas

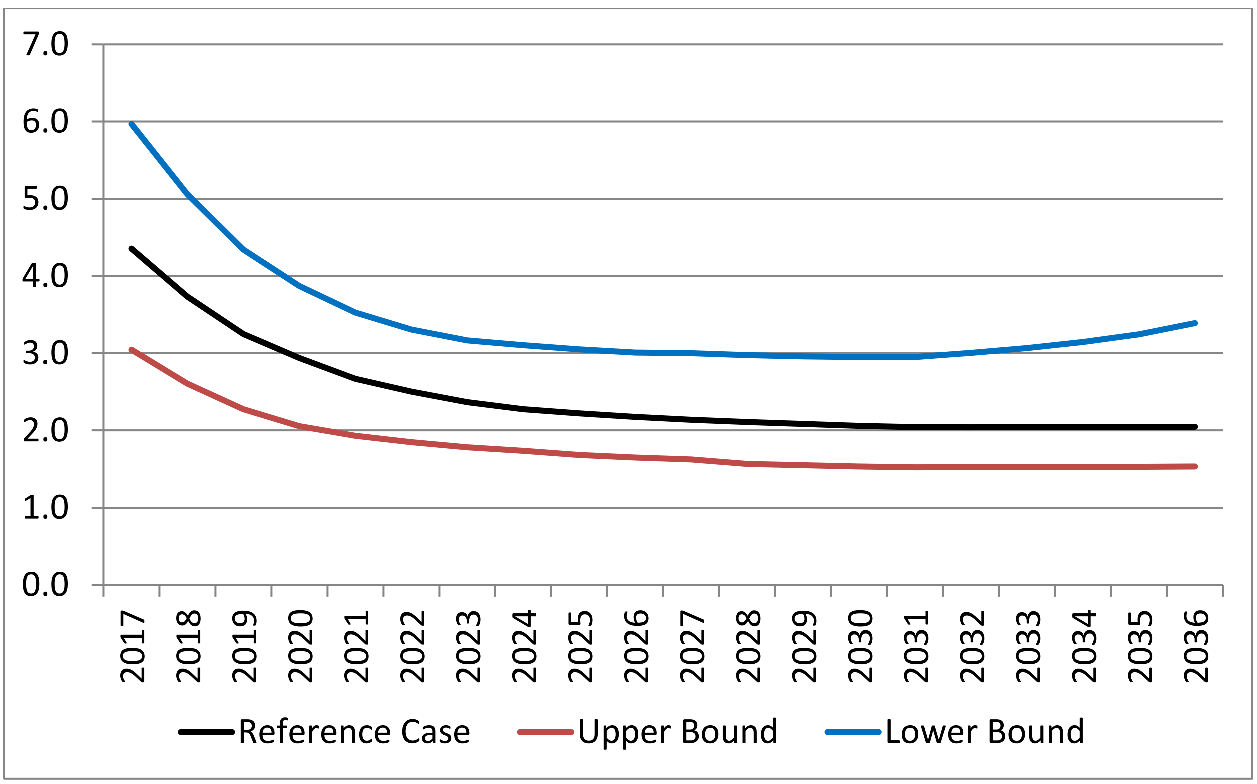
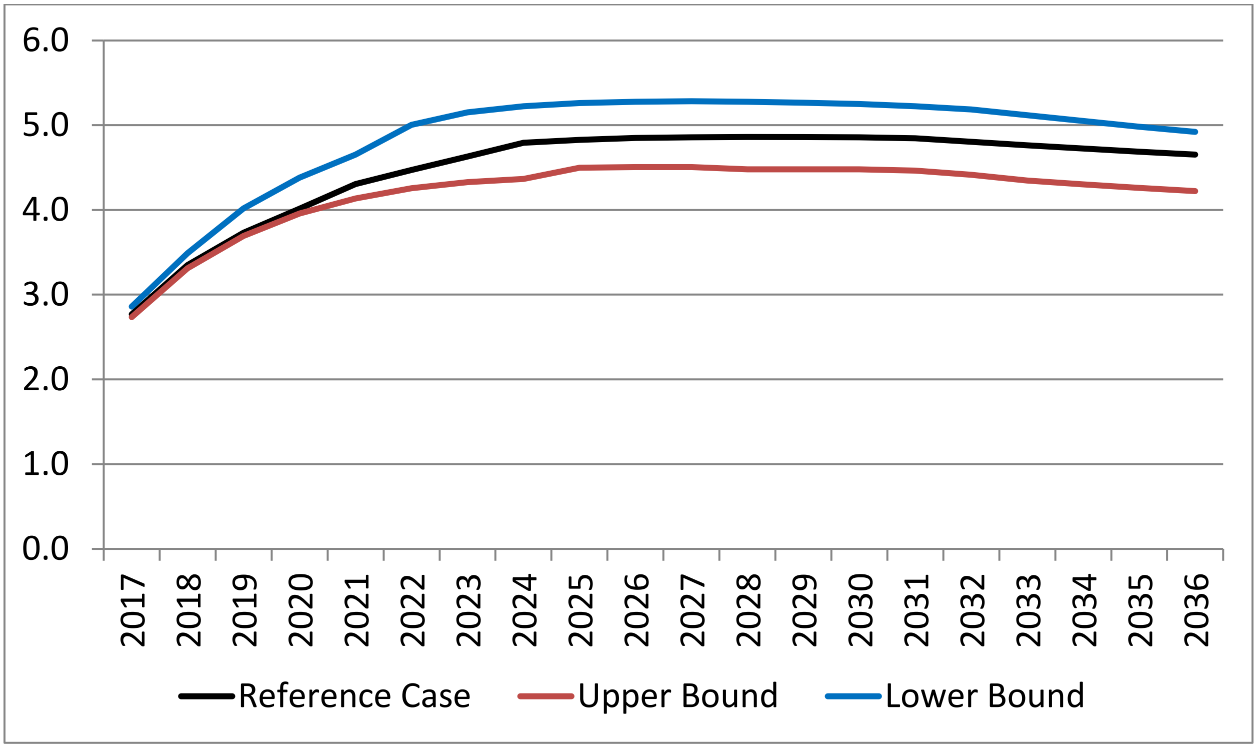


Figure 4-12: Estimated CCE Results by Scenario ($/GJ) – All Program Areas



Please see Appendix C-2 for cost effectiveness test results of each of the program areas within the 2017 LTGRP C&EM analysis.

4.2.3.4 Estimated Market Potential Energy Savings from Top Measures

Tables 4-9 to 4-12 below outline projected 2036 cumulative market potential energy savings for the top ten measures in the Reference Case and illustrate how these energy savings change across the scenarios. Overall, projected energy savings in the Upper Bound increase less from the Reference Case than Lower Bound energy savings decrease from the Reference Case. This appears to be due to Lower Bound annual demand (and thus energy savings opportunities) decreasing significantly more over the Reference Case than Upper Bound annual demand increases over the Reference Case. The residential program area top ten measures account for

90 percent of Reference Case program area energy savings. For the commercial and industrial program area this ratio is 65 and 96 percent, respectively. Some measures display zero energy savings in the Upper Bound while other measures display such zero values in the Lower Bound. In the Upper Bound, this appears to be due to the impact of decreased cost effectiveness as a result of the low natural gas and carbon price parameters in this scenario. In the Lower Bound, this appears to be due to reduced energy savings opportunities from accelerated codes and standards and loss of annual demand. FEI's forthcoming 2018 and future C&EM expenditure schedules will be informed by the measure data from the 2017 LTGRP's C&EM analysis and will make program design and delivery decisions in accordance with changing customer needs, regulatory requirements and technology evolution.

Table 4-9: Estimated 2036 Cumulative Savings from Top 10 Measures by Reference Case – All Program Areas

Measures	REFERENCE CASE 2036 Cumulative Savings (GJ)	UPPER BOUND 2036 Cumulative Savings (GJ)	UPPER BOUND % Change from Reference Case	LOWER BOUND 2036 Cumulative Savings (GJ)	LOWER BOUND % Change from Reference Case
Com | NC measure 45 %>code	1,581,337	2,631,732	66%	819,329	-48%
Res | Smart Thermostats	1,364,259	1,433,232	5%	706,260	-48%
Ind | Process Boiler Load Control	1,006,385	0	-100%	247,243	-75%
Res | Efficient Fireplaces	980,244	986,687	1%	974,217	-1%
Res | Home Energy Reports	682,987	711,710	4%	359,450	-47%
Com | HVAC Control Upgrades - Direct Digital Data	672,362	373,675	-44%	128,123	-81%
Res | ENERGY STAR Home	559,221	766,373	37%	35,404	-94%
Ind | Gas Ventilation Optimization	527,271	612,812	16%	209,427	-60%
Ind | Heat Recovery Systems	475,244	619,890	30%	210,595	-56%
Com | 'Gas Condensing Boiler_ ROB	464,484	503,378	8%	102,730	-78%

Table 4-10: Estimated 2036 Cumulative Savings from Top 10 Measures by Reference Case – Residential Program Area

Measures	REFERENCE CASE 2036 Cumulative Savings (GJ)	UPPER BOUND 2036 Cumulative Savings (GJ)	UPPER BOUND % Change from Reference Case	LOWER BOUND 2036 Cumulative Savings (GJ)	LOWER BOUND % Change from Reference Case
Res | Smart Thermostats	1,364,259	1,433,232	5%	706,260	-48%
Res | Efficient Fireplaces	980,244	986,687	1%	974,217	-1%
Res | Home Energy Reports	678,661	705,222	4%	358,683	-47%
Res | ENERGY STAR Home	559,221	766,373	37%	35,404	-94%
Res | Condensing Gas Tankless Water Heater	365,968	373,020	2%	266,322	-27%
Res | Crawlspace Duct Ins	279,659	295,545	6%	133,456	-52%
Res | Attic Insulation	230,539	244,145	6%	103,881	-55%
Res | Non-Condensing Gas Storage Water Heater	188,474	200,644	6%	0	-100%
Res | Passive House	162,467	230,622	42%	7,850	-95%
Res | Basement Insulation	131,909	137,616	4%	52,819	-60%

Table 4-11: Estimated 2036 Cumulative Savings from Top 10 Measures by Reference Case – Commercial Program Area

Measures	REFERENCE CASE 2036 Cumulative Savings (GJ)	UPPER BOUND 2036 Cumulative Savings (GJ)	UPPER BOUND % Change from Reference Case	LOWER BOUND 2036 Cumulative Savings (GJ)	LOWER BOUND % Change from Reference Case
Com | NC measure 45 %>code	1,581,337	2,631,732	66%	819,329	-48%
Com | HVAC Control Upgrades - Direct Digital Data	672,362	373,675	-44%	128,123	-81%
Com | ?Gas Condensing Boiler_ ROB	464,484	503,378	8%	102,730	-78%
Res | Heat Control System for Boilers	351,360	506,668	44%	0	-100%
Res | Fireplace Timers	310,968	490,350	58%	0	-100%
Com | Condensing Make Up Air Unit_ Gas	304,921	258,153	-15%	69,598	-77%
Com | Comprehensive Retrocomissioning	261,513	292,099	12%	79,929	-69%
Com | Gas Boiler - Mid Efficiency	260,351	0	-100%	59,118	-77%
Com | NC measure 30 %>code	220,115	506,276	130%	3,032	-99%
Res | Central High Eff Boiler Replace	215,482	272,243	26%	271	-100%

Table 4-12: Estimated 2036 Cumulative Savings from Top 10 Measures by Reference Case – Industrial Program Area

Measures	REFERENCE CASE 2036 Cumulative Savings (GJ)	UPPER BOUND 2036 Cumulative Savings (GJ)	UPPER BOUND % Change from Reference Case	LOWER BOUND 2036 Cumulative Savings (GJ)	LOWER BOUND % Change from Reference Case
Ind | Process Boiler Load Control	1,006,385	0	-100%	247,243	-75%
Ind | Gas Ventilation Optimization	527,271	612,812	16%	209,427	-60%
Ind | Heat Recovery Systems	475,244	619,890	30%	210,595	-56%
Ind | Energy Management	378,387	237,218	-37%	184,125	-51%
Ind | Process Control	339,593	371,147	9%	108,900	-68%
Ind | Unit Heater	227,530	470,528	107%	75,674	-67%
Ind | Condensing Boiler	184,986	278,421	51%	73,951	-60%
Ind | Insulation	91,732	113,356	24%	34,640	-62%
Ind | Regenerative Catalytic Oxidizer	86,550	100,398	16%	27,913	-68%
Ind | Improved Condensate Return	71,373	0	-100%	28,254	-60%

4.2.3.5 Reference Case C&EM Results Sensitivity to Incentive Level

In its decision on the 2014 LTRP, the Commission directed FEI to provide in the 2017 LTGRP DSM funding scenarios that reflect the results of the most recent CPR and, at a minimum, should include a reference, a high, and a low DSM funding scenario. FEI provided these scenarios in Section 4.2.3.2 above.

Recently, the Commission and FEI's stakeholders have also shown interest in the sensitivity of FEI's C&EM analysis to changes in the value of FEI's incentives as a proportion of incremental measure cost. FEI instructed the consultant that prepared the BC CPR to use the BC CPR's Bass Diffusion model to explore how different levels of incentive value impact projected energy savings and estimated C&EM expenditures. While the BC CPR model is separate from FEI's 2017 LTGRP forecast model and the 2017 LTGRP Reference Case differs from the BC CPR, the BC CPR's results provide directional insight into this sensitivity.

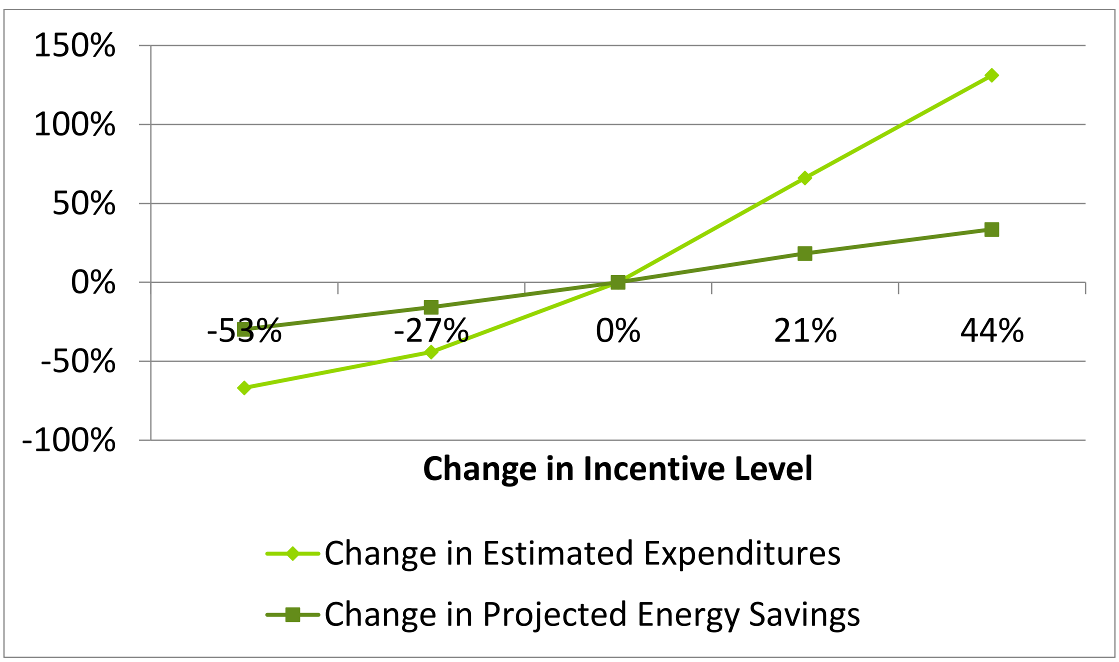
Table 4-13 below summarizes the inputs into the sensitivity analysis. The BC CPR consultant chose the Highest and Lowest input levels to represent the upper and lower bounds on possible incentive strategies. The Lowest input levels represent cases where the incentives are at the low end of industry experience, yet high enough to avoid undue free ridership (i.e. incentives are high enough to promote measure adoption above natural non-incentivized rates). The Highest input levels are intended to represent aggressive incentives, while still requiring participants to cover a small portion of the measure incremental cost. The industrial program area is the exception to this where the Highest input level was elevated to 100 percent because the BC CPR Baseline incentive level was already relatively high. The Low and High incentive levels are set at the approximate midpoints between the Baseline and the respective Lowest and Highest incentive levels.

Table 4-13: Sensitivity Inputs – BC CPR Incentive Levels as Percentage of Incremental Measure Cost

Sensitivity	Commercial	Industrial	Residential
Lowest	30%	30%	30%
Low	45%	60%	40%
Baseline*	61%	89%	52%
High	75%	95%	70%
Highest	90%	100%	90%

Figure 4-13 below illustrates the trend-line results from the sensitivity analysis at the aggregate C&EM portfolio level for the year 2035. Projected energy savings respond linearly to changes in the relative incentive level and have a flat slope. In contrast, estimated expenditures respond on an upward curve with a total slope that is steeper than the slope of the projected energy savings function.[129] Increasing the level of incentives by 44 percent for the aggregate C&EM portfolio yields 34 percent higher projected energy savings at 131 percent higher estimated expenditures:

Figure 4-13: Sensitivity Results Trend-Lines – BC CPR 2035 Incentive Level versus Estimated Expenditures and Energy Savings, All Program Areas



FEI emphasizes that its C&EM program team sets actual incentive levels based on its market research and experience when developing specific programs or preparing C&EM expenditure schedules. In contrast, the BC CPR's Bass Diffusion model represents a theoretical construct

[129] The energy savings trend is driven more by the industrial and commercial than by the residential program area. The estimated expenditure trend is driven more by the residential than by the commercial and industrial program areas.

that is calibrated to FEI's historical program performance and North American industry benchmark data.

4.2.3.6 Estimated Long Term C&EM Impacts on Peak Demand

In its decision on the 2014 LTRP the BCUC requested FEI to make stronger linkages between the peak demand and the annual demand forecasts, to understand how "[…] new insights on evolving customer consumption patterns might affect time-of-day demand as well as annual demand […] and how changes in base load annual demand under different scenarios translate into changes in base load peak demand under the same scenario assumptions."[130]

FEI commissioned Posterity to develop an exploratory process linking peak demand forecasts to the end-use scenarios used in the annual demand forecasts. Section 6.2.1.3 further discusses this process. Overall, Posterity's approach suggests that the 2017 LTGRP's C&EM forecast decreases peak demand. Section 6 discusses in detail how this may impact infrastructure expansion requirements across FEI's regional transmission systems. FEI emphasizes that Posterity's approach currently is theoretical in nature and unsupported by direct measurement. Thus FEI's infrastructure planning continues to rely on FEI's traditional peak demand forecast method (Traditional Peak Method).

4.2.4 Long Term Plan for Implementing C&EM Activities

FEI submits C&EM expenditure schedules to request BCUC approval for its short or medium term C&EM funding envelopes. Based on the results of the BC CPR and the 2017 LTGRP C&EM analysis (and in light of BC provincial energy goals), FEI will develop its next C&EM expenditure schedule for the period beyond 2018. FEI will submit this expenditure schedule to the Commission in 2018 after submission of the 2017 LTGRP.

In the long term, based on the 2017 LTGRP C&EM analysis, FEI projects that it will continue to perform residential, commercial, industrial, low income, innovative technologies, conservation education and outreach as well as enabling C&EM activities. The measures analyzed in the BC CPR and the LTGRP C&EM analysis will inform these activities. In addition, FEI will continue monitoring the cost effectiveness of its C&EM activities and identifying any new measures that can be included in its activities. Over the 2017 LTGRP planning horizon, FEI will operationalize these activities via successive C&EM expenditure schedules. Across these future expenditure schedules, FEI's specific program offers will likely change to suit the evolving marketplace, legislative provisions (including future adequacy requirements), end-use technologies, and FEI customer needs. During the 2017 LTGRP planning horizon, FEI will update its long term C&EM analysis via successive future LTGRPs.

[130] Decision and Order G-189-14, dated December 3, 2014. p. 22.

4.3 *OTHER DSM ACTIVITIES*

While the legislative framework for DSM in BC focuses on energy conservation as the primary means to achieve demand side energy reductions, in the broader context, demand side management encompasses a range of activities in addition to energy conservation. The California Standard Practice Manual, which serves as the general standard of cost effectiveness analysis in the US, identifies the following categories of DSM strategies to distinguish between different types of DSM activity.[131]

- **Conservation:** Programs that reduce natural gas consumption during all or significant portions of the year. This includes all energy efficiency improvements. FEI's C&EM programs fall under this category of load management strategies and are discussed in Section 4.2.
- **Load Management:** Programs that may either reduce peak demand or shift demand from peak to non-peak periods. Since the largest portion of natural gas demand in BC is for space and water heating which are more difficult to shift, and because the natural gas system acts to store energy allowing it to be drawn down over a longer period of time than with electricity, programs that reduce or shift peak demand for natural gas are more challenging in BC. However, increasing the load factor by adding customers who use natural gas in a flat manner helps to manage the system. Transportation customers are an example of this type of customer, as are other manufacturing customers such as those in fertilizer production or LNG for export.
- **Fuel Substitution:** Programs that increase annual consumption of natural gas or electricity by inducing the choice of one fuel over another. Two of FEI's current incentive-based initiatives could be characterized as fuel substitution: the residential fuel switching program and the Company's NGT activities. These two initiatives, discussed later in this section, have the benefit of increasing natural gas consumption and thereby having a downward impact on customer rates, while at the same time reducing customers' GHG emissions as natural gas replaces the combustion of higher carbon fossil fuels.
- **Load Building:** Programs that increase the annual consumption of electricity or natural gas by increasing sales of electricity, natural gas or both. In the broader context of DSM, FEI's fuel switching program and NGT initiatives are also examples of load building demand side activities in that they increase the annual use of natural gas.

The California Standard Practice Manual also notes that recent utility program proposals aimed at "load retention," "sales retention," "market retention," or "customer retention" may be treated as either a fuel substitution or a load building program since in most cases, the effect is identical to such programs.[132] FEI's current activities aimed at building load and retaining customers, for the benefit of FEI customers, are described here in Section 4.3. This discussion is not intended

[131] California Public Utilities Commission and California Energy Commission. 2001. "California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects". p. 2.
[132] Ibid. p. 3.

to address any of the requirements of Section 44.1(2) of the UCA —however, the initiatives discussed below help to meet BC Government energy and GHG emission objectives.

Currently, the Company is undertaking two programs that, although they are not demand-side measures as defined in BC's CEA, are demand side activities in the broader sense. These are FEI's fuel switching program and NGT initiatives. Expenditures and cost recovery mechanisms for the fuel switching program and NGT initiatives are separate and distinct from the Company's C&EM activities and have been approved by the Commission at current levels through proceedings separate from the current one. Since the fuel switching program is relatively small and NGT initiatives have been extensively reviewed through other regulatory processes, these initiatives are discussed here only to the extent that they provide examples of the types of fuel substitution and load building activities that FEI should continue to explore, implement and expand where there are benefits to customers and where they create an opportunity for the Company to help meet government energy and emission goals. FEI is also examining the potential for adding new, large industrial load customers and is currently engaging a wide network of builders, developers and other influencers of natural gas use in order to increase awareness of the benefits of natural gas and encourage new load.

The impact of the fuel switching program, NGT activities, annual demand for large new industrial customers, as well as every day sales activities for natural gas demand is already incorporated into the annual energy demand forecasts (Section 3), and therefore, their potential impact on system infrastructure is inherently considered in the system capacity planning and gas supply discussions in Sections 5 and 6, respectively. The main goal, consequently, is to present them here as examples of load management strategies that the Company should continue to explore, implement and expand where they are found to be in the interests of customers by adding throughput to the natural gas system thereby reducing rates while also helping to achieve government energy and emissions reduction objectives. (GHG emission reductions and rate impacts are discussed in Section 8).

4.3.1 Fuel Switching

FEI's fuel switching program (previously known as 'Switch 'n' Shrink') supports customer additions and demand growth, and includes initiatives designed to result in lower overall GHG emissions by using natural gas instead of other fuels such as coal, oil, diesel or propane. This program also promotes energy efficiency through installation of new high efficiency natural gas heating equipment.

Historically, FEI offered this program to its residential customers under the 'Switch 'n' Shrink' moniker. From 2010 until the end of 2016, the Switch 'n' Shrink program had at total of 4,349 participants. A 2012 technical analysis of the program concluded that participants consumed less energy, reduced GHG emissions and lowered their operations costs as a result of the lower cost of gas. [133,134]

[133] Or approximately 11 GJ, based on the energy content of the normalized annual heating oil consumption.

FEI re-launched the program as 'Connect to Gas' in Q3 of 2017. The program changes under this re-launch refine eligibility rules, clarify how FEI's C&EM and Connect to Gas initiatives relate to each other, and encourage the efficient use of energy.

4.3.2 NGT

As discussed in Section 2 FEI is implementing a strategy to stimulate growth in the CNG and LNG market that is focused on return-to-base fleet vehicles, marine vessels, and remote communities. Section 3 provides the annual demand forecast for CNG and LNG. Section 6 discusses the impact of CNG and LNG demand scenarios on FEI's system infrastructure.

4.3.3 New Large Industrial Customers

Additional load from new large industrial customers helps maintain rate competitiveness by increasing throughput on the gas delivery system. With the low natural gas price environment (refer to Section 2.2 for context on natural gas prices), large volume customers have indicated interest to FEI in expanding operations or developing new major industrial facilities that use natural gas as a feedstock.

Within its scenario analysis and contingency planning, FEI is examining its gas delivery systems' and gas supply planning's ability to accommodate transportation service (Firm Transportation) for new, large industrial demand in various locations across its service territories. Sections 6.3.1 and 6.3.2 illustrate an example of a large industrial customer that has requested Firm Transportation and the effect that the increased demand would have on system reinforcement requirements.

Any major required reinforcements to serve potential new industrial loads would be evaluated as part of a formal submission to the BCUC once firm agreements regarding natural gas services have been made.

4.4 *TOTAL ANNUAL DEMAND AFTER DSM*

Figure 4-14 below summarizes forecast total annual demand including FEI's base customers, FEI's projected NGT customers, and the effect of projected C&EM activity. As initially outlined in Section 3.4.9, Figure 4-14 also illustrates the hypothetical impact on the Reference Case and Upper Bound scenario of a potential small scale LNG export and processing facility located on the former Woodfibre pulp mill site near Squamish. Without the hypothetical impact of the Woodfibre LNG Project example, total Reference Case annual demand increases by 38 percent across the planning period when taking into account the impact of both forecast NGT and also C&EM activity. This Reference Case total represents the annual demand that FEI plans to in the 2017 LTGRP.

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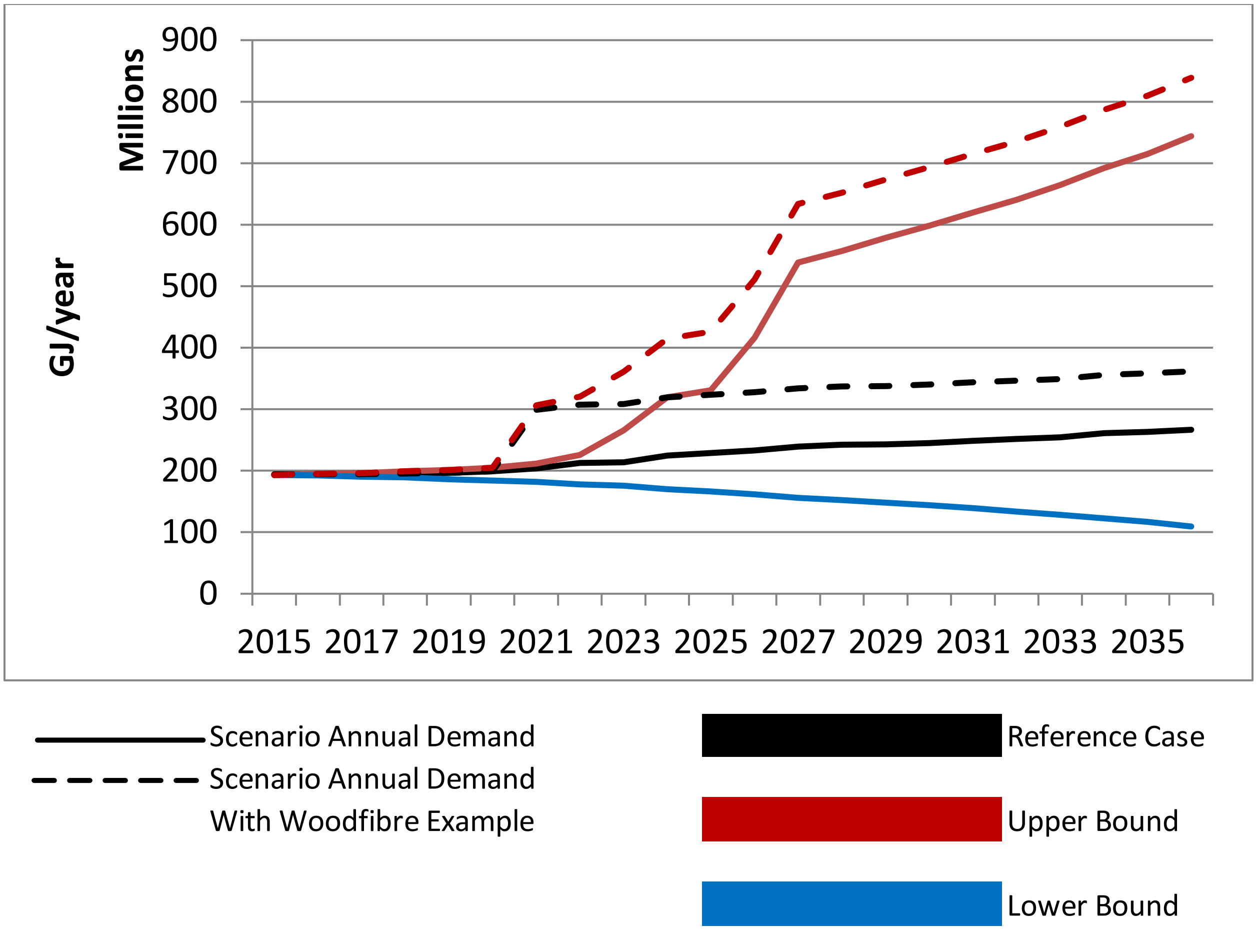
[134] InterVistas Consulting (November 21, 2012). "FortisBC Switch 'N Shrink Program Carbon Emissions and Cost Savings Analysis". This report uses a natural gas emission factor of 0.051 tCO_2e.

Figure 4-14: Total Annual Demand After DSM - Including NGT and Woodfibre LNG Project Example



4.5 CONCLUSIONS AND RECOMMENDED ACTIONS

DSM activity continues to be an important part of FEI's resources for meeting customers' energy needs, improving energy efficiency, helping to manage customers' energy costs, optimizing use of the energy infrastructure in BC and reducing GHG emissions. The C&EM analysis shows that significant energy and GHG emissions reductions can be achieved over the planning horizon under the range of future scenarios examined for the LTGRP. The analysis also shows that the C&EM measures implemented through the planning period will shift depending on how the future actually unfolds. Combined with analysis of the impacts of C&EM activities on the capacity requirements of FEI's natural gas transmission system discussed in Section 6, this 2017 LTGRP meets the requirements in Sections 44.1(2)(b) and (f) of the UCA to provide an explanation of how the Utility plans to use C&EM activities to reduce energy consumption and help meet customers' demand for energy over the long term, and to explain the extent to which C&EM activities can defer the need for new infrastructure projects.

FEI should continue to examine opportunities to develop other DSM initiatives that offer similar benefits or to expand existing offerings and where appropriate, seek approval for expenditures related to those offerings. Recommended actions to acquire and implement demand side resources over the planning horizon are to:

- Develop, based on the results of the BC CPR and the 2017 LTGRP C&EM analysis (and in light of BC provincial energy goals), a C&EM expenditure schedule for the period beyond 2018 and submit this request to the Commission after submission of the 2017 LTGRP.
- Implement the near-term C&EM expenditure schedule for the period beyond 2018 in accordance with the BCUC's future decision on FEI's forthcoming expenditure application.
- Continue to examine the potential for all forms of DSM and analyse the potential benefits and risks for FEI and its customers of implementing new and creative programs that help meet customer energy needs, optimize the use of utility infrastructure, keep energy rates down and/or reduce customers' GHG emissions.
- Continue to work with federal, provincial and municipal governments and other potential partners to explore and identify ways in which FEI's DSM activities can continue to help meet government objectives while ensuring benefits for FEI and its customers.

5. GAS SUPPLY PORTFOLIO PLANNING AND PRICE RISK MANAGEMENT

Section 2 of this 2017 LTGRP discussed FEI's planning environment as a basis for Section 3 to provide a long term annual demand forecast and Section 4 to consider the impact on forecast annual demand of FEI's projected C&EM activities. On this basis, Section 5 addresses how FEI plans to meet such demand in the long term via its gas supply arrangements. These arrangements encompass FEI's activities and means to contract for both natural gas as well as the resources to bring this gas to the FEI pipeline system. Subsequently, Section 6 will analyze long term requirements for FEI's own infrastructure and options for meeting these requirements over the planning horizon.

This section is organized as follows:

- Section 5.1 provides background information on FEI's gas supply portfolio planning instruments and regulatory requirements for gas supply planning in the LTGRP;
- Sections 5.2 to 5.4 discuss relevant regional developments, FEI's supply portfolio planning, and long term planning strategies; and
- Section 5.5 outlines FEI's long term approach to Price Risk Management.

It is important to note that gas supply portfolio planning considers a subset of the total system throughput that FEI considers for system capacity planning in Section 6. FEI's gas supply planning is responsible for ensuring that the forecast normal and peak day demand of core market (Core) customers is appropriately planned for[135]. The gas supply requirements for the remaining portion of the total system throughput are the responsibility of customers who have elected to take Firm Transportation. These Firm Transportation customers arrange for their own supply that is then transported by FEI to their premises. In contrast, system capacity planning needs to consider total system throughput to ensure that sufficient capacity exists on FEI's system to reliably move gas supply to meet the demand of all customers. Table 5-1 below illustrates the differences between FEI's customer service types for gas supply portfolio and system capacity planning in the LTGRP.

[135] As outlined in Table 5-1, this also applies throughout Section 5 to any applicable delivery component of Interruptible customers.

Table 5-1: Summary of LTGRP Customer Service Types

LTGRP Customer Service Type	Rate Schedules	FEI Gas Supply Portfolio Planning	FEI System Capacity Planning
Core	1, 2, 3, 4, 5, 6	Included	• Rate Schedules 1, 2, 3, 5, 6 included; and • Rate Schedule 4 (seasonal) excluded.
Firm Transportation	• 23, 25; and • Contracted firm delivery component of 22 (including 22A and 22B) and other special Rate Schedules.	Excluded (these customers may secure their commodity supply on their own or through a shipper agent)	Included
Interruptible	• 7, 27; and • Interruptible component of 22 (including 22 A and 22B) and other special Rate Schedules.	• For Rate Schedule 7 and any non-transportation component of special Rate Schedules: ○ Included: contracted firm delivery component; ○ Excluded: interruptible delivery component; and • Excluded for all other Interruptible service customers.	Interruptible components excluded (FEI can reduce natural gas flow to these customers during peak conditions to any firm contract amount)

This section and the Annual Contracting Plan (ACP) rely on FEI's traditional method for deriving system-wide demand for each day throughout the entire year as well as for the peak design day (i.e. the coldest day of the design year estimated via extreme value analysis within a return period of 20 years). In contrast, Section 6, which discusses FEI's resource needs and alternatives, relies on location-specific (not system-wide) peak demand. Section 6 outlines FEI's Traditional Peak Method for deriving peak demand and also explains FEI's test in this 2017 LTGRP for arithmetically linking the annual end-use demand forecast to peak demand.

Key factors in FEI's gas portfolio planning include resource cost and availability, which are determined in the competitive natural gas marketplace. Consequently, gas supply portfolio planning activities must also consider regional marketplace developments that will affect traditional regional gas flows, supply and demand in the region, as well as the cost and availability of regional market resources for FEI (briefly highlighted in Section 5.2 and further discussed in Appendix A). At this point, these gas market developments include understanding the shale gas supply potential in northern BC, initiatives by TransCanada in capturing this BC gas for its Alberta markets, and the potential for additional industrial demand in the region (e.g. methanol or LNG exports).

Currently, FEI contracts for all of the gas supply resources required over the short to medium term. However, as infrastructure in the region is fully utilized and now very constrained, new regional demand will require the construction of new infrastructure. The timing of when the new demand materializes and when new infrastructure is completed will likely present significant uncertainty for the natural gas marketplace. While FEI is likely to avoid facing issues over the short to medium term given its planning approach, these challenges may have significant impact on regional participants who have historically relied on interruptible transportation capacity. Currently, these participants are able to serve the demand of their customers by accessing some transportation capacity in the secondary market and by purchasing more costly gas supply at the Huntingdon-Sumas market hub. In the long term, however, as new regional demand materializes, much of this capacity may be taken back to serve this new demand. For FEI this may cause some Firm Transportation[136] customers to seek to return to Core service.

In this section, the term ‘region’ broadly refers to the PNW which includes BC. However, US-specific gas supply considerations are different from BC-specific considerations within the PNW region. For orientation, Figure 5-1 below provides an overview of FEI’s operating region, the supply basins that service markets in the PNW, the transportation pipelines and storage facilities required by these markets, and the location of the market supply hubs where commodity purchases are transacted.

[136] Throughout Section 5, this also applies to any applicable delivery component of Interruptible customers.

1 **Figure 5-1: Regional Supply Resources – Pipelines, Storage and Trading Hubs**

2

For managing market price risk, physical tools such as commodity purchases using different index and supply hubs, and the use of storage, as well as financial tools, such as hedges, help FEI maintain cost effective supply of natural gas and reduce adverse market price movements on rates. As previously mentioned in Section 2, while natural gas prices have continued to remain low in recent years because of the growth in shale gas supply, market price volatility remains because of frequent supply and demand imbalances. Furthermore, natural gas prices are not expected to remain at their current low levels over the long term. While the focus of price risk management in the past has been primarily on short term planning, FEI believes the current market price environment creates opportunities for longer-term strategies. Going forward, these could include consideration of longer term instruments or tools that could improve long term cost certainty. These strategies could then help to provide improved rate stability and ensure better security of supply for customers.

5.1 BACKGROUND

5.1.1 Relationship Between FEI's Gas Supply Planning Instruments

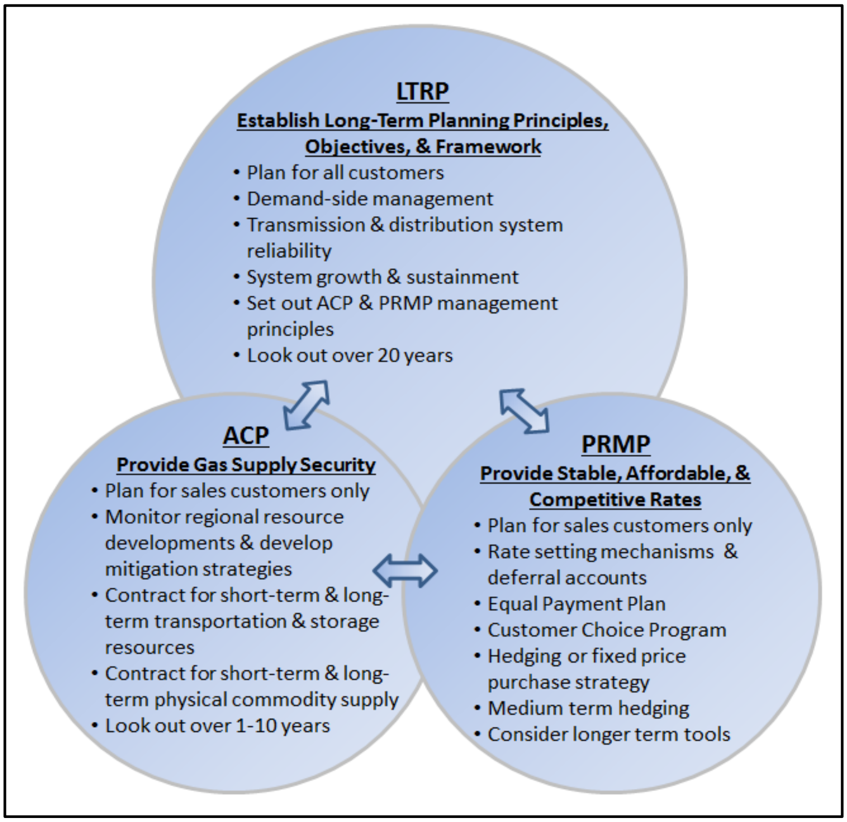
FEI uses multiple tools for planning its gas supply and price risk management activities. These tools are the LTGRP, ACPs and PRMPs. An important difference between the LTGRP and the ACP and PRMP is the type of demand forecast on which the various plans are prepared. The LTGRP is based on a broad range of long term demand forecast scenarios based on the total system throughput of all customers. In contrast, the ACP and PRMP are based on short term and medium term forecasts derived from trends observed in recent years (or on customer reported expectations in the case of industrial customers) and only consider the demand of Core customers, a subset of total system throughput.

The LTGRP establishes long term planning principles, objectives, and a framework that is used to help ensure the long term provision of safe, reliable, and cost effective service to all customers. In doing so, the LTGRP also sets out gas supply contracting and price risk management principles within the context of a 20-year outlook. The ACP and the PRMP each describe more detailed strategies and tactics for managing either the physical availability of natural gas supply or the impact of gas costs on rates.

The ACP is an annual plan that focuses on the next gas year's resource requirements but also looks out beyond the next gas year at any market conditions that may impact future supply procurement strategies. Although the ACP is primarily concerned with ensuring the physical availability of natural gas supply, it also enables several price risk management benefits. These include diversity and purchasing term supply from different market hubs, purchasing term supply on a daily and monthly indexed basis, and using storage resources to take advantage of any summer-winter price differentials.

The PRMP provides strategies and tools to enhance existing price risk management in managing the impacts of market price volatility on commodity rates and in capturing market price opportunities to help provide customers with affordable rates. The PRMP is, to a large degree, informed by the ACP since the ACP determines the physical resources required and degree of portfolio exposure to market prices. Figure 5-2 below illustrates the general components included in each instrument and the relationship between them:

Figure 5-2: Components Of And Relationship Between FEI Gas Supply Planning Processes



FEI is not seeking approval of its gas supply portfolio or price risk management activities as part of the LTGRP, as these approvals are sought through separate applications to the Commission. Discussion of the Company's ACPs and PRMPs is included in the LTGRP in order to provide context for resource planning considerations.

5.1.2 Regulatory Requirements for Gas Supply Planning in the LTGRP

Section 44.1(2) of the UCA outlines multiple requirements for long term resource plans. In relation to energy supply, the UCA requires long term resource plans to provide:

> e) Information regarding the energy purchases from other persons that the public utility intends to make in order to serve the estimated demand referred to in paragraph (c); and

f) An explanation of why the demand for energy to be served by the facilities referred to in paragraph (d) and the purchases referred to in paragraph (e) are not planned to be replaced by demand-side measures.[137]

FEI submits that Section 5 of this LTGRP meets the above UCA requirements by outlining the long term considerations that apply to FEI's energy purchases and the impact of demand drivers, such as DSM, on such considerations. FEI's ACP and PRMP operationalize these considerations in the short and medium term and, in doing so, will consider specific purchase requirements and demand driver impacts that affect FEI at their time.[138]

5.1.3 Factors Impacting FEI's Long Term Gas Supply

At a high level, the major market factors that may affect FEI's gas supply planning over the long term include:

- Large scale industrial projects (such as the large industrial point loads discussed in Section 3.4.9 that would not rely on their own pipeline connections to gas supply resources) potentially in-service by 2020 have already secured firm transportation capacity on existing regional pipelines for a portion, if not all, of their supply requirements. Once these projects come online, the regional flow dynamics and price for all customers may be impacted.
- Changes in the demand forecast within FEI's natural gas service areas[139] and regional local distribution utilities in the PNW.
- Risk of FEI's shorter duration market storage assets, specifically Mist, being recalled by approximately 2021/22.[140]
- Any major pipeline expansion in the region will require planning and lead time for approvals and implementation, given a greater amount of uncertainties now tied to large scale pipeline expansions (i.e. new customer contributions to underwriting the expansion and environmental/regulatory challenges).
- The significant supply potential in NEBC, specifically in the Montney region, has prompted the development of competing infrastructure initiatives to provide greater access to existing and new markets. These developments could impact FEI's future access to secure reliable natural gas supply at a fair market price in BC.

[137] http://www.bclaws.ca/Recon/document/ID/freeside/00_96473_01#section44.1

[138] The impact of demand-side measures to date is inherently considered in the ACP since the short term demand forecast, on which the ACP is based, captures these recent efficiency trends. Future ACPs will likewise consider future demand-side measures.

[139] Service areas include Mainland, Fort Nelson, Whistler and Vancouver Island.

[140] NW Natural's 2016 Integrated Resource Plan indicates future load growth within its service region (Oregon and Washington). https://www.nwnatural.com/aboutnwnatural/ratesandregulations/regulatoryactivities/integratedresourceplanning.

The following sections explain FEI's approach to handling these long term uncertainties. Section 5.2 commences this explanation by summarizing regional market developments. Section 5.3 outlines FEI's gas supply planning process and describes the sources as well as the need for diversification of regional gas supply resources. On this basis, Section 5.4 details the elements of FEI's long term supply planning and contracting strategy and Section 5.5 discusses price risk management.

5.2 REGIONAL MARKET DEVELOPMENTS

Significant changes continue to occur in the region that will affect FEI's long term gas supply resource contracting. Regional resources that are currently available are fully utilized to meet existing customer demand during colder than normal winters, as evident from three of the past ten winters. However, demand for natural gas is expected to increase in the future within both FEI's natural gas service areas and more broadly in the PNW region, which could have a significant impact on supply and demand dynamics in the region. For instance, the addition of new load will require the construction of new transportation capacity so that demand in the Lower Mainland and the US I-5 corridor can be served reliably. The potential new regional load is discussed in Appendix A. However, providing new transportation capacity will require advance planning, given that a limited regional pipeline expansion is unlikely to be completed before November 2020 and a further more significant regional pipeline expansion is unlikely to occur before 2023. The timetable for a more significant regional pipeline expansion may be subject to considerable changes, as it will only be undertaken after shippers commit to contribute to underwriting an expansion and may face environmental and regulatory challenges.

Another major development in the region is the significant supply potential in NEBC has prompted the development of infrastructure initiatives to provide greater access to existing and new markets. With increasing demand from industrial, power generation and oil sands demand within Alberta, and a push by producers to access this economic supply source, TransCanada has brought forward plans to expand into NEBC to access the significant resource that is located there. TransCanada's proposed projects will compete for the same supply currently accessed by Westcoast Energy Inc. (Westcoast) and on which FEI is reliant on for its customers. These regional pipeline initiatives are discussed in greater detail in Appendix A.

Finally, over the past few years, prices at the AECO/NIT market have dropped significantly, and are forecasted to remain lower than other gas market hub prices in the US and Canada, as the western gas market faces challenges to clear the substantial supply producers seek to bring to it. At the same time, less natural gas supply from the WCSB has been required by traditional eastern US and Canadian markets due to the growth in gas supply and pipeline connections from the Marcellus and Utica shale regions located in the north eastern US. This trend will likely continue as more pipeline expansions connecting this supply to eastern markets are expected to come into service in the near future. Western Canadian producers had hoped that the decline in its eastern market share would be offset by the emerging LNG export market in the PNW. However, this market has been slow to develop in the region and now faces an uncertain future given the delays and cancellations of many of these potential projects. As a result, the increase in supply combined with stagnating demand from the WCSB has caused AECO/NIT prices to plummet. It remains to be seen if and when gas producers will cut back on gas production in reaction to these low prices. These current low market prices provide an opportunity for FEI to capture and maintain low gas costs under its price risk management activities for customers.

5.3 SUPPLY PORTFOLIO PLANNING

5.3.1 Background and Overview of the Gas Supply Planning Process

Key factors in FEI's portfolio planning include resource cost and availability, which are determined in the natural gas marketplace where FEI competes with other parties. Basic elements of the gas supply portfolio include the purchasing of gas commodity volumes, contracting on third party transportation pipelines that connect supply to market, and contracting for storage resources, which allows the movement of gas to and from storage facilities as required. Gas supply is also provided via FEI's own on-system LNG storage facilities.[141]

Competition among market participants for supply and for transportation capacity on the regional transportation infrastructure means that utilities must remain vigilant in identifying regional developments that could negatively impact customers or, conversely, identifying opportunities that could provide benefits. FEI is involved in several regulatory proceedings and works with regional associations to help manage regional issues. These issues include ensuring the availability of regional gas supply as well as the appropriate development and tolling of new infrastructure that facilitates the reliable movement of supply to market.

FEI files an ACP with the Commission in the spring of each year, in which FEI assesses the overall North American market and evaluates the regional market with respect to supply and infrastructure. Key objectives of the ACP are:

1. To contract for resources that appropriately balance cost minimization, security, diversity and reliability of gas supply in order to meet the Core customer forecast design peak day and annual requirements; and
2. To develop a gas supply portfolio mix, which incorporates flexibility in the contracting of resources based on short term and long term planning and evolving market dynamics.

FEI's portfolio is designed to provide secure and reliable daily gas supply to Core customers so that system-wide forecasted normal, design and peak design day demand is met. FEI also evaluates the impact of the RNG initiatives; however, given the small relative volume of this

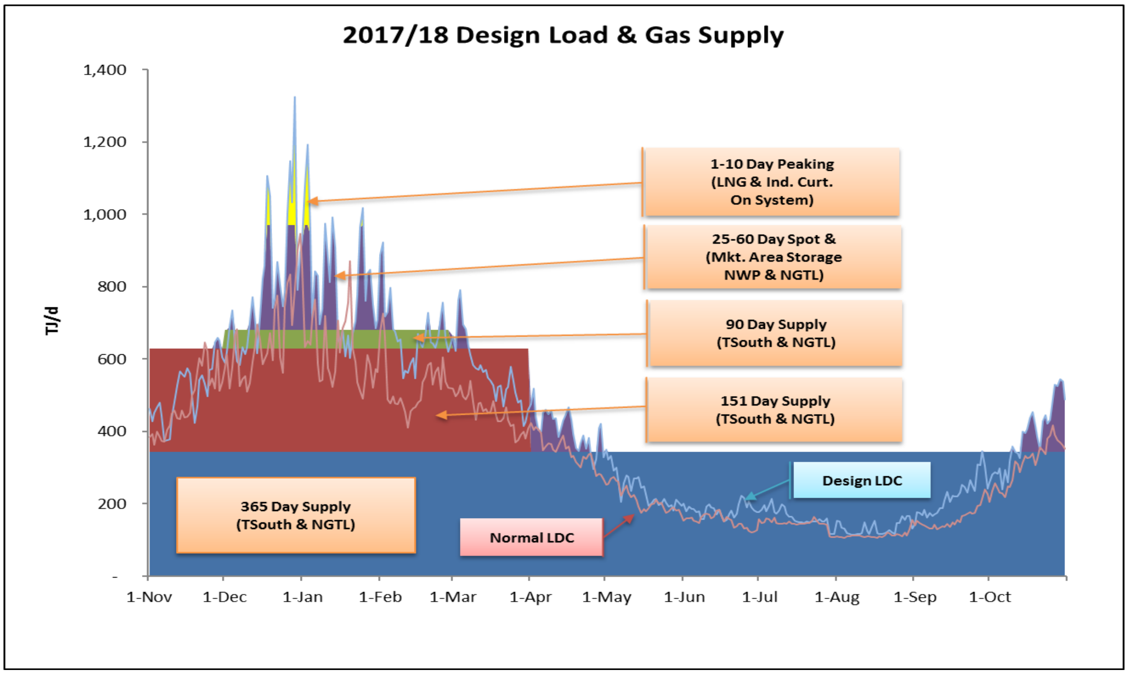
[141] The FEI-owned Tilbury LNG storage facility in Delta, BC currently has a capacity of approximately 0.6 million GJ. The Mt. Hayes LNG storage facility near Ladysmith, BC has a capacity of approximately 1.6 million GJ. The current 1.1 million GJ expansion at Tilbury will serve the transportation fleet market.

supply (current and forecasted) to the FEI system, it has not yet warranted an adjustment to the portfolio.

Supply resources include contracted term and spot supply, gas injected and withdrawn from various leased storage facilities, and use of company owned on-system LNG facilities. Many of these resources are contracted for the long term if they are cost effective and reliable, which is prudent given how limited these resources are in the region. Over the short term, the portfolio does not generally change significantly from year-to-year. However, the portfolio can and may need to rebalance over the long run as market changes occur and new infrastructure is developed.

Figure 5-3 illustrates the gas supply resources that are planned to be used in the 2017/18 gas contract year and how their durations fit the forecast annual normal and design load for Core customers.

Figure 5-3: 2017/18 FEI Forecasted Peak and Normal Loads vs. Resources[142]



This figure also illustrates that the colder weather in the winter period is highly variable, which requires resources that are flexible so that they can be deployed on relatively short notice to meet changes in load requirements.

5.3.2 Sources of Regional Natural Gas Supply Resources

FEI, on an ongoing basis, evaluates its portfolio of resources, which includes a mix of transportation pipeline capacity, storage and supply options in order to balance security and diversity of gas supply, while attempting to minimize the cost of the total portfolio. FEI currently

[142] This forecast is for Core requirements and does not represent total system throughput.

purchases its supply from two market hubs - Station 2 in NEBC, and AECO/NIT in Alberta. Alternative market hubs for consideration when contracting for supply are on the international border at Huntingdon-Sumas and Kingsgate.

FEI also contracts seasonal and shorter duration storage resources in order to meet seasonal and peaking demand requirements during the winter season, while balancing the overall pipeline system of FEI on a daily basis. Contracting considerations for storage facilities are generally planned to cover a longer time horizon, due to the limited availability of such resources in the region.

FEI contracts for seasonal storage at Aitken Creek Storage in NEBC and currently with Rockpoint Gas Storage in Alberta. These seasonal storage assets are available to be utilized throughout the winter season (November-March).

FEI also contracts for shorter duration market area storage resources, which are needed when colder than normal winter loads are greater than the supply available from seasonal storage and termed gas supply. FEI contracts these shorter duration assets at Jackson Prairie Storage in Washington and Mist Storage in Oregon. FEI also contracts with third parties such as Westcoast, TransCanada, and Northwest Pipeline (NWP) for transportation capacity in order to move supply purchased at the different market hubs, and to manage withdrawals and injections from storage facilities for delivery to FEI's transmission system.

Contracting for transportation capacity on Westcoast's T-North and T-South system provides FEI with access to gas supply from NEBC. Westcoast's T-North system allows FEI to access gas supply north of the Station 2 market hub, and to inject or withdraw from the Aitken Creek storage facility. Westcoast's T-South system allows gas supply to be delivered from Station 2 to FEI's Lower Mainland and Interior delivery system.

Contracting for capacity on TransCanada's NGTL and FoothillsBC systems and utilizing FEI's own Southern Crossing Pipeline (SCP) allows FEI to access gas supply from the AECO/NIT and Kingsgate markets and Alberta located storage facilities.

Finally, transportation capacity on NWP provides access to supply from storage facilities south of the border in Washington and Oregon states. Additionally, FEI uses its own on-system LNG storage facilities at Tilbury LNG and Mt. Hayes LNG to provide gas supply during periods of cold and extreme winter weather or during emergency situations.

5.3.3 Importance of Diversification of Gas Supply Resources

It is critical that FEI's supply and resource portfolio incorporate a flexible variety of resources ranging from purchased term and spot gas supply, seasonal and short duration third party storage contracts, and high volume on-system resources. Each resource within the portfolio has different characteristics and functions to meet the load requirements of FEI's customers. For example, while seasonal winter supply is used to meet average winter loads during each day of the winter, peaking resources such as Tilbury LNG storage are designed to be used on only the coldest days of the winter. The resources are selected based on how they meet the load profile, its cost, and their availability in the marketplace. Accessing gas supply from a variety of locations and sources provides FEI with a diverse pool of resources that is essential to help mitigate locational supply disruptions and price risk.

FEI and other utilities in the PNW rely heavily in the winter months on gas supply originating from NEBC that is transported on Westcoast's T-North and T-South pipelines. To manage the risk of supply interruptions associated with well freeze-offs, upsets in processing plants, and potential transmission force majeure events, FEI sources gas from producers that have supplies flowing out of Westcoast's Fort Nelson, McMahon, and Pine River gas plants, as well as from several smaller facilities for delivery to Station 2. Historically, two-thirds of gas supply in BC flowed from Pine River located east of Station 2, McMahon located south of Fort St John, and Fort Nelson located south of the town of Fort Nelson. However, over the past few years, the supply from these plants has declined significantly. The drop in production levels from these three plants is due to the sustained low commodity prices making them uneconomic. New production is now focused primarily on the Montney basin, where the cost of supply is significantly lower. This has led to increasing production in a number of smaller plants that are tied to Westcoast's T-North system. Production growth at these smaller plants is important because it has helped to diversify from the dependency on the three major gas plants. However, reliance on these smaller plants may come with additional risk over time. The risk exists that producers in the Montney basin may not be able to maintain their production levels given the significant drop in regional prices, as discussed briefly in Section 5.2. Moreover, with TransCanada's expansions in BC (discussed in Appendix A), the portion of NEBC gas production could change between Station 2, Alliance, and NGTL.

5.4 *FEI'S LONG TERM SUPPLY PLANNING AND CONTRACTING STRATEGY*

FEI's existing portfolio of resources will be able to meet forecast demand in the coming gas contracting years for the Core customers. However, certain market conditions that have been discussed throughout this section may unfold that could impact future resources available to FEI. This 2017 LTGRP presents FEI's contingency planning considerations, which illustrate how FEI may be able to respond to market conditions that differ from the Reference Case assumptions.

A reduction in FEI's demand forecast will not create a major risk to FEI's long term planning strategy because of the contracting flexibility of FEI's portfolio:

1. Commodity Purchases – Although FEI has entered into some long term supply commitments with counterparties, a majority of the gas supply purchased for the Core customers is negotiated on an annual basis and priced off a market index. Therefore, FEI could easily reduce or resell the amount of commodity purchases, if Core demand declines.
2. Transportation Capacity – FEI's transportation portfolio has been designed so that portions of capacity on third-party pipelines are up for renewal each year. This would allow FEI to de-contract most of its transportation capacity over a five-year period if it

encounters a future with significantly lower demand than expected in the Reference Case.

3. Storage Portfolio – FEI's approach to storage contracts is similar to the transportation portfolio; however, the contract terms may not necessarily expire on an annual basis but on a two or three-year period. Storage contracts are harder to manage because there are no renewal rights embedded in the contract terms so FEI must balance term length versus the risk of losing access to storage supply. In any case, if the load duration curve changes over time such that less storage supply is needed, FEI will still have the ability to determine, as a long term solution, an approach to de-contracting storage resources.

As such, the severity of the risk to FEI customers (in terms of access to sufficient and cost effective gas supply) of demand outperforming Reference Case expectations is higher than the severity of demand underperforming in relation to Reference Case expectations. This is due to the limited transportation and storage resources currently available in the region, and FEI must often compete with other regional utilities, such as those in Washington and Oregon, for these resources. Moreover, any potential infrastructure development could face significant delays, as discussed in Section 5.2. Therefore, if demand greatly increases compared to the Reference Case, caused by a large industrial project or demand from NGT, there may be a mismatch in available new infrastructure to serve that demand.[143] It is for this reason that FEI must continue to be proactive in securing reliable and diversified gas supply cost effectively over the long term. In order to meet these objectives, FEI continues to use the following broad strategies to secure future resources:

- FEI continues to actively participate in pipeline infrastructure developments, tolling proceedings and other initiatives to help ensure that the market hubs at which FEI contracts for gas supply continue to improve their market liquidity. This will help ensure that FEI's gas supply remains cost effective.
- FEI continues to establish key relationships with major producers that plan to develop gas supply in NEBC, including the Montney and other producing regions, over the long term. Efforts include seeking long term supply arrangements with producers who are evaluating or actively involved in developing their production sources in order to commit them to supply the Station 2 marketplace; and
- FEI continues to evaluate opportunities within its own operating region to improve infrastructure that will provide greater access to regional markets, leading to better diversity and reliability within the gas portfolio over the long term. These potential infrastructure developments are discussed at a high level in Appendix A.

[143] FEI's long term planning strategy will not be impacted by any large scale LNG projects that, by virtue of their natural gas demand, will require new pipeline infrastructure before they can begin service. The LNG projects that could impact FEI are the smaller scale projects that may have already contracted firm transportation on existing pipelines.

In addition to these strategies, FEI has also started to contract for some resources in excess of what Core customers are forecast to require in the short term. This approach is reasonable because the costs and ability to manage contract renewals within the portfolio of resources help to reduce the risk to Core customers. The alternative is to attempt to contract for additional resources in the future when they are forecast to be needed. However, in the future regional market factors may make it more difficult or even impossible to contract for critical additional resources on a firm basis. If, during this period, FEI's Core load requirements decline year-over-year and/or market developments proceed at a pace that do not result in any incremental demand, FEI's contract portfolio offers the flexibility to either allow contracts to roll off or decrease contracted amounts when they are up for renewal.

5.5 *PRICE RISK MANAGEMENT*

FEI operates in a marketplace characterized by volatile market prices and competing sources of energy for customers. Ensuring that natural gas rates remain competitive with other energy sources, maintaining affordable and reasonable rates for customers and reducing market price volatility are fundamental to retaining existing load, adding economic new load, and providing rate stability for customers. FEI has developed diversified procurement strategies and utilized PRMPs to manage commodity price risk and facilitate competitive and affordable natural gas rates. While the cost of natural gas relative to other energy sources can be a factor that is considered by energy users, FEI recognizes that other factors are also important, such as the impact of public policy and level of GHG emissions.

5.5.1 Price Risk Management Vision, Guiding Principles and Objectives

In the Commission's decision regarding the 2014 LTRP FEI was directed to include in the next long term resource plan a description of its long term vision for price risk management and provide broad principles, which can be used to inform future price risk management plans. FEI's long term vision for price risk management is to effectively reduce the impacts of market price volatility on commodity rates for FEI's customers. This vision is consistent with the 20-year vision of this 2017 LTGRP. As discussed in Section 8, FEI's 20-year vision is to be BC's trusted energy provider for safe, reliable and cost effective natural gas delivery services to its customers and to be a healthy, growing contributor to BC's economy and to the well-being of BC's communities. By effectively managing the impacts of market price risks, FEI enables customers and communities to consider natural gas as a competitive and affordable source of energy. For example, while natural gas market price volatility, causing fluctuations in natural gas commodity rates and bills, may not prompt natural gas customers to switch to another source of energy for home heating immediately or in the near term, it may cause them to consider switching fuel sources when it comes time to upgrade or retrofit their heating appliances. This may unnecessarily increase costs for customers over the long run. Effective price risk management can help mitigate such market price volatility.

FEI's guiding principles for its long term price risk management include the following:

- Reduction of market price risk: adverse market price movements and their subsequent impacts to customers through commodity rates should be reduced;
- Capture market opportunities: where possible, FEI should capture low-priced market opportunities in the interests of keeping rates low for customers; and
- Cost effective: price risk management tools and strategies should be cost effective so as to not significantly increase costs for customers.

FEI's price risk management objectives include mitigating market price volatility to support rate stability and capturing favourable prices to provide customers with more affordable rates. These objectives should be met in a cost effective manner in order to provide value for customers. FEI considers these objectives applicable for the medium (up to 5 years) and long term (beyond 5 years). As discussed in Section 5.3.2, FEI's supply contracts, whether for the upcoming gas contracting year or longer terms, are based on market index prices, which means that the purchase cost for this supply is unknown until gas delivery occurs. As there is uncertainty in terms of gas market supply, demand and pricing in the future, FEI believes it prudent to cost effectively reduce some of this price risk for customers. FEI's contracting strategies include securing commodity supply, transportation and storage contracts out several years and beyond. Nevertheless, the cost of the natural gas commodity supply fluctuates with market prices and can cause volatility in commodity rates for customers.

Although natural gas prices are currently low relative to price levels before the shale gas era (as discussed in Section 2), they continue to remain volatile and may increase in the future as demand for natural gas helps to balance the over-supply situation. The focus of FEI's price risk management in the past has been primarily on medium term planning; however, FEI believes the current market price environment provides opportunities for longer term strategies in the interests of meeting the objectives. The objectives for the medium and longer term are the same, but the tools for managing price risk management are different. For example, the use of gas storage helps to manage gas price volatility for the next winter period but does not mitigate potential price volatility five years from now. Longer term instruments or tools could include fixed price purchases or making a capital investment in natural gas supply from a producer (such as in a Volumetric Production Payment (VPP) arrangement). Not only do these provide longer term cost certainty and help provide stability in rates, but they also ensure security of supply for customers. FEI's current 2017 PRMP includes requests for approval relating to five-year fixed price hedges but does not seek approval for longer term fixed price purchases or investment in reserves. FEI plans to continue to investigate longer term strategies such as VPPs and, if warranted, will bring forward any requests to the Commission for approval in the future.

In this current low market price environment, FEI's hedging strategy has been an opportunistic one, capturing low market prices based on predefined hedging price targets founded on consideration of gas producers' break-even costs. It has also included capturing the currently favourable discount, or basis, between Station 2 and AECO/NIT prices, through fixed-price purchases, per the ACP to lower costs for customers. However, if, for example, market conditions were to change such that market gas prices were higher and more volatile, FEI would consider adjusting its hedging tools and strategy to a more defensive approach, potentially using call options or costless collars to mitigate upside price risk while still providing the benefit of achieving lower costs if market prices were to fall.

It is essential that FEI periodically review its price risk management tools and strategies to determine if they are effectively meeting the objectives. Currently, FEI prepares and submits a Price Risk Management Annual Report to the Commission, which summarizes the performance and effectiveness of price risk management plans and includes any recommendations for adjusting or refining strategies. FEI also hosts workshops on a periodic basis, for stakeholders and Commission staff, to discuss the price risk management initiative performance. These workshops assist FEI in gaining feedback in order to make recommendations going forward. While the goal of FEI's price risk management is not to "beat the market", it must be cost effective over time to provide value for customers. FEI considers the development of its price risk management an iterative process, which evolves over time, depending on market conditions and customers' preferences.

More discussion of FEI's price risk management tools and strategies is provided in the next section.

5.5.2 Physical Resources

The FEI gas supply portfolio includes diversified commodity, storage and transportation resources to maintain supply reliability and moderate commodity price uncertainty. As outlined in Section 5.1, the LTGRP sets out gas supply contracting principles within the context of a 20-year outlook. In accordance with these long term principles, ACPs (which cover a shorter time horizon than the LTGRP and are submitted separately to the Commission for review) outline FEI's approach to physical resources. While the ACPs include the portfolio of resources for each upcoming gas year, they also include resources and contracts that extend for ten years and longer. This is because the natural gas marketplace is competitive and many resources cannot be acquired, or contracted for, just prior to each gas contract year but instead must be planned for and arranged ahead of time.

Volatility in natural gas prices is partially managed by maintaining access to liquid trading hubs, utilizing a variety of storage and transportation resources, and using different pricing structures and contract terms. FEI considers access to appropriate natural gas infrastructure and minimizing reliance on any one price point a critical element of price risk management. FEI diversifies the gas supply portfolio to manage price risk, including taking into consideration the following measures:

- Diversifying gas pricing by purchasing at various market hubs, including Station 2, AECO/NIT, and Kingsgate;
- Purchasing physical supply at daily and monthly prices;

- Procuring seasonal and market area storage capacity and deliverability from third parties. Storage provides a natural physical winter hedge by locking in the value between summer and winter gas prices for gas that will be used during the heating season. Storage also increases security of supply and reliability by significantly reducing the risk of gas well or plant upsets and by providing greater operational flexibility (day-to-day and intra-day nominations) for load balancing to meet unexpected changes in supply or demand;
- Contracting for base load supply based on the average daily load over the contract year. In the summer, any base load supply that is not needed to meet load is injected into storage so that it will be available to help meet higher demand in the winter months;
- Contracting for long term supply contracts, up to ten years in length, with BC gas producers and other counterparties to support supply security at Station 2;
- Contracting for term purchases outside the gas year (up to three years out) if the Station 2 monthly discount to AECO/NIT is wider than a target level laid out in the ACP. This allows FEI to layer in term supply, by reducing the buying exposure at Station 2 during a given contract year;
- Diversifying storage resources with different facilities and staggered contract expiry dates. Storage contract terms and expiry dates are staggered to provide optionality for portfolio shaping, reduce negotiation failure risks, and alleviate the need to contract for large volumes of storage capacity, particularly during periods of high storage prices.
- Contracting for transportation capacity with staggered expiry dates. FEI has pipeline contracts with terms ranging between one to twenty years, however, the majority of its contracts are negotiated for terms of five years or less. Staggering expiry dates reduces the risk of having to re-contract for all or most of the required transportation capacity at once, and provides the flexibility to adjust capacity-based changes to supply and storage resources. With limited exceptions, transportation agreements currently have full or limited renewal rights upon notification as specified under the respective contracts;
- Contracting for transportation capacity to access different market hubs. FEI has firm transportation contracts with Westcoast, TransCanada (in BC and Alberta), NWP and SCP to diversify sourcing of supply from numerous supply hubs; and
- The Tilbury LNG and Mt. Hayes LNG facilities are utilized to balance the load in cold or extreme weather conditions, or to provide gas supply during emergency conditions. The high level of deliverability from these facilities will greatly assist in managing price volatility at the Huntingdon-Sumas marketplace while providing a secure source of on-system gas supply.

Other potential instruments or tools for managing longer-term market price volatility could include investment in natural gas reserves or long term fixed price contracts. Investment in natural gas reserves would provide even longer-term price protection. This could involve entering into a joint venture arrangement with a natural gas producer, wherein the right to a portion of the gas production is earned by paying a share of the costs to develop the gas plays. Managing the risks associated with investing in reserves would be of paramount importance to FEI. These risks could include those relating to drilling, completing, and operating wells and would differ from typical regulated utility assets. This type of transaction would not provide the same degree of price certainty as a hedging or fixed price purchase strategy but would provide cost-based supply for a longer period. FEI suggests that long term fixed price hedges better suit FEI's risk profile and field of expertise. However, at this point, FEI plans to investigate investing in reserves as a longer term strategy for helping to ensure security of supply and to provide cost stability.

Long term fixed price contracts would involve FEI purchasing physical supply from a natural gas producer at a fixed price for a term of up to ten years. Fixed-price physical purchases provide long term security of supply as well as provide a hedge against market price volatility. The significant decline in forward market AECO/NIT gas prices to levels near gas producer break-even costs (as discussed in Section 2) suggests that the value of this type of instrument may not be much higher than one involving investing in reserves, but without the production risk and additional work and time relating to due diligence. In addition, long term fixed price purchases up to ten years out provide more flexibility in terms of adjusting to FEI's future customer load requirements than investing in gas reserves, which is a commitment of up to thirty years. While FEI has traditionally experienced increasing gas load requirements in the past, there is no guarantee that this will continue indefinitely into the future (as discussed in Sections 3 and 6).

5.5.3 Locational Basis Risk

Locational basis risk results when the pricing at one market hub disconnects from that of other regional market hubs. The Huntingdon-Sumas market hub, with its Sumas pricing, is considered to have relatively high locational basis risk, due to regional market forces that can severely disconnect prices from other market hub prices, such as AECO/NIT and Station 2, and cause high volatility in prices. Such periods of pricing disconnects occur when increased demand in the PNW region exceeds the delivery capacity at Huntingdon and causes Sumas prices to increase significantly above other prices.

FEI is somewhat limited in its ability to reduce this basis risk due to the limited regional resources available to the PNW utilities. Key ways to manage this locational basis risk include contracting for market area storage, relying on on-system LNG resources, and reducing Huntingdon supply in the portfolio when possible. The use of storage and on-system LNG resources also provides the Company with much needed intraday flexibility, overnight withdrawals, and security of supply in the portfolio. The Mt. Hayes LNG facility has also recently reduced the need for peaking supply at Huntingdon during extreme weather, thereby reducing portfolio exposure to Huntingdon-Sumas prices.

This Huntingdon-Sumas price disconnection risk is not expected to diminish in the short term given the current transportation infrastructure, winter demand in the region, and the potential for greater power generation and industrial demand. New infrastructure in the region that brings more gas supply to the Huntingdon and PNW I-5 demand corridor[144] could help reduce some of this basis risk over the long term. FEI will continue to monitor developments in this regard, and respond appropriately, to provide the Company's customers with continued protection.

5.5.4 Financial Hedging

Financial hedging strategies are another way of managing price volatility. Hedging involves the use of financial derivative instruments wherein the market index-based price for gas supply purchases is converted to a fixed price or capped price (i.e. financial swap) via a transaction with a counterparty, such as a bank. The benefits of this approach include greater gas supply price and cost certainty and protection against rising market prices. It is important to note that hedging directly impacts the cost of gas supply for the medium or longer term while other rate smoothing mechanisms, such as the use of deferral accounts, do not directly affect gas costs but rather defer costs or surpluses for refunding over the shorter term.

Under its current 2017 PRMP (submitted June 13, 2017 and pending approval by the Commission), FEI's medium-term hedging strategy will enable FEI to capture low AECO/NIT market prices near gas producer break-even cost levels. This is an opportunistic strategy wherein hedges are only implemented if certain pre-defined market price targets are reached. However, the current low market gas price environment further out in time creates an opportunity for longer-term hedges, providing greater cost certainty and stability in the portfolio. Therefore, FEI's 2017 PRMP also includes the request to implement hedges with terms of up to five years, given that FEI's price risk management objectives are long term in nature. These hedges can include financial swaps or fixed price physical purchases – the overall effect in terms of mitigating price volatility is the same. However, fixed price physical purchases do offer the additional benefit of security of supply.

5.6 *CONCLUSION*

Effective gas portfolio planning and price risk management on both a short and long term basis enables FEI to secure cost effective, reliable gas supply and reduce rate volatility for customers. Given the significant marketplace developments in terms of North American gas supply, demand and pricing as well as regional infrastructure changes, FEI must continue to monitor changes and be proactive in assessing challenges and identifying opportunities.

Regional market developments (discussed in Appendix A) such as infrastructure initiatives to facilitate the movement of natural gas from BC to the Alberta market and west to supply LNG export projects may change traditional regional gas flows, along with supply and demand balances and pricing. In addition, industrial developments such as methanol and LNG projects in the Lower Mainland and the US PNW could also have an impact on gas pricing and flow factors from approximately 2020 and beyond. By monitoring these developments and responding to changes through portfolio planning, FEI can help ensure continued access to cost

[144] The I–5 demand corridor includes BC's Lower Mainland and Vancouver Island, Western Washington and Western Oregon.

effective supply for Core customers. FEI will continue to examine these regional developments and participate in regional project approval processes wherever it sees a need to act to protect customers' interests in maintaining secure, cost effective supply sources and infrastructure over the long term. This includes continuing to examine potential opportunities on FEI's own transmission and storage systems.

As discussed in Section 2, natural gas prices are near their lowest levels in a decade. However, market price volatility continues to be present and recent price forecasts suggest that future market prices will likely be higher as supply and demand come into a more sustainable balance. Effective price risk management can help reduce this market price volatility and is fundamental to retaining existing load and adding new load. FEI will continue to explore a range of price risk management activities to mitigate the impact of commodity price increases and volatility on customers' rates in both the near and long term. FEI will also continue to make separate applications to the Commission for approval of the price risk management activities that the Company believes are in the best interests of its customers.

6. SYSTEM RESOURCE NEEDS AND ALTERNATIVES

6.1 *INTRODUCTION*

A key aspect of ensuring safe, reliable and secure supply of natural gas to customers is identifying when and where any capacity constraints may appear and planning for the facilities, or system resources, that FEI needs to construct over the planning horizon to enable unrestrained delivery of natural gas to consumers. This section discusses FEI's examination of the Utility's natural gas delivery infrastructure and identifies any system resource needs in consideration of regional peak capacity to ensure that FEI's systems continue to serve the energy needs of customers across the province. This section is intended to address the requirements in Sections 44.1(2)(d) and (f) of the UCA.

Growth in peak demand is among the most significant challenges for FEI's long term planning. System expansion needs are driven by annual increases in forecast peak demand. A low gas commodity price environment and the use of cleaner natural gas over traditional fossil fuels are stimulating increased interest from the industrial sector in using natural gas for new or expanded applications, although this interest can change quickly as energy prices change. Growth in natural gas demand as a transportation fuel is also increasing as a result of these market conditions. At the same time, FEI's system sustainment planning process identifies important near-term and longer term system renewal requirements; most recently projects of this nature are underway in the Lower Mainland area of FEI's system. FEI takes a broad outlook that considers long term system capacity and sustainment plans, potential new, large increases in industrial load, and growing CNG and LNG demand, enabling an integrated approach to determining the most effective system improvements.

Section 6.2 discusses FEI's approach to system capacity planning, describing the method for determining peak demand forecasts and infrastructure project alternatives to address forecasted capacity constraints. Peak demand forecasts for system capacity (infrastructure) planning include considerations of demand at the local and regional level. This is a bottom up and more granular approach than the approach used when considering system wide peak demand use in gas supply planning (see Section 5). Traditionally, FEI has built regional peak demand forecasts based on the current peak hour use per customer (UPC_{peak}) that is held constant over the planning horizon. Recently, FEI has worked with a consultant, Posterity, in studying a potential means of applying knowledge gained from the end-use method of forecasting annual demand to forecast how UPC_{peak} might vary for each end-use future scenario presented in Section 3.4.4.

Section 6.3 discusses the capacity of FEI's natural gas transmission infrastructure to meet current and forecast peak demand for each of FEI's major transmission service regions – Vancouver Island, Coastal and Interior. Forecasts resulting from FEI's Traditional Peak Method forecast as well as the unique regional peak demand forecasts for each end-use scenario are presented and discussed. Consideration is also given to potential future new LNG and CNG and industrial loads that are not captured in the Core and Firm Transportation demand forecast.

Forecast capacity constraints and significant projects impacting FEI's transmission laterals and Distribution System networks are described in Sections 6.3.4 and 6.3.5, respectively.

Section 6.4 provides a description of other major system projects, not driven by system capacity considerations that FEI currently anticipates may result in CPCN applications in the next several years.

6.2 SYSTEM CAPACITY PLANNING

Ensuring adequate capacity within the transmission and distribution systems to meet existing and forecast load is critical to ensuring the safety and reliability of natural gas delivery. This section outlines the natural gas system infrastructure and the system capacity needs to continue delivering energy safely, reliably and at the lowest reasonable cost to the Company's customers. After determining forecast growth in natural gas demand and the expected impact of demand-side measures across FEI's service areas, FEI's system capacity planners examine the capacity of gas transmission systems to meet the anticipated demand. When forecast demand exceeds available capacity, a gas system expansion is required. Different system expansion alternatives are then identified in order to examine how to most effectively address specific capacity constraints.

Supply-side (gas supply) system resources must be designed to meet peak demand requirements of the Core and any applicable firm component for Interruptible customers on the system. Gas supply considers a system wide peak in assessing supply side resources. On a system wide basis an increase in peak demand in one location can be offset by a decrease in demand in other regions and still meet the supply requirements of the system as a whole. As system demand changes year over year supply resources can generally be adjusted in a timely and responsive manner to meet the peak requirement (see Section 5).

Infrastructure projects on transmission systems to address system capacity constraints are often large and take many years to plan and execute. As a result, securing infrastructure resources is not as responsive as securing gas supply resources. In addition, the location of customer demand on the system is a significant factor in determining the ability (capacity) of the system to deliver. Increasing peak demand in one region cannot necessarily be offset by a system expansion or decrease in peak demand in another region. To address the specific local and regional requirements, regional peak demand forecasts are built from the bottom up, assembling the peak demand from the recent consumption and regional weather history of each customer within the system. For commercial or industrial loads that are not temperature dependent, their contract firm or maximum consumption values are used. Planning for transmission system expansion is based on this regional peak forecast of demand for Core customers but also includes Firm Transportation not included in gas supply resource planning.

6.2.1 On-System Infrastructure Planning

Gas system infrastructure planning must ensure that gas system assets are of sufficient capacity (in terms of size, compression requirements and volume, for example) to meet the demand on a given system. To ensure constraints are identified and considered with sufficient lead time to plan and construct the necessary infrastructure, peak demand forecasts over a 20-year planning horizon are used.

In general, system demand growth is determined by region and applied to hydraulic models which determine resulting pressures at different locations for existing pipe, compression and LNG facilities. Eventually, demand exceeds capacity and a system expansion is required. In addition to load growth, other factors can also affect system capacity. For example, increased urban density close to existing pipeline assets can lead to a class location designation change and may result in a subsequent reduction in allowable operating pressure for that pipeline. Class location designations are defined in CSA standard Z662-15 and used as a protective measure in pipeline design to address population density and other criteria in the vicinity of a pipeline. A reduction in operating pressure will lead to a decrease in available pipeline capacity. These additional factors must be taken into account and are briefly discussed in this section.

6.2.1.1 System Expansion Planning Considerations

Pipeline capacity is determined by the quantity of gas that can be transported from a supply point at a given supply pressure to delivery points at or above required minimum delivery pressures. The key objective of any new capacity expansion options is to maintain, under peak conditions, pressures at all delivery points sufficient for the system to deliver to the consumer the contracted quantities of natural gas. Physically, pipeline capacity depends on the diameter and length of the pipeline, internal roughness of the pipeline, maximum operating pressure (MOP), required minimum delivery pressures and the distribution of customer demand along the system. Pipeline pressures are constrained by the MOP. The MOP is established in accordance with provincial regulations and good engineering practice in consideration of original construction specifications. To overcome friction and allow gas to flow through the pipeline, a pressure differential between the supply and delivery points is required. Compressors are used to increase this pressure differential and move large volumes of natural gas at high pressures through the transmission pipelines to major delivery points. The end pressures, which vary inversely with flow, are then controlled by pressure-regulating stations before natural gas enters the intermediate or distribution pressure systems for delivery to customers.

There are three resource options to evaluate when planning system expansions: pipelines, compression and storage. To solve capacity constraints, each alternative is analysed with respect to overall cost, difficulty of implementation, operational flexibility, implementation time, and other factors within the overall philosophy of system sustainment and reliability. Often, some combination of the three resource options leads to an optimal solution:

Pipelines

To increase throughput capacity, an existing pipeline can be replaced by a larger diameter pipeline (increasing the flow area and decreasing the gas velocity) or it can be "looped" with a parallel pipeline.

Compression

Adding compression helps to increase the average pipeline pressure, thereby providing a higher supply (or driving) pressure to move the gas. This higher pressure also increases the gas density leading to a reduction in gas pipeline velocity and correspondingly lower rate of pressure drop along the pipeline. Compressors can be added to existing compressor sites to provide additional station throughput capacity or new compressors can be added at intermediate locations on the pipeline.

On-System Storage

Storage facilities located within a service region are considered "on-system" supply-side resources. FEI considers LNG storage to be an on-system storage facility. During low demand periods, natural gas is liquefied and pumped into the storage facility. Conversely, during high demand periods, stored gas is vaporized and compressed back into the pipeline system in order to maintain pipeline operating pressure and increase system capacity without having to install throughput capacity from pipelines or compressors. Since FEI can call upon these resources when necessary, system security and reliability increases through the use of these on-system storage facilities. Another benefit of FEI's LNG facilities is the ability to provide customers with the potential to buy LNG for fuel use.

6.2.1.2 System Capacity Planning Considerations

Options to improve the capacity of a system to deliver to consumers are identified through hydraulic analysis using computer models of the pipeline systems. Computer simulations allow various "what if" scenarios to be evaluated and compared against one another. In determining the need for transmission system expansions, FEI considers the following:

- Optimizing resource capacity additions to meet demand requirements over a 20-year planning period.
- Correlating actual billed consumption information against temperature to determine the expected demand under design temperature conditions.
- Planning capacity additions to meet Core and Firm Transportation peak demand. Interruptible demand is not considered when identifying system improvements to sustain this peak demand. System improvements identified for peak demand provide opportunities for interruptible customers during off peak conditions.
- Designing transmission systems to meet peak demand. Core demand varies on an hourly basis and typically exhibits a morning peaking period between six and ten a.m.

and an evening period between five and nine p.m. The peak hour demand for these customers can be more than 40 percent above the hourly average (daily demand/24 hours). Transmission systems are designed to meet this peak demand condition.

- The amount of line pack within a transmission system determines whether it should be designed to meet peak day or peak hour conditions. A pipeline system with a large relative line pack can temporarily support increased demand out of the system that exceeds the supply into the system. As demand exceeds supply the amount of gas "packed" in the pipeline (i.e. line pack) is reduced and pressure in the pipeline is drawn down , until such time that the demand drops below the supply into the system, at which point pressure (and line pack) can recover. Pipeline length and operating pressure determine the amount of line pack available in the system. Typically, longer, larger diameter systems operating at higher pressures with high line pack are designed to peak day conditions; conversely, systems with lower amounts of line pack (due to factors such as lower pressures and smaller volumes) are designed to meet peak hour loads.
- Long lead times are needed for large infrastructure projects. This is due to regulatory reviews, public consultation, conceptual design, and detailed engineering, procurement, construction and commissioning schedules.

6.2.1.3 Regional Peak Demand Forecasting

Traditional Peak Method

FEI has long established methods for creating regional peak demand forecasts that have worked well in identifying system constraints and developing projects to address constraints in a timely fashion. FEI's Traditional Peak Method forecast is built from a "load gather" process that determines unique daily and hourly UPC_{peak} values for each customer. Values for most customers are based on regression analysis of average consumption against local temperature using the most recent 24 months of consumption information extracted from monthly meter read data. Measured values are then extrapolated to the regional design temperature where the customer is located, a temperature representing a 1 in 20 year extreme value determined for each region. For customers where hourly consumption data is available (typically large commercial and industrial customers) UPC_{peak} is determined directly from that data. These unique hourly UPC_{peak} values for each customer are then grouped by rate and region to determine average hourly UPC_{peak} for each region and rate schedule that can then be applied to an account forecast to determine a peak demand forecast. A unique UPC_{peak} for residential, small commercial and large commercial rate schedules in 66 separate regions across the province is developed in FEI's Traditional Peak Method. For large industrial demand the Traditional Peak Method forecast has not applied any forecasted growth or decline in the number of these customers. This is because the ability to forecast both the future load and location of these customers is subject to a great deal of speculation. UPC_{peak} for large industrial customers varies widely and can significantly impact local system capacity. Speculating on infrastructure requirements for loads of unknown magnitude and location has little value in long term planning of facilities whose design can be greatly influenced by their location within the transmission or distribution system. However, to explore impacts to peak demand as a result of potential changes in industrial account forecasts, FEI has produced both high and low account forecasts that show increasing or decreasing account numbers, respectively. These forecasts have been applied to the regional peak demand forecasts using the average peak demand for existing industrial customers in that region as an estimate of the peak demand for any new account additions or subtractions. As the location of new industrial demand is not specifically known, this increase or decrease in industrial peak demand was applied proportionally across the relevant transmission system.

UPC_{peak} values used in the Traditional Peak Method forecast are determined based on current measured consumption for customers. When applied to the 20-year account forecast to determine the peak demand forecast, these values are assumed to remain unchanged over the planning horizon. As such, there is no explicit allowance for evolving customer utilization in this approach. The estimates of UPC_{peak} are, however, refreshed annually so that assessments of future capacity constraints are always determined against current customer consumption patterns and end uses that reflect the presently measured impacts of energy economics, housing renewal, and DSM programs.[145]

The Traditional Peak Method forecast currently remains FEI's base forecast for determining infrastructure requirements and timing for addressing capacity constraints. For system capacity contingency planning in the 2017 LTGRP, FEI creates High and Low Traditional Peak Method forecast scenarios by applying high and low variations of its LTGRP customer forecast to the Traditional Peak Method's UPC_{peak} values. The method for developing the High and Low customer forecast perturbations is comparable to the method used for the annual demand forecast in Section 3.

Deriving Regional Peak Demand Forecasts from End-Use Scenarios

In its decision regarding the 2014 LTRP the BCUC asked FEI to make stronger linkages between the peak demand and the annual demand forecasts, to understand how "[…] new insights on evolving customer consumption patterns might affect time-of-day demand as well as annual demand […] and how changes in base load annual demand under different scenarios translate into changes in base load peak demand under the same scenario assumptions."

FEI has since commissioned Posterity, a consultant, to develop an exploratory process linking peak demand forecasts to the end-use scenarios used in the annual demand forecasts. At this point, the exercise is theoretical in nature and unsupported by direct measurement. As such, FEI's infrastructure planning continues to rely on the Traditional Peak Method. The exploratory end-use method does, however, provide a means of assessing a range of peak demand forecast possibilities and the impact on system capacity upgrade project scope and timing.

Posterity's approach relies on applying a series of appliance load shape profiles, developed from industry studies on appliance use, to sequentially break down annual consumption into

[145] In the Section 6 analyses, the term DSM refers to FEI's forecast C&EM activity from Section 4.2 only.

peak monthly consumption, monthly to peak daily consumption and finally daily to peak hourly consumption. Using the base year LTGRP inputs developed for the annual demand forecast Posterity then derived a base year hourly UPC_{peak} for each rate schedule and region. The results were corrected to peak design temperatures for each region. Posterity then determined calibration factors to match the derived UPC_{peak} values for the base year to FEI's current values of UPC_{peak} (determined from FEI's established load gather process and used in FEI's Traditional Peak Method regional peak demand forecasts). The process, using the derived calibration factors, can then be applied similarly to any year in any scenario to derive UPC_{peak} forecasts and subsequently peak demand forecasts in a format that can be easily applied to FEI's established capacity modelling methods.

The results are interesting in providing a means for relating annual demand more directly to peak demand. Future effects of DSM programs and the impact on peak demand and infrastructure requirements can be reviewed using this approach. This exercise also provides some indication of how various end-use scenarios might influence the peak hour factor (PHF), the ratio of peak hour consumption to peak day consumption. The results of this exploratory, end-use approach are represented below in the sections discussing each regional transmission system.

Since the exploratory end-use method is not based on metered FEI customer data, the Traditional Peak Method forecast which intrinsically reflects the current effects of DSM programs remains FEI's base forecast for determining infrastructure requirements and timing for addressing capacity constraints. By relying on the Traditional Peak Method, Section 6.3 thus addresses the requirements of section 44.1(2)(f) of the UCA. FEI will continue monitoring potential metering solutions that may allow FEI to field-validate the projections of the exploratory end-use peak demand forecast method and to better serve its customers.

6.3 *REGIONAL TRANSMISSION SYSTEM CAPACITY PLANS*

For capacity planning purposes, FEI is split into three main transmission systems and a number of smaller transmission laterals. The three main transmission systems are:

- Vancouver Island Transmission System (VITS or VI Transmission System): encompassing customers served on Vancouver Island, the Sunshine Coast, Squamish and Whistler;
- Coastal Transmission System (CTS): encompassing the Fraser Valley and surrounding cities, Metro Vancouver and North Vancouver; and
- Interior Transmission System (ITS): encompassing Southern Interior communities in the Kootenays, the Okanagan Valley and the South Thompson Valley.

Each of the three main transmission systems is discussed in further detail below. For each system, FEI will discuss:

- Existing major system infrastructure;
- Demand and capacity balance, which determines approximately when demand in the region will reach the ability of the system to deliver natural gas during peak conditions, thus identifying when system constraints will occur;
- Peak demand forecast sensitivity using the range of peak demand forecasts;
- System expansion alternatives. These are the infrastructure options that exist for solving identified system constraints. The options for constraints that occur in the near term are presented in more detail than those that are further out in the planning period;
- The impact of new demand for natural gas as a transportation fuel (CNG and LNG) on the expected timing of system constraints and consideration of alternative solutions; and
- The impact of potential large, new industrial loads on the expected timing of system constraints and consideration of alternative solutions.

In forecasting peak demand associated with future CNG, for the VITS, CTS and ITS, FEI projected that incremental annual CNG demand of 200 TJ/year would trigger a new fuelling station somewhere in the system. A typical fuelling station designed to deliver up to 200 TJ/year is estimated to exert a peak hour demand of 2,200 standard m^3/hour. These peak demands are based on fast fill stations currently installed or being designed throughout the FEI system. The projected CNG facility demand is then distributed proportionally across the region and is included in each forecast. To illustrate the relative impact of CNG, forecasts with and without the CNG forecast included are shown in most demand forecast graphs in the following sections.

FEI examines these factors to identify the expected timing of system constraints and the action plan needed to develop formal solutions that may require further expenditure applications to the Commission. Year after year, changes in the planning environment and new information may emerge that could impact the timing of the constraints or the alternative solutions being considered. Such changes will be presented in future LTGRPs or in any required applications to the Commission.

6.3.1 Vancouver Island (VI) Transmission System

The Vancouver Island Transmission System serves Vancouver Island, the Sunshine Coast and feeds the communities of Squamish and Whistler. It consists of 626 km of high pressure pipelines including three twinned marine crossings of the Georgia and Malaspina Straits, three compressor stations, and the Mt. Hayes LNG storage facility in Ladysmith. Natural gas for VI customers is delivered from upstream sources on the Westcoast pipeline system to the Huntingdon-Sumas trading point. From Huntingdon, the VI Transmission System demand transits through the CTS to the start of the VI system at Eagle Mountain in Coquitlam. The Mt. Hayes LNG storage facility has improved system reliability and enabled significant operational flexibility of the combined CTS and VITS.

Figure 6-1 shows the layout of the VI Transmission System including the location of the Mt. Hayes LNG storage facility, compressor stations, major industrial customers and locations of distribution networks.

Figure 6-1: Layout of the VI Transmission System

VI Demand and Capacity Balance

The VI Transmission System needs to serve the natural gas capacity requirements for the following customers:

- VI Core residential and small commercial customers located on Vancouver Island and the Sunshine Coast, in Squamish and in Whistler;
- Pulp and paper mills represented by the Vancouver Island Gas Joint Venture (VIGJV);

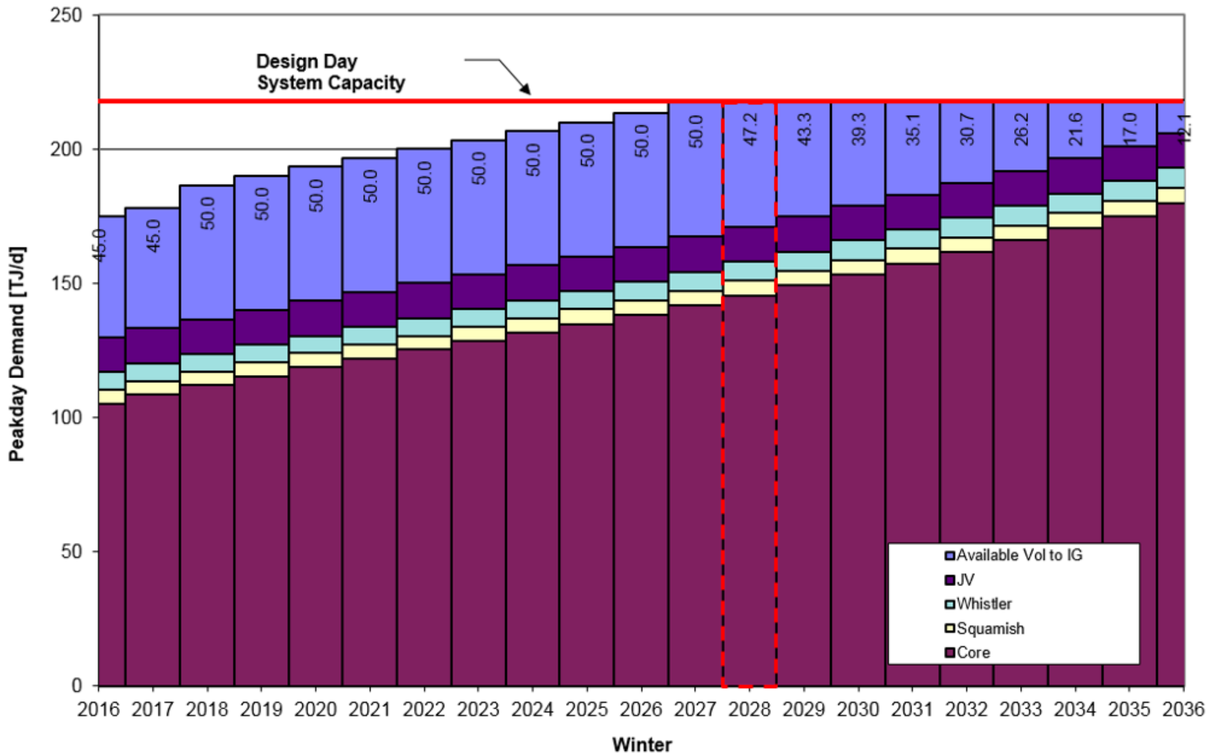
- BC Hydro for its Island Generation (IG) Plant, pursuant to a long term Transportation Service Agreement; and
- Forecasted expectations for demand from customers using natural gas as a transportation fuel.

Peak demand for VI's Core and Firm Transportation customers follows. As of November 2016, the current contract demand requirement for BC Hydro Island Generation is 45 TJ/d. For the 2017-18 winter, BC Hydro has requested and been granted a contract demand of 45 TJ/d. Since this contract demand can be amended for the following year (i.e. for 2018-19) to a maximum value of 50 TJ/d, FEI has analysed transmission requirements for the VI Transmission System based on the BC Hydro Island Generation contract demand increasing to and remaining at 50 TJ/d from 2018 onwards. The Vancouver Island Gas Joint Venture has recently increased its contract demand from 12 to 13 TJ/d starting in the 2015-16 winter season. For demand and capacity modelling, it is assumed that Vancouver Island Gas Joint Venture demand is fixed at 13 TJ/d from 2015 onwards. From the CNG forecast provided in Section 3.4.7.1 it was approximated that 10 percent of the total annual forecast demand would appear in the VI system.

Prior to installation of the Mt. Hayes LNG storage facility, the VITS was fully subscribed and relied upon a right to call back capacity from BC Hydro Island Generation during design weather events in order to serve its Core and Firm Transportation market design day (i.e. peak demand) requirements. Construction of the Mt. Hayes LNG storage facility was completed in 2011 and the facility entered service for the 2011-12 winter season. This on-system storage facility optimizes the existing system infrastructure by providing significant operational flexibility, regional storage resource benefits for FEI's customers, and improved system reliability.

The Mt. Hayes facility has a storage capacity of 1.5 Bcf (approximately 1,614 TJ), a liquefaction capacity of 7.5 million standard cubic feet per day (MMscfd), and a send-out deliverability of 150 MMscfd (161 TJ/d). Traditionally, the capacity of the VITS is represented by allocating one third of the Mt. Hayes sendout capacity to the VITS, with the balance remaining available for the rest of the FEI system. The peak day capacity on the following figures reflects this arrangement. Further capacity constraints on the VITS are not expected until 2028, at which time additional Mt. Hayes send-out capacity above the one third allocation is required. Figure 6-2 shows the peak demand and capacity balance for the VITS with 2015 Traditional Peak Method long range forecast, Core design day demand, and daily transportation requirements for Vancouver Island Gas Joint Venture mills (13 TJ/d, 2015 onwards) and BC Hydro Island Generation (50 TJ/d, 2018 onwards). The CNG demand relative to the Core and Firm Transportation customer peak demand is small in the base forecast and is barely noticeable in the demand plot for the VI Transmission System. This graph shows a capacity constraint on the VI Transmission System by 2028.

Figure 6-2: VI Demand-Capacity Balance with the Mt. Hayes Facility (Traditional Case)

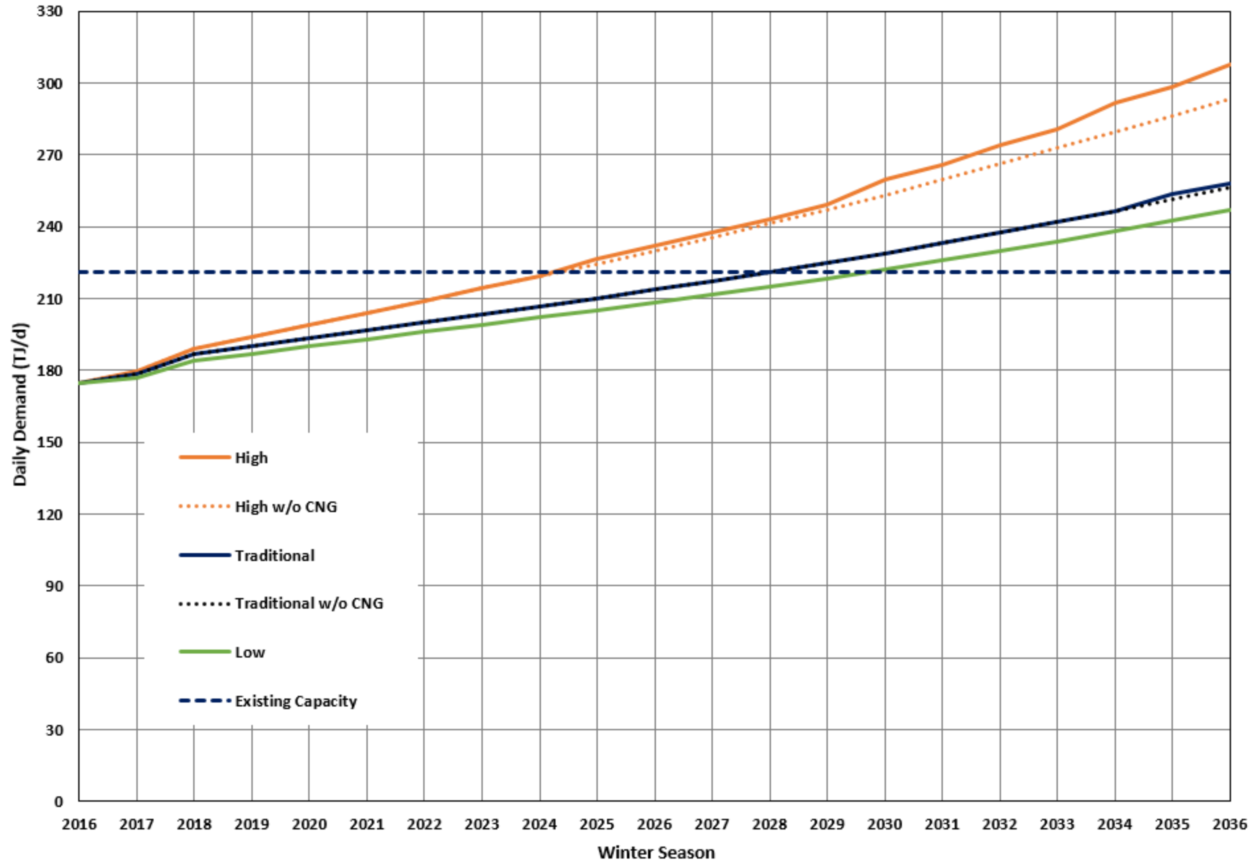


VI Peak Demand Forecast (Traditional with Low and High Forecast Scenarios)

The VI regional peak demand forecast shown in Figure 6-3 below was analysed against Low and High demand scenarios. The Low and High demand scenarios were determined by applying high and low variations of the account forecast to the UPC_{peak} values derived in the Traditional Peak Method.[146] With respect to large industrial account additions, which traditionally have not been forecast because of the widely varied and unique demands of these customer classes, the high and low load forecasts represent an increase and reduction in industrial class customers, respectively. In order to approximate the UPC_{peak} for these customers, an average of existing customer UPCs in the region was used. In addition, the CNG forecast is included in the each forecast. Figure 6-3 shows that the Low and High scenarios move the VI capacity constraint back by two years to 2030, or advance it by three years to 2025. For comparison, the dotted lines show the peak demand forecast after removing the impact of CNG. In the case of the Low forecast the influence of CNG demand is negligible. Note that in Figure 6-3 there is a 5 TJ/d increase in demand in 2018. This represents BC Hydro Island Generation's contractual right to request a firm capacity of 50 TJ for 2018.

[146] The method for developing the Low and High account forecast perturbations is comparable to the method used for the annual demand forecast in Section 3.

Figure 6-3: VI Demand-Capacity Balance Using Traditional, Low and High Peak Demand Scenarios



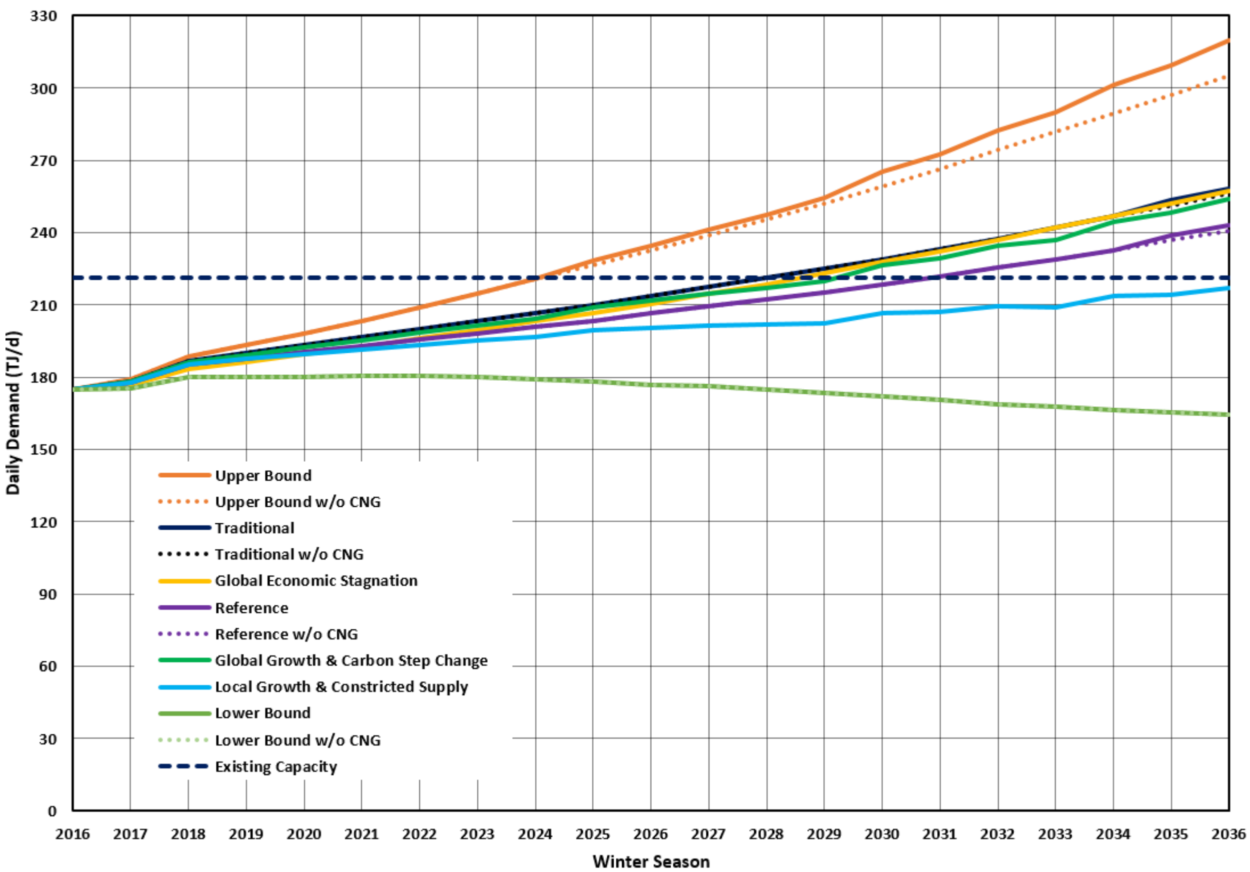
Sensitivity of VI Peak Demand to Alternative CNG and LNG demand forecasts

NGT growth on the VITS is largely in CNG, with growth in LNG demand being addressed through expansion at Tilbury in the Lower Mainland. In 2036 CNG base case peak demand will amount to 2 TJ/d across the system and as high as 14 TJ/d in the high forecast. This forecasted range of peak demand is not sufficient to influence the timing of system expansion requirements in any of the forecasted scenarios.

VI Peak Demand Forecast with End-Use Peak Demand Scenarios

A comparison of the peak demand forecasts using the Traditional Peak Method as well as the end-use scenarios is shown in Figure 6-4 below. The end-use method shows a wide variation in peak demand forecasts showing both increasing and decreasing demand over time. The forecasts are bounded on the upper end by the Upper Bound scenario with high economic growth and low commodity and carbon pricing and on the lower end by the Lower Bound scenario with low economic growth and high commodity and carbon pricing. The Reference Case illustrates the possible impact of declining UPC_{peak} on the “business as usual” forecast scenario and shows lower demand growth than the Traditional Peak Method forecast which assumes no variation over the planning horizon in the average UPC_{peak} values. Figure 6-4 shows that the Reference Case scenario defers the capacity constraint by 3 years to 2031. The Upper Bound scenario advances the timing of the capacity constraint by 3 years to 2025. The Global Growth and Carbon Step Change and Global Economic Stagnation scenarios show increasing peak demand in the planning horizon, very similar to the Traditional Peak Method forecast predicting a capacity constraint by 2029. The Local Growth and Constricted Supply scenario predicts moderate growth within the existing system capacity and the Lower Bound scenario shows a slow decline in peak demand over time with no capacity constraint projected within the planning horizon.

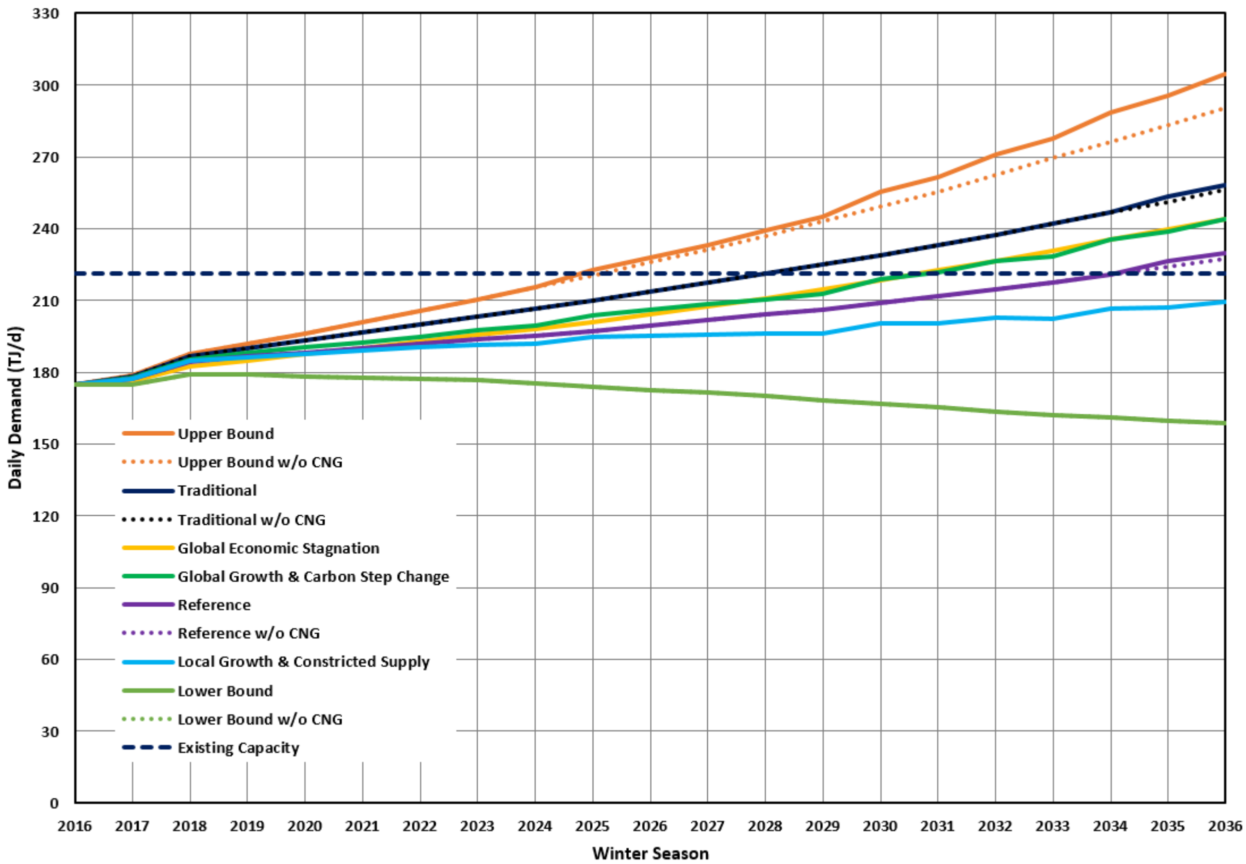
Figure 6-4: VI Demand-Capacity Balance Using Traditional and End-Use Peak Demand Scenarios



VI Peak Demand Forecast with End-Use Peak Demand Scenarios with DSM

A comparison of the peak demand forecasts using the Traditional Peak Method as well as the end-use scenarios with DSM impacts is shown in Figure 6-5 below. The addition of DSM has the impact of moving all the end-use peak demand scenario forecasts downward. The Upper Bound scenario continues to show a capacity constraint in 2025. The Global Growth and Carbon Step Change and Global Economic Stagnation scenarios defer the constraint to 2031. The capacity constraint in the Reference Case forecast is deferred to 2035, compared to 2031 when using the Reference Case forecast without DSM. The Local Growth and Constricted Supply scenario again predicts low but increasing growth within the existing system capacity, and the Lower Bound scenario shows a decline in peak demand over time with no capacity constraint projected within the planning horizon.

Figure 6-5: VI Demand-Capacity Balance Using Traditional and End-Use Peak Demand Scenarios with DSM



VI System Expansion Alternatives

The identified capacity constraint in 2028 occurs six years after expiry of the FEI-BC Hydro Transportation Service Agreement (TSA) for service to BC Hydro's Island Generation facility. If FEI and BC Hydro extend the TSA beyond 2022, based on current Traditional forecast numbers, the VITS would have the following resource options to manage forecast demand for the Core and Firm Transportation customers (including the transportation requirements for the Vancouver Island Gas Joint Venture and BC Hydro Island Generation) and to thus address the capacity constraint that occurs in 2028:

OPTION 1: COMPRESSION NEAR SQUAMISH

Maintain the traditional VI send-out and storage allotment from Mt. Hayes and install a new single compressor station (V2) near Squamish in 2028. In order to meet the projected demand of the High and end-use Upper Bound forecasts, V2 is required by 2024 and pipeline looping on the south of Vancouver Island, south of Mt. Hayes, along with additional compression and looping on Texada Island may be required by 2030.

OPTION 2: INCREASE MT. HAYES SEND-OUT ALLOTMENT WITH COMPRESSION NEAR SQUAMISH

Increase the VI send-out and storage allotment from Mt. Hayes to provide more on-system supply for the VITS during peak demand periods. This option defers requirements for additional compression near Squamish by 2 to 4 years to 2029 in the High forecasts and 2030 in the Traditional forecast. The High and end-use Upper Bound forecasts may also require additional compression upgrades and south Vancouver Island and Texada Island pipeline loops in 2030. This option involves accommodating an adjustment of gas supply strategy between FEI's Vancouver Island and Mainland regions for storage and send-out services from Mt. Hayes.

KEY INPUT: RENEGOTIATE BC HYDRO CONTRACT WITH IG

Renegotiating the existing peaking agreement with BC Hydro in 2022 may allow curtailment of flows to IG to meet Core and Firm Transportation market requirements. Depending on the peaking agreement reached with IG, reduction of the peak day firm quantity has the potential to defer the capacity constraint within the planning horizon or move it beyond the 20-year forecast horizon altogether. The final agreement will be a key factor in determining the requirement and timing of the preferred option for capacity expansion.

Table 6-1 presents analysis results for the VI Transmission System expansion portfolio assuming the BC Hydro Island Generation contract continues with a firm amount of 50 TJ/d. The earliest date that a system expansion would be required is in 2024 for the High demand scenario. Given that an operational solution (Option 2) is available to defer a V2 compressor installation to later in the planning horizon, this is the preferred and most cost effective solution.

Table 6-1: Summary of VI Transmission System Expansion Portfolio and Timing

Demand Scenario	Option 1: Install Compressor near Squamish (V2)		Option 2: Increase Mt. Hayes Send-Out Allotment and Defer Squamish V2 installation	
High and Upper Bound	Install V2	2024	Increase Send Out	2024
			Install V2	2025
	Additional Compression and Install South Vancouver Island and Texada Island Pipeline Loops	2030	Additional Compression and Install South Vancouver Island and Texada Island Pipeline Loops	2030
Traditional	Install V2	2028	Increase Send Out	2028
			Install V2	2031
Reference	Install V2	2031	Increase Send Out	2031
			Install V2	2034
Low	Install V2	2030	Increase Send Out	2030
			Install V2	2034

In addition to capacity expansion on the VITS, there are two pressure control station additions served from new pipeline taps from the VITS that are identified for installation in the next few years to improve capacity in the growing distribution systems of Campbell River (Deerfield Road area) and Nanaimo (Extension Road area).

Potential Large New Industrial Loads

The High forecasts discussed previously address some additions of large industrial loads generally across the system. Additions of large single customers on the VITS are evaluated on a case-by-case basis to ensure they are in the interests of customers and align with FEI's objectives of delivering cost effective, safe and reliable energy. Low natural gas prices and possibly other market dynamics in BC have spurred interest from a range of industries in locating or expanding facilities that would use large volumes of natural gas within the province. Any required major reinforcements to serve potential new industrial loads would be evaluated as part of a formal submission to the BCUC once firm agreements regarding natural gas services have been made.

As a result of inquiries received, FEI is exploring developing the Utility's systems to accommodate transportation service for new, large industrial demand in various locations in its service territories. One such example in the VI service territory is a small scale LNG export and processing facility (Woodfibre LNG Project) located on the VITS at the former Woodfibre pulp mill site near Squamish. Woodfibre LNG Limited, a subsidiary of Pacific Oil & Gas, and FEI entered into a Development Agreement and, for a number of years, FEI has been carrying out development work, including a feasibility study, engineering, and exploring the regulatory and other approvals required to expand the VITS to provide a firm natural gas transportation service to the Woodfibre LNG Project. Woodfibre LNG Limited has presently indicated that it expects to require Firm Transportation service from FEI of up to 236 MMscfd on the VITS.[147] Should a final investment decision be made, the estimated in-service date of this facility is currently projected no earlier than 2021.

To accommodate this load addition, there is a need to reinforce the existing VITS with pipeline looping and added compression near Squamish. This infrastructure expansion would match the Firm Transportation capacity contracted by Woodfibre LNG Limited under peak demand, preserving available capacity for existing customers, but would allow large volumes of interruptible capacity to be available for much of the year. FEI expects the Woodfibre LNG Project to help reduce costs for firm service on FEI systems and thus provide benefits to FEI's existing customers through lower rates.

The Woodfibre LNG Project is an example of large industrial load being considered in detail on an FEI system and the challenges of forecasting and planning around such a load addition. These projects take many years of advance planning and design, and are significant in scope and impact on the pre-existing system. The projects are managed and are designed to preserve existing capacity and service to customers and eventually, if approved, are constructed to meet

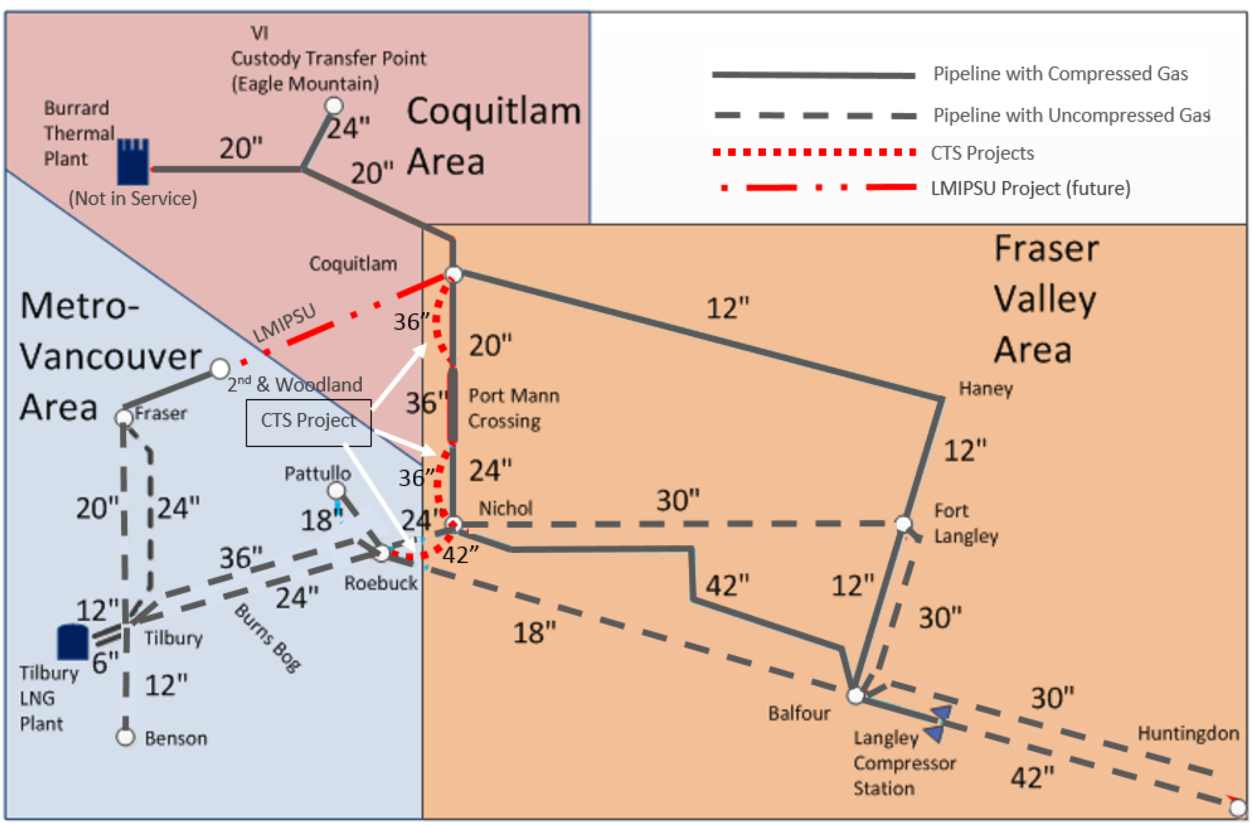
[147] As a transportation service customer, the Woodfibre LNG Project would not impact FEI's Vancouver Island gas supply planning as the customer would independently acquire its gas supply.

FEI system requirements and the very specific process and economic needs of the industrial customer. The solution for the Woodfibre LNG Project and required system changes would look significantly different if the location of the project were at a different point on the FEI system. However, the process of managing the timing of large load additions and associated system expansion requirements without eroding service reliability to existing customers would not change.

6.3.2 FEI Coastal Transmission System

The CTS consists of a 276 km network of pipelines providing gas transportation from the Huntingdon-Sumas trading point to various metering and regulating stations in the Fraser Valley, Metro Vancouver and Coquitlam areas. There are two primary capacity related facilities on the CTS: the Langley Compressor Station, which is used to boost pressures on the CTS during periods of high demand, and the Tilbury LNG storage facility, which is used to provide peaking gas supply during colder weather. The CTS delivers gas to the distribution networks in the Lower Mainland and to the VI Transmission System at Eagle Mountain in Coquitlam. The schematic diagram in Figure 6-6 shows the general layout of the CTS.

Figure 6-6: Schematic of the Coastal Transmission System Including the Langley Compressor Station and Tilbury LNG Storage Facility



CTS Peak Demand and Capacity Balance

There have recently been several changes that have impacted the CTS capacity balance. The CTS capacity to support growth has been enhanced by the construction of three transmission pipeline loops (these enter service in late 2017 and were described in Section 5.2 of the 2014 LTRP):

- A 1.5 km NPS 42 pipeline loop of an existing NPS 24 pipeline between Nichol and Roebuck Valve Stations in Surrey;
- A 4.9 km NPS 36 pipeline loop of an existing NPS 24 pipeline between Nichol and Port Mann Valve Stations in Surrey; and
- A 4.5 km NPS 36 pipeline loop of an existing NPS 20 pipeline between Cape Horn Valve Station and Coquitlam Gate Station in Coquitlam.

Approval for the construction of these loops, collectively identified as the CTS project, was granted through BC Government Direction No. 5 under OIC 557 in 2013 (please see Section 2.3.3.5 for details). The project loops existing pipelines that were single points of failure on the CTS and additionally addresses the existing capacity constraints on the CTS that were identified in Section 5 of the 2014 LTRP.

In addition to the CTS project, the LMIPSU projects (Coquitlam Gate IP Project and Fraser Gate Project) are currently in progress. The Coquitlam Gate IP Project will replace an existing NPS 20 pipeline nearing the end of its service life, between Coquitlam Gate Station and 2nd Avenue and Woodland Drive Station in Vancouver with a new high capacity NPS 30 pipeline. The Fraser Gate Project will replace approximately 300 meters of NPS 30 pipe with new NPS 30 pipe to upgrade the Fraser Gate IP Pipeline to current seismic design standards. The LMIPSU projects impact the CTS by shifting peak load within the transmission system from Fraser Gate to Coquitlam Gate.

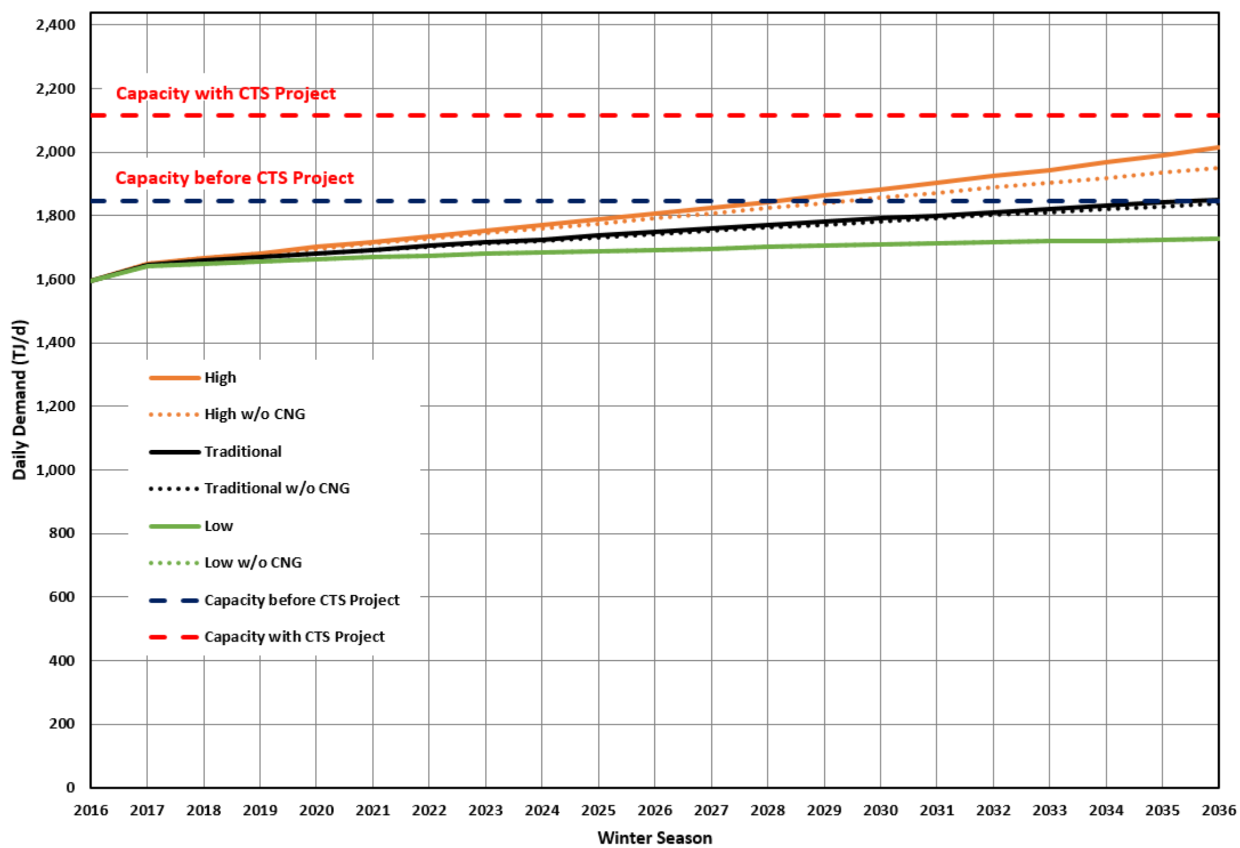
Finally, as anticipated, BC Hydro phased out the Burrard Thermal power generation plant effective November 1, 2016. The retirement of Burrard Thermal reduced the firm peak demand on the CTS by 215 MMscfd.

CTS Peak Demand Forecast Sensitivity (Traditional with Low and High Forecast Scenarios)

Currently, with the CTS project in place and Burrard Thermal decommissioned, the CTS has sufficient capacity to support Traditional, High or Low peak demand throughout the 20-year planning horizon with additional capacity to support increased LNG capacity at locations like Tilbury LNG in Delta and the Woodfibre LNG Project site in Howe Sound. For the foreseeable future, additional expansion requirements for the CTS will be driven by similar LNG additions or other large industrial demand in the Lower Mainland or VITS rather than Core customer growth.

The regional Traditional, Low and High peak demand forecasts are shown in Figure 6-7 and compare forecast peak demand to system capacity in order to illustrate when system constraints may occur. Peak demand for CNG as a transportation fuel is included in the forecast. For comparison, the forecast without CNG is shown as the dotted lines. The system capacity as it existed before the CTS project is also shown in comparison to the expanded capacity with it installed. With installation of the CTS project, FEI does not expect any capacity constraints to occur within the 2017 LTGRP planning horizon under these forecasts.

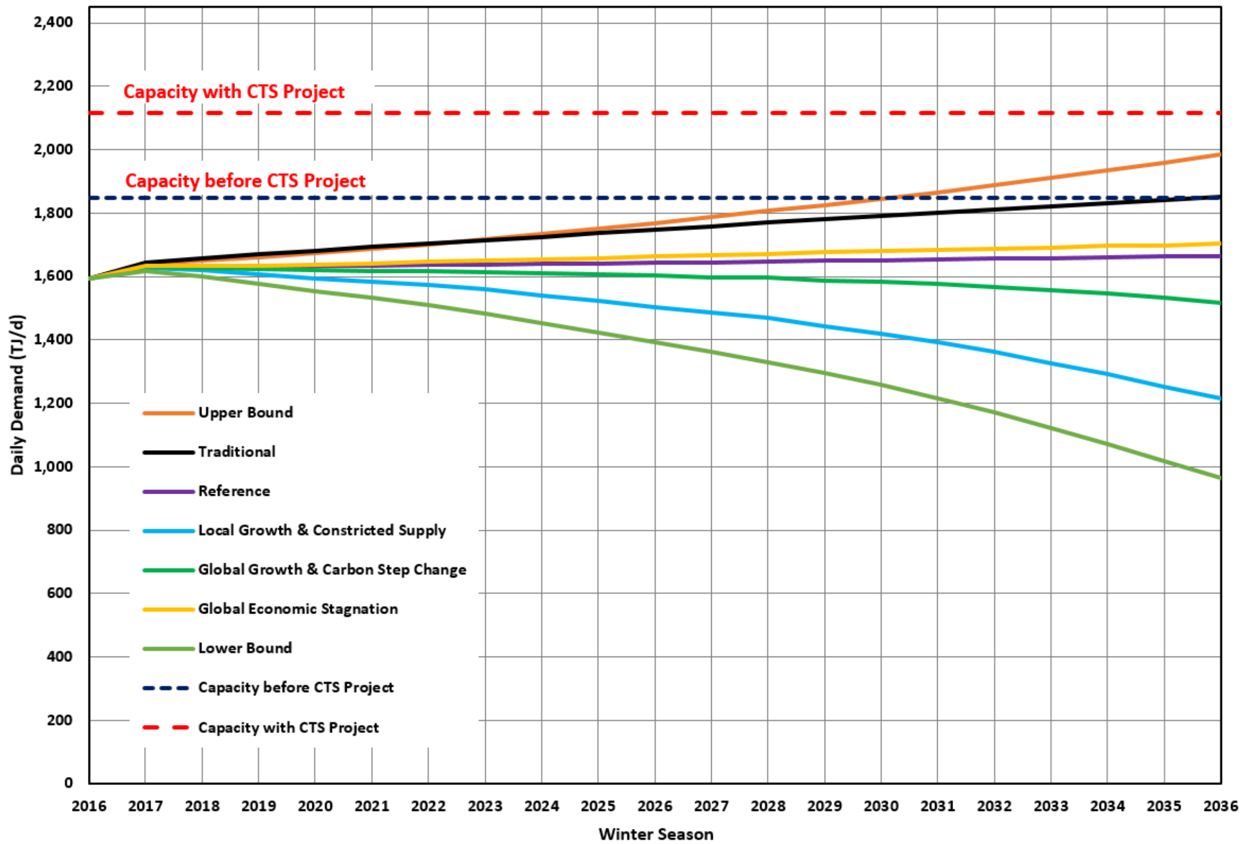
Figure 6-7: CTS Demand-Capacity Balance Using Traditional, Low and High Peak Demand Scenarios



CTS Peak Demand Forecast with End-Use Peak Demand Scenarios

Figure 6-8 provides a look at peak demand derived via the exploratory peak demand forecast method from the end-use scenarios. As in Figure 6-7 above, these forecasts also include the peak demand of CNG as a transportation fuel. For comparison, the Traditional forecast is also included. The forecasts show a wide range of peak demand, with the Upper Bound scenario showing greater growth in the forecast period than the Traditional forecast. The Reference Case and the Global Economic Stagnation scenarios show very slight increases in peak demand over the forecast, while the remaining scenarios show modest to more significant peak demand decline with the Lower Bound scenario showing the greatest peak demand decline.

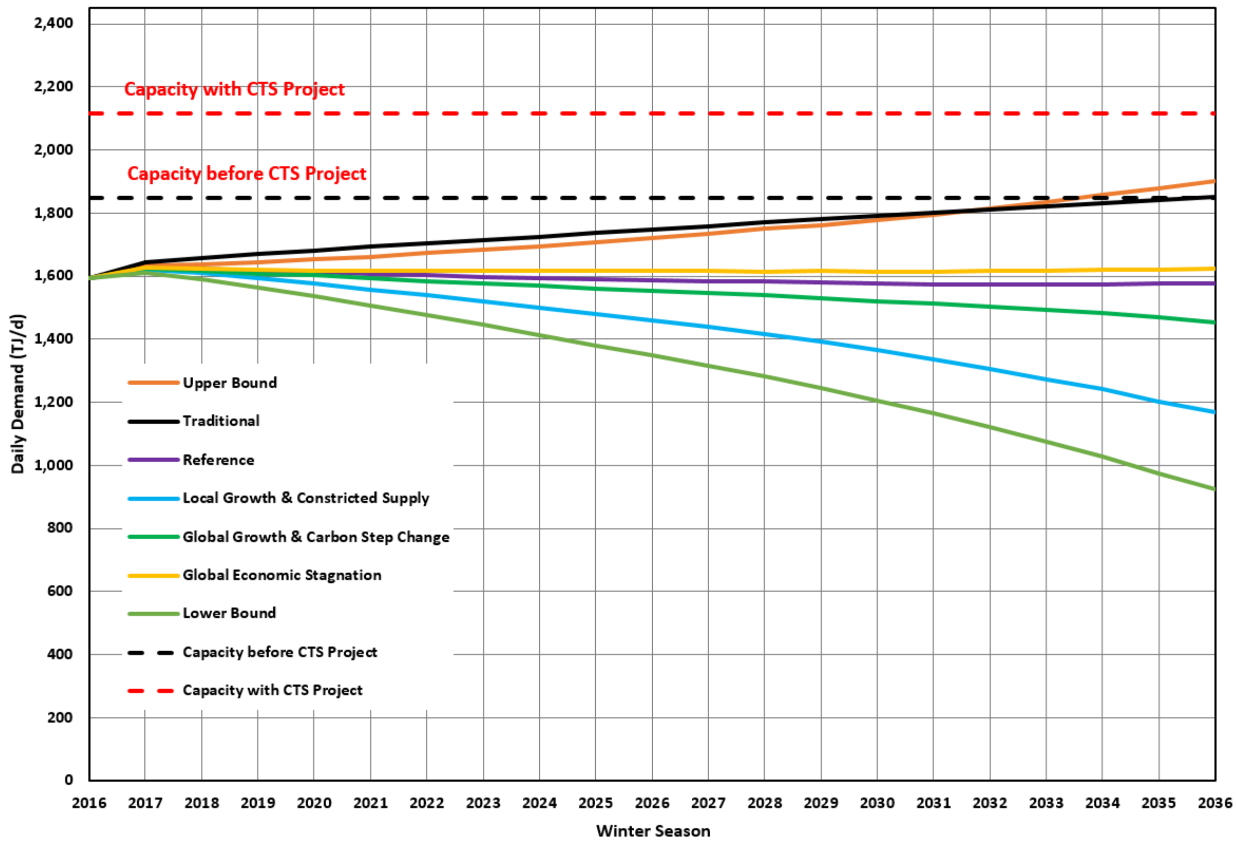
Figure 6-8: CTS Demand-Capacity Balance Using End-Use Peak Demand Forecasts



CTS Peak Demand Forecast with End-Use Peak Demand Scenarios with DSM

Figure 6-9 shows the end-use scenarios with DSM program impacts added. Applying the impacts of DSM using the end-use peak demand method moves all end-use scenario forecasts lower. The Upper Bound shows growth to be very comparable to the Traditional forecast, exceeding it slightly in the last years of the planning horizon. The Global Economic Stagnation scenario shows flat to very slight positive growth through the forecast and the Reference Case scenario shows very slight decline in peak demand through the forecast horizon. The remaining scenarios show moderate to more significant decline in peak demand through the forecast.

Figure 6-9: CTS Demand-Capacity Balance Using End-Use Peak Demand Forecasts with DSM



Impact of Potential Future Demand for LNG Transportation Fuel

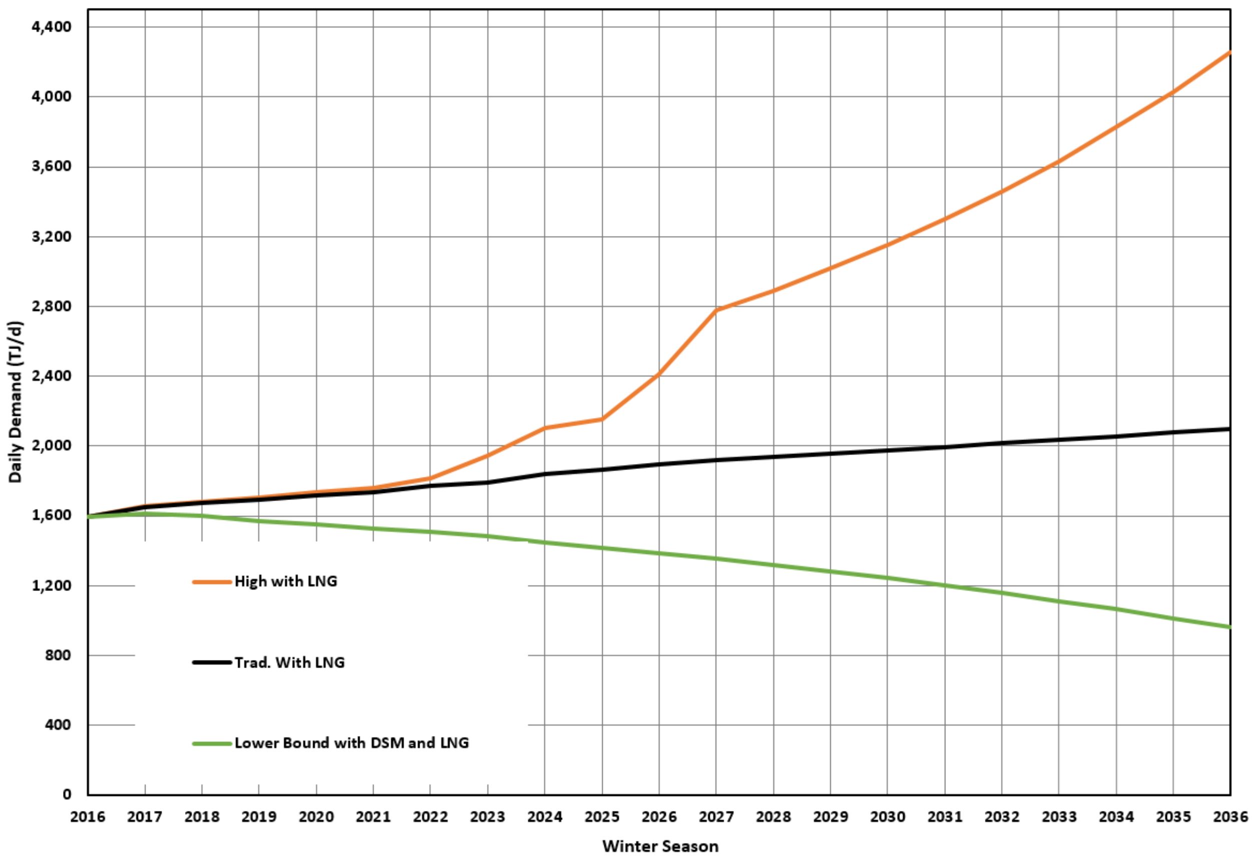
Natural gas demand for transportation consists of both the markets for CNG and LNG as vehicle fuel. Additional CNG load for transportation would be added in relatively small increments at various points on the system and has been included in the previous forecasts presented. In contrast, the greater potential demand and the point source nature of additional LNG production at Tilbury may create broader system impacts and could trigger the need for suitable system reinforcements of the CTS. The demand for natural gas from transportation sector fuel customers is forecast to continue growing over the next 20 years (see Section 3.4.7); the Lower Mainland area will likely drive LNG and CNG demand growth due to increasing road and coastal marine transport demand.

Based on FEI's natural gas demand forecasts for LNG, future phases of Tilbury LNG expansion beyond the current Phase 1A will need to be constructed. FEI's long term outlook must consider the system requirements for such an expansion.

For LNG, the demand on the transmission system originates from a point source – the location of the LNG liquefaction and storage facility used to serve that demand. FEI expects demand by LNG customers across the FEI service territories to be primarily served by the Tilbury LNG liquefaction and storage facility in Delta, BC, or from the Tilbury, South Delta or Richmond areas.

Figure 6-10 shows the impact of the Traditional, High and Lower Bound (with DSM) peak demand forecasts including LNG and CNG demand on the CTS over the next 20 years. These three forecasts define the widest range of peak demand (the highest highs and the lowest lows) for all the forecasts explored.[148]

Figure 6-10: Impact of Traditional, High and Lower Bound (with DSM) on CTS Peak Demand Including LNG and CNG



The peak demand forecasts shown have a very similar profile to the annual demand with LNG forecasts shown in Figure 3-18. The production of LNG is consistent throughout any day of the year and has no seasonal or daily peak. In practice, the actual peak demand that may occur on the CTS in any given period would be dependent on the liquefaction capacity installed at the LNG plant to meet the forecast. LNG liquefaction trains generally operate at a fixed production rate and, for reasons of efficiency, do not vary production rates substantially when in operation.

[148] High with LNG and Traditional with LNG rely on FEI's Traditional Peak Method. These forecasts also use the High or Base NGT market development assumptions, respectively (see Section 3.4.7 for further details about the assumptions). Lower Bound with DSM and LNG relies on the exploratory end-use peak demand forecast method. This forecast also uses the Low NGT market development assumptions from Section 3.4.7 and the Lower Bound DSM results from Section 4.2.

The peak demand profile on the CTS would therefore occur in a more defined stepwise fashion with each step corresponding to a phase of expansion at the LNG facility.

To illustrate the potential impact of the LNG forecasts on the CTS, the expansion of the CTS through the CTS and LMIPSU projects followed by a series of additional hypothetical CTS expansion phases are described in Table 6-2, with the corresponding capacity for liquefaction that could be delivered to the Tilbury area.

Table 6-2: CTS Expansion Scenarios for LNG

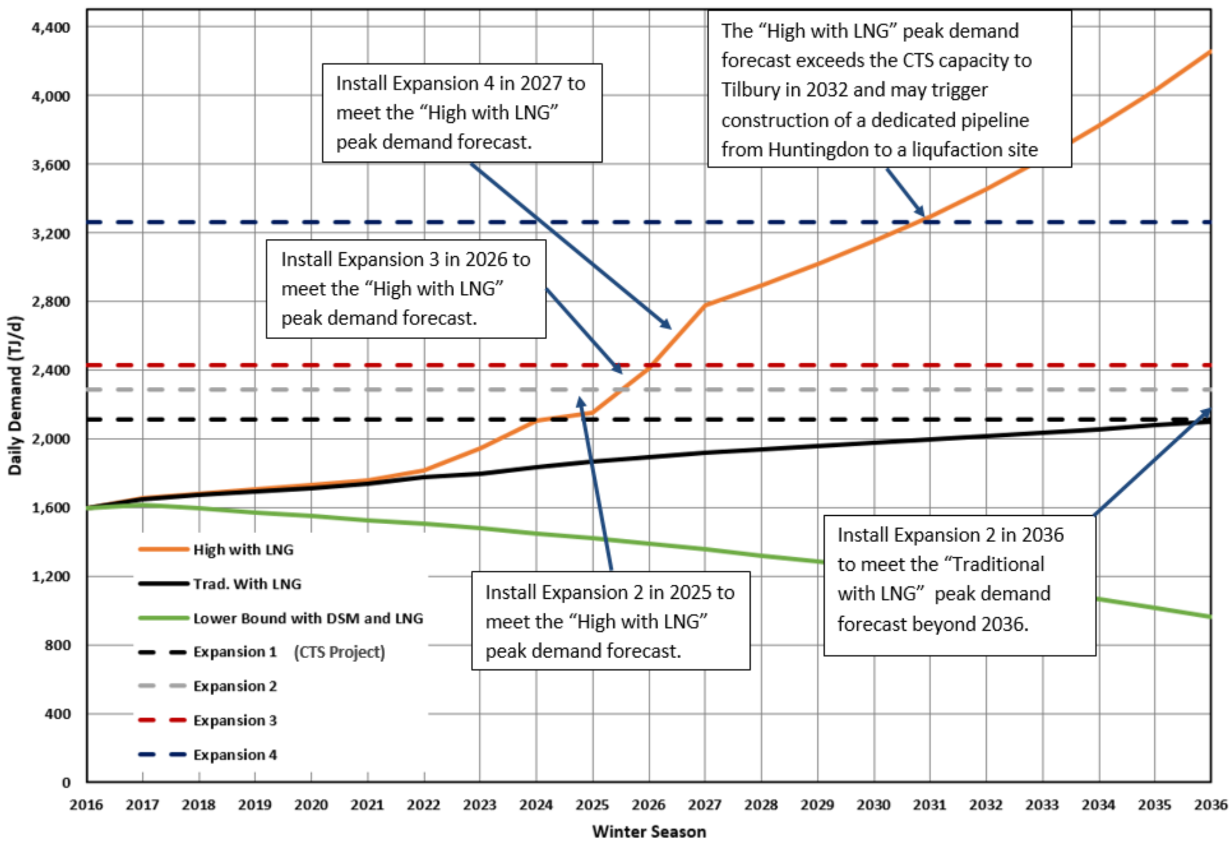
Expansion Scenario	CTS Expansion Description	Max CTS Delivery to Tilbury Island, Delta
1	After CTS and LMIPSU projects	264 TJ/d
2	a) Add Replacement of 1.9 km NPS 6 feed to Tilbury Plant b) Add 15,000 HP to existing facility at Langley Compressor Stn.	436 TJ/d
3	a) Add 14.8 km NPS 42 Loop from Langley Compressor to Clayton Valve Stn. b) Add 15,000 HP to existing facility at Langley Compressor Stn.	577 TJ/d
4	a) Add 28.1 km NPS 42 Loop from Clayton Valve Stn. To Tilbury Area. b) Add 25 km NPS 42 Loop from Huntingdon to Langley Compressor Stn. c) Add 15,000 HP to existing facility at Langley Compressor Stn.	1,414 TJ/d

The recent expansion project at the Tilbury LNG site will draw a peak demand of approximately 37.7 TJ/day. The additional peak capacity afforded by the CTS project (up to 264 TJ/d) will easily accommodate this LNG expansion phase. Figure 6-11 illustrates that the CTS would meet the expected Traditional peak demand forecast with LNG and CNG until 2036 at which point an expansion to meet future demand may be required.

Expanding capacity to deliver to the Tilbury site beyond 264 TJ/d may be required within the planning horizon to meet a High LNG forecast and can be accomplished in large part by expansion projects as described in Table 6-2. Expansion Scenario 2, replacing approximately 1.9 kilometers of NPS 6 pipe and adding 15,000 horsepower (HP) in additional compression at

FEI's existing Langley Compressor site would enable a total of 436 TJ/d to be delivered to the Tilbury site. Adding additional pipeline looping of the CTS and incremental expansion of compression at Langley Compressor Station as described in Expansion Scenarios 3 and 4 would show an intermediate, and then, the ultimate phased expansion within the CTS, enabling up to 577 TJ/d and 1,414 TJ/d, respectively, to be delivered to Tilbury while also meeting the peak demand requirements of the CTS. Figure 6-11 shows how these potential expansion scenarios might be phased relative to the LNG Peak Demand Forecasts.

Figure 6-11: Phased Expansion of the CTS to meet LNG forecasts



Potential Large New Industrial Loads

The High forecast with high LNG demand includes forecasted industrial account additions distributed proportionally throughout the CTS. This captures generic typical industrial demand increases. However, a single large industrial customer can be large enough to disrupt this forecast and have an impact on any potential expansion plans. The specific requirements for system facility expansion are very dependent on the magnitude and location of any proposed large industrial consumer on the system. As discussed previously, the Woodfibre LNG Project facility, should it proceed, will be served from the VI Transmission System. This facility would impact the CTS as the CTS delivers the VITS requirements to the Eagle Mountain compressor facility in Coquitlam. Table 6-3 shows examples of how deliverability to the Tilbury, or other adjacent South Delta or Richmond locations might change should the Woodfibre LNG Project facility proceed with a requirement to deliver approximately 260 TJ/d. With the CTS project in service, the requirement to deliver 260 TJ/d at Eagle Mountain would reduce the deliverability to the Tilbury area from 264 TJ/d to 98 TJ/d, a reduction of 166 TJ/d at Tilbury. The deliverability reduction at Tilbury is not equal to the full 260 TJ/d added to the VI Transmission System as the CTS has a lesser constraint to deliver gas north through Coquitlam to Eagle Mountain than to deliver gas west to the Tilbury area. If the CTS expands as described in Expansion Scenario 4, this variance in deliverability reduces from 166 TJ/d to 108 TJ/d (adding 260 TJ/d at Eagle Mountain reduces the deliverability to the Tilbury area by only 108 TJ/d). This is a consequence of the CTS expansions inherently improving the deliverability in both regions of the CTS. However, due to the existing configuration of the CTS, each region has capacity constraints that respond to the compression additions and pipeline loops to different degrees. If a large industrial load of the same magnitude as the Woodfibre LNG Project was added in the Tilbury, South Delta, Richmond region of the CTS instead of at Eagle Mountain there would be a more direct 1:1 impact on deliverability to the Tilbury region. This is representative of the challenges inherent in analysing the system capacity and infrastructure requirements to support large industrial demand additions to complex pipeline systems when both the specific demand and location are uncertain.

Figure 6-12 identifies the locations within the CTS of the Expansion Scenarios discussed.

Figure 6-12: CTS Expansion Scenarios to Meet Potential LNG or Large Industrial Load Growth

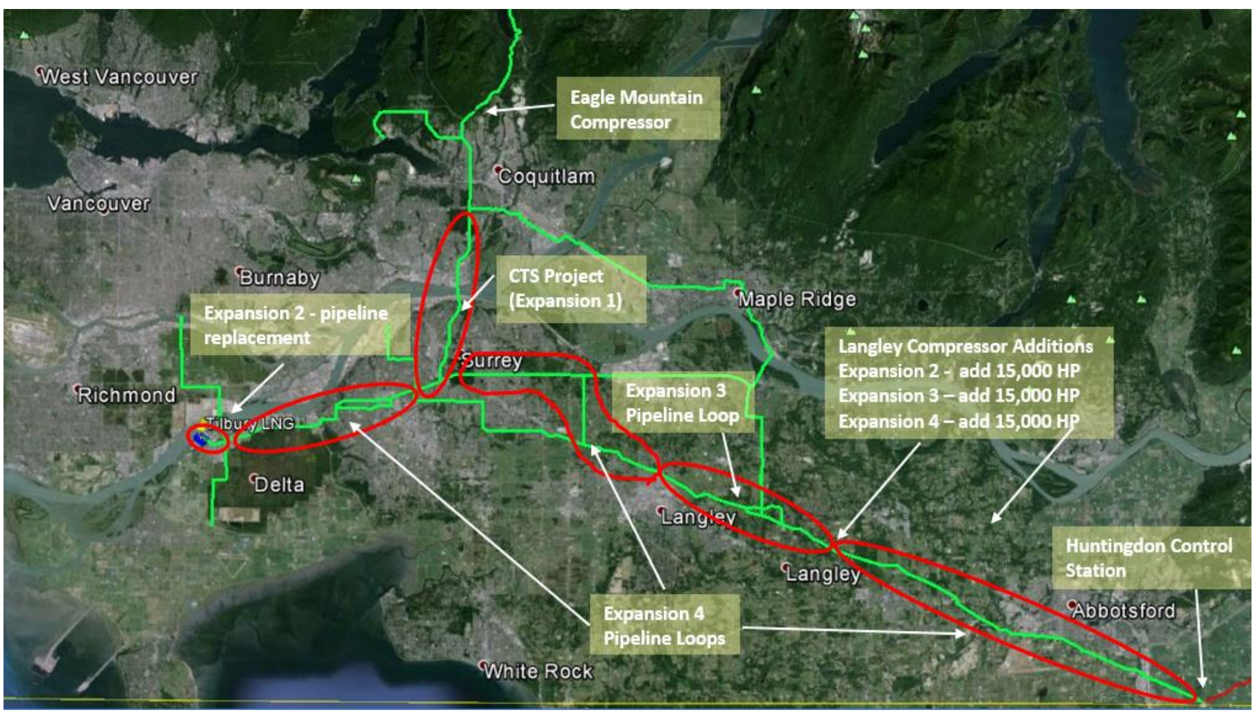
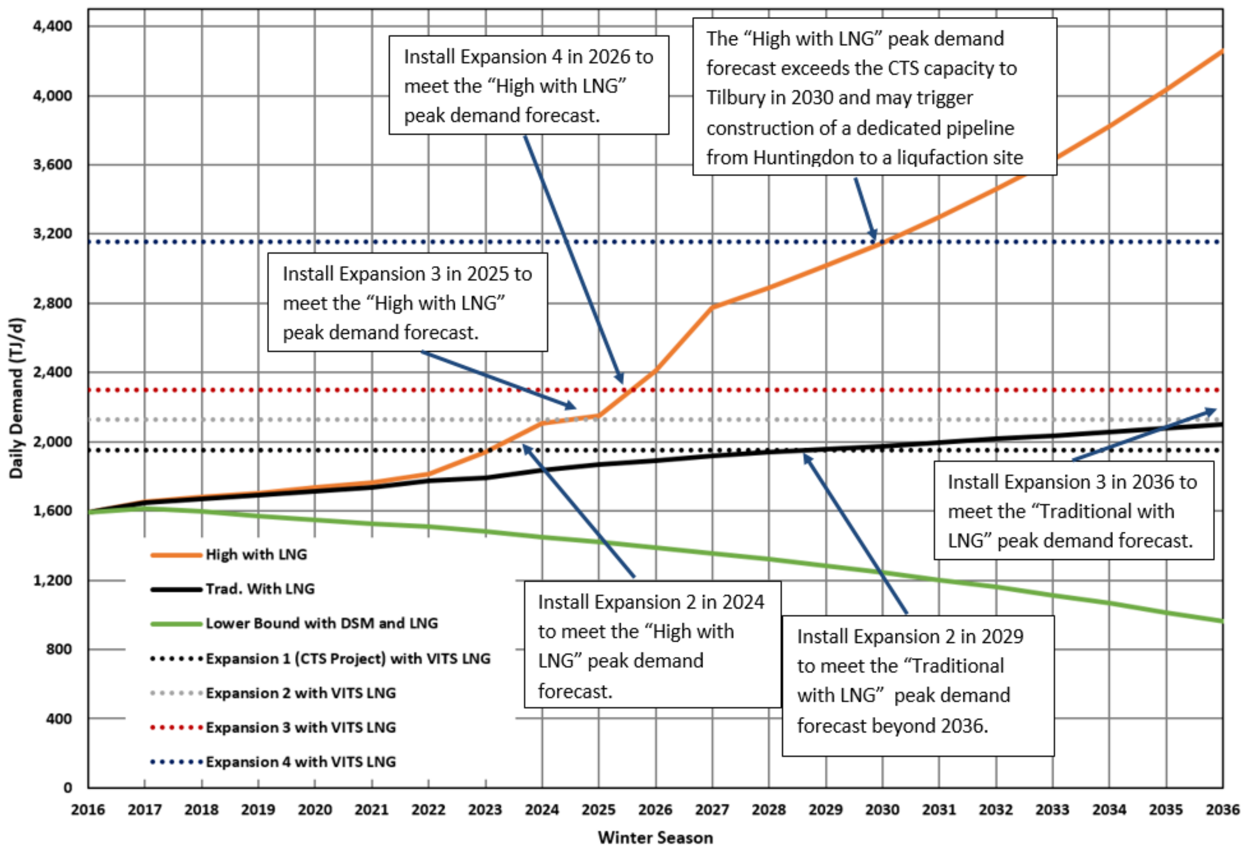


Table 6-3: CTS Expansion Scenarios for LNG

Expansion Scenario	CTS Expansion Description	Max CTS Delivery to South Delta/Richmond	
		With Export LNG on VI System (260 TJ/d)	Without Export LNG on VI System
1	CTS project	98 TJ/d	264 TJ/d
2	a) Add Replacement of 1.9 km NPS 6 feed to Tilbury Plant b) Add 15,000 HP to existing facility at Langley Compressor Stn.	276 TJ/d	436 TJ/d
3	a) Add 14.8 km NPS 42 Loop from Langley Compressor to Clayton Valve Stn. b) Add 15,000 HP to existing facility at Langley Compressor Stn.	448 TJ/d	577 TJ/d
4	a) Add 28.1 km NPS 42 Loop from Clayton Valve Stn. to Tilbury Area. b) Add 25 km NPS 42 Loop from Huntingdon to Langley Compressor Stn. c) Add 15,000 HP to existing facility at Langley Compressor Stn.	1,306 TJ/d	1,414 TJ/d

Figure 6-13 compares how adding 260 TJ/d to the VI system might shift the timing of hypothetical expansion phases of the CTS. The reduced delivery capacity in the Tilbury, South Delta or Richmond area is shown as the dotted lines. For the Traditional forecast with LNG the change would advance the need for Expansion 2 from 2036 to 2029 and trigger the requirement for Expansion 3 by 2036. For the High forecast with LNG the change would advance the timing for each proposed phase of expansion by one to two years.

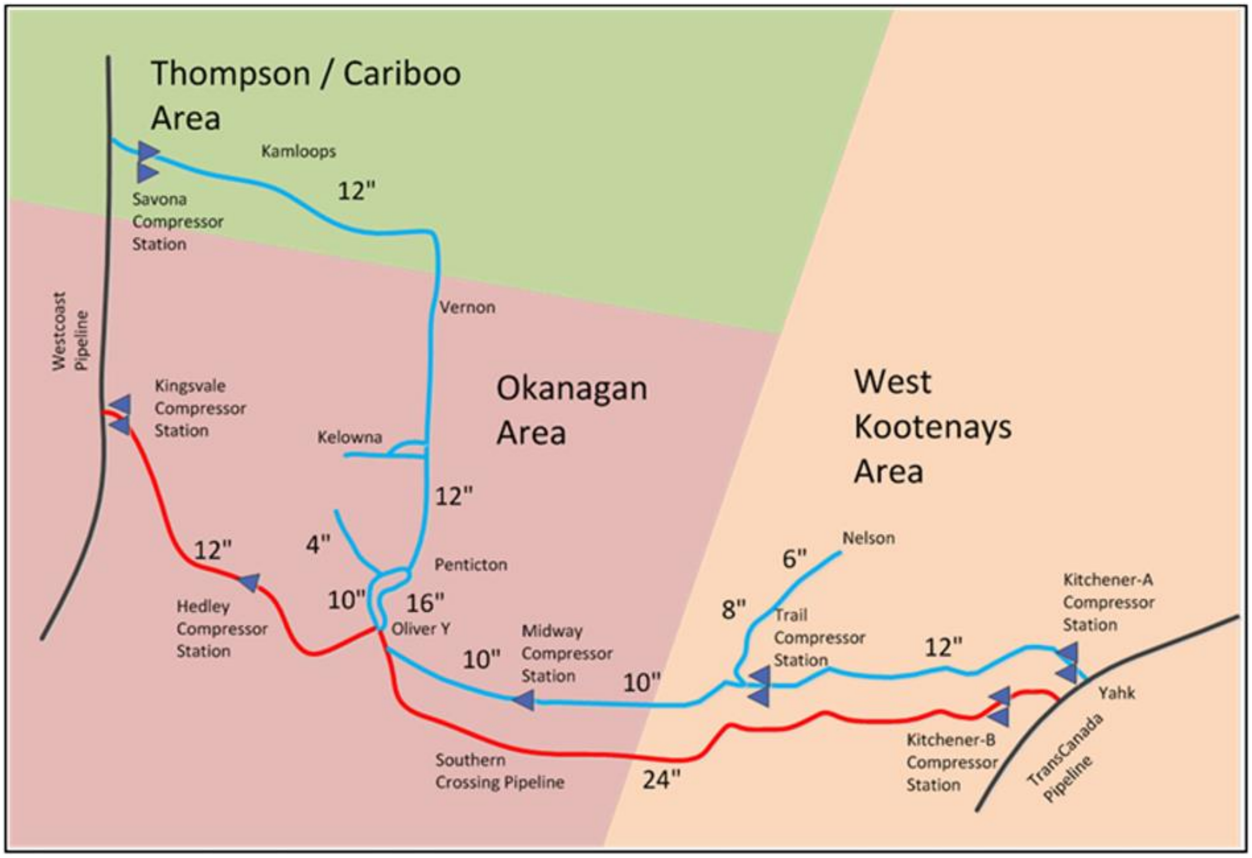
Figure 6-13: Expansion Phases of the CTS for LNG with 260 TJ/d VI System Expansion



6.3.3 FEI Interior Transmission System

The ITS consists of 1,515 km of transmission pipelines operating at maximum operating pressures between 4,600 Kilopascals gauge pressure (kPag) and 9,928 kPag. The ITS system interconnects supply from Westcoast pipelines in the west and TransCanada pipelines in the east. Gas received from the Westcoast pipeline at Savona typically supplies customers in the Thompson and North Okanagan regions, while gas received from the TransCanada Pipeline at Yahk supplies customers in the West Kootenay region via pipelines to Trail and Oliver. The FEI-owned SCP is a bi-directional transportation pipeline between Yahk and Oliver. From the Oliver hub, referred to as the Oliver-Y, pipelines transport gas to serve customers in the South and Central Okanagan. In winter periods, the Kingsvale-Oliver pipeline transports gas from the SCP via the Oliver-Y hub to Kingsvale for redelivery to the Lower Mainland via the Westcoast Pipeline. Figure 6-14 shows the layout of the ITS system.

Figure 6-14: FEI Interior Transmission System



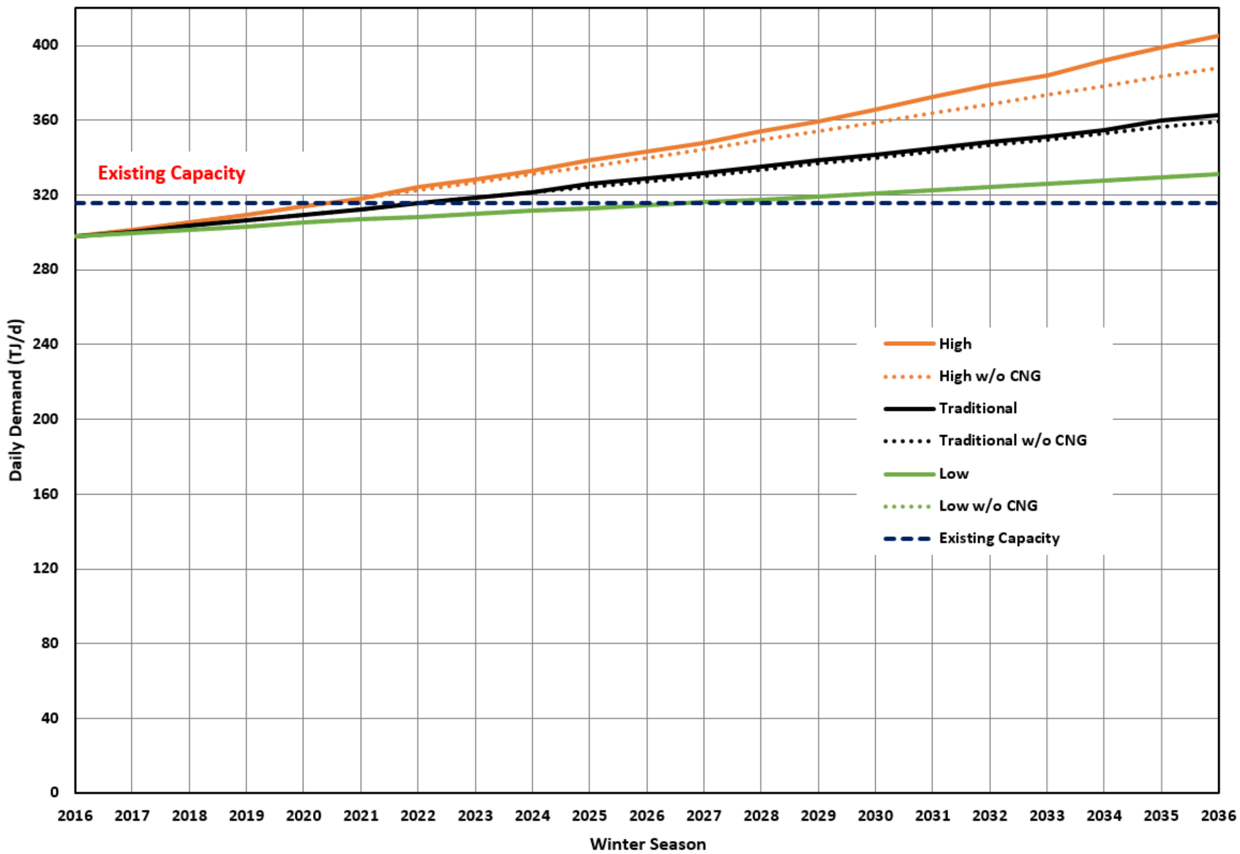
ITS Demand and Capacity Balance

Approximately 60 percent of the current ITS Core and Firm Transportation customer demand is concentrated in the South, Central and North Okanagan regions. Growth in the Okanagan region is one of the main factors driving the location of future incremental capacity additions to the ITS. Because the ITS is characterized by long pipeline lengths through a number of less densely populated areas, the system benefits from line pack effects – the "storage" of usable pressurized gas up to the pipeline MOP that can be drawn on to support short term peak demand. The ability to draw down the gas that is stored in the ITS allows FEI to plan the ITS on a peak day, rather than a peak hour, maximum flow. The current peak day system capacity for the ITS is approximately 315 TJ/d.

As previously described, natural gas is delivered to the ITS from two upstream pipelines—the Westcoast pipeline at Savona in the west and the TransCanada Pipeline at Yahk in the east. The ITS peak demand will reach pipeline capacity when the system cannot maintain minimum system pressures near the high load centres in the Central Okanagan region.

The Traditional case peak demand forecast for this region is shown in Figure 6-15, indicating this capacity constraint occurs in 2022. The High and Low peak demand forecasts show the capacity constraint could appear as early as 2021 or as late as 2027. For comparison the forecasts without CNG are shown as the dotted lines.

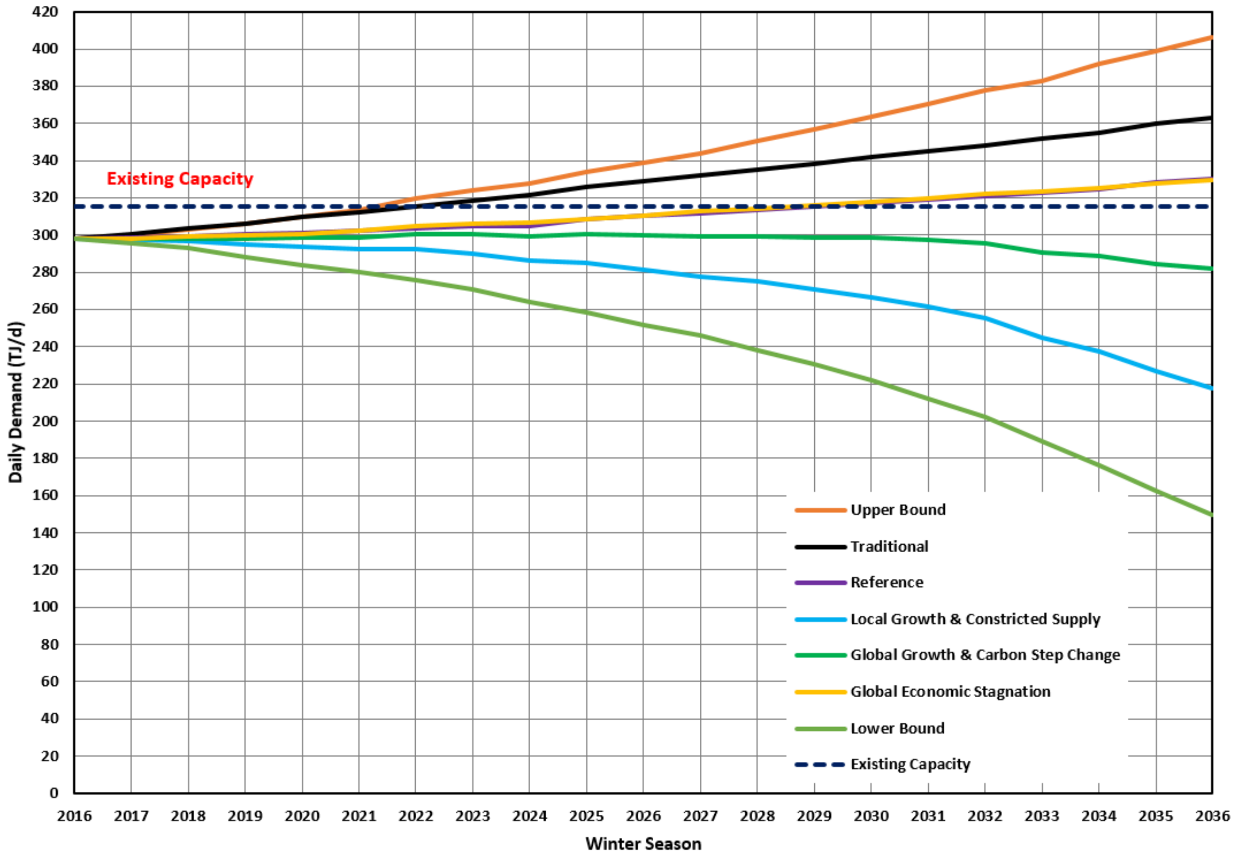
Figure 6-15: ITS Forecast Demand and Capacity Curves - Traditional, High and Low Scenarios



ITS Peak Demand Forecast with End-Use Peak Demand Scenarios

Figure 6-16 provides a look at the peak demand forecast derived from the end-use scenarios for the area served by the ITS. These forecasts include the CNG forecast as well. For comparison the Traditional forecast is also included. The forecasts show a wide range of peak demand, with the Upper Bound scenario showing greater growth in the forecast period than the Traditional Peak Method, with a capacity constraint appearing in 2022. The Reference Case and the Global Economic Stagnation scenarios show lesser increases in peak demand over the forecast, indicating that the capacity constraint might appear in 2030. The remaining scenarios show modest to more significant peak demand decline, remaining within the bounds of the current ITS capacity, with the Lower Bound scenario showing the greatest peak demand decline.

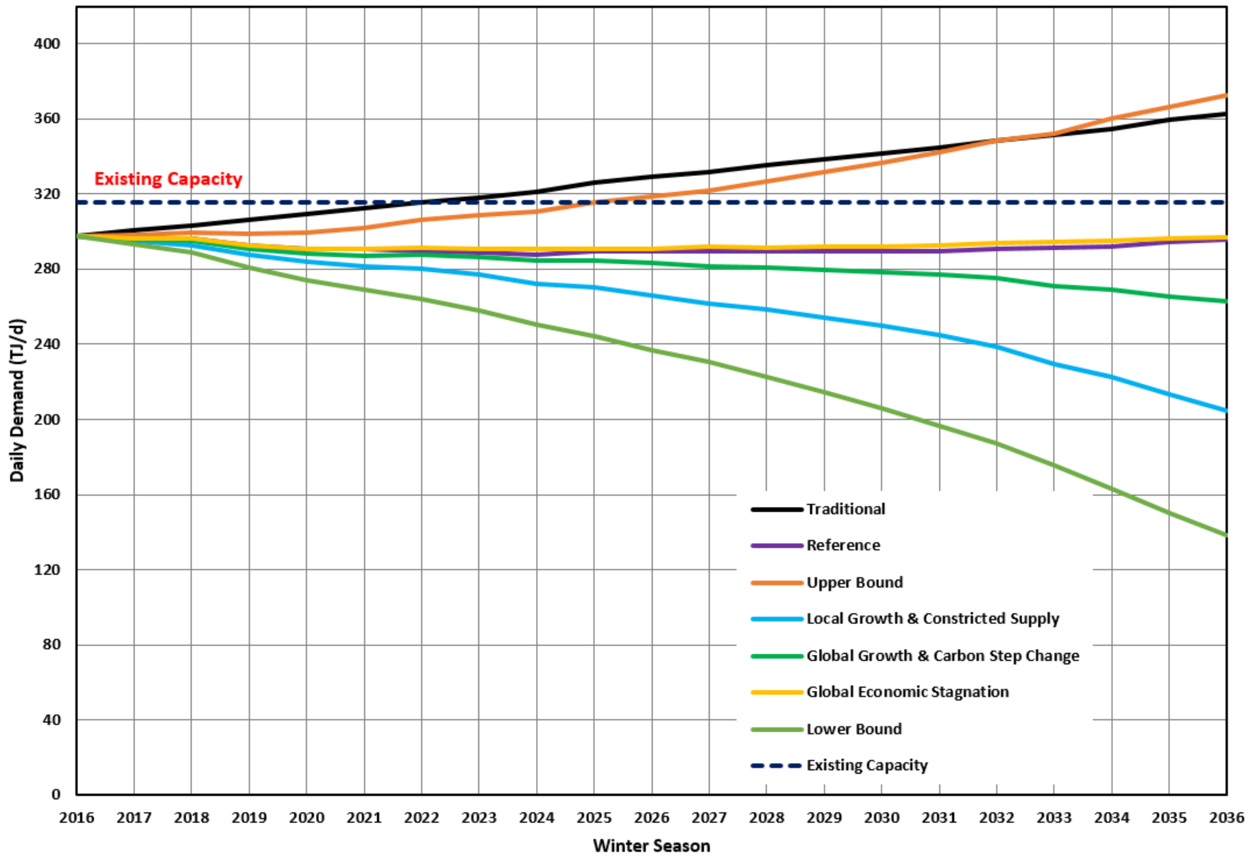
Figure 6-16: ITS Demand-Capacity Balance Using End-Use Peak Demand Forecasts



ITS Peak Demand Forecast with End-Use Peak Demand Scenarios with DSM

Figure 6-17 shows the end-use scenarios with DSM program impacts added. Applying the impacts of DSM using the end-use peak demand method moves all end-use scenario forecasts lower. The Upper Bound shows peak demand initially growing slower than the Traditional forecast, then increasing and exceeding the Traditional forecast slightly in the last years of the planning horizon. The Reference Case and the Global Economic Stagnation scenario shows flat to very slight positive growth through the forecast and no longer exceeds the existing capacity of the ITS within the planning horizon. The remaining scenarios show moderate to more significant decline in peak demand through the forecast horizon.

Figure 6-17: ITS Demand-Capacity Balance Using End-Use Peak Demand Forecasts with DSM



ITS System Expansion Alternatives

Four reinforcement alternatives have been identified to meet the Traditional case demand forecast:

OPTION 1 – OKANAGAN REINFORCEMENT SOUTH LOOP FROM ELLIS CREEK WITH ADDITIONAL COMPRESSION

The first alternative solution to address the capacity constraint in 2022 is installation of a NPS 20, or 508 mm, diameter pipeline loop that follows the existing pipeline right of way, running from Ellis Creek (Penticton) to north of Naramata, a distance of approximately 28 kilometres. This pipeline looping would be accompanied by an additional compressor unit at Kitchener-B compressor station and would increase gas supply delivered from the TransCanada Pipeline at Yahk via the SCP. In 2035, the Kelowna #1 lateral (consisting of both 4 and 8 NPS pipelines on the lateral) would have to be upgraded to dual NPS 8 pipeline (i.e. remove existing NPS 4 and replace with NPS 8).

OPTION 2 – PIPELINE REPLACEMENT AND PRESSURE UPGRADES WITH ADDITIONAL COMPRESSION

This alternative is currently being explored to defer the south loop reinforcements by replacing up to 9 km of NPS 12 pipe that currently has an MOP below the rest of the ITS pipeline between Penticton and Kelowna. This will enable an increase in the MOP north of the existing Ellis Creek control valve in Penticton which is currently limiting pipeline pressures in this region of the ITS to 5,171 kPag. The pipeline upgrades would eventually allow an MOP of 6,584 kPag at Ellis Creek and defer any further NPS 20 looping to beyond 2036. The same compressor upgrades at the Kitchener B compressor station as required for Option 1 would still be required.

OPTION 3 – OKANAGAN REINFORCEMENT NORTH LOOP FROM SAVONA

The third alternative is installation of a NPS 20 (508 mm) loop running from Savona to Valve SN 3-2 (East of Kamloops) a distance of approximately 52 kilometres. This pipeline looping would increase gas supply delivered via the Westcoast pipeline at Savona. In 2028, the Kelowna #1 lateral (consisting of both 4 and 8 NPS pipelines on the lateral) would have to be upgraded to dual NPS 8. In 2033, an additional extension to the NPS 20 pipeline loop of just over 9 km would be required, followed by an upgrade in 2035 to the 4.1 km NPS 4 Coldstream lateral in Vernon.

OPTION 4 - LNG STORAGE FACILITY

The third alternative is an LNG storage facility located between Westwold and Grandview Flats close to Vernon in addition to upgrading the Kelowna #1 Lateral. An LNG facility located closer to the load centre allows natural gas to be moved into storage in times of low gas demand when excess pipeline capacity is available, and provides on-system delivery to the region during periods of high demand.

Figure 6-18 below shows the potential locations of the three system resource expansion options on the ITS.

Figure 6-18: Location of Possible ITS Reinforcement Options

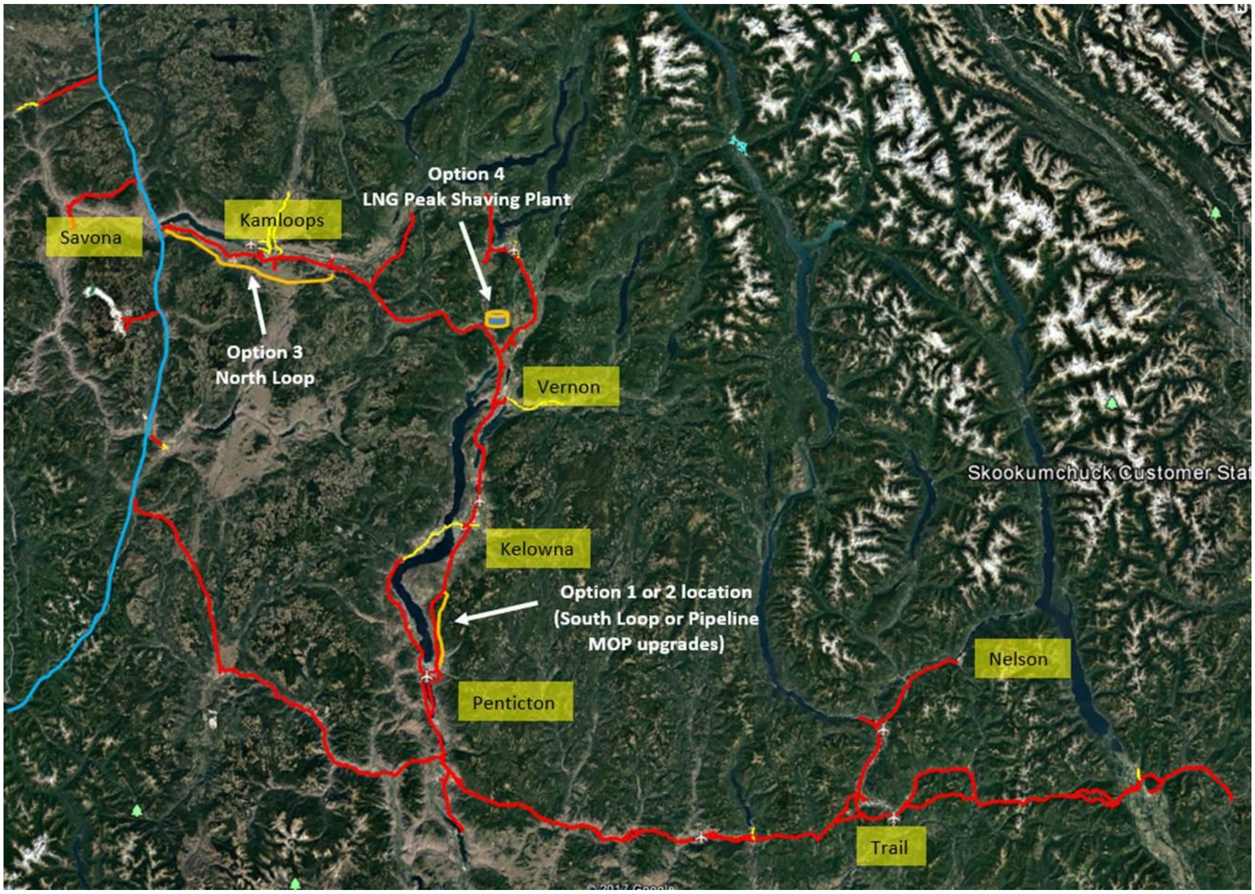


Table 6-4 summarizes the scope and required timing for the ITS facility additions for each resource option with timing variances for the various forecasts. In general, the High and Upper Bound forecasts advance and the Reference and Low forecasts delay required system infrastructure additions in relation to the Traditional forecast.

Table 6-4: ITS Resource Requirements

Option 1: Okanagan Reinforcement - South Loop	28 km x NPS 20 pipeline Ellis Creek to North of Naramata 3rd Compressor Unit at Kitchener B Station	Upgrade Kelowna #1 Lateral 2.1 km x NPS 8 Pipeline	South Loop Extension 8 km NPS 20 Pipeline
High and Upper Bound	2021	2031	2032
Traditional	2022	2035	-
Reference	2030	-	-
Low	2027	-	-

Option 2 – Pipeline MOP upgrades	Replace 3.3 km NPS 12 pipeline and increase Ellis Creek to 5,791 kPag and 3rd Compressor unit at Kitchener B Station	Replace 5.5 km NPS 12 pipeline and increase Ellis creek to 6,584 kPag	Upgrade Kelowna #1 Lateral 2.1 km x NPS 8 Pipeline
High and Upper Bound	2021	2027	2027[1]
Traditional	2022	2028	2036
Reference	2030		
Low	2027		

[1] High forecast also requires NPS 20 south loop and Coldstream lateral upgrade in 2033

Option 3: Okanagan Reinforcement - North Loop	52 km x NPS 20 pipeline Savona to West of Kamloops	Upgrade Kelowna #1 Lateral 2.1 km x NPS 8 Pipeline	North Loop Extension 9.3 km NPS 20 Pipeline and Coldstream Lateral upgrade 4.1 km NPS 6
High and Upper Bound	2021	2023	2029[2]
Traditional	2022	2028	2033
Reference	2030	-	-
Low	2027	-	-

[2] High forecast also requires that the North Loop Extension be 39.5 km longer than Traditional forecast

Option 4: LNG Storage and Peak Shaving	LNG Plant	Upgrade Kelowna #1 Lateral 2.1 km x NPS 8 Pipeline
High and Upper Bound	2021	2021
Traditional	2022	2022
Reference	2030	2030
Low	2027	2027

Potential New Industrial Load

Based on the FBC 2016 LTERP filed with the BCUC in November 2016, a simple cycle gas-fired turbine (SCGT) power generating station was identified as one of the preferred long term options in the Okanagan area between 2026 and 2035, possibly 2033, to meet growing peak electricity demand. Adding this load in 2033 would impact the ITS expansion options. In the case of Option 1, for example, the Okanagan Reinforcement South Loop extension would be required for the Traditional forecast just before the generating station in-service date.

6.3.4 Transmission Laterals

FEI operates transmission laterals that connect to the Westcoast and TransCanada pipelines to serve communities and industrial users in north-central and southeastern BC. The Cache Creek/Ashcroft Lateral has been identified as the only lateral to have insufficient capacity to meet the forecast demand throughout the 20-year planning horizon.

The Cache Creek/Ashcroft Lateral is served from the Westcoast pipeline in the Thompson region. The lateral delivers gas to Cache Creek and Ashcroft, which are located approximately 70 km west of Kamloops. The lateral consists of a combination of two pipelines and is at its capacity to meet peak demand. Reductions in available supply pressure from the Westcoast pipeline are increasing the possibility of curtailment to an industrial customer on the lateral. Addition of a 19-22 km pipeline loop is required to meet current Firm Transportation service to the industrial customer. FEI continues to work cooperatively with this customer to manage demand under peak conditions to avoid the need for the pipeline loop.

6.3.5 Distribution System Capacity

By convention, FEI considers infrastructure operating at or below 2,069 kPag as distribution assets, which are further divided into:

- IP systems operating above 700 kPag up to 2,069 kPag; and
- Distribution pressure systems operating at or below 700 kPag.

For ease of operation and maintenance, safety to the public and reliable service, distribution networks operate at a relatively low pressure. In general, FEI operates its distribution networks at a MOP of 420 kPag; on Vancouver Island and the Sunshine Coast, FEI typically operates its distribution networks at a MOP of 550 kPag. Supply resources for distribution systems include:

- *Pressure regulating stations* – capacity reinforcement to a distribution network could be obtained by the addition of a new regulating station as an additional supply source; and
- *Distribution pipelines* – similar to a pipeline except at a lower operating pressure, capacity reinforcement in a distribution network can be accomplished by increasing the effective cross-sectional area of a distribution pipe section. This can be achieved by replacing an existing pipe with a larger diameter pipe, adding a parallel pipe (a loop) or by introducing gas into the network from an alternate source (a back feed).

Since distribution systems operate at a low pressure through relatively small diameter pipes, there is little line-pack capability for managing hourly demand fluctuations. Therefore, capacity requirements for distribution systems are based on peak hourly demand rather than peak daily demand.

Distribution system improvement projects generally occur more frequently and are smaller in scale than transmission system projects. Distribution system improvement projects are routinely identified as part of the capital planning process and are not discussed in any detail here. The 2014 LTRP identified two systems where more significant changes were being assessed. The following is a brief update on the status of these systems as well as a description of work underway on the Whistler distribution system.

6.3.5.1 Metro Vancouver IP System

Construction on the LMIPSU projects referred to previously in Section 6.2 will begin in 2018. The LMIPSU projects will replace an existing, end of life, 20 km NPS 20 pipeline between Coquitlam Gate Station and 2nd Avenue and Woodland Drive Station in Vancouver with a new high capacity NPS 30 pipeline. This new pipeline will significantly improve the capacity and security of supply to more than a quarter of a million natural gas customers in the region. In addition, the LMIPSU pipeline will also address capacity constraints identified for the Metro Vancouver IP System in previous LTRP submissions that were to be addressed with two NPS 30 pipeline looping projects in South Vancouver (totalling 4.8 kilometres in length).

6.3.5.2 Revelstoke Propane System

FEI operates a satellite, off-grid propane distribution system that serves residential and commercial customers in the Revelstoke area. Due to its geographic location, Revelstoke is located too far away to economically connect to the natural gas grid. Consequently, propane is transported by railcar and tanker truck to Revelstoke where it is then off-loaded into storage tanks, vaporized as needed and distributed to customers through an underground pipeline system. Core demand growth in Revelstoke is forecast to be minimal and serviceable by the pipe, storage and send-out capacity of the current system. However, plans for a large scale ski hill and resort development could potentially double the area's load requirements in 20 years and would require FEI to expand the propane system with pipeline extensions, main looping, additional storage tanks and loading facilities. The development has been delayed though, and this delay has resulted in FEI delaying the planned expansion indefinitely, pending status of the development. As part of FEI's commitment to provide safe and reliable service to its customers, current plans are to increase the capacity of Revelstoke's second vapourizer in order to provide full redundancy.

FEI has identified Revelstoke's satellite propane system as a potential opportunity to convert the community from propane to natural gas. FEI has conducted an internal pre-feasibility study on using LNG from Tilbury for a possible conversion from propane to natural gas using a satellite LNG station at Revelstoke. Converting the town of Revelstoke from propane to natural gas could provide GHG emission reduction benefits. Based on current propane consumption levels of FEI's Revelstoke customers, the community's GHG emissions would fall by 2,019 metric tonnes of carbon dioxide equivalent (CO_2e) per year.[149] At this point, economics do not support this conversion but FEI will keep monitoring this potential opportunity.

[149] This estimate is made using a current normalized annual propane energy consumption of 212,500 GJ/year, a propane emission factor of 61 $kgCO_2e$/GJ and a natural gas emission factor of 51.5 $kgCO_2e$/GJ.

6.3.5.3 Whistler Distribution System

The Whistler distribution system is supplied by the VI Transmission System at Squamish. From Squamish, an NPS 8 pipeline operating at 2069 kPag follows the Highway 99 corridor north to Whistler. The pipeline was commissioned in 2009 and the Whistler distribution system was converted from propane to natural gas that summer, prior to the 2010 Winter Olympics. Since that time, there has been sustained growth in the community. In late 2014, a series of phased system improvements were proposed to be installed between 2015 and 2020 that would ultimately result in extending the NPS 8 2069 kPag pipeline approximately 5 km further north into the community along with another Gate Station facility to address growth. In 2016, BC Transit announced its intention to convert the Whistler transit fleet to CNG and construct a CNG fuelling facility at its existing transit site on the north side Whistler. The facility will begin operation late 2017 or early 2018. As a result of this substantial load near the northern extremities of the system, the need arose to advance the future system improvement phases from future years to the present.

The limited alignment options for the extended pipeline have been challenging and delays have resulted as FEI continues to work with the Ministry of Highways, the Resort Municipality of Whistler, BC Hydro and others to secure approval for the proposed alignment. As an interim measure, pending completion of the system upgrades, FEI and BC Transit have worked cooperatively. BC Transit has allowed the installation and operation of a portable small scale LNG peak shaving unit at the transit site to provide for peak demand requirements for the surrounding Whistler natural gas consumers as well as the initial needs of the BC Transit CNG fuelling compressors when they are commissioned in the winter of 2017-2018. FEI expects to complete the required pipeline and station facilities in 2018.

6.4 *OTHER MAJOR SYSTEM PROJECTS*

Of the capacity driven transmission system projects outlined in Section 6.2 the Okanagan Reinforcement Project is currently the only project anticipated to occur before 2022 and FEI is currently initiating Front End Engineering Design studies in anticipation of a future CPCN application. Several other significant projects that address needs other than system capacity are also under consideration for CPCN applications in the near term. While these projects are not driven by capacity, FEI strives to ensure any projects integrate effectively with system capacity requirements of each system. A brief description of each project under consideration follows:

Transmission System Laterals In-Line Inspection (ILI) Capability

FEI operates transmission pressure laterals across the province served from either FEI operated transmission systems, the Westcoast pipeline or TransCanada and ranging from several hundred meters to several tens of kilometres in length. A total of more than 400 km of these pipeline laterals are between NPS 6 and NPS 10 and currently are not configured to allow ILI tools to be used as part FEI’s pipeline integrity management programs. ILI technology is an effective tool for detecting and subsequently repairing pipeline corrosion and defects prior to leaking or rupture. FEI is currently investigating the cost and justification to install tool launching and receiving facilities and remove existing pipeline obstructions on up to thirty-one lateral pipeline segments.

Pattullo Bridge Crossing Replacement

The Pattullo Bridge currently supports a major FEI NPS 20 distribution system crossing of the Fraser River. This crossing provides nearly 15 percent of the peak hour supply to the Metro Vancouver region. It is integral to the resiliency provided by the major regional supplies at Fraser Gate in Vancouver, Coquitlam Gate in Coquitlam and the LMIPSU that will be under construction in 2018. TransLink has indicated the existing bridge will be replaced by the end of 2021 and has directed FEI to decommission the existing distribution line by the end of 2021. FEI is currently conducting the Front End Engineering Design study necessary to examine the feasibility and cost of establishing a replacement crossing or equivalent prior to decommissioning the current bridge crossing.

Southern Crossing Pipeline Class Location Project

Urban development around existing pipelines can drive changes in pipeline class location as defined in CSA Z662(15) and necessitate changes to increase pipeline safety factors. Pipeline safety factors can be increased by either:

- Decreasing pipeline operating pressures at existing or new pressure control stations; or alternatively
- Replacing the identified pipeline segment in populated areas with higher grade and/or thicker walled pipe.

Installing additional mainline valves may also be necessary in either case. Decreasing pipeline operating pressure to increase the safety factor will reduce the capacity of the pipeline. Replacing the pipeline segments with higher grade and/or thicker walled pipe can maintain operating pressures (and capacity) or allow increases. The SCP is an NPS 24 pipeline operating between Yahk and Oliver in the BC Southern Interior. The Class Location Project will address the installation of several kilometres of pipe replacement and seven new mainline valves between 2019 and 2022 to sustain established pipeline operating pressure and pipeline safety factors.

Advanced ILI on Pipelines Currently Inspected with ILI

Advanced ILI technology for pipelines that are already ILI capable is being considered by FEI, but is in the early stages of development. One advanced technology considered is Electro-Magnetic Acoustic Transducer (EMAT) ILI. EMAT technology can detect Stress Corrosion Cracking (SCC) and cracks in alignments currently not detected by traditional ILI tools. The implementation of this technology may necessitate:

- Alterations of the sending and receiving barrels to accept the newer tools;

- Alterations to the transmission pipelines so that the new tools can traverse them without hindrance or interruption to ensure successful data collection; and
- The installation of flow control equipment and/or transmission loops to facilitate the control (i.e. reduction) of the gas flow velocity in order to ensure successful data collection.

The initial scope of this activity would focus on older pipeline systems in the CTS and the ITS that currently are ILI capable already.

Bridge Crossing Seismic Upgrade Assessment – Lower Mainland

FEI Integrity Management is expanding on seismic assessment of below ground assets in the Lower Mainland region to assess system risks that include security of supply associated with pipeline crossing on third-party infrastructure. Specifically, FEI is evaluating the NPS 24 IP pipeline located on the Ironworkers Memorial Bridge, with the objective to determine if upgrades should be considered to improve the resiliency of the piping during a seismic event or whether a new underwater crossing would be more appropriate.

Reliability Upgrade to Langley Compressor Facility

The Langley compressor facility consists of two 7,400 HP units. If additional phases of Tilbury LNG expansion occur or large industrial load additions like the Woodfibre LNG Project proceed, Langley compressor units would be needed to run for periods of several days to weeks in winter periods. The current units, although they have the required horsepower, are no longer produced and supported by the manufacturer and the current units are not considered reliable for the type of sustained operation that may be required in the event that such large loads materialize on the CTS or VITS. These units would likely require replacement when such demand appears to ensure reliable performance in sustained operation.

6.5 RECOMMENDATIONS FOR SYSTEM REQUIREMENTS TO MEET GROWTH NEEDS

Sustaining FEI's existing natural gas system infrastructure and planning to meet future demand growth are undertaken to ensure that planned improvements optimize operation of the system as a whole. With annual increases in forecast peak demand and potential new sources of demand from NGT and industrial sources, the VI, CTS and ITS transmission systems could all face capacity constraints within the 20-year planning period. FEI's plans to address system capacity are to:

- Continue monitoring and studying the system capacity constraints identified to occur in 2028 on the VI Transmission System and complete the analysis of system reinforcement and load or supply reallocation alternatives;

- Identify system reinforcements that would be required to maintain system reliability and resilience for Core customers as LNG expansion or other large industrial loads are added on the CTS system;
- Continue to monitor and study the system capacity constraints identified to occur in 2022 in the Okanagan region of the ITS and complete the analysis of system reinforcement alternatives in anticipation of a CPCN application to the BCUC in the next two to three years; and
- Continue evaluating other major system projects outlined in Section 6.4 and submit CPCN applications for these projects if required.

7. STAKEHOLDER ENGAGEMENT

Connecting with customers, communities and other stakeholders on long range planning issues is of critical importance to FEI. Effective stakeholder engagement provides valuable insight that can impact the energy planning process, demand forecasting and C&EM program development, through to the development of an action plan for implementing the Company's preferred resource solutions.

When soliciting stakeholder input during the resource planning process, the BCUC's Resource Planning Guidelines encourage utilities to "focus such efforts on areas of the planning process where it will prove most useful and to choose methods that best fit their needs."[150] FEI undertook a number of initiatives to offer stakeholders the opportunity to participate in discussions to inform the 2017 LTGRP. These activities continued until the third quarter of 2017 and included:

- Workshops with the dedicated RPAG;
- Community Engagement workshops in communities served by FEI; and
- Other activities that indirectly inform the resource planning process, including dialogue with First Nations, advisory groups, industry associations and other stakeholders.

FEI considers stakeholder engagement for resource planning to be an on-going process and one element of the many stakeholder activities that the Company undertakes for a range of purposes. This section summarizes the range of stakeholder engagement initiatives leading up to the 2017 LTGRP.

7.1 *RESOURCE PLANNING ADVISORY GROUP*

The RPAG engages strategic representatives of municipalities, government, First Nations, customers, associations and organizations in the development of the LTGRP. The group consists of members with interest and experience in the resource planning process and significant industry knowledge who provide key insight and feedback to FEI. The RPAG membership includes representatives of the following entities:

- First Nations Energy and Mining Council
- BC Ministry of Energy and Mines
- Community Energy Association
- Commercial Energy Consumers Association of BC
- BC Business Council
- BCUC (as an information provider)

[150] http://www.bcuc.com/Documents/Guidelines/RPGuidelines_12-2003.pdf. p.5.

- City of Kamloops
- City of Prince George
- Greater Vancouver Board of Trade
- Union of BC Municipalities
- BC Public Interest Advocacy Centre
- City of Victoria
- BC Sustainable Energy Association
- Pembina Institute
- NWGA
- Multiple third-party utilities in the PNW

RPAG workshops provide a forum for discussing many broad themes, including but not limited to the following:

- LTGRP process, inputs and analytical results;
- Forecasting methods and results;
- FEI initiatives and expectations;
- The energy and emissions planning environment; and
- Energy and emissions policy and regulation.

FEI held three RPAG workshops between 2016 and 2017 to review key steps in the LTGRP process and to discuss inputs into and results from the 2017 LTGRP analysis. Engagement from attendees was in the form of questions and discussion throughout each presentation, as well as interactive sessions allowing for more in-depth discussion and feedback. Table 7-1 below outlines meeting dates and major topics discussed. After the first RPAG meeting on November 30, 2016, FEI fielded an online survey to the RPAG membership in order to gauge the RPAG's attitudes towards FEI's proposed forecast and scenario analysis methods. The online survey revealed RPAG support for FEI's approach.

Table 7-1: RPAG Meetings and Major Topics Covered

Meeting Date	Topics Discussed
November 30, 2016	• Annual demand forecast approach • Policy environment review • Regional gas market update • Scenario analysis process and methods • Qualitative scenario inputs and proposed scenario plotlines
April 11, 2017	• Annual demand Reference Case • Quantitative scenario inputs and preliminary annual demand results • System capacity planning methods
August 9, 2017	• NGT annual demand scenarios • DSM analysis • System requirements and options analysis • Projected portfolio natural gas delivery rate and GHG impacts

The feedback submitted by the RPAG to FEI has been useful in helping FEI to develop the 2017 LTGRP. Through the RPAG workshop sessions, stakeholders have been able to provide FEI with input on areas, such as demand forecasting and scenario analysis methods as well as annual demand drivers and scenarios. More specifically, some of the feedback and areas of stakeholder interest in the workshops included the following items:

- Distinguishing aspirational goals from specific targets in energy and emissions policy;
- Framing and clearly delimiting the annual demand scenario analysis;
- Validating the annual demand scenario analysis method and inputs;
- Considering First Nations perspectives in the 2017 LTGRP report; and
- Considering emerging information on innovative natural gas technologies, such as cellulosic biogas.

Examples of FEI's ability to benefit from and implement such feedback in the 2017 LTGRP include items, such as the following:

- Explicitly addressing innovative natural gas technologies that will help FEI to meet its customers' preferences for natural gas while also addressing societal plans for GHG emissions reductions (see Sections 2.4.2, 2.4.3, 8.2.4 and 9);
- Applying the MTRC test to forecast commercial and industrial C&EM activities in scenarios that are subject to the Accelerated outcome on the Non-Price Carbon Policy Action critical uncertainty in order to account for potential future regulatory easements

that further recognize the non-energy benefits of C&EM programs (see Section 4.2.2.2); and

- Clarifying more explicitly how FEI's Traditional Peak Method versus its exploratory peak demand forecast method relate to the scenarios established by the end-use annual demand forecast (see Section 6.2.1).

FEI also received feedback, which it considered but was unable to implement in the 2017 LTGRP. Examples of such feedback include the following items:

- Including a Resource Planning Objective in Section 1 of the 2017 LTGRP that specifically addresses cost effective GHG emissions reductions. FEI considered this item and concluded that this objective is implicit in its existing objective *Ensure consistency with provincial energy objectives* (see Section 1.3.3).
- Showing up to ten years of historical data in all charts to provide more context to the forecast data. FEI considered this item and concluded that including such additional data would render charts too dense in the printed version of the 2017 LTGRP.

As resource planning is an iterative and on-going process, some of the feedback and recommendations received from the RPAG during this planning period will also be considered by FEI in the next iteration of the resource planning process.

7.2 COMMUNITY ENGAGEMENT WORKSHOPS

FEI recognizes the importance of considering diverse community perspectives when planning for the future, and has established resource planning Community Engagement workshops to gather feedback from stakeholders throughout FEI's service territories. Individuals involved in a variety of roles are invited to attend these ongoing events, including:

- Community planners/developers;
- Energy and sustainability managers and professionals;
- First Nations representatives;
- Municipal community leaders;
- Energy and sustainability non-profit organizations;
- Real estate builders and developers;
- Large businesses/manufacturers;
- Local businesses and business associations; and
- Other interested parties.

FEI hosted nine Community Engagement workshops until the end of May 2017 in communities across BC, with over 50 registrants.[151] These workshops sought input on a variety of topics related to resource planning, including distribution and safety, demand forecasting, the impact of evolving energy technologies and uncertain energy and emissions policy. FEI presented plans to meet the future needs of customers and communities, and discussed issues affecting energy supply and demand, along with other initiatives to help meet future energy needs such as DSM, RNG, and NGT.

Themes consistently identified by stakeholders included:

- Programs to help customers and communities manage energy costs and emissions, such as C&EM, RNG and NGT;
- Energy affordability considerations;
- Natural gas and carbon pricing trends;
- Finding solutions to reduce GHG emissions.
- Emerging natural gas technologies, such as cellulosic biogas;
- New FortisBC Alternative Energy Services offerings such as district energy systems;
- Advanced metering and billing options; and
- Coordinating activities between utilities and municipalities.

Overall, the 2017 LTGRP Community Engagement workshops facilitated the sharing of valuable long term planning information between stakeholders and FEI. In particular, the workshops assisted FEI in identifying energy issues or planning opportunities in municipalities throughout BC. Stakeholders appreciated the opportunity to learn about FEI's initiatives and energy issues in BC, speak directly with FEI staff in an open and consultative format, and offer feedback on how the Company is addressing the challenges that impact its customers. Attendees gave positive feedback on the workshop evaluation forms and stated that they found the workshops both valuable and informative. The workshop discussions were robust and customer-focused, and they demonstrated that FEI's long term planning considerations align well with stakeholder expectations.

7.3 OTHER ENGAGEMENT ACTIVITIES

7.3.1 Dialogue and Engagement with First Nations

FEI is a leader in developing and building mutually beneficial working relationships with First Nations communities. Understanding, respect, open communication and trust continue to be FEI's aim when working with First Nations groups throughout the province.

[151] Penticton, Rossland, Cranbrook, Kamloops, Prince George, Abbotsford, New Westminster, Colwood, Courtenay.

FEI works to ensure that First Nations' interests are represented in the Company's various advisory groups. The RPAG and Energy Efficiency and Conservation Advisory Group (EECAG) both include members that represent BC First Nations, which ensures that First Nations play an active role in the ongoing resource planning process. In addition, First Nations have participated in Community Engagement workshops throughout the preparation of this 2017 LTGRP.

FEI's Statement of Aboriginal Principles[152] ensures the Company's business operations are conducted with respect for social, economic and cultural interests. One of these principles declares FEI's commitment to dialogue through clear and open communication with Aboriginal communities on an ongoing and timely basis for the mutual interest and benefit of both parties. To meet this objective, FEI aims to establish an open dialogue with First Nations at the earliest planning stages to ensure that First Nations engagement and accommodation requirements are met. For example, FEI, when entering into talks regarding its EGP Project, was made aware that the Squamish Nation had developed its own project assessment process that would be independent of the existing government environmental assessment process. The objective of that assessment process was to provide the Squamish Nation with the ability to make an informed decision on a proposed project based on information the Squamish Nation had gathered and an opportunity to have government to government discussions to make a shared decision with the Crown on a proposed project. FEI sought to work with the Squamish Nation and provided necessary funding and support for what is now called the Squamish Process. As a result of the process, FEI proposed a number of changes to the project, including a new location for a compressor station, re-routing around culturally sensitive sites, and a construction methodology which would avoid surface disturbance in the Skwelwil'em Squamish Estuary Wildlife Management Area. The Squamish Nation Chiefs and Council voted to approve the project, with a set of conditions, in June 2016 and the BC Government issued an Environmental Assessment Certificate for the project in August 2016.

The importance of engaging First Nations "early and often" has been reiterated by First Nations representatives throughout FEI's 2017 LTGRP engagement activities. FEI strives to engage First Nations in its projects early and often. As part of its long term resource planning Community Engagement activities, FEI was invited by a First Nation in the BC Interior to present on its integrated resource planning process and activities. FEI conducted a half-day workshop which included an outlook on potential FEI projects in the region. During the workshop, the First Nation voiced feedback on two issues: (1) a concern about the cost and affordability of space heating in regions that do not have access to natural gas, combined with support for making available natural gas service to First Nations, and (2) support for C&EM programs that facilitate First Nations to upgrade the energy performance of existing buildings or to construct energy efficient new buildings.

[152] Appendix D-29: https://www.fortisbc.com/About/OurCommitments/AboriginalRelations/Pages/Statement-of-Principles.aspx.

7.3.2 BC CPR Technical Advisory Committee (TAC)

The BC CPR informed the 2017 LTGRP's C&EM analysis. FEI, in collaboration with the other BC utilities that co-founded the CPR (please see Section 4.2.1 for details), established a Technical Advisory Committee (TAC) for the BC CPR. The BC CPR TAC is a group of knowledgeable members of the public with significant interest, stake, and experience in determining energy conservation potential in BC and provided technical advice and feedback during the development of the BC CPR.

7.3.3 Industry and Market Involvement

FEI meets regularly with industry associations and other organizations such as the Canadian Home Builders' Association (CHBA), Quality Urban Energy Systems of Tomorrow (QUEST), the Urban Development Institute (UDI) and the Union of British Columbia Municipalities (UBCM) in order to share information and insight. This dialogue is mutually beneficial as it allows FEI to stay abreast of industry trends and developments while facilitating the distribution of important information to stakeholders.

FEI's involvement with such organizations allows the Company to develop a more comprehensive picture of how the energy market is evolving. Participating in conferences, workshops and other engagement opportunities with these organizations has helped to position FEI as a leader in the marketplace, strengthen the Company's credibility, and generate a number of business opportunities.

7.4 *CONCLUSION AND RECOMMENDATIONS*

FEI has a strong record of conducting effective stakeholder engagement activities. Continuing its practice from the 2014 LTRP, FEI has consulted a dedicated RPAG and hosted a number of Community Engagement workshops to engage diverse perspectives on FEI's planning activities across the communities that the Company servers.

These initiatives adhere to the stakeholder engagement considerations contained in the BCUC's Resource Planning Guidelines and continue to be beneficial to the development of FEI's LTGRPs. The information gained through these activities inform FEI's market research and analysis, identifying long term planning issues of concern to a number of stakeholder groups, and identifying interested stakeholders who may become more engaged in the LTGRP process.

FEI recommends continuing with the RPAG and community engagement activities in order to build on the successful interest and input obtained through these initiatives. FEI will also continue to assess the success of these activities and make enhancements as needed based on the feedback received.

8. 20-YEAR VISION FOR FEI

The BCUC's decision regarding the 2010 LTRP included a requirement for the 2014 LTRP to describe a vision of FEI in 20 years:

> …pursuant to section 44.1(2)(g) of the UCA the Panel directs the following be included in the next LTRP: 1. [FEU] – A 20 Year Vision. This vision could describe what [the FEU] may look like in the future: its business lines, its customers, the expectations for supply and demand and the major issues it will deal with over the 20 year resource plan timeframe.[153]

The directive lists a number of areas appropriate to be covered in the 20-year vision. Following the approach of the 2014 LTRP, this section of the 2017 LTGRP presents a brief description of FEI's long term vision along with the following:

- The contextual background that in part defines FEI's 20-year vision for the LTGRP in response to this directive;
- The challenges inherent in defining a 20-year vision and the limitations thereof; and
- Those components of a 20-year vision as listed by the BCUC within their directive and for which information is available for FEI to include.

FEI's long term vision is to be BC's trusted energy provider for safe, reliable and cost effective natural gas delivery services to its customers, and to be a healthy, growing contributor to the BC economy and to the well-being of communities in BC. FEI has examined a broad range of future potential conditions under which it must realize this vision. Since the likelihood of correctly predicting the future is low, FEI's approach has been to identify a set of resources to acquire that will meet the range of analyzed potential futures rather than to attempt to predict a most likely future and plan only to that future. Sustainability represents a key component of this vision and FEI considers all three pillars of this concept: social, environmental, and economic sustainability. As such, Section 8 addresses how new technologies and market transformation may impact FEI's operating environment (Sections 8.2, 8.4, and 8.7), how FEI's forecast natural gas demand and activities may impact customer rates and average bills (Section 8.6) and how FEI's activities will impact GHG emissions and BC's energy objectives (Section 8.3).

8.1 *CONTEXT AND LIMITATIONS FOR FEI'S LONG TERM VISION*

The BCUC's directive to include a 20-year vision in the 2010 LTRP was issued at a time when FEI was developing service initiatives to provide low carbon thermal energy solutions complimentary to the Company's natural gas services. Since that time, the Commission has undertaken a review of the regulation of low carbon thermal energy solutions and determined that thermal energy projects not exempt from regulation are "most appropriately undertaken

[153] Terasen Utilities 2010 Long Term Resource Plan, BCUC Decision, February 1, 2011.

through an Affiliated Regulated Business".[154] As a result, some items that the Commission contemplated for the 20-year vision are no longer appropriate for FEI's 2017 LTGRP. For example, FEI's consideration of low carbon thermal energy services is limited to the potential impact that such services provided by other parties may have on demand for natural gas, rather than being included as a new initiative undertaken by FEI.

Another important limitation to describing FEI's long term vision is the degree of detail that can be included. The Commission's directive was made at a time when the outlook for natural gas supply resources and long term gas price forecasts was different than it is today. The 20-year vision directive does not appear to have contemplated the government's shift in emphasis to the development of natural gas resources and a provincial LNG strategy, for exports, economic development, job creation and global emission reductions. As outlined in Section 2, FEI has developed the current 2017 LTGRP within a planning environment that is characterized by continued high policy uncertainty. A long term vision thus cannot be made so specific that it does not allow for changes in the planning environment.

Like the 2014 LTRP, the 2017 LTGRP has attempted to address the items outlined by the Commission for inclusion in its 20-year vision without being so specific that it quickly becomes outdated as changes in the planning environment occur. The remainder of this section discusses how the 2017 LTGRP has addressed the following items:

- Market transformation;
- The relationship between GHG reductions and demand and FEI's forecasted contribution to BC's GHG reduction targets;
- The potential impact of new technologies and market conditions on demand for natural gas;
- FEI's new initiatives;
- BC's energy objectives;
- The impact of long term demand variations on customer rates; and
- Key drivers impacting the need for resources.

8.2 *MARKET TRANSFORMATION*

The 2017 LTGRP incorporates analysis of four areas which FEI will discuss in this section: (1) transformation of the market for natural gas as a transportation fuel, (2) market transformation of C&EM technology that is inherent in the DSM analysis (please see Section 4), (3) a range of assumptions about how much low carbon thermal energy demand might replace natural gas demand in the alternate future scenarios, and (4) a range of assumptions about how FEI may use RNG and other innovative technologies to help meet market preferences while also supporting BC energy objectives.

[154] BCUC AES Inquiry Report. December 2012.

8.2.1 NGT

Section 3.4.7 discusses the impact of varying levels of NGT market transformation on customer demand for natural gas over the 20-year planning period. This section splits the analysis into CNG and LNG demand. FEI assumes a range from one to 15 percent CNG market capture in the relevant transportation market sectors by 2036. While capturing 15 percent of the applicable CNG market is reasonably possible, FEI's Reference Case demand forecast uses a more modest 4 percent market capture rate by 2036. FEI's LNG demand forecast ranges between adding a low amount of 13 million GJ only to adding a high amount of more than 500 million GJ over the planning period. While adding more than 500 million GJ over 20 years is reasonably plausible by transforming energy use in the marine market, FEI's Reference Case uses a more moderate LNG demand forecast, which assumes only 5 percent additional annual growth beyond 2028 and adds approximately 78 million GJ of annual demand by the end of the planning horizon.

Section 6.3 analyses and discusses the impact on FEI's infrastructure needs of these alternate NGT adoption scenarios.

8.2.2 C&EM Technologies

Section 4 of this 2017 LTGRP addresses the annual demand impact of C&EM technology (Figure 4-1 summarizes this impact). Sections 6.2 and 6.3 discuss the impact on system resources of such technologies.

Although FEI has not identified the extent of market transformation that will occur for each measure or technology via specific C&EM programs, the analysis results do represent an estimate of the amount of energy efficiency that can be achieved by the Company over the planning horizon.

8.2.3 Low Carbon Thermal Energy

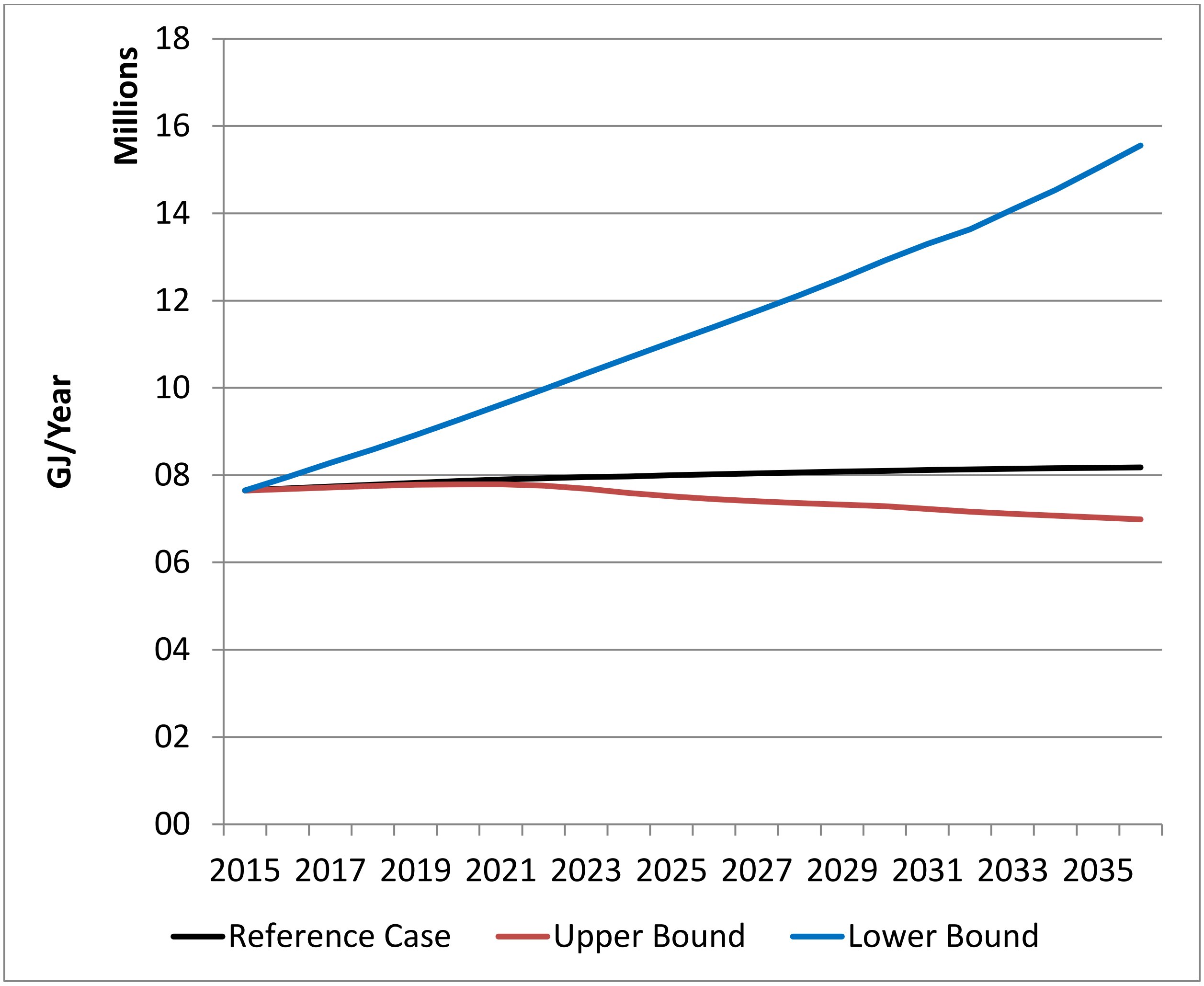
Low carbon thermal energy solutions such as geo-exchange systems, waste heat recovery systems and solar thermal systems can displace both existing and future expected demand for natural gas. While FEI does not offer these services to its customers, the potential for other third party service providers to do so creates a risk to FEI's annual demand profile and thus to the Company's revenue expectations. The 2017 LTGRP has addressed this risk by including varying levels of displacement of natural gas demand by low carbon thermal technologies in its alternate future scenarios (presented in Section 3 and Appendix B-1). The highest level of displacement is included in the lowest natural gas demand scenario (Lower Bound) while the lowest level of displacement is included in the highest natural gas demand scenario (Upper Bound).

Figure 8-1 below illustrates the low carbon thermal energy demand profile for the Reference Case as well as the Upper and Lower Bound scenarios over the next 20 years. In the Reference Case, low carbon thermal energy demand grows by seven percent over the planning period. In the Upper Bound scenario, this growth switches to a decline of nine percent. In the Lower

Bound scenario, low carbon thermal energy demand grows significantly and displaces eight percent of 2015 base year natural gas demand by 2036. The 2017 LTGRP annual demand forecast assumes that any fuel switching away from natural gas that is not absorbed by RNG or low carbon thermal energy will result in increased electricity demand. A complete analysis of the impacts of this potential increased demand for electricity is an important consideration, but is outside the scope of this LTGRP. While this shift may not appear significant in terms of market transformation, it is an important trend for FEI to monitor and address as it represents a risk to the demand and revenues from the Company's customers. Please see Appendix B-1 for the scenario analysis input assumptions that inform this forecast behavior.

This highlights the need for FEI to invest in other load building initiatives such as NGT and to support development of its RNG program and other technologies that enable FEI to meet market preferences while also helping to meet BC energy objectives. With today's limited but growing market penetration of low carbon thermal energy systems, FEI will continue to monitor thermal energy demand in order to gauge its impact over time on the Company's natural gas load and system capacity.

Figure 8-1: Low Carbon Thermal Annual Demand



8.2.4 RNG and other Innovative Natural Gas Technologies

Section 3.4.6 discusses the annual demand impact of RNG across the 2017 LTGRP's alternate future scenarios. Even FEI's high assumption of RNG demand results in RNG accounting for a small proportion of FEI's total annual demand (less than three million GJ, compared to a maximum allowance of approximately 8.9 million GJ under the GGRR, as discussed in Section 2.3.3.4) by the end of the planning horizon. However, this analysis assumes current RNG supply technologies. If cellulosic biogas technologies become commercially scalable at reasonable cost, RNG demand may account for a significant share of FEI's demand within 20 years.

Similarly, other technologies exist that may decarbonize the natural gas stream and enable the natural gas infrastructure to store electric energy (indirectly by injecting into the pipeline system hydrogen derived via electrolysis), decarbonize natural gas end-use appliances or increase beyond 100 percent the efficiency of natural gas appliances. Section 2.4.3 outlines how FEI is monitoring and, where applicable, supporting the evolution of such technologies. If such technologies become commercially scalable at reasonable cost, they may mitigate policy-driven risks of downward pressure on natural gas demand (identified in Section 2) and create an investment opportunity for the Company. As such, FEI, its customers, and the public would benefit from FEI having access to a funding envelope that FEI can use to monitor, and where applicable, support such innovative natural gas technologies. FEI's 2017 LTGRP stakeholder engagement activities suggest that stakeholders support FEI monitoring and, where appropriate, supporting such technologies.

8.3 *GHG EMISSIONS FORECASTS*

The BCUC has requested FEI to discuss the relationship between demand and GHG emissions within its 20-year vision. The BCUC also identified as part of a 20-year vision a discussion of FEI's contribution to BC's GHG targets. Outlined in Part 1(2) of the province's CEA, BC's energy objectives include taking demand side measures to conserve energy, encouraging efficient energy use, fostering the development in BC of innovative technologies that support energy conservation and efficiency, encouraging switching from one kind of energy to another that decreases provincial GHG emissions, and reducing BC's GHG emissions. FEI's C&EM activities, NGT initiative, RNG offering and Connect to Gas Program are all important activities that help to meet these goals. FEI notes that BC's current energy objectives apply to the province as a whole and do not identify any sector-specific allocations.

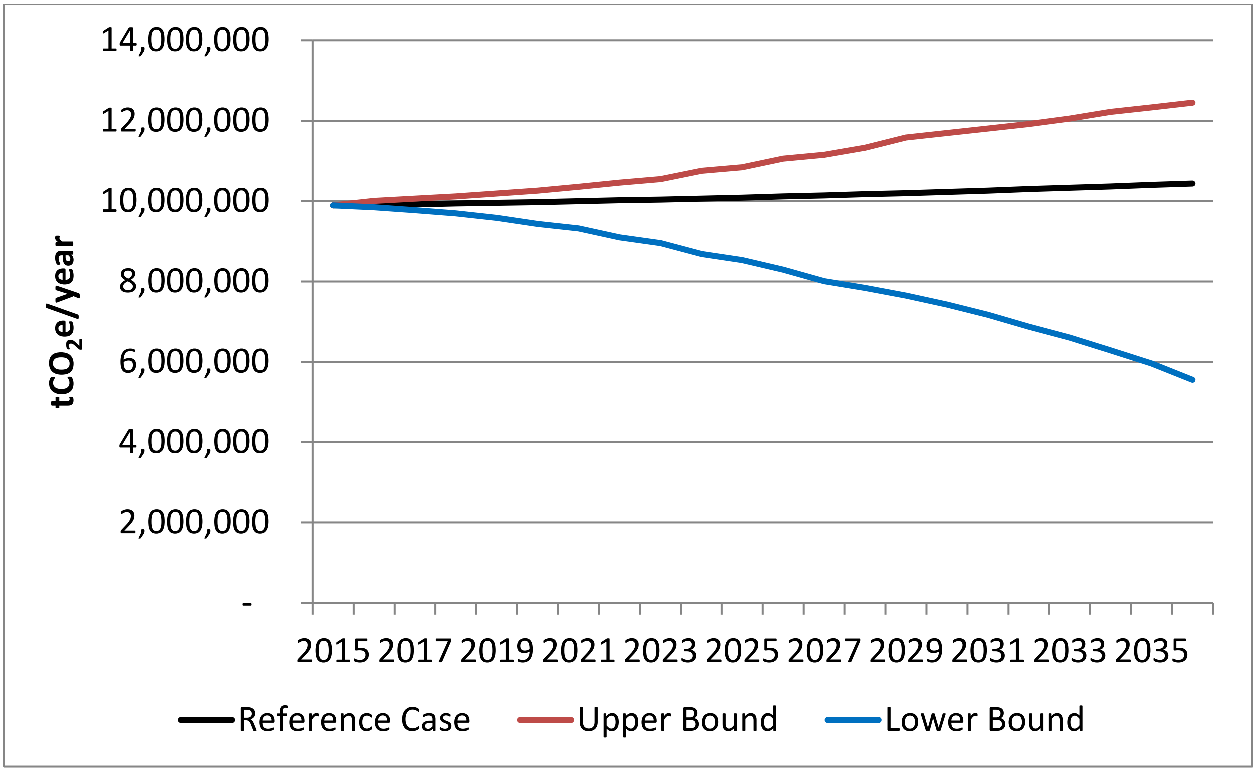
Section 8.3.1 below discusses the relationship between GHG emissions and annual demand while Section 8.3.2 outlines FEI's forecast contributions to BC's GHG emissions targets.

8.3.1 Relationship between GHG Emissions and Annual Demand

Natural gas is the cleanest, lowest GHG-emitting fossil fuel. The 2017 LTGRP's GHG emissions analysis simply details the CO_2 equivalent emissions in metric tonnes of FEI's customers combusting natural gas. As such, the 2017 LTGRP's GHG emissions reduction analysis does not quantify impacts of GHG-reducing upstream initiatives, such as electrifying natural gas extraction and processing facilities or implementing methane leakage controls in extraction, processing, and storage facilities. Potential implementation of a renewable portfolio standard would likely also cause downward pressure on GHG emissions from natural gas while presenting a risk of upward pressure on natural gas commodity costs. As outlined in Appendix B-1, the 2017 LTGRP scenario analysis uses a range of natural gas and carbon prices to encapsulate possible price fluctuations.

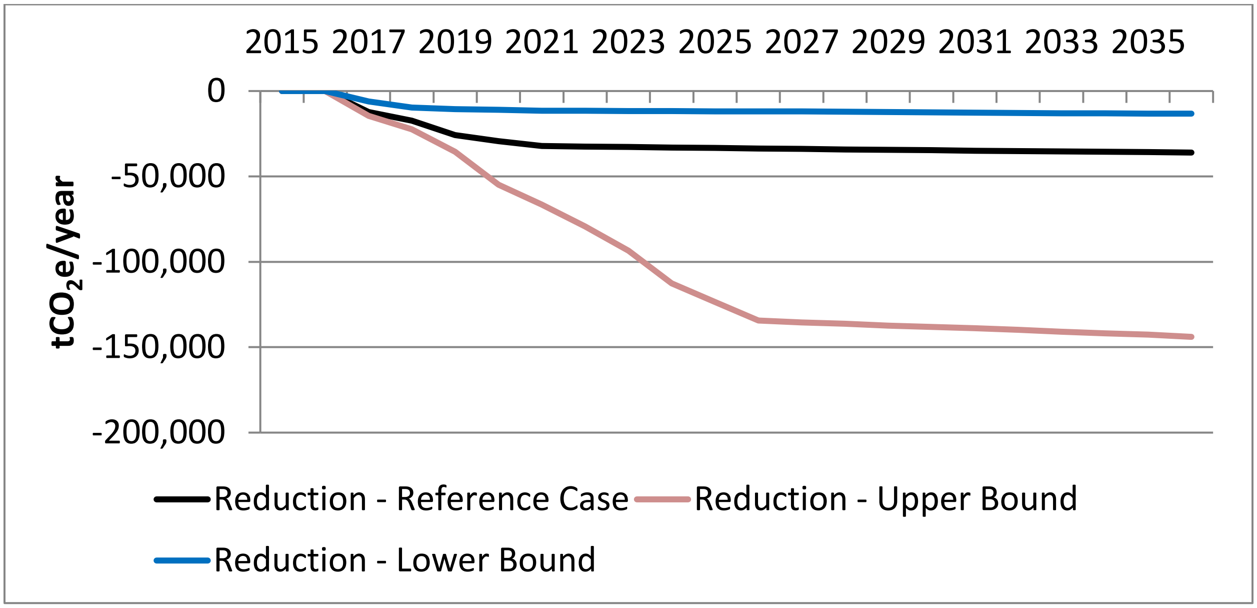
Figure 8-2 below illustrates the emissions of FEI's residential, commercial, and industrial customers without considering the emissions impacts of FEI's NGT, RNG, and C&EM initiatives. In the Reference Case, emissions grow by five percent across the forecast horizon. In the Upper Bound scenario emissions grow by 26 percent, whereas Lower Bound emissions decrease by 44 percent across the planning horizon.

Figure 8-2: Annual GHG Emissions of Residential, Commercial, Industrial Customers (metric tonnes) – Excluding NGT, RNG, and C&EM



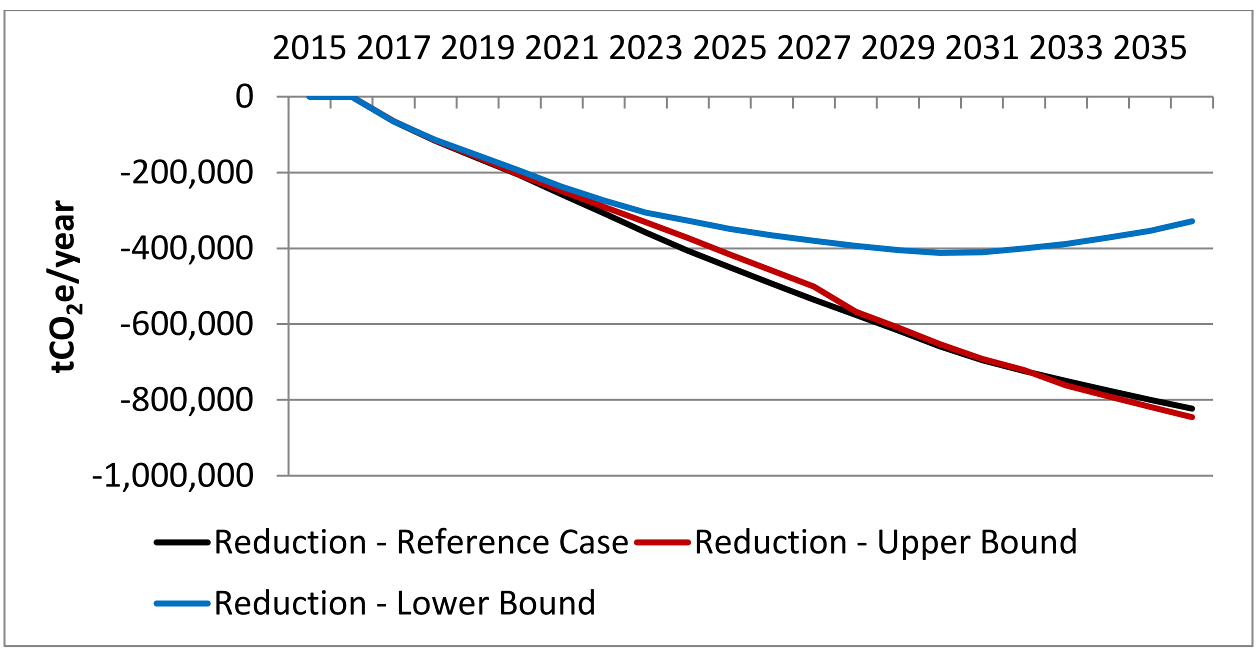
FEI's RNG initiative reduces GHG emissions because the initiative displaces the combustion of fossil natural gas with the combustion of RNG sourced from biomass (biomass decomposition emissions are considered part of the natural carbon cycle). Figure 8-3 below illustrates these forecast emissions reductions. FEI's method for determining emissions reductions from its RNG initiative is conservative because it does not account for avoided landfill methane emissions that are diverted as a result of the initiative. For example, a portion of organic waste that would normally be placed in landfills is being diverted to digesters. The methane that would have been created in the landfill would not normally be fully captured because landfills typically only capture between approximately 50 and 75 percent of their methane production. In contrast, an RNG digester captures approximately 100 percent. Based on using a calculated capture of 50 to 75 percent of methane at landfills versus approximately 100 percent at a digester, this could result in approximately 6 to 12 times additional avoided GHG emissions that FEI does not use in its calculated emission reductions. In the Reference Case, the 2036 RNG forecast result accounts for an emissions reduction of 0.4 percent over the 2036 emissions presented in Figure 8-2 (above). This value changes to 1.5 percent and 0.1 percent for the Upper and Lower Bound scenarios, respectively.

Figure 8-3: Annual GHG Emissions Reductions of RNG Customers Only (metric tonnes)



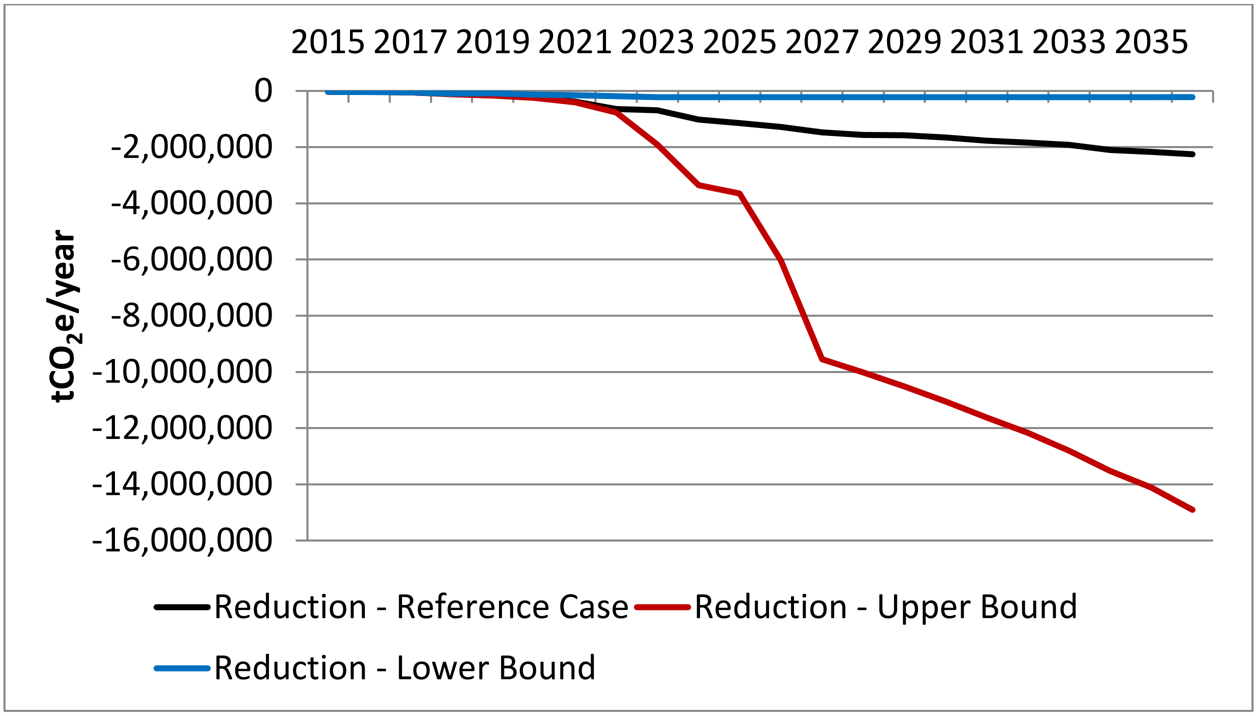
C&EM program participants generate emissions reductions because they effectively eliminate a portion of their pre-participation natural gas demand. Figure 8-4 below illustrates these forecast emissions reductions. In the Reference Case, FEI's 2036 C&EM forecast result accounts for an emissions reduction of 8.3 percent over the 2036 emissions presented in Figure 8-2 (above). This value changes to 8.5 percent and 3.3 percent for the Upper and Lower Bound scenarios, respectively.

Figure 8-4: Annual GHG Emissions Reductions of C&EM Program Participants Only (metric tonnes)



FEI's NGT customers generate emissions reductions because they use natural gas to displace consumption of higher-emitting fossil fuels. As such, NGT emissions reductions are a function of the NGT annual demand forecast presented in Figure 3-16 and the difference in emissions intensity between the incumbent fuels and natural gas. Figure 8-5 below illustrates these forecast emissions reductions. In the Reference Case, FEI's 2036 NGT forecast result accounts for an emissions reduction of 22.5 percent over the 2036 emissions in Figure 8-2 (above). This value changes to 150.7 percent and 2.0 percent for the Upper and Lower Bound scenarios, respectively.[155]

Figure 8-5: Annual GHG Emissions Reductions of NGT Customers Only (metric tonnes)

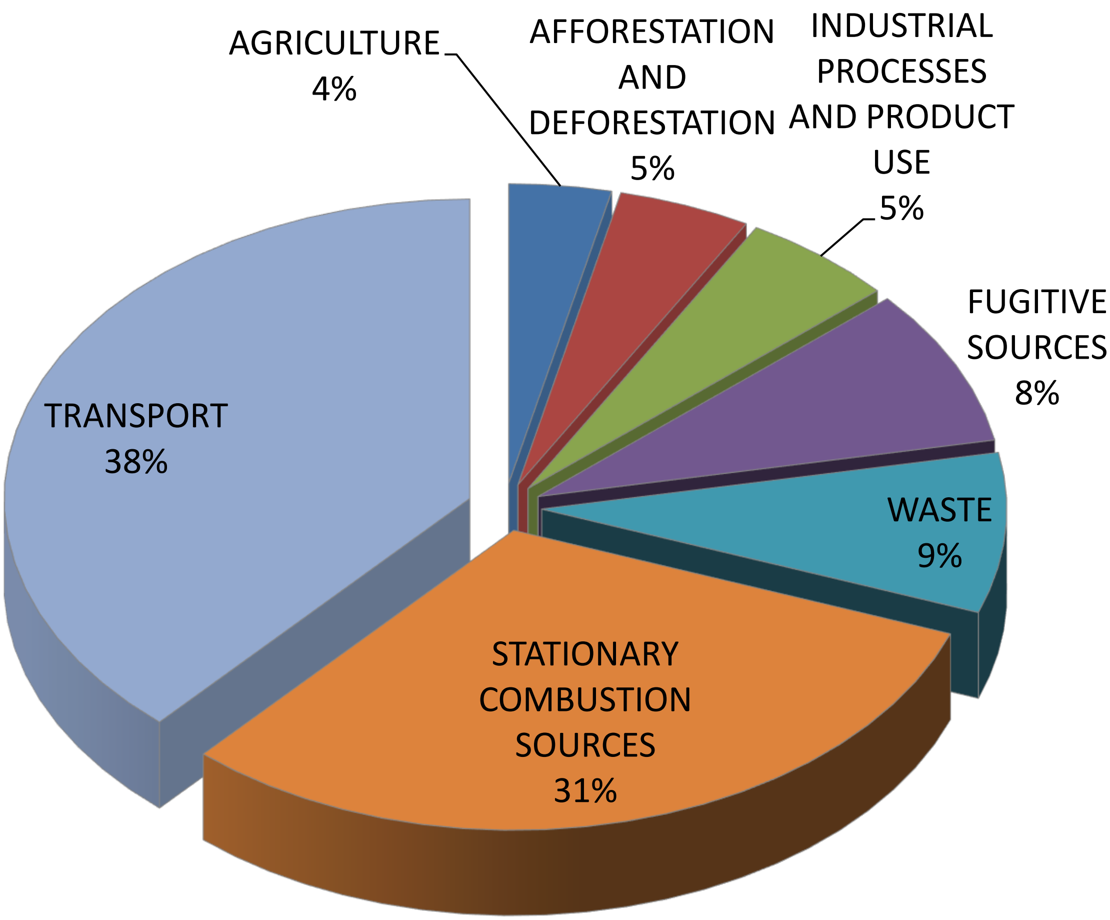


8.3.2 FEI's Contributions to BC's GHG Emissions Targets

To provide context, Figure 8-6 below illustrates BC's 2014 GHG emissions (64.5 million metric tonnes of CO_2 equivalent) by category. Transport accounts for more than one third of 2014 emissions.

155 NGT emissions reduction factors are sourced from GHGenius. RNG and C&EM emissions factors are sourced from the BC Ministry of Environment & Climate Change Strategy.

Figure 8-6: 2014 BC GHG Emissions[156]



The combined impact of FEI's forecast RNG and C&EM emissions reductions (illustrated individually in Figures 8-3 and 8-4 above) results in 2036 Reference Case emissions declining by three percent in relation to the 2015 base year. The Upper Bound scenario changes this figure to 16 percent growth. The Lower Bound scenario displays a 47 percent decline. In the Reference Case, forecast 2036 NGT emissions reductions (illustrated in Figure 8-5 above) amount to 2.3 million metric tonnes. This figure changes to 14.9 million metric tonnes in the Upper Bound and 0.2 million metric tonnes in the Lower Bound scenarios, respectively. Overall, these GHG emissions reductions occur in the Transport, Stationary Combustion Sources, and Industrial Processes and Product Use categories of Figure 8-6.

156 FEI from 2014 BC GHG Inventory Report. Climate Action Secretariat.

Some forecast NGT emissions reductions are realized outside the current boundaries of the BC emissions inventory. This most impacts the Upper Bound which includes internationally travelling vessels whose energy demand accounts for the majority of NGT annual demand in the Upper Bound scenario. Since climate change represents a global challenge, all emissions reductions outlined in Section 8.3.1 above contribute to addressing this challenge no matter where such reductions occur.

In order to show how forecast emissions reductions from FEI activities compare to BC's GHG emissions reduction goals, FEI used a linear regression to calculate targeted province-wide 2036 emissions levels from BC's 2014 reported province-wide emissions, the percentage emissions reductions target from the Government of Canada's 2017 Nationally Determined Contribution under the Paris Agreement (reducing GHG emissions by 30 percent from 2005 until 2030), and BC's legislated sector-agnostic 2050 emissions reduction target. FEI received stakeholder support for using the Government of Canada's 2030 percentage reduction target as a reasonable alternative to the GGRA's 2020 target as an interim step towards the GGRA's ultimate 2050 target. Based on this calculation, BC would have to reduce its 64.4 million metric tons of 2014 CO_2 equivalent emissions by 29.3 million metric tons by 2036 (a reduction of approximately 45 percent). Applying the same calculation to the BC CLP suggests that the Plan accounts for 25 million metric tons of emissions reductions by 2036 (a reduction of approximately 35 percent).

Table 8-1 below compares 2036 emissions reductions of FEI's initiatives with the calculated 2036 emissions reductions target.[157]

Table 8-1: Comparison of FEI's Emissions Reduction Activities with the Calculated Emissions Reduction Target

GHG Reductions Required to Meet the Calculated 2036 Target ($MtCO_2e$, 2014 Base)	Forecast Emissions Reductions in 2036 ($MtCO_2e$, 2015 Base)		
29.3	**Reference Case**	**Upper Bound**	**Lower Bound**
RNG	0.04	0.14	0.01
C&EM	0.8	0.8	0.3
NGT	2.3	14.9	0.2

Notes:
Some forecast NGT emissions reductions are realized outside the current boundaries of the BC emissions inventory.

[157] FEI's RNG, C&EM and NGT initiatives each have their own merits and run under separate regulatory approval processes.

As part of developing its long term vision and given current trends in the discourse on energy use and emissions policy (see Section 2.3), FEI examined potential pathways through which emerging initiatives and technologies could help FEI lead efforts to pursue long term GHG emissions abatement in each of the economic categories that FEI's activities can address. Please see Appendix E for this examination. Stakeholders have supported including this examination in order to better illustrate that pathways to a lower carbon future do exist that include, and may be better enabled by, the use of natural gas and natural gas infrastructure.

8.4 POTENTIAL IMPACT OF NEW TECHNOLOGIES AND MARKET CONDITIONS ON DEMAND

FEI has incorporated a range of annual demand end-use forecast scenarios for commercial, residential and industrial demand discussed in Section 3.4.4. FEI does not attempt to specify what technology innovations or market changes occurred in each scenario, as the purpose of the end-use forecasting method is to model a range of directional impacts on demand that could be caused by changing market trends, policies or technologies. The Company further examines the impact of market and technology trends favorable for natural gas use by modelling the impact of NGT demand on total annual demand in Section 3.4.8 and the impact of potential large new industrial demand in Section 3.4.9. Section 3.4.6 discusses the impact on annual demand of FEI's RNG initiative.

The impact of new technologies on peak demand is discussed in Section 6.2.

The end-use forecasting method has also provided the opportunity for FEI to examine technology and market trends that result in declining annual demand (see Figure 3-8 for the full range of annual demand forecasts). The Company believes that this range of forecasts from declining demand to demand growth—largely from transportation and industrial customers—represents a reasonable range of potential future demand scenarios for which to plan over the next 20 years.

8.5 BC'S ENERGY OBJECTIVES

Section 2 of BC's CEA outlines 16 energy objectives for the Province. Of those, three are directed specifically at BC Hydro and a number of others are related specifically to electricity resources and are not applicable to the natural gas services offered by FEI. The discussion below outlines how the 2017 LTGRP has addressed the remaining BC energy objectives.

ENERGY OBJECTIVE (B) TO TAKE DEMAND-SIDE MEASURES AND TO CONSERVE ENERGY:

Section 4.2 of the 2017 LTGRP discusses the analysis of potential C&EM measures and Section 4.2.4 sets out a plan for implementing C&EM activity that will reduce demand for natural gas during the planning period.

ENERGY OBJECTIVE (D) TO USE AND FOSTER THE DEVELOPMENT IN BRITISH COLUMBIA OF INNOVATIVE TECHNOLOGIES THAT SUPPORT ENERGY CONSERVATION AND EFFICIENCY AND THE USE OF CLEAN OR RENEWABLE RESOURCES:

FEI's existing C&EM programs contain an innovative technologies component. Technology evaluation results from this component have informed the BC CPR and thus the 2017 LTGRP DSM analysis. As such, the 2017 LTGRP DSM analysis contains some innovative technologies, such as smart learning thermostats. Section 4.2 of the 2017 LTGRP discusses the analysis of potential C&EM measures and Section 4.2.4 sets out a plan for implementing C&EM activity that will reduce demand for natural gas during the planning period.

The 2017 LTGRP discusses FEI's NGT initiative (Section 2.4.1) which fosters technology adoption to meet the needs of FEI customers while increasing annual and peak demand (Section 3.4.7 and 6.3) but putting downward pressure on the Company's customers' GHG emissions (Section 8.3) and FEI's long term rate projections (Section 8.6).

ENERGY OBJECTIVE (G) TO REDUCE GREENHOUSE GAS EMISSIONS:

Section 8.3 quantifies the extent to which FEI's RNG, C&EM, and NGT activities can reduce GHG emissions under alternate future scenarios. FEI notes that BC's current legislated GHG emissions reductions targets are not sector-specific.

ENERGY OBJECTIVE (H) TO ENCOURAGE SWITCHING FROM ONE KIND OF ENERGY SOURCE OR USE TO ANOTHER THAT DECREASES GREENHOUSE GAS EMISSIONS IN BRITISH COLUMBIA:

FEI's Connect to Gas and NGT initiatives are each an example of fuel switching initiatives that move customers from higher to lower GHG-emitting fuels and are discussed as ongoing initiatives that have been considered in the development of the 2017 LTGRP. Of these, the NGT initiative has the highest potential for GHG emission reductions as shown in Section 8.3.

ENERGY OBJECTIVE (I) TO ENCOURAGE COMMUNITIES TO REDUCE GREENHOUSE GAS EMISSIONS AND USE ENERGY EFFICIENTLY:

The 2017 LTGRP DSM analysis contains activities that encourage communities to reduce GHG emissions and use energy efficiently. Section 4 of the 2017 LTGRP discusses the analysis of potential DSM activities and Section 4.2.4 sets out a plan for implementing C&EM activity that will reduce demand for natural gas during the planning period. The analysis projects FEI's C&EM programs to increase by two thirds near the middle of the planning horizon.

ENERGY OBJECTIVE (J) TO REDUCE WASTE BY ENCOURAGING THE USE OF WASTE HEAT, BIOGAS AND BIOMASS:

FEI's RNG offering is designed to encourage the collection of biogas from organic waste sources in BC. The RNG offering is discussed in Section 2.4.2 with the annual demand outlook presented in Section 3.4.6.

ENERGY OBJECTIVE (K) TO ENCOURAGE ECONOMIC DEVELOPMENT AND THE CREATION AND RETENTION OF JOBS:

FEI has an important role to play in this objective by remaining a healthy, growing contributor to BC's economy and to the well-being of BC communities as described in the long term vision presented in the introduction to Section 8. Capital investments from projects identified in Section 6 as solutions to capacity constraints or system sustainment requirements will contribute to BC's economy and the communities in which FEI operates. Further, FEI's C&EM activities have been shown to have economic and job creation benefits in addition to energy and emission reduction benefits.[158]

ENERGY OBJECTIVE (N) TO BE A NET EXPORTER OF ELECTRICITY FROM CLEAN OR RENEWABLE RESOURCES WITH THE INTENTION OF BENEFITING ALL BRITISH COLUMBIANS AND REDUCING GREENHOUSE GAS EMISSIONS IN REGIONS IN WHICH BRITISH COLUMBIA TRADES ELECTRICITY WHILE PROTECTING THE INTERESTS OF PERSONS WHO RECEIVE OR MAY RECEIVE SERVICE IN BRITISH COLUMBIA):

By continuing to serve BC's thermal energy needs with natural gas, FEI will help to curb increases in electricity demand that would otherwise be caused by gas-to-electric fuel switching in either new or existing buildings. While this electric load avoidance would not eliminate emissions in BC, it would preserve more of BC's clean electricity for potential export to other jurisdictions within the electricity trading region. Such electricity exports could economically benefit British Columbians and may result in greater emissions reductions by displacing coal or natural gas fired electricity generation currently in use in those jurisdictions.[159] At the same time and as discussed in Section 8.2.4, progress is being made on technologies and initiatives that will help to decarbonize the natural gas that does directly serve thermal energy end uses in BC. Continuing to serve BC's thermal energy needs with natural gas helps to maintain BC's natural gas infrastructure which may enable BC to capitalize on future low carbon energy opportunities, such as cellulosic biogas or power-to-gas (see Sections 2.4.2 and 2.4.3).

8.6 *IMPACT OF LONG TERM DEMAND ON PROJECTED CUSTOMER DELIVERY RATES*

One of FEI's central objectives is to provide customers with cost effective delivery service.

Customer demand can have a significant effect on delivery rates as increasing natural gas demand has a downward impact on delivery rates for all customers, all else being equal. As such, the Company aims to increase system efficiency and optimize infrastructure use by maintaining sufficient throughput on FEI's distribution system.

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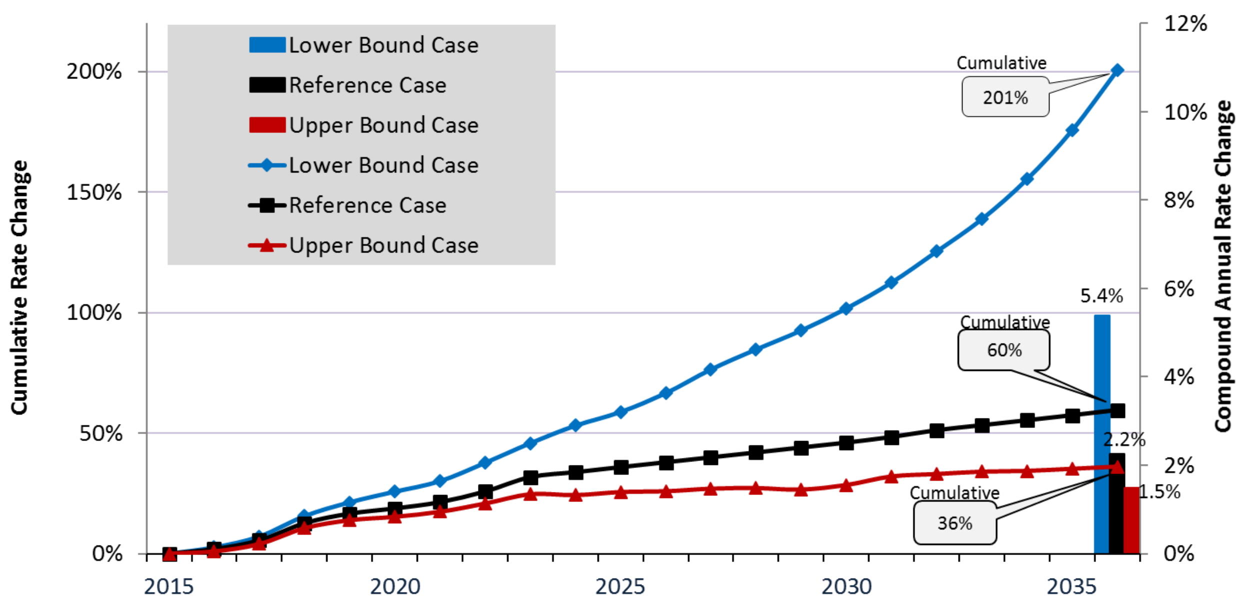
158 ICF Marbek (May 2011). Conservation Potential Review 2010 FortisBC. "Impact of CPR-2010 Natural Gas Savings on the BC Economy (2010-2030)".

159 Using natural gas directly to meet thermal energy demand is more efficient than using fossil fuels to generate electricity (see Section 2.3.2.4). While the majority of BC's electricity is supplied by hydroelectric resources, other jurisdictions in BC's electricity trading region do rely on fossil fuels for power generation.

To provide context for FEI's long term volume forecasts as they relate to delivery rates, Figures 8-7 through 8-9 provide a directional look at the potential impact of long term demand on customer rates. Using approved rates and actual volumes from 2015[160], the following figures include the cost of service for major capital items and forecast C&EM activity plus an escalation of the cost of service by a growth factor of two percent per year, divided by delivery volumes in each scenario. The figures do not consider future rate design changes and are not indicative of a detailed rate forecast—they simply provide a directional, 20-year view of FEI's delivery rates over time.

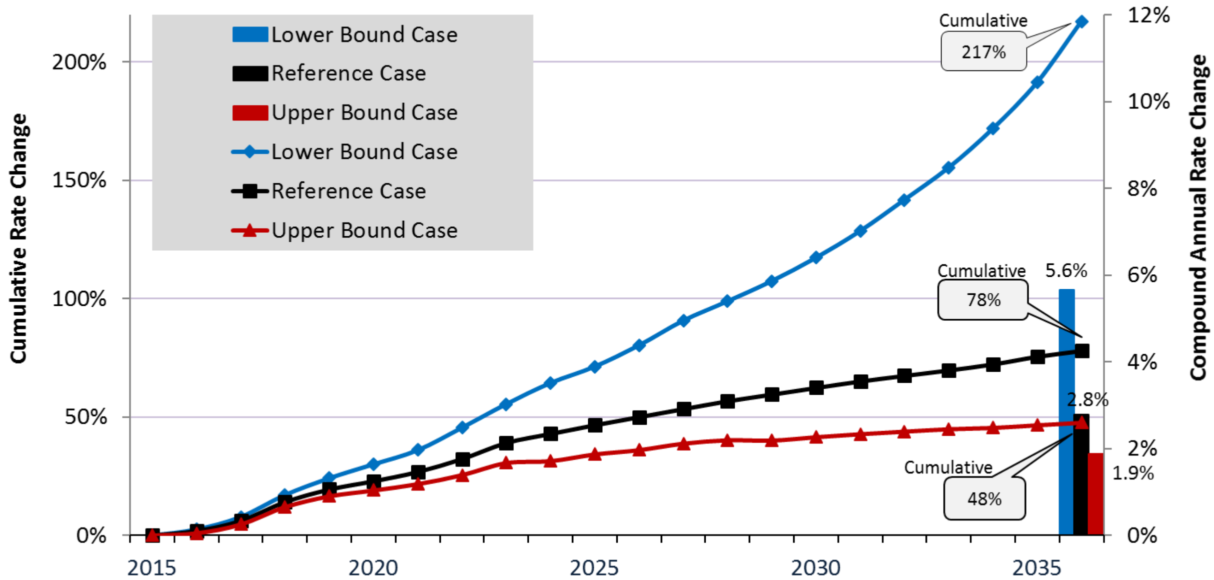
Figure 8-7 illustrates the delivery rate direction for the Reference Case, the Upper and the Lower Bound scenarios, respectively. In the Reference Case, the compound annual delivery rate change is 2.2 percent, which amounts to a 60 percent cumulative delivery rate change over the 20-year planning horizon. Below, Figures 8-8 and 8-9 illustrate the expected influence on delivery rates of FEI's C&EM and NGT initiatives. In general, as the volume of delivered gas decreases, delivery rates increase because less throughput on the system results in higher delivery costs per customer. C&EM programs incent customers to use less gas, causing demand for gas on the system to fall, thereby putting upward pressure on delivery rates. FEI also recovers the cost for its C&EM programs from its customer base which reinforces this upward pressure effect. As such, the compound annual delivery rate change in the Reference Case of Figure 8-8 grows to 2.8 percent which amounts to a 78 percent cumulative delivery rate change over the planning horizon in this simplified model.

Figure 8-7: Delivery Rate Direction – All Rate Schedules (without C&EM, NGT)



160 The projected delivery rate analysis uses 2015 actuals to remain consistent with the 2015 base year of the annual energy demand forecast from Section 3.

Figure 8-8: Delivery Rate Direction – All Rate Schedules with C&EM (without NGT)



Conversely, adding NGT demand (shown in Figure 8-9 below) increases total demand on the system and thus puts downward pressure on delivery rates. When adding the effect of NGT demand to the previous two projections, the Reference Case compound annual delivery rate change falls to 2.3 percent and the cumulative delivery rate change over the 20-year planning horizon also falls to 62 percent. In sum, holding all else constant, increasing delivery volumes has a positive effect for rates. Expanding the NGT market is an important opportunity for growth on the delivery system and underscores the importance for the Company to explore other opportunities for growth that will assist in mitigating upward pressure on delivery rates.

Figure 8-9: Delivery Rate Direction – All Rate Schedules with C&EM and NGT

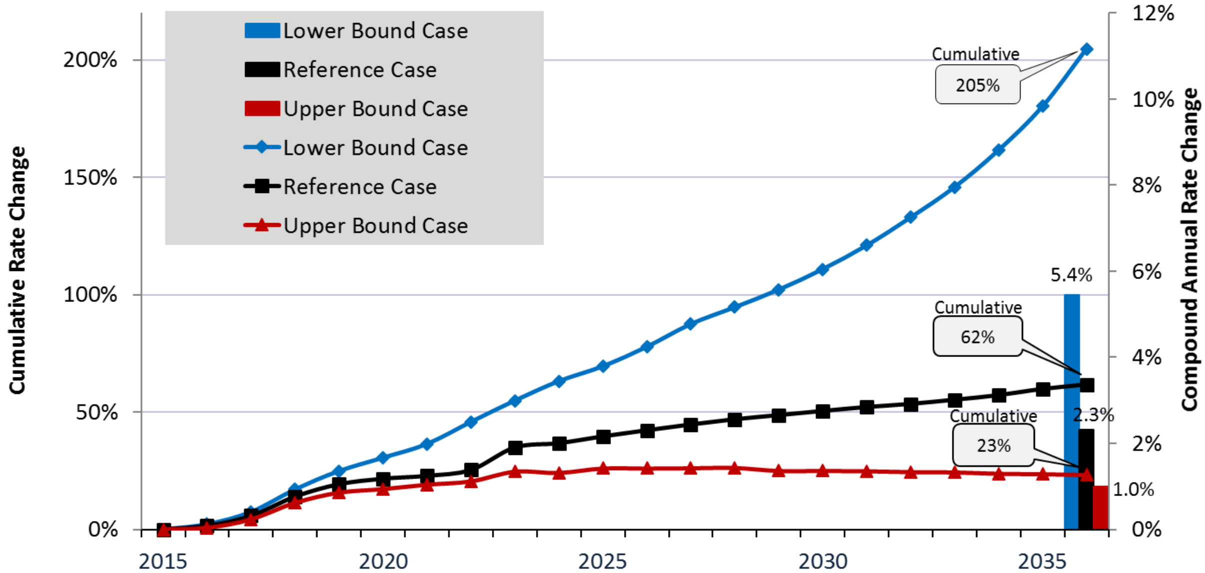


Table 8-2 below summarizes the aforementioned delivery rate impact projections.

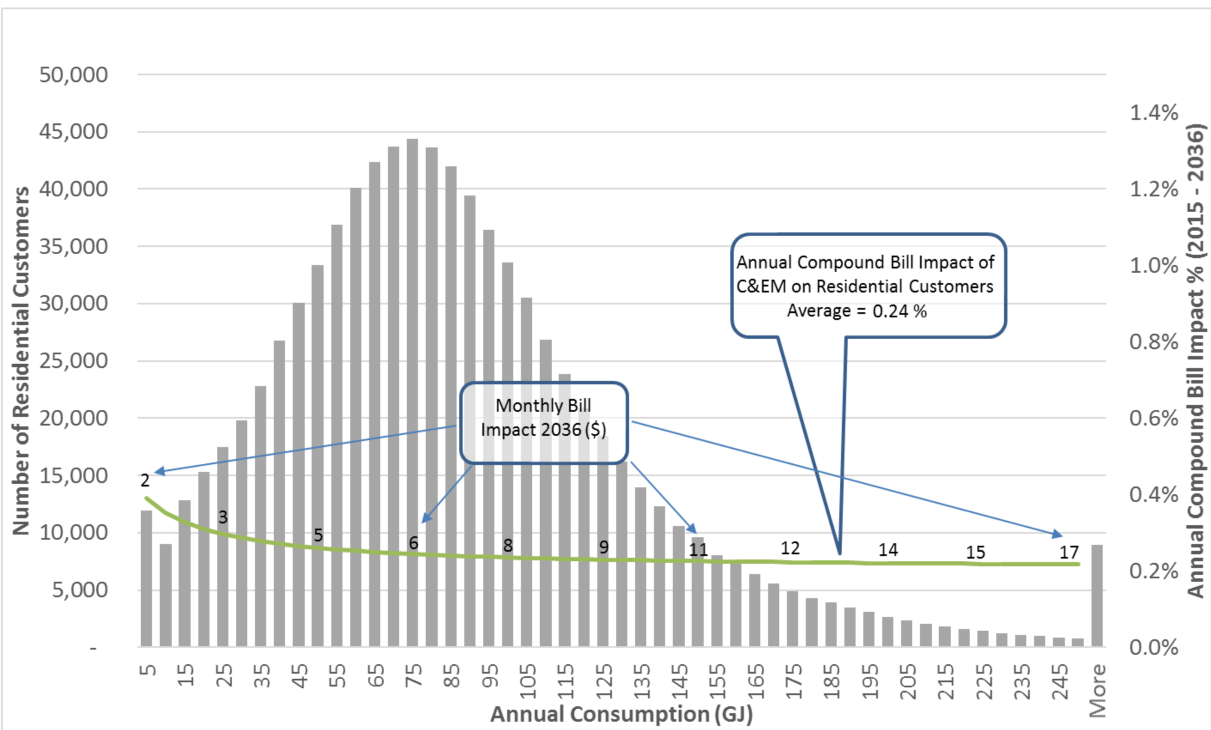
Table 8-2: Summary and Comparison of Average Projected Delivery Rate Changes

	Rate Change (2015-36, %)					
	Base		Base + C&EM		Base + C&EM + NGT	
	Cumulative	Compound Annual	Cumulative	Compound Annual	Cumulative	Compound Annual
Reference Case	60	2.2	78	2.8	62	2.3
Upper Bound	36	1.5	48	1.9	23	1.0
Lower Bound	201	5.4	217	5.6	205	5.4

To provide further context on the customer impact of FEI's projected C&EM activity, Figures 8-10 to 8-12 below provide a directional look at the potential total bill impact (including commodity and delivery) of such C&EM activity. The figures do not consider future rate design changes and are not indicative of a detailed bill forecast - they simply provide a directional view of estimated

2036 total C&EM bill impacts.[161] Annualized percentage compound 2015-2036 bill impacts are higher for low consumption customers than for high consumption customers. In contrast, monthly absolute 2036 impacts are higher for high consumption customers than for low consumption customers. In the Reference Case, average annualized percentage compound 2015-2036 bill impacts are 0.24 percent. This average value is increased to 0.25 percent for the Upper Bound scenario but decreases to 0.13 percent for the Lower Bound scenario. This appears to be due to the combination of two primary factors: (1) projected C&EM energy savings and expenditures increase from the Lower Bound scenario across the Reference Case to the Upper Bound scenario (which creates upward pressure on projected rates), but (2) the carbon price and natural gas commodity cost decrease from the Lower Bound scenario across the Reference Case to the Upper Bound scenario (which places downward pressure on estimated bills but also reduces the base values upon which percentage bill impacts are calculated). These dynamics also apply to Table 8-3 which displays estimated total bill impacts for average customers in select commercial and industrial Rate Schedules. Overall, estimated bill impacts of C&EM are forecast to be small.

Figure 8-10: Estimated Total Bill Impact of Projected C&EM Activity on Residential Customers – Reference Case



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[161] This analysis indicates estimated bill impacts from the perspective of a customer that does not participate in C&EM programs. C&EM program participants are likely to experience cost savings on their bills.

Figure 8-11: Estimated Total Bill Impact of Projected C&EM Activity on Residential Customers – Upper Bound

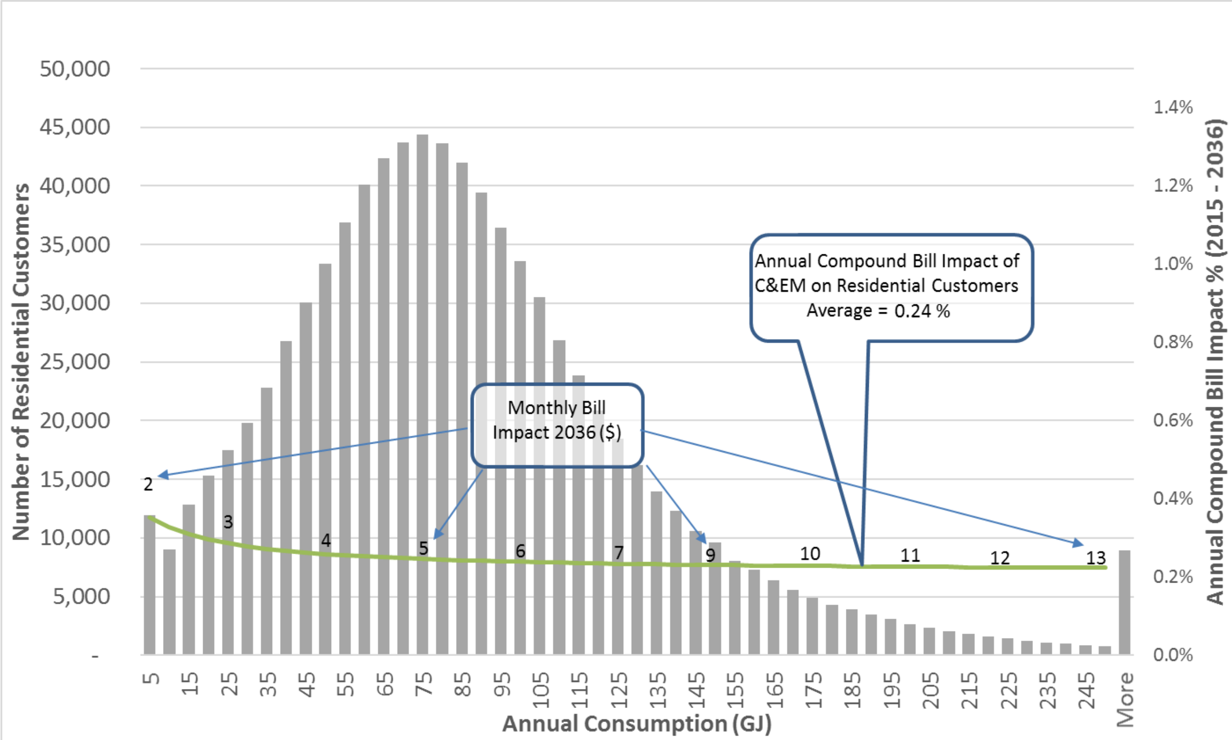

Figure 8-12: Estimated Total Bill Impact of Projected C&EM Activity on Residential Customers – Lower Bound

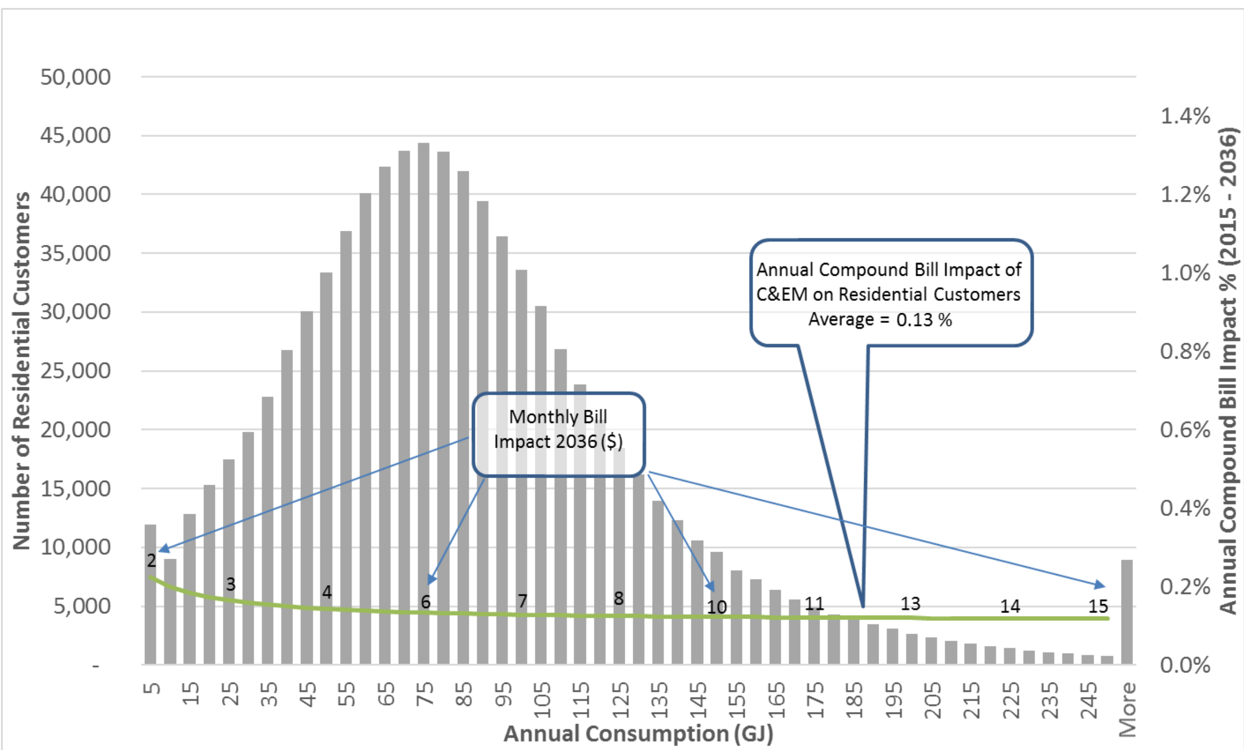

Table 8-3: Estimated Total Bill Impact of Projected C&EM Activity on Commercial and Industrial Customers[162]

Rate Schedule	Result	Reference Case	Upper Bound	Lower Bound
2	2015-2036 Annualized Compound Bill Impact	0.28%	0.24%	0.14%
	2036 Monthly Bill Impact ($)	24	17	13
3	2015-2036 Annualized Compound Bill Impact	0.25%	0.20%	0.10%
	2036 Monthly Bill Impact ($)	213	140	90
6	2015-2036 Annualized Compound Bill Impact	0.35%	0.19%	0.30%
	2036 Monthly Bill Impact ($)	467	183	415
7	2015-2036 Annualized Compound Bill Impact	0.23%	0.15%	0.20%
	2036 Monthly Bill Impact ($)	1,354	701	979
22	2015-2036 Annualized Compound Bill Impact	0.08%	0.05%	0.05%
	2036 Monthly Bill Impact ($)	12,352	5,199	8,082

8.7 KEY DRIVERS IMPACTING THE NEED FOR RESOURCES

The key drivers impacting the need for resources are the amount of natural gas demand over the forecast horizon, the impact that demand will have on available system capacity, system sustainment requirements for continued delivery of safe, secure and cost effective gas supply, and the amount and nature of demand side activities that FEI expects to undertake over the planning period. The demand forecast is presented in Section 3 and the amount of energy savings from C&EM activities is presented in Section 4. Section 6.3 presents the analysis of system capacity requirements and the expected timing of capacity expansions. Other major system projects identified in Section 6.4 may be needed regardless of the extent to which demand grows. The system capacity requirements identified in Section 6.3 may shift in terms of timing depending on how quickly demand grows, but they may also be easily integrated into system sustainment projects to satisfy both needs under all of the future scenarios examined.

The final driver impacting the need for resources is the extent to which the planning environment may change over the planning period and the nature of those changes. FEI believes that the demand scenarios analyzed in this 2017 LTGRP adequately capture the range of planning environment changes that may begin to unfold by the time the next LTGRP is prepared.

Section 8.6 shows the importance of adding natural gas demand in new markets to help offset increases in customer rates caused by declining UPC in other sectors, and the risk of further declines represented in the lower demand forecast scenarios (presented in Section 3).Therefore, resources to conduct customer and market research, and to identify and acquire customers in new and traditional markets are among the resources that FEI must continue to maintain over the planning horizon.

[162] The total bill impact analysis for Rate Schedule 22 assumes the same commodity cost values and midstream as well as distribution adders as the analysis for the other commercial and industrial rate schedules.

8.8 CONCLUSION

The context in which to provide a 20-year vision for FEI is significantly different today than it was six years ago when the Commission issued the applicable directive in the 2010 LTRP Decision. Notably, FEI was developing service initiatives to provide low carbon thermal energy solutions, the outlook for natural gas supply and long term gas price forecasts was significantly different, and since that time, the Government of BC has placed increasing emphasis on developing natural gas resources for transportation use and export. Uncertainty remains about the further evolution of this policy direction due to recent changes in government in BC and the US.

In Section 8, FEI has explained how and where the 2017 LTGRP addresses a number of items related to a 20-year vision. This section also highlights the need to monitor a small but important trend of growing low carbon thermal energy demand, the extent to which FEI initiatives contribute to BC's overall GHG reductions, and how variations in demand over the planning period can influence customer delivery rates. Since decreases in demand (whether through market trends or C&EM activities) place upward pressure on delivery rates while increases in demand lead to the reverse effect, the Company will continue to explore opportunities for demand growth on the distribution system. This includes FEI monitoring and, where applicable, participating in efforts to test and implement innovative natural gas energy technologies that help meet FEI's customers' needs while also supporting BC energy objectives.

9. ACTION PLAN

The following Action Plan describes the activities that FEI intends to pursue over the next four years based on the information and recommendations provided in this 2017 LTGRP. Pursuant to Order G-189-14, dated December 3, 2014, FEI confirms that it has built this Action Plan based on its Reference Case end-use annual demand forecast and its Traditional Peak Method forecast.

1. Continue monitoring and analyzing the energy planning environment.

Being aware of and understanding the many factors that influence FEI's long term analysis is critical to providing appropriate context for the analysis, results and recommendations that are made throughout the LTGRP. FEI will continue to monitor market and policy developments that may impact regional gas flows, supply, demand and pricing. FEI's research and investigations will seek to uncover any potential challenges as well as identify opportunities to improve on the secure, reliable and cost effective energy services that the Company provides to its customers.

2. Continue exploring the application of projected changes across end-use patterns to peak demand forecasting.

In the 2017 LTGRP, FEI outlined an exploratory method for examining peak demand under projected changes across end-use patterns. This method is theoretical and not based on metered FEI customer energy consumption. As such, FEI continues using its well-established Traditional Peak Method for analyzing peak demand for system capacity planning. This Traditional Peak Method is based on metered data and serves as FEI's basis for developing action plans and contingencies around such plans. FEI will continue monitoring potential metering solutions that may allow FEI to field-validate the projections of the exploratory end-use peak demand forecast method and to better serve its customers.

3. Protect and promote the interests of the Utility's customers by securing a reliable, cost effective long term gas supply.

Fundamental objectives for FEI are to procure a stable, secure gas supply over the long term while minimizing the cost of the annual portfolio. In order to meet these objectives, FEI will use the following broad strategies to secure future resources:

- Manage volatility in natural gas prices by maintaining access to liquid trading hubs, utilizing a variety of storage and transportation resources, and using different pricing structures and contract terms.
- Continue to actively participate in pipeline infrastructure developments, tolling proceedings and other initiatives to ensure that the marketplace in BC offers supply liquidity and competitive pricing compared to neighbouring regional markets.

- Continue to establish key relationships with major producers that plan to develop gas supply in the Horn River, Montney and other producing regions of BC over the long term, including those actively involved in attempting to develop LNG exports to Asian markets.
- Evaluate opportunities within FEI's own operating region to improve infrastructure that will provide greater access to markets, leading to better diversity and reliability within the gas portfolio over the long term.
- Continue using financial hedging strategies as approved by the Commission in FEI's PRMPs and, where applicable, request Commission approval for an expansion of financial hedging strategies via future PRMPs.

FEI also plans to investigate VPP or similar arrangements with gas producers as a longer term strategy for helping ensure security of supply and provide cost stability for customers.

4. Continue monitoring and evaluating system expansion needs in the Okanagan and Vancouver Island areas to maintain reliable and cost effective gas delivery to FEI's customers.

FEI's Traditional peak demand forecast method has identified a capacity constraint in the Okanagan region of the ITS in 2022. Under the High Traditional scenario this constraint is projected to occur as early as 2021. Under the Low Traditional scenario this constraint is projected to be delayed to 2027. The Company will continue to evaluate the four proposed reinforcement options presented in Section 6.3.3 as part of FEI's contingency planning. In addition, the Company will continue to monitor developments in FBC's long term planning and the potential need for natural gas generation as a back-up to renewable electricity production during peak electric demand periods. Should FBC proceed with a gas-fired peaking generating station, this or any other large additional industrial load will result in a need to submit a CPCN for facility expansion.

FEI's Traditional Peak Method forecast has identified a capacity constraint in the VI Transmission System in 2028. Under the High Traditional scenario this constraint is projected to occur as early as 2024. Under the Low Traditional scenario this constraint is projected to be delayed to 2030. The Company will continue monitoring VI Transmission System capacity and evaluation the two reinforcement options presented in Section 6.3.1 as part of the FEI's contingency planning. FEI will submit a CPCN for system expansion if required.

5. Plan for and prepare CPCN applications for near-term system requirements identified in Section 6 to support safe, reliable and cost effective gas delivery to FEI's customers.

The high priority projects on the CTS and FEI's regional infrastructure for which the Utility intends to submit CPCN applications and will be examining in the near term are:

- Upgrades to lateral pipeline segments in the interior region to enable and implement In Line Inspection programs (referenced in Section 6.4 as Transmission System Laterals ILI Capability);
- The Southern Crossing Pipeline Class Location Project;
- The Patullo Bridge Crossing Replacement;
- The evaluation of major bridge crossings on the CTS to determine if upgrades should be considered to improve the resiliency of piping during a seismic event (referenced in Section 6.4 as Bridge Crossing Seismic Upgrade Assessment – Lower Mainland);
- Implementation of advanced technology In Line Inspection programs (e.g. EMAT) for the transmission pipelines that are already inspected using current technology; and
- A potential reliability upgrade to the Langley compressor facility.

As FEI's planning efforts are undertaken to ensure that planned improvements optimize operation of the system as a whole, these system upgrade requirements have been integrated with the reinforcement options that are under consideration to meet FEI's capacity needs.

6. Continue implementing the Company's NGT initiatives to meet market needs while capturing an important opportunity for load growth and GHG emissions reductions.

FEI will continue implementing the Company's NGT initiatives to provide an important source of load growth on FEI's natural gas system while also capturing a significant opportunity for GHG emissions reductions. This includes implementing any required expansions to the Tilbury LNG facility and FEI's CTS for meeting NGT and non-NGT LNG demand as discussed in Sections 6.3.1 and 6.3.2 and pursuant to the BC Government's Direction No. 5.

7. Pursue approval of C&EM funding for the period beyond 2018 by submitting for BCUC approval a C&EM expenditure schedule in 2018.

Pursuant to Order G-189-14, FEI will develop a C&EM expenditure schedule and seek approval for this from the BCUC in 2018. This expenditure schedule will be informed by the results from the BC CPR and the 2017 LTGRP C&EM analysis.

FEI will continue to examine the potential for all forms of DSM activity to optimize the use of BC's energy infrastructure by implementing programs that help meet customer energy needs while working toward BC energy objectives.

8. Pursue approvals as necessary of a funding envelope dedicated to enabling FEI to further monitor and, where applicable, support innovative natural gas technologies which may help FEI meet market preferences while also supporting solutions for BC's emissions policy objectives.

As described in Sections 2.4.2, 2.4.3, and 8.2.4 such technologies, including but not limited to power-to-gas, cellulosic biogas, natural gas heat pumps, end-use appliance combined heat and power, and end-use appliance carbon capture, may have a significant impact on energy use patterns and GHG emissions. During FEI's 2017 LTGRP RPAG and Community Engagement workshops, stakeholders considered and supported FEI monitoring and, where appropriate, supporting such technologies.

Appendix A

REGIONAL MARKET OVERVIEW

APPENDIX A: REGIONAL MARKET OVERVIEW

1.1 INTRODUCTION

Regional resources in the Pacific Northwest that are currently available are fully utilized to meet existing customer demand in the region during normal and colder than normal winters. However, demand for natural gas is expected to increase in the near future within both FEI's natural gas service areas and the PNW, which could impact supply and demand dynamics. For instance, the addition of new load will require further transportation capacity to be constructed so that demand in the Lower Mainland and the US I-5 corridor can be served reliably. Additionally, the significant supply potential in Northeast BC (NEBC) has prompted the development of infrastructure initiatives to provide greater access to existing and new markets. With increasing demand from industrial, power generation and oil sands demand, and the need to replace supply declines elsewhere within Alberta, TransCanada PipeLines Limited (TransCanada) continues to bring forward plans to expand into NEBC to access the significant resource that is located there.

FEI is actively involved in National Energy Board (NEB) proceedings that potentially affect FEI's access to supply and is involved in developing solutions with regional stakeholders to help ensure issues related to third party pipeline infrastructure are resolved fairly. These activities are important because they help to ensure that customers in BC will continue to have reliable access to gas supply at fair market prices.

As a basis for the discussion in this appendix, Figure A-1 provides an overview map of existing pipeline systems in BC, Alberta and the US PNW.

Figure A-1: Overview map of the Western Canadian and US PNW region

1.2 THE IMPORTANCE OF NEBC SUPPLY

Improvements in production technologies that have unlocked the potential of shale and tight gas resources have transformed the North American natural gas supply picture. In BC, the natural gas potential is second only to the Marcellus shale gas play that is being developed in the northeast region of United States. A recent joint study conducted by the NEB, Yukon Geological Survey, the Northwest Territories Geological Survey and the British Columbia Ministry of Natural Gas Development reported the estimated total potential of marketable gas in the Western Canadian Sedimentary Basin (WCSB) (discovered and undiscovered) is now 1,051 Tcf.[1] The 1,051 Tcf estimation is 230 Tcf higher than the NEB's previous estimate in 2013 of 821 Tcf.[2] Taking into consideration that annual natural gas demand in Canada is approximately 3.5 Tcf, the WCSB resource represents the equivalent of approximately 300 years of supply at the current consumption level.[3] The Montney formation in BC alone represents 271 Tcf of potential marketable natural gas.[4]

As a result of the size of this resource and its attractive production economics, production of natural gas from basins located in NEBC has the potential to grow significantly in the coming years. This supply will be able to support existing markets in BC, as well as support potentially new markets (LNG and methanol exports) and meet growing industrial demand in Alberta, specifically from continued oil sands growth. However, the impact of these developments for FEI customers remains difficult to foresee with any accuracy because the quantity and timing of additional market demand and new matching transportation capacity remains uncertain.

The prospect of new markets for production has not developed as quickly as many producers active in the WSCB had hoped. Environmental and regulatory review and approval requirements have slowed the development of new markets for this gas. Also, the crash in commodity prices in 2014 has eroded the economic attractiveness of much of the LNG export development considered for NEBC. Producers have been able to manage through this period by focusing on further production efficiencies. However, continued production efficiency improvement is increasingly difficult to realize.

Compounding this challenge over the past few years has been the steady displacement of traditional eastern Canadian and US markets for natural gas produced in the WCSB by production in other more competitive basins. This decline is driven primarily by the development of shale gas basins, in particular the Marcellus shale gas play, that are located

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1 Appendix D-2: https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/ltmtptntlbcnwtkn2016/index-eng.html.

2 Appendix D-3: https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/ltmtptntlmntnyfrmtn2013/ltmtptntlmntnyfrmtn2013-eng.pdf.

3 Appendix D-30: https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/2016-2018ntrlgsdlvrblty/ntrlgsdlvrblty20162018-eng.pdf.

4 Appendix D-3: https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/ltmtptntlmntnyfrmtn2013/ltmtptntlmntnyfrmtn2013-eng.pdf. Note: the Montney formation geographically straddles the border between BC and Alberta. The total ultimate potential for the full Montney formation is 449 Tcf.

much closer to key consuming markets in eastern North America. These developments, combined with a producer push to develop new supply in anticipation of new markets, have reduced commodity prices over the past few years; prices are forecast to remain at the current low level in the near future.

Gas producers in Western Canada who need reasonable certainty that new markets will materialize in order to continue to develop new supply given current commodity pricing levels, now face an uncertain market environment. While increased industrial, power generation, and oil sands demand will help to offset reduced demand from traditional markets, significant new markets are required in order to fully develop the potential of the WCSB, including the new supply basins located in NEBC.

1.2.1 The Configuration of Regional Infrastructure

FEI is required to serve several major regional demand centres in BC that are largely isolated from each other by considerable distances and spread across a large, varied geographical footprint. Serving customers across this diverse geography and balancing daily system loads requires interconnection with third party pipelines and access to a flexible mix of supply, storage, and transportation resources.

As a matter of additional complexity, BC's geography, its location relative to supply basins, and its winter seasonal market, has limited transportation infrastructure available that connects the BC marketplace to sources of supply. As a consequence, the BC market is extremely reliant on supply originating in production basins located in NEBC. Approximately 75 percent of FEI's current supply is sourced in BC and transported to FEI's service area via Westcoast Energy Inc.'s (Westcoast) T-North and T-South pipeline systems. This reliance on NEBC supply is unlikely to change significantly in the short to medium term given that only limited pipeline capacity exists to connect supply from Alberta and for redelivery from market area storage located in the US PNW.

In response to the potential increase in demand in Alberta and the slower than expected development of LNG exports off the BC coast, attention has increasingly turned to expanding pipeline connectivity from supply basins located in NEBC to Alberta. The majority of recent pipeline expansions to the AECO/NIT market, such as the Groundbirch Mainline and Towerbirch lateral pipelines by TransCanada's Nova Gas Transmission Ltd. (NGTL) system, now provide BC producers with the option to flow increased supply directly to the AECO/NIT marketplace, bypassing the Westcoast T-North system. Future facilities additions in NEBC contemplated by TransCanada for its NGTL system will accelerate this trend. Gas production from smaller plants in the Montney region has displaced traditional supply from the Fort Nelson and Pine River Plants. A number of the future NGTL system expansions are planned in the Montney region, and could shift the proportion of gas flowing through Station 2, given the attractiveness to producers of direct access to the AECO/NIT marketplace. This development would have a significant impact on markets reliant on the Westcoast systems, such as those served by FEI.

Notwithstanding this development, it is possible for gas produced in BC to flow onto the NGTL system into Alberta and then flow back into BC. The infrastructure connections with Westcoast's T-North system at Groundbirch and Gordondale could permit flow from NGTL onto Westcoast's system. However, this requires the addition of facilities on the NGTL system. Such additions would result in increased costs to access this gas since shippers would have to pay the AECO/NIT price plus both the NGTL system delivery toll and the Westcoast T-North toll to deliver gas to Station 2. T-North tolls would also increase as a result of facilities additions that would be required to increase capacity in order to accommodate any significant increase in flows on T-North to Station 2 from the Groundbirch/Gordondale area on the NGTL system.

1.2.2 US Production Impact on The Regional Market

The significant shale gas potential in North America and the improvements in drilling technology have provided North America with an abundant supply of low cost natural gas. This ability to maintain production even with a relatively low commodity price has resulted in supply outpacing demand across most regions in North America.

The WCSB faces a particular challenge in this environment because US shale production is taking place very close to the WCSB's traditional markets in eastern North America, which has caused a significant portion of these markets to contract with this new supply source. Unless additional demand develops to match the growth in supply, prices will likely remain low for the near future and the ability of producers to survive in this environment becomes more uncertain.

1.2.3 Implications for FEI

The ability to maintain production in an environment facing sustained low commodity prices, and where considerable uncertainty exists about the timing of when new demand may materialize and new infrastructure is constructed, are the primary reasons for FEI to believe that it is critical to monitor and actively participate in developments affecting the BC and regional gas marketplace. This activity includes monitoring the development of major regional infrastructure and pipeline systems, the emergence of new markets and sources of gas supply, the emergence of new regional regulatory issues, and the evaluation of major new infrastructure requirements within FEI's own systems.

FEI's involvement in these developments allows it to identify when the gas supply portfolio strategy needs to be altered by, for example, adjusting the use and mix of counterparties, pricing strategies or fundamentally altering transportation and storage arrangements. These activities are critical to helping ensure that FEI remains effective in providing reliable gas supply to customers so that it is able to continue to meet the security of supply, diversity, and cost minimization objectives of the gas supply portfolio.

1.3 NEBC DEVELOPMENTS

Developing new supply in the Montney basin has increasingly been the primary focus of producers active in the WCSB since new production technology made shale gas development economically attractive over the past decade. Within the WCSB, sub-plays in the Montney formation in BC have among the most attractive production economics in North America. As a result, development interest is concentrated in a small geographical area with market access provided primarily by Westcoast's T-North system and to a lesser extent by Alliance Pipeline and by the NGTL system.

Over the past decade, NGTL proposed to construct a number of extensions of its system into the North Montney region in BC, offering direct access to the large and very liquid AECO/NIT market. These facilities extensions by NGTL have been contentious, with interveners, including FEI, taking the position that the proposed tolling of these facilities places too little cost accountability on the shippers requesting the facilities and that this tolling creates incentives for shippers to bypass Westcoast's T-North system entirely. Any bypass of the Westcoast system raises a concern about the future liquidity of the Station 2 market and the ability of participants in that market to bid on the physical gas molecule.

1.3.1 BC LNG Export Projects

Since 2010, over twenty different LNG export projects have been announced, proposing liquefaction terminals located on the coast of BC, as well as large diameter pipelines to transport natural gas from production basins in NEBC. The main driver of these projects had been the desire to take advantage of the historically lower North American natural gas prices compared to Asian natural gas prices. Asian markets were also attracted by the desire to diversify their sources of supply and by the political stability and mature market structure for accessing natural gas that Canada offers.

With the collapse in oil prices in 2014, global oil-indexed LNG prices declined, undermining the economic viability of these projects. Environmental and regulatory hurdles have also contributed to hampering the development of many of the proposed major projects. A number of smaller projects, and one major project by PETRONAS of Malaysia, have been cancelled. As a result, the remaining projects face an uncertain future. A potential need, however, to build new liquefaction capacity by 2023 offers hope that some of these projects may be sanctioned to proceed in the next year or two.

Although the economic, regulatory and environmental hurdles are significant, smaller scale projects, such as the Woodfibre LNG Project, continue to be active with their development plans and could emerge as frontrunners to become one of the first terminals to export LNG from BC.

The prospect of several major LNG export terminals located on the coast of BC prompted considerable producer activity in the liquids-rich North Montney basin. This activity was undertaken to prove the existence of sufficient supply to serve several major potential projects. When it became more likely that the LNG export projects faced delay following the 2014 price collapse, producers were forced to consider other markets, such as Station 2, served by Westcoast, and AECO/NIT, served by NGTL. Both pipelines proposed and received approval to construct new pipeline infrastructure to move considerable additional supply to market.

1.3.2 The Westcoast System

Westcoast is regulated by the NEB and is an affiliate of Enbridge Inc. The Westcoast T-North system transports natural gas produced in BC through its system to the interconnect with the Westcoast T-South system at Station 2 for transportation to markets located in BC and the PNW. It also transports supply east to the NGTL system at the Groundbirch and Gordondale interconnects to access the AECO/NIT marketplace and via a number of other pipelines to various markets in North America. FEI relies on the Westcoast systems to transport Station 2 supply to and from Aitken Creek Storage located in NEBC and to transport supply from Station 2 to the FEI system in the BC Interior, the Lower Mainland, and on Vancouver Island.

Prompted by producers seeking market access for significant additional supply, Westcoast received NEB approval over the last several years to construct the Jackfish Lake, High Pine, and Wyndwood expansion projects on the T-North system. These projects will provide additional capacity for deliveries to Station 2 and to the interconnect with the NGTL system at Groundbirch. These projects will be placed into service in 2017 and 2018. FEI supported these projects because of the additional supply that will be brought to or move through Station 2 even though they impact the T-North toll significantly.

Westcoast is planning to apply for NEB approval of a further project, Spruce Ridge that will also bring additional new supply to or through Station 2 for delivery to the NGTL system. If approved, this project is planned to be placed into service in 2019.

These Westcoast projects are important because they will help to ensure that the liquidity at Station 2 will be maintained, which is critical given FEI's reliance on this market hub for reliable, cost effective supply. FEI will continue to monitor developments relating to additional projects proposed by Westcoast in order to assess the potential impact they may create.

1.3.3 The NGTL System

The NGTL system is regulated by the NEB and is an affiliate of TransCanada Pipelines Limited. The NGTL system transports natural gas produced in British Columbia and Alberta through its system to the AECO/NIT marketplace and via a number of other pipelines to various markets in North America. FEI relies on TransCanada's NGTL and FoothillsBC systems to transport AECO/NIT gas supply to and from storage locations in Alberta and to transport gas supply from Alberta to the FEI system where they interconnect in the southeast of BC.

The favourable production economics and size of the resource located in the Montney basin, but limited infrastructure in NEBC to bring it to market, prompted producers to seek direct access to the NGTL system. In response, NGTL has proposed a number of extensions of its system into NEBC since 2009. Three extensions were approved by the NEB and constructed:

the Groundbirch Mainline, the Horn River Mainline, and most recently, the Towerbirch lateral. Other significant extensions that were required to support the development of LNG export projects were given conditional approval but are unlikely to be constructed as planned following the recent cancellation of the Northwest LNG project by PETRONAS.

TransCanada is directly involved in the proposed development of BC regulated pipelines that are planned to transport natural gas to a number of LNG export facilities which are proposed to be located on the northwest coast of BC. Gas supply is planned to be transported from NEBC and from the AECO/NIT market via extensions of the NGTL system. Much or all of this additional supply will be produced in plants that will not be connected to the Westcoast T-North system and bypass it entirely. These developments are important for FEI because they could impact FEI's access to secure and reliable natural gas supplies in the future at fair market prices in BC.

NGTL is expected to continue to initiate plans to provide additional transportation capacity to move production from NEBC into Alberta. FEI will continue to monitor developments relating to such projects in order to assess the potential impact they may create.

FEI's need to monitor such facilities developments is also important because past facilities proposed by NGTL in NEBC have been contentious. Interveners, including FEI, took the position that the proposed tolling of these facilities places too little cost accountability on the shippers requesting the facilities and that this tolling creates incentives for shippers to bypass Westcoast's T-North system entirely.

NGTL's recent filing of its North Montney Variance Application is another example of a project that is likely to be contested on the same grounds as other NGTL projects proposed for NEBC. This project proposes to alter the North Montney Project, for which NGTL received conditional approval, by changing its intended purpose and changing the facilities to be built. Instead of using the facilities to support a major LNG export project, they are now planned to be used to bring additional supply to the AECO/NIT market. NGTL however, proposes to retain the tolling conditions the NEB ordered when it provided the original approval for the North Montney Project. Those conditions require NGTL to seek approval of a new tolling methodology for the facilities. If NGTL does not receive such approval, standalone tolling will apply. FEI has an interest in ensuring that the original tolling conditions ordered by the NEB are maintained and addressed.

Given the contentiousness of these NGTL facilities applications, the NEB is separately considering a potential inquiry into the appropriate tolling treatment for facilities proposed by federally regulated pipelines in NEBC and matters relating to competition for the development of gas infrastructure in the area. These issues are too broad in scope to be addressed in individual facilities applications. FEI is expected to be a participant in the process if the NEB orders an inquiry.

1.4 FEI SYSTEM DEVELOPMENTS

FEI continues to explore further developing parts of its own system to accommodate the potential for increased demand from large industrial loads, such as LNG projects. Successfully serving such new loads would increase system throughput significantly on a daily basis and potentially have a net positive rate impact for existing customers. Current projects include the Woodfibre LNG Project located near Squamish and the expansion of the Tilbury LNG facility.

1.4.1 Woodfibre LNG Project

Woodfibre LNG Ltd. (WLNG), a subsidiary of Pacific Oil and Gas Limited of Singapore, is proposing to construct and operate an LNG export facility (estimated to cost about $1.6 billion) at the former Woodfibre Pulp Mill site located near Squamish. As part of its plans, WLNG has requested natural gas transportation (NGT) service from FEI so that it can access gas supply for its plant.

Figure A-2: Woodfibre LNG Project Location on FEI's Transmission System

To meet WLNG's NGT service requirement for the Woodfibre LNG Project, FEI will need to expand its existing system, which includes adding new pipeline looping and compression. In order to support WLNG's timeline, FEI must have the pipeline expansion completed and in-service before WLNG's LNG plant becomes commercially operational. WLNG will need to formally authorize FEI to commence work on the pipeline before any construction can begin.

1.4.2 Tilbury LNG Expansion

FEI is currently expanding the Tilbury LNG facility to include a 1 Bcf/d LNG storage tank with 32 MMcf/d (35 TJ/day) of liquefaction. This expansion will provide LNG primarily for the transportation market sector and is expected to enter service at the end of 2017.

An evolving market for LNG from Tilbury could come from the shipping industry, which will be required to reduce sulfur and nitrous oxide particle emissions from the use of heavy fuel oils globally starting in 2020. This requirement could result in more companies moving to cleaner fuels such as LNG or methanol for new vessels and converting some existing ships to these fuels.

The port location of the Tilbury facility, combined with the availability of existing pipeline infrastructure to transport gas supply for liquefaction, provides customers with a significant benefit and long term access to LNG. In addition, the Tilbury location has the potential to further expand over time to meet the needs of projects that are suitably sized for development in the Lower Mainland. Pipeline capacity expansions on both FEI's system and upstream will be required so that gas can be sourced from market hubs to support such projects in the Lower Mainland. Such pipeline infrastructure growth options are discussed in this appendix in Section 1.5 below.

1.5 BC PIPELINE EXPANSION OPTIONS

The construction of any of the infrastructure projects discussed above will impact the amount of gas flow into the BC and PNW region. Although it is unlikely that all announced projects will proceed, it is very likely some will come to full development over the course of the next few years. Even this level of development will have a significant impact on the region with respect to the volume of gas supply flowing, pipeline capacity utilization and possibly gas pricing. The volume of daily baseload gas required for each of the projects is significant when compared to the amount of gas that currently flows into the region and the design capacity of existing regional pipeline systems. The existing regional pipeline capacity is constrained already during key periods in the winter months in order to meet the current requirements of customers in the Lower Mainland and the US I-5 corridor.

The PNW region, including British Columbia, has historically been a winter seasonal market and the regional resources consisting of pipeline capacity and storage have been developed to meet this seasonal demand rather than high load factor baseload demand. Regional pipeline capacity is used to meet loads in the summer while, in the winter, both pipeline capacity and storage resources are generally required to fully serve demand. Regional pipeline capacity is utilized at a high level or near capacity for a large proportion of the winter. Even two or three of the above named projects in full or partial scope will require significant incremental regional pipeline capacity in order to serve the combined needs of existing and new customers.

The greatest impact of any future capacity constraints will affect existing industrial-type customers who are responsible for purchasing their own supply directly or through a marketer.

Today, these customers purchase gas at the Station 2 market for delivery to the Huntingdon-Sumas area using available excess pipeline capacity on the T-South system. This approach has been followed over the course of the last decade as the firm capacity on the T-South system from Station 2 to the Huntingdon-Sumas marketplace had not been fully contracted, which led to the availability of large gas volumes to flow on interruptible capacity. Continuing with this approach for purchasing gas is likely to become less certain when new demand comes online since all available capacity on T-South has now been fully contracted by shippers. This lack of available firm transportation capacity in the region is driving the evaluation of regional solutions that would bring incremental gas supply to the Lower Mainland and Huntingdon-Sumas marketplace.

1.5.1 Westcoast System

Since the vast majority of FEI's supply is transported on Westcoast's T-North and T-South systems, it is important for these systems to remain competitive and provide supply for the existing marketplace, while evaluating opportunities for growth. Proponents of new regional projects will require access to large volumes of baseload gas supply. The supply for these potential projects is expected to flow largely on Westcoast's T-North and T-South systems, especially if the projects are located in southern BC or even parts of the US PNW.

Therefore, the Westcoast T-South system will require staged expansions over the next several years to accommodate new industrial demand. From a capital expenditure point of view, capacity expansions of any type would require long term commitments from creditworthy shippers. Project proponents that request system expansions will be required to provide security and backstop the capital costs during the development stages of new capital intensive expansions.

Westcoast announced an open season on April 25, 2017 for a relatively minor expansion to increase capacity on T-South between Station 2 and Huntingdon to gauge shipper interest for firm commitments. This resulted in shippers signing very long term contracts for the entire 190 MMcf/d of volume that was offered in the open season. The incremental capacity is expected to be in service in late 2020. It is FEI's understanding that any new Westcoast expansions in addition to the 2020 in-service capacity may only be viable if the nature of the expansions results in a major increase in capacity on the T-South system. Such expansions may only be economically viable if they are supported by major new loads in the Lower Mainland and PNW region. A major expansion on Westcoast's T-South system is estimated to require a minimum of five years to complete after an open season is successfully concluded.

1.5.2 Kingsvale-Oliver Reinforcement Project (KORP)

FEI continues to look at KORP as a regional solution that could be developed as an alternative to a major expansion on Westcoast's T-South system in order to provide the PNW with pipeline diversity and improved security of gas supply. This bi-directional pipeline can also provide BC producers with access to markets, by connecting northern BC supply basins to markets in PNW, California and Nevada via deliveries to Kingsgate for flow on TransCanada's Gas Transmission Northwest (GTN) pipeline system.

KORP consists primarily of a 161 km, 24-inch or greater diameter pipeline expansion from Oliver to Kingsvale, BC on FEI's existing interior system. KORP would be able to deliver additional gas supply to meet the needs of projects that are suited for the Lower Mainland region. A collaborative tolling structure could provide shippers with a viable solution when regional pipeline infrastructure developments are being assessed.

Recently, there has been renewed interest from producers and large end-use shippers to contract for pipeline capacity in order to move gas to markets such as Huntingdon-Sumas on a firm basis. This phenomenon has not been seen since the early 2000s when producers started to decontract their firm pipeline capacity on the T-South system and avoid demand charges while focussing their attention to move gas to the more liquid AECO/NIT marketplace. However, the oversupply of gas around North America has prompted producers to compete for market share that was readily available to them prior to the emergence of large scale prolific shale gas basins.

The construction of the KORP system would help to strengthen regional pipeline infrastructure and also provide pricing diversity and improve the security of supply for projects needing baseload gas supply. This project provides the region with a viable alternative and add 300-400 MMcf/d of new pipeline capacity for projects that could be situated in the Lower Mainland. FEI will continue to monitor developments in the region and work with parties to help develop infrastructure solutions that will effectively meet the needs of the region.

1.6 US PACIFIC NORTHWEST INFRASTRUCTURE UPDATE

In response to potential new industrial demand, several potential major pipeline and infrastructure projects are being considered for construction in the US PNW. These projects could impact gas flows and pricing dynamics within the region if some or all projects are constructed over time.

1.6.1 Northwest Innovation Works Methanol Projects

Northwest Innovation Works (NWIW) is proposing to construct a methanol production plant in Kalama, Washington hat will use natural gas to produce methanol. NWIW is in the final stages of garnering full permitting needed to declare a positive final investment decision for a USD$ 1.8 billion plant south of Tacoma, in the Port of Kalama.

The multiple trains planned for each methanol plant would require anywhere from 125 MMcf/d to 150 MMcf/d of gas supply per train depending upon the size of the production trains and whether or not there is a requirement for gas to be used for electricity generation. Based on the current regional pipeline infrastructure, it is expected that a significant portion of gas supply for the Kalama plant will primarily be met via the Westcoast T-South system in addition to sourcing gas from other regional hubs via the Northwest Pipeline (NWP) system.

If the Kalama plant becomes operational and if NWIW evaluates the potential of building other plants in the vicinity of the Kalama plant, the regional pipeline infrastructure will need to be expanded. Depending upon the location of additional plants, pipeline expansion options include routes that access gas from BC, Alberta and the Rockies supply basins or some combination thereof (discussed in Section 1.1.6.2 in this appendix).

Figure A-3: NWIW's Port of Kalama Project Location

1.6.2 Potential Regional US Pipeline Expansion Options

Other pipeline expansion projects that have been assessed in the past and have the potential to be developed in the US PNW region if large scale industrial demand materializes include:

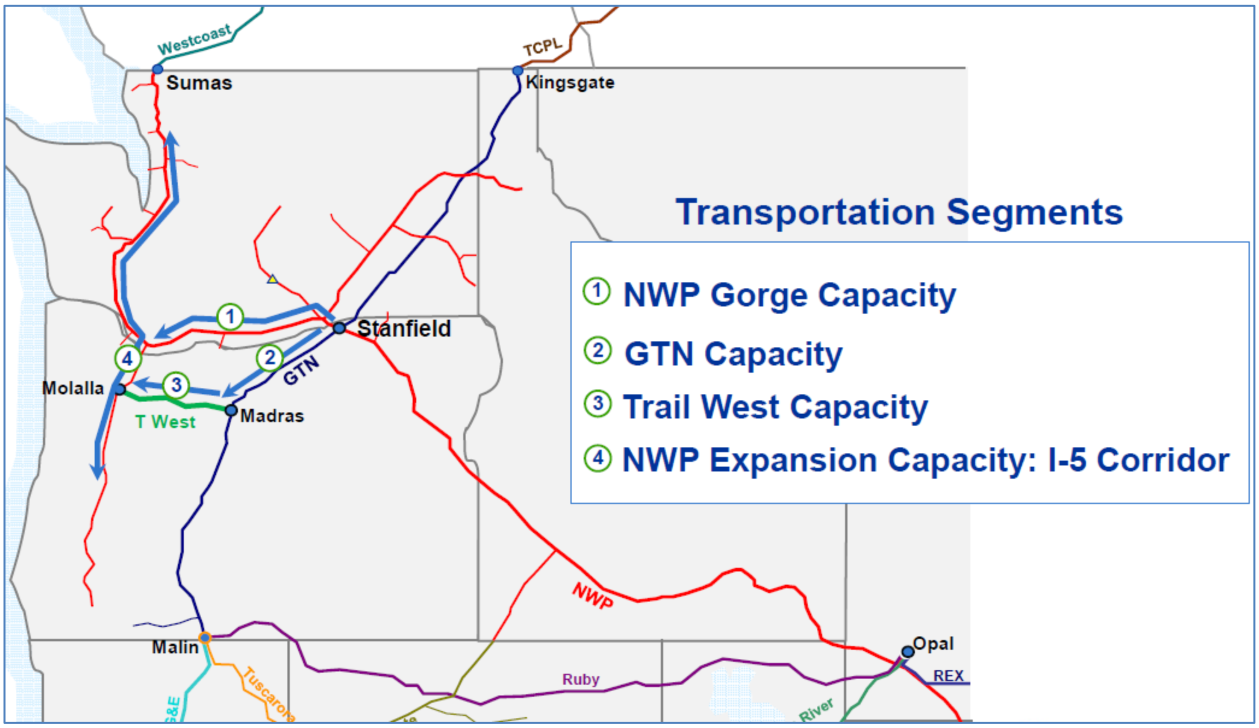
i) The Trail West expansion proposed by Northwest Natural Gas Company would receive gas from TransCanada's GTN system for delivery to the Molalla area on the NWP system. This expansion could enable NWP to expand its system from the Molalla area to flow gas northbound.

ii) Expand the NWP Gorge capacity on the NWP system that will expand the system westbound from Stanfield. This would allow gas to flow north into the Seattle and Tacoma region.

iii) Expand the NWP system from Sumas south on the I-5 corridor to Woodland, Washington. The project plan included 140 miles of 36-inch diameter pipe to be constructed in ten different segments around NWP's existing right-of-way along the I-5 corridor in Washington State between Sumas and Woodland. This project would access gas from the Sumas marketplace.

Figure A-4 below illustrates the potential pipeline expansions that could occur in the US PNW.

Figure A-4: Potential US PNW Pipeline Projects[5]



1.7 KEY CONCLUSIONS ON REGIONAL INFRASTRUCTURE

The pipeline capacity in BC and the PNW region is projected to be constrained over time if industrial projects that require additional gas supply are approved for construction. Meeting the needs of such projects that require daily baseload gas volume can only be fulfilled by adding new pipeline capacity rather than via other resources, such as storage. The development of new pipeline systems will only proceed if industrial project proponents are prepared to financially underpin any new pipeline expansion.

The system or systems that ultimately expand will depend on the locations of the potential future industrial projects. For example, projects that are developed in the Lower Mainland, such as a

[5] TransCanada Presentation (December 11 & 12, 2014). "GTN Collaboration Meeting, Phoenix, AZ".

staging of expansions at FEI's Tilbury location, will require gas supply to be accessed from the WCSB for delivery from Station 2 and/or the AECO/NIT market hub. This large scale increase of incremental gas supply will need to be complemented with expanding pipeline capacity either on Westcoast's T-South system or via a combination of both T-South pipeline and KORP expansion. A development of methanol plants or other large scale loads in the US PNW around the southern part of Washington or northern Oregon vicinity will require a solution such as a Trail West pipeline expansion. All these projects will require some level of expansions on adjoining pipeline systems that feed into each other. This is mainly due to the vast distances between the gas production regions and the location of the proposed industrial projects.

All parties will need to work collaboratively in order to develop solutions that serve the interest of everyone concerned at large, ranging from project developers, pipeline companies, gas producers, First Nations and local stakeholders, in order to ensure the successful advancement of large scale projects in BC and PNW marketplace.

Appendix B

ANNUAL ENERGY DEMAND FORECASTING

Appendix B-1

END-USE DEMAND FORECAST SCENARIO PARAMETERS

APPENDIX B-1: END-USE DEMAND FORECAST SCENARIO PARAMETERS

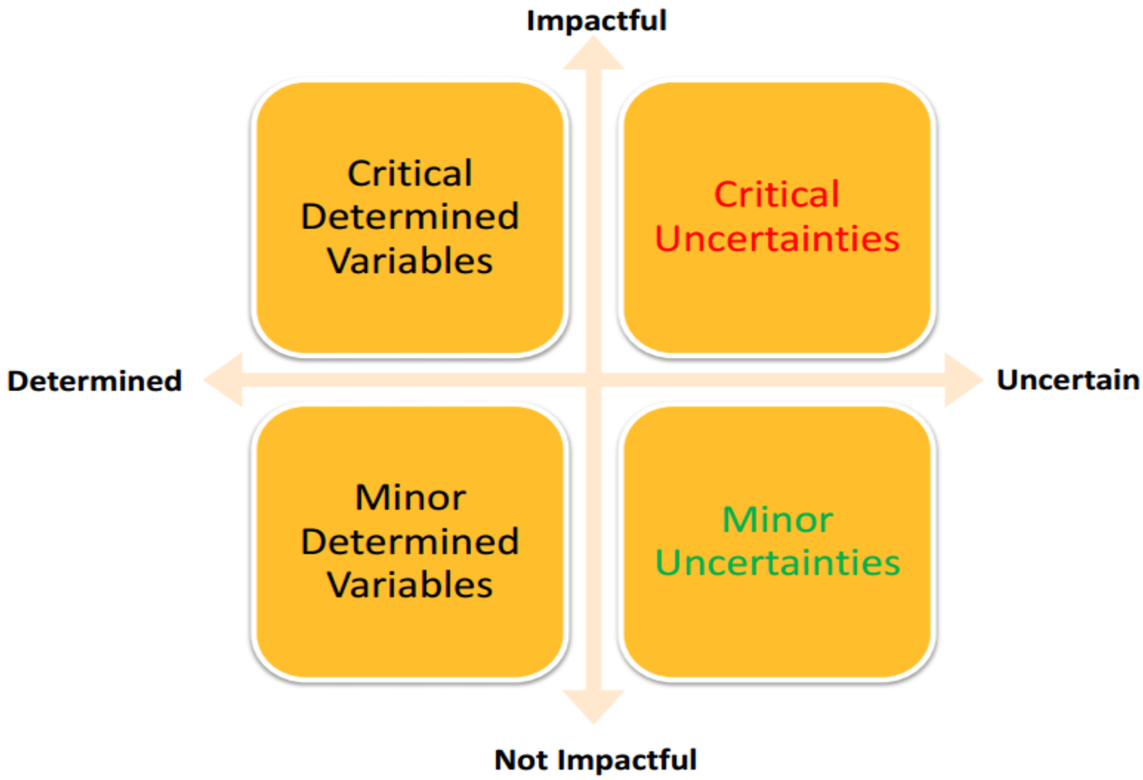
The Reference Case provides a baseline against which forecast demand under five different alternate future scenarios is examined. Since FEI's planning environment for energy services continues to change and present uncertainty, the five future scenarios are intended to provide insight into the impact on demand of a broader range of potential future conditions than has been examined in previous LTRPs. These five scenarios were developed based on critical uncertainties identified with input from the scenario analysis work for the 2014 LTRP, both internal FEI stakeholders and members of the external Resource Planning Advisory Group (RPAG), as well as themes that emerged from the 2017 LTGRP's community engagement workshops. The critical uncertainties represent those future conditions that stakeholders felt could have the biggest impact on FEI's business.

Following a standard scenario planning approach, FEI's scenario analysis proceeds in four steps:

1. Evaluating planning environment variables and identifying critical uncertainties;
2. Determining the number of outcomes and their broad qualitative boundaries for each selected critical uncertainty;
3. Determining plausible combinations of outcomes for each critical uncertainty and creating reasonable scenario plotlines; and
4. Populating quantitative data into the outcomes for each critical uncertainty and iterating with internal and external stakeholder feedback.

The first step in the above list intends to focus the scenario analysis by determining which of the manifold variables in the planning environment should be used to alter the Reference Case into various alternate future scenarios. This involves selecting the most impactful and most uncertain variables. Figure B1-1 below illustrates how FEI classified planning environment variables for this first step:

Figure B1-1: Classification of Planning Environment Variables



FEI intentionally held each step separate from the other steps. Selecting critical uncertainties first and then determining their qualitative boundaries before generating the plotlines and populating quantitative data guards against inadvertently favoring certain visions of the future over others by presupposing scenario results rather than focusing on inputs.

The following sections outline the qualitative boundaries of the outcomes of each critical uncertainty, illustrate the actual quantitative trajectories for these outcomes, and discuss how these trajectories impact the end-use forecast model.

1.1 Qualitative Details on Scenario Critical Uncertainties

Table B1-1 below summarizes the outcomes that FEI modelled for each critical uncertainty and briefly discusses any specific attributes that apply to individual critical uncertainties:

Table B1-1: Summary of Modelled Critical Uncertainty Trajectories

Critical Uncertainty	Modelled Trajectories	Comments
Economic Variables		
Economic Growth	- High - **Reference** - Low	Please see Section 1.2.1.1 in this appendix for an explanation of how FEI modelled economic growth assumptions.
Natural Gas Price	- High - **Reference** - Low	Multiple factors, such as regional demand patterns, natural gas extraction costs and policies that regulate natural gas extraction, influence natural gas prices. This critical uncertainty and its modelled trajectories intend to encompass the effect of such factors.
Policy Variables		
Carbon Price	- High increase - Medium increase - **Reference** - Low	N/A
Non-Price Carbon Policy Action	- Accelerated - **Reference** - Delayed	This critical uncertainty accounts for building codes (for newly constructed dwellings), appliance standards, and other effects and policy actions that may results in customers switching from natural gas to other end-use fuel types.

Critical Uncertainty	Modelled Trajectories	Comments
Extraneous Variables		
RNG Demand	- High - **Reference** - Low	The links between the core end-use forecast and the RNG annual demand forecast are qualitative only because RNG represents an emerging market. FEI provided the core end-use forecast scenario parameters to its RNG program team and requested this team to prepare three forecast trajectories (Reference Case, Low, High) based on these scenario parameters. FEI's RNG program team prepared the three forecast trajectories by modulating expectations about committed projects, projects under negotiation, and assumptions about plausible future capture rates. FEI's RNG program team also shaped the resulting RNG annual demand forecast trajectories to align with expectations about RNG supply availability at reasonable prices. FEI's forecast trajectories assume current RNG supply technologies.
CNG and LNG Demand for Vehicles	- High - **Base** - Low	Similar to the RNG forecast, the links between the core end-use forecast and the NGT annual demand forecast are qualitative only because NGT represents an emerging market. FEI provided the core end-use forecast scenario parameters to its NGT programs department and requested this department to prepare three forecast trajectories (Base, High, Low) based on these scenario parameters.

Critical Uncertainty	Modelled Trajectories	Comments
Large Industrial Point Loads	- **Reference** - Woodfibre example	Please see Section 3.4.9 in the Application for FEI's discussion of this critical uncertainty.

The following section discusses the detailed quantitative inputs of each critical uncertainty.

1.2 Quantitative Details of Scenario Critical Uncertainties

1.2.1 CRITICAL UNCERTAINTY INPUTS

1.2.1.1 Economic Growth

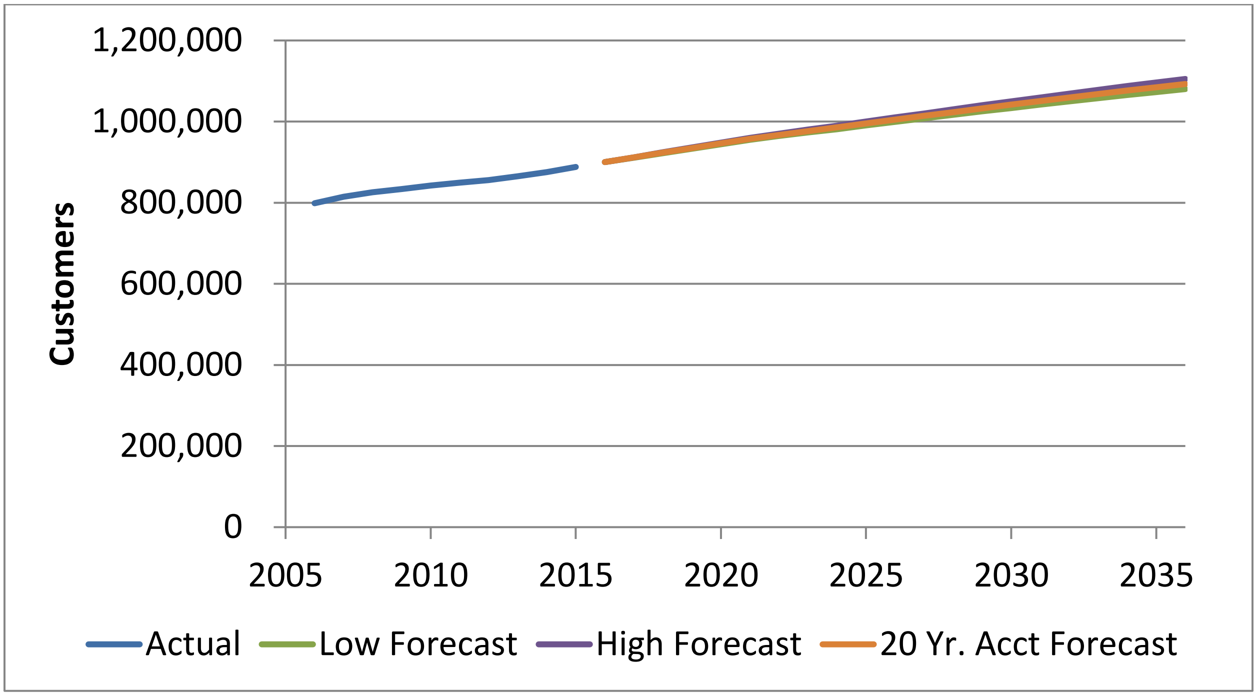
The 2017 LTGRP provides further analysis to simulate the impact of economic growth on customer counts. FEI relies on simulation because its research does not suggest sufficient correlation between Gross Domestic Product (GDP) and natural gas consumption or customer counts. Moreover, relying on third party GDP growth forecast ranges introduces an additional source of potential forecast errors.

As an alternative to any strong direct correlation between GDP growth and customer numbers/natural gas consumption, the 2017 LTGRP relies on a statistical approach using Prediction Intervals (PI). This approach applies FEI's historical variance in customers by rate schedule to FEI's Reference Case customer forecast. The 2017 LTGRP uses these PI to perturb the Reference Case customer forecast into respective High and Low customer forecast outcomes.

This statistical method serves as a proxy to model the potential impact of economic growth on customer numbers but may also account for other intrinsic factors, such as FEI marketing and promotional campaigns. Note that rate schedules with fewer customers experience a greater range between their High and Low outcomes than larger rate schedules.

Figures B1-2 to B1-6 illustrate the customer number trajectories for key rate schedules.

1 **Figure B1-2: Customer Forecast Parameters – Rate Schedule 1**



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3 **Figure B1-3: Customer Forecast Parameters – Rate Schedule 2**

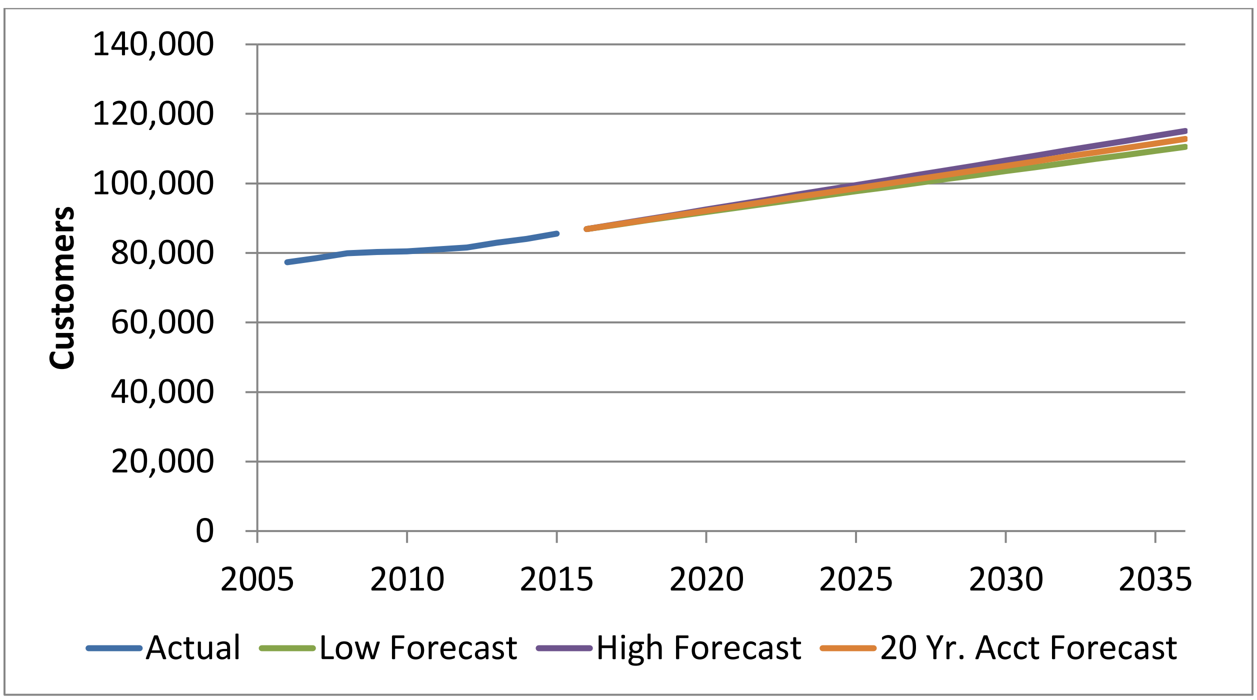

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Figure B1-4: Customer Forecast Parameters – Rate Schedule 3

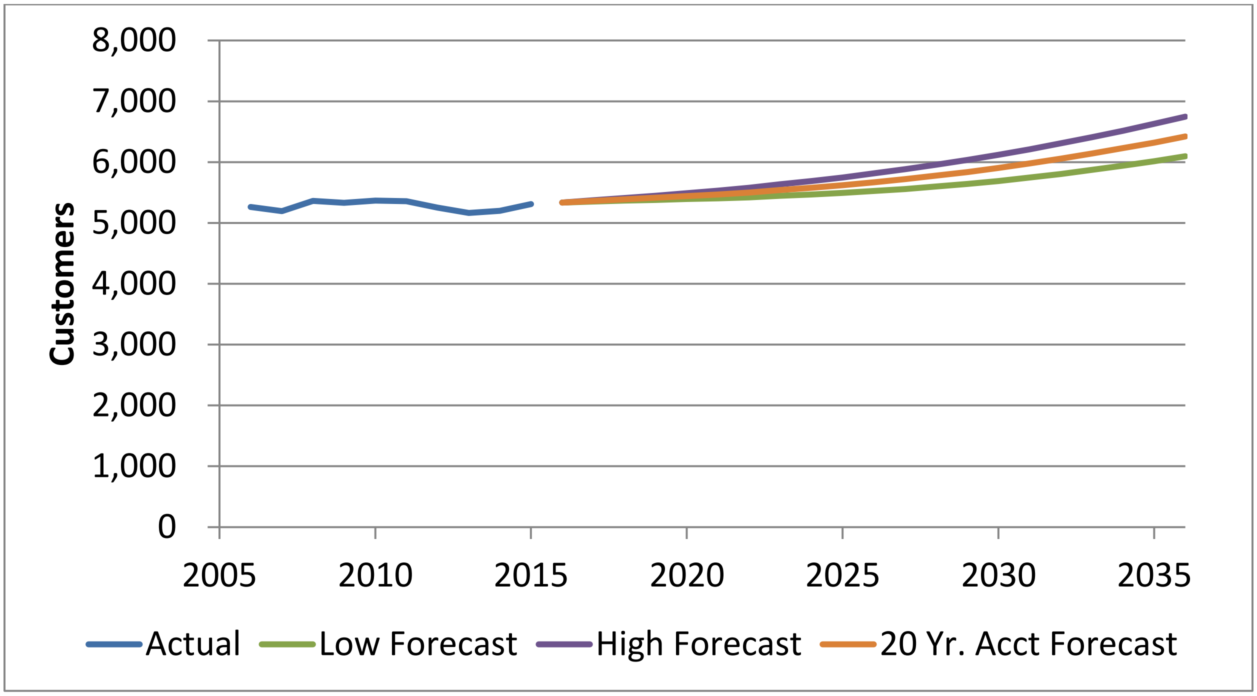


Figure B1-5: Customer Forecast Parameters – Rate Schedule 23

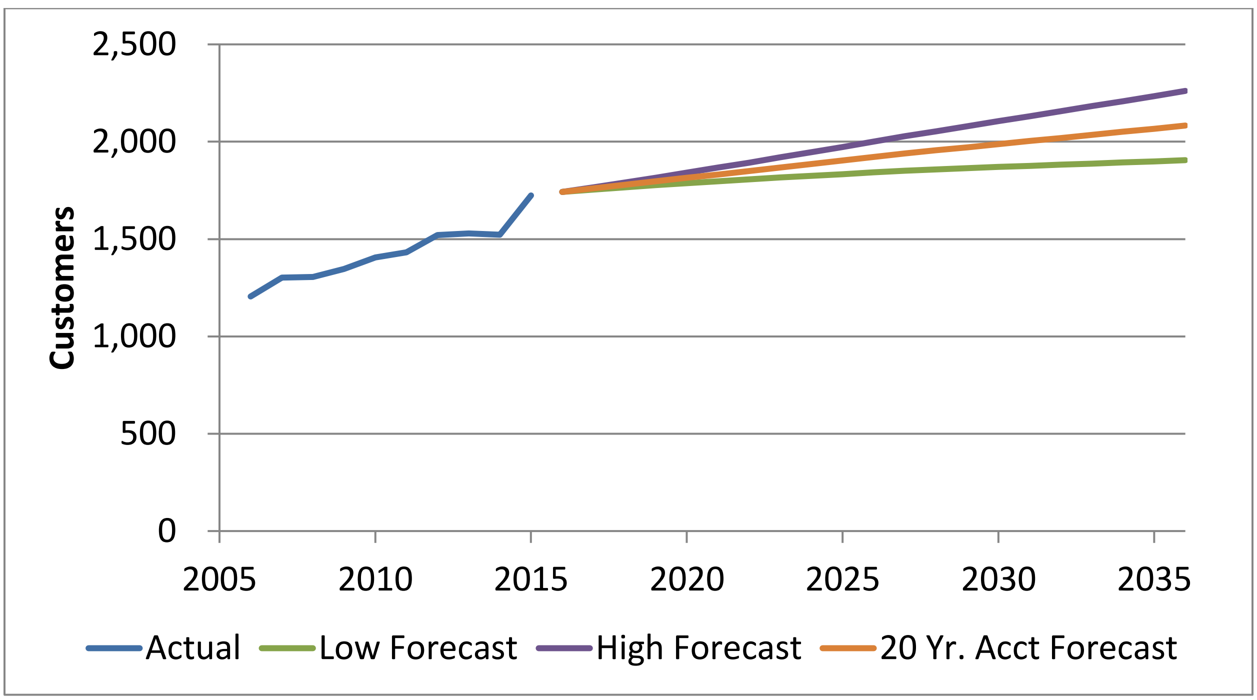
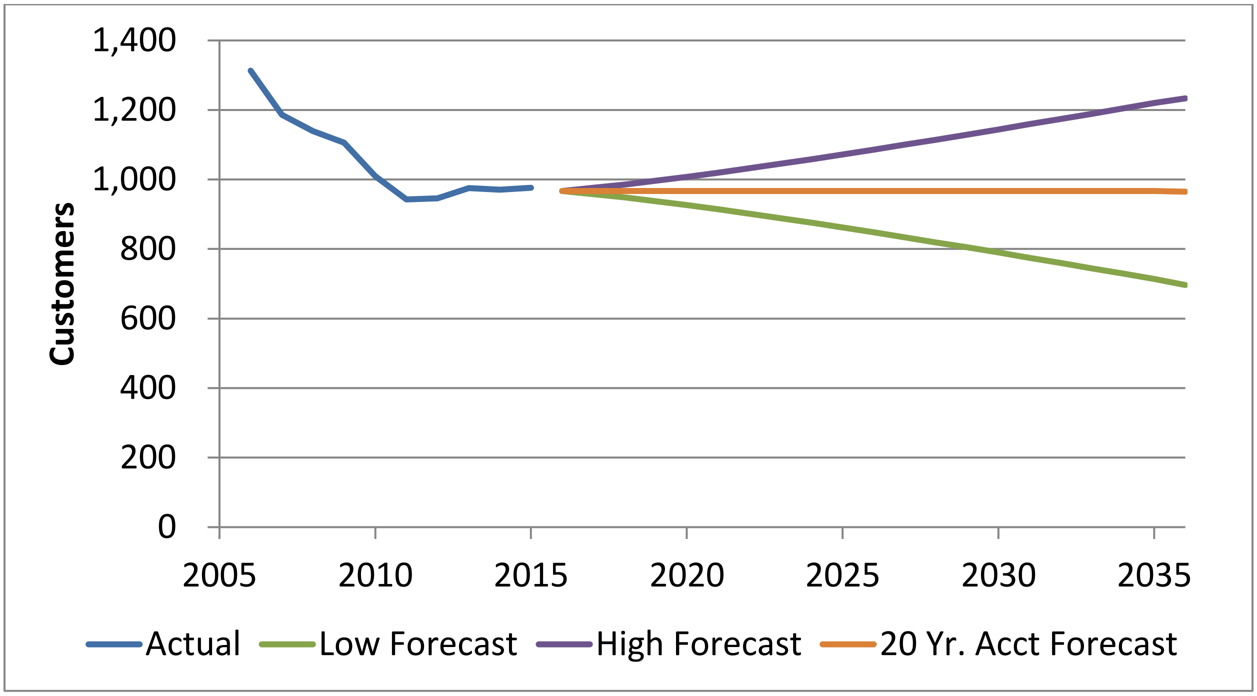


Figure B1-6: Customer Forecast Parameters – Industrial Rate Schedules



1.2.1.2 Natural Gas Price

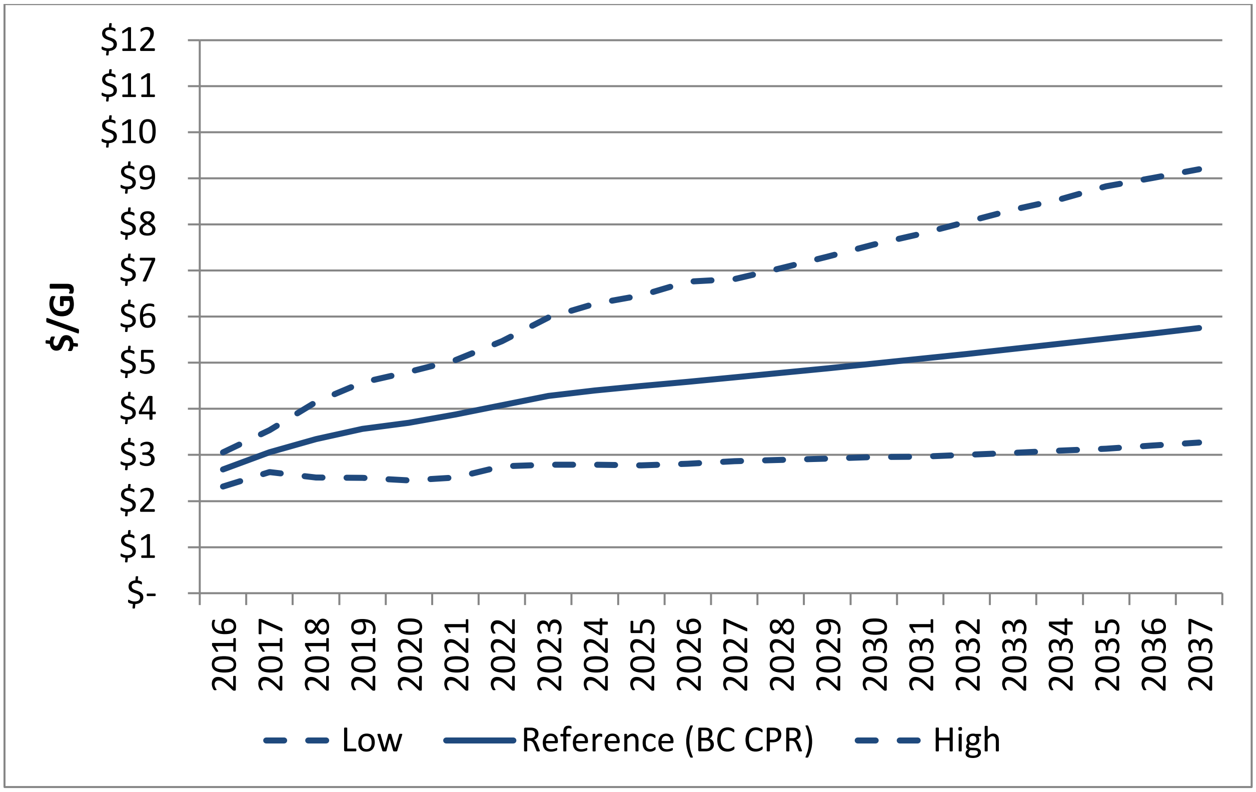
FEI relied on forecasts from multiple third party expert entities to prepare the 2017 LTGRP natural gas price forecast trajectories. The Reference Case natural gas price trajectory represents the same trajectory that FEI used for the BC CPR. FEI selected this trajectory for the 2017 LTRGP in order to facilitate the BC CPR results informing FEI's calibration of the 2017 LTGRP DSM analysis.

In its 2015 natural gas price forecast, Northwest Power and Conservation Council (NPCC) generates its own base, low, and high trajectories based on its expertise and consultation with a wide array of Pacific Northwest (PNW) experts. This forecast is bullish about the prospects of large scale LNG export terminals emerging in the PNW. FEI's BC CPR natural gas price forecast is less bullish about these prospects as it uses more recent input data.

The 2017 LTGRP applies the low-high range from the 2015 NPCC forecast to the BC CPR natural gas price forecast in order to generate LTGRP High and Low natural gas price outcomes. In doing so, FEI avoids having to average multiple third party forecast values to create High and Low natural gas price outcomes. This also enables FEI to take advantage of the newer input data in the BC CPR natural gas price forecast and to facilitate the BC CPR informing the 2017 LTGRP DSM analysis.

FEI validated the resulting natural gas price trajectories against a range of existing recent third party forecasts, including the International Energy Agency (IEA) and GLJ Petroleum Consultants Ltd. (GLJ). Figure B1-7 below displays the resulting Reference Case, High, and Low natural gas price trajectories. The range between High and Low serves as a proxy not only for price changes due to shifting demand-supply conditions but also potential policy actions that may impact the commodity price, such as upstream GHG reduction initiatives.

Figure B1-7: Sumas Natural Gas Price Forecast – Annual Prices



1.2.1.3 Carbon Price

FEI and FBC collaborated to develop their long term carbon pricing trajectories by consulting internal and external subject matter experts. The resulting carbon pricing trajectories take into account the Canadian federal carbon pricing backstop mechanism. The trajectories have been validated via the LTERP RPAG and have also received support from the LTGRP stakeholders (in the RPAG and FEI's community engagement workshops).

Figure B1-8 below displays the 2017 LTGRP's carbon pricing outcomes. These include one addition in relation to the 2016 LTERP. FEI added a Low trajectory at BC's 2016 carbon tax level since the possibility exists that BC's carbon price may remain constant at this level if BC's government does not increase it and if the Canadian federal carbon pricing backstop mechanism does not proceed or flounders during its interim review. The Low and Reference carbon price outcomes assume that prices will increase by inflation after 2022. This prevents the carbon prices in these outcomes from dropping back to or even below current levels in real terms by the end of the planning period. This carbon pricing range intends to account for considerable policy uncertainty in relation to BC provincial, Canadian federal, and wider North American developments (as discussed in Section 2 of the Application).[1]

Figure B1-8: Carbon Price Forecast – Per Metric Tonne

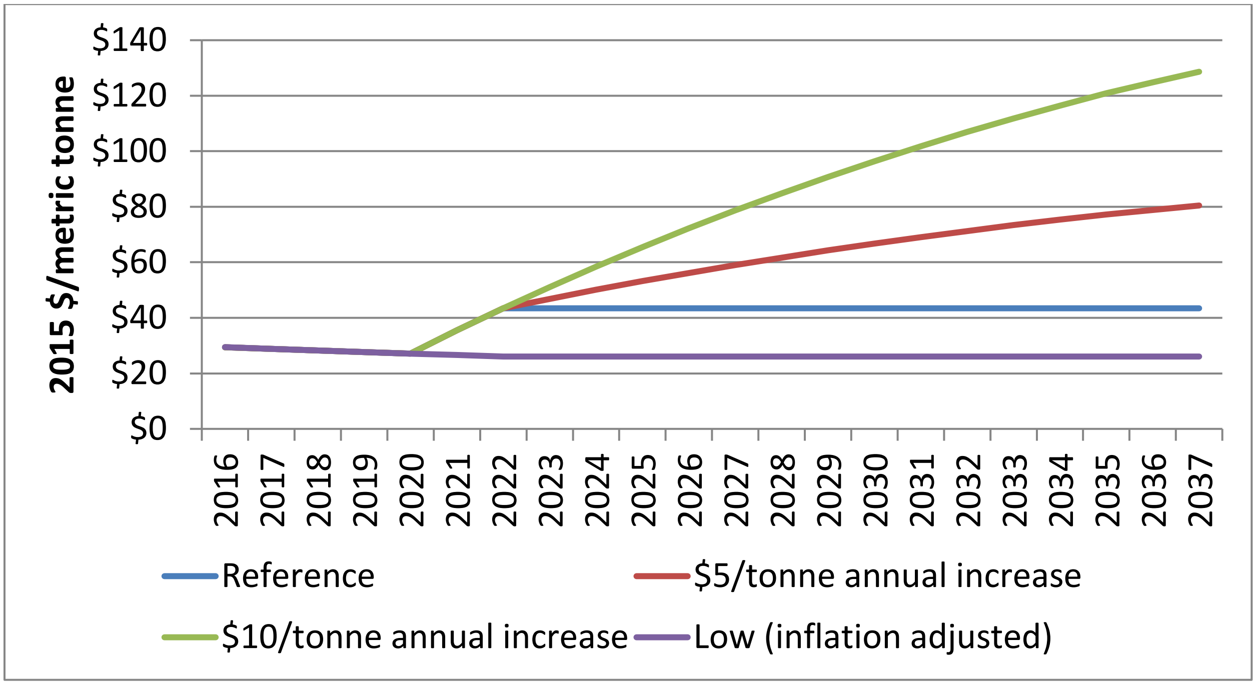
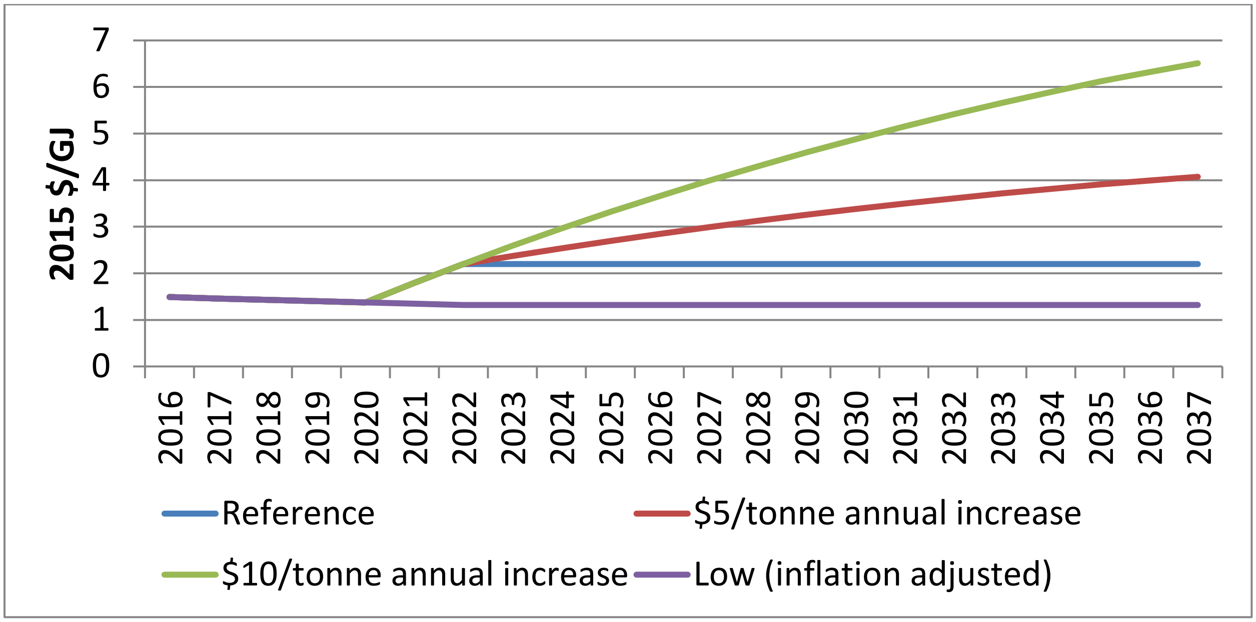


Figure B1-9 below illustrates that, in dollar per GJ terms, the carbon pricing critical uncertainty is significant when compared with the natural gas price critical uncertainty range in Figure B1-7 above. As such, carbon pricing represents considerable risk for annual demand across the planning period.

[1] The September 11, 2017, BC budget update proposes to increase the carbon tax by $5 per tonne per year for the next four years, beginning April 1, 2018, until the carbon tax rate is equal to $50 per tonne in 2021. If this increase is maintained each year, as proposed in the updated budget, the carbon tax will increase to $50 per tonne one year earlier than FEI's Reference Case carbon price assumption. The current BC budget does not provide any indication that increases to the carbon tax will continue to occur once the tax rate reaches $50 per tonne. Between 2018 and 2021, the BC budget update causes the proposed BC carbon price to be higher than FEI's Reference Case carbon price assumption. In the long run, however, the variance between FEI's Reference Case carbon price assumption and the information provided in the BC budget update is immaterial.

Figure B1-9: Carbon Price Forecast – Per GJ



1.2.1.4 Non-Price Carbon Policy Action

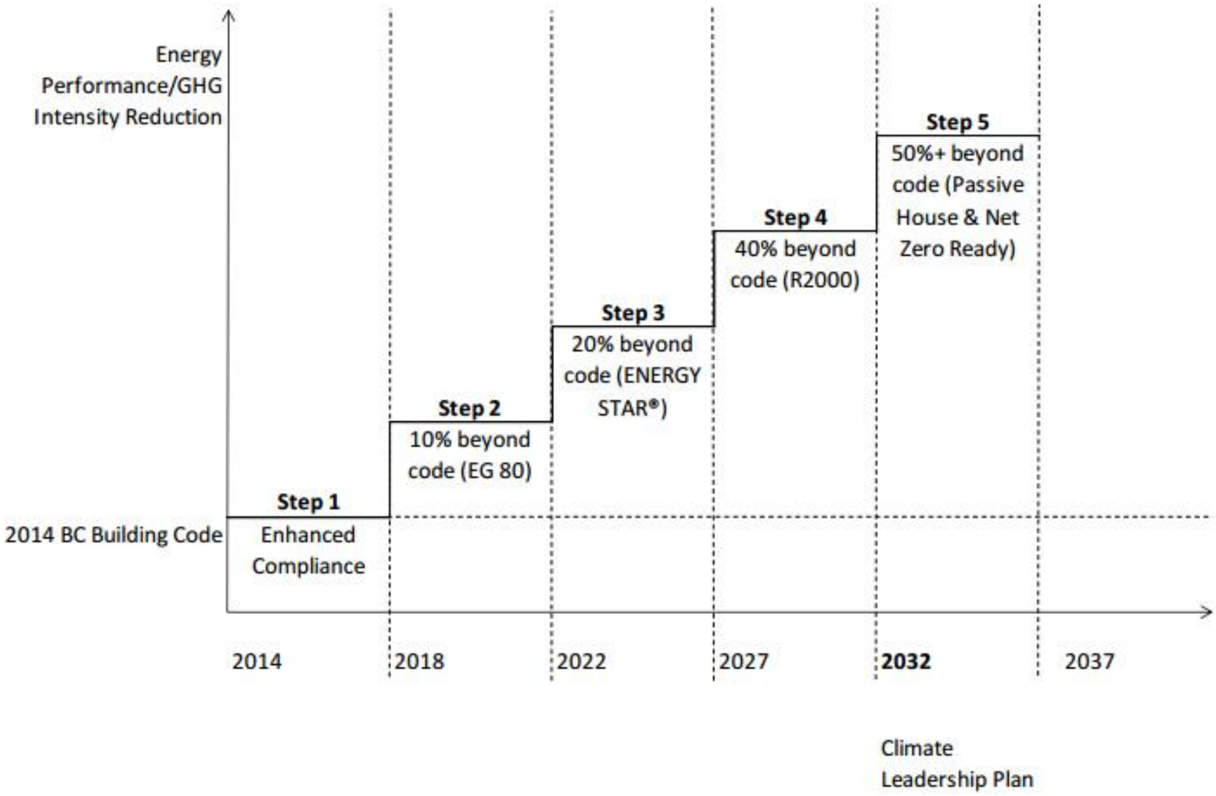
Non-price carbon policy accounts for the impact of building codes (for new construction), appliance standards (for retrofits in existing buildings or appliance installations during new construction), and any other undetermined effects or policy actions that may result in customers switching away from natural gas to another end-use fuel type.

1.2.1.4.1 <u>Building Codes</u>

The Reference Case, which is based on known, legally enshrined and mandatory requirements, assumes that the 2014 iteration of the BC Building Code (BCBC) will remain unchanged across the planning period. This is an important starting point against which to compare other outcomes on this critical uncertainty.

Nevertheless, BC has enacted the BC Energy Step Code and the provincial CLP declares a goal of net zero ready new construction for 2032. To account for the plausibility of future changes in the BCBC, the 2017 LTGRP progressively applies the voluntary and non-time bound steps from the BC Energy Step Code across relatively even time periods throughout the planning horizon in order to achieve the CLP's 2032 target. As such, 2017 LTGRP scenarios that are subject to the Accelerated outcome on the Non-Price Carbon Policy critical uncertainty, assume that the entire province moves along this step code ladder over time as the BCBC is updated. Figure B1-10 below illustrates this dynamic for a subset of dwellings:

Figure B1-10: Lower Mainland Single Family Dwellings – Accelerated Non-Price Carbon Policy Illustration



Similarly, the possibility exists that extraneous factors may hamper new building performance or introduction of enhanced building codes. To account for this, the 2017 LTGRP assumes that scenarios which are subject to the Delayed outcome on the Non-Price Carbon Policy critical uncertainty see new buildings performing at discounted rates in relation to the code-mandated level. Based on industry research of how well BC buildings actually perform in relation to mandatory new construction performance requirements, the 2017 LTGRP assumes such buildings to perform at 63 and 70 percent of mandated performance, respectively, for residential and commercial buildings.

1.2.1.4.2 Appliance Standards

The Reference Case assumes that currently mandatory or legally enshrined appliance standards continue across the entire planning period. The Reference Case also accounts for some natural change in average appliance efficiencies across the planning period, such as commercial domestic hot water tanks changing from 0.75 Thermal Efficiency (TE) to 0.80 TE as they are replaced.

Scenarios that are subject to the Accelerated outcome on the Non-Price Carbon Policy Action critical uncertainty include the following additional performance requirements for residential appliances:

- Minimum 50 percent Fireplace Efficiency (FE) starting in 2018;
- For boilers, minimum 90 percent Annual Fuel Utilization Efficiency (AFUE) in 2020 and 95 percent AFUE in 2025; and
- For furnaces, minimum 95 percent AFUE in 2020.

When the 2017 LTGRP performed its annual demand scenario analysis, Natural Resource Canada (NRCan) published preliminary information on its Amendment 15 with likely impacts for residential and commercial water heaters. Amendment 15 represents one of successive updates to Canada's national energy efficiency regulations which govern appliances that are sold in Canada across national or provincial boundaries. Despite consultation with external and FEI's internal experts, the performance details of these impacts remained unclear until the annual demand scenario analysis had reached its point of no return for including additional information. Sensitivity analysis of the above regulatory impacts on space heating on annual demand, suggest that any impact of NRCan Amendment 15 on water heating annual demand will be less than 1.2 percent by the end of the planning horizon.

1.2.1.4.3 Other Policy Actions that May Result in Fuel Switching

In the 2017 LTGRP, fuel switching occurs as function of price response (to natural gas cost or carbon price) but not as function of efficiency increases in new construction. For example, a home that is built to the ENERGY STAR® standard rather than current BCBC levels in the model, does not automatically switch from one fuel to another. This treatment of efficiency increases is consistent with how the BC CPR treats such increases.

To account for the impact of such effects and the effects of undetermined policy actions that may compel customers to switch from natural gas to another fuel type (e.g. Orders in Council 100 and 101, discussed in Section 2.3.3.5 of the 2017 LTGRP), the 2017 LTGRP scenario analysis includes a backstop mechanism that mandates minimum levels of fuel switching across the planning period for scenarios that are subject to the Accelerated outcome on the Non-Price Carbon Policy Action critical uncertainty. The backstop levels are based on updates of research conducted for the 2014 LTRP and, for the residential sector specifically, extrapolated fuel share change data from the BC CPR. The backstop levels break out as follows:

- Across the planning period, 15 percent of commercial buildings connect to district energy systems and are thus removed from FEI's natural gas system;
- If not motivated by price response already, at least the following amount of switching from natural gas to other fuels occurs for the following buildings across the planning period:
    - Depending on their location and building type, 26 to 36 percent of residential dwellings and apartment buildings switch their space heating and 16 to 25 percent switch their domestic hot water away from natural gas;

- In addition to district energy connections, 2 percent of commercial buildings switch their hot water loads away from natural gas; and
- 1 percent of industrial facilities switch their hot water loads away from natural gas.

1.2.2 CRITICAL UNCERTAINTY IMPACTS ON THE FORECAST MODEL

Table B1-2 below summarizes how each critical uncertainty impacts the mechanics of the 2017 LTGRP forecast model and discusses specific attributes of individual critical uncertainties.

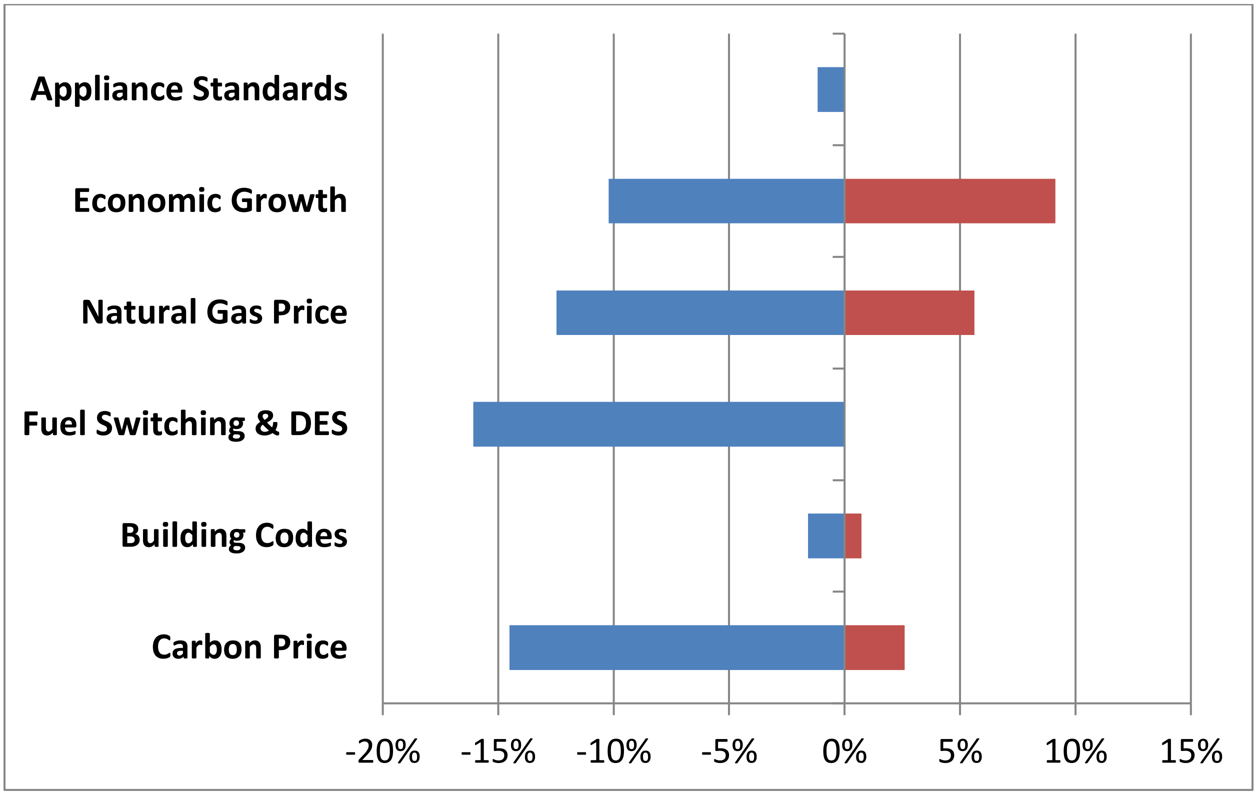
Table B1-2: Summary of Critical Uncertainty Impacts on the Forecast Model

Critical Uncertainty	Model Levers	Comments
Economic Factors		
Economic Growth	- Residential building stock - Commercial floor area - Industrial facilities	See Table B1-1 above.
Natural Gas Price	Long run natural gas fuel share	Based on a literature review of existing research by FEI and Posterity, the 2017 LTGRP uses -0.2 and -0.5 as the long run price sensitivity values for residential and commercial/industrial customers, respectively. Since these are long run values, the 2017 LTGRP forecast model calculates the total fuel share change from these values by the end of the planning period and subsequently solves for the required annual change rates required to produce the total change. The model ensures that the calculated annual change rates are achievable in relation to the rate of end-use equipment replacements.
Policy Factors		
Carbon Price	Long run natural gas fuel share	This critical uncertainty relies on the same mechanics as the Natural Gas Price critical uncertainty.

Critical Uncertainty	Model Levers	Comments
Non-Price Carbon Policy Action	- Long run natural gas fuel share - Natural gas use per customer - Natural gas appliance efficiency	See Table B1-1 above.
Extraneous Factors		
RNG Demand	- RNG fuel share - Conventional natural gas fuel share	See Table B1-1 above.
CNG and LNG Demand for Vehicles	- Commercial rate schedule demand - Industrial rate schedule demand	See Table B1-1 above. The 2017 LTRGP forecast implements the forecast NGT volumes by multiplying forecast vehicle numbers by average use per vehicle rates.
Large Industrial Point Loads	- Industrial rate schedule demand	See Table B1-1 above.

Figure B1-11 below illustrates how sensitive total annual demand is to the High versus Low (Accelerated versus Delayed) outcomes for each individual critical uncertainty. This figure emphasizes that the 2017 LTGRP gives healthy consideration to factors that may reduce annual demand across the planning period. Individually, the critical uncertainties have no more than 17 percent impact on annual demand, but the 2017 LTGRP scenarios combine these critical uncertainties. The manner in which critical uncertainties combine to form alternate future scenarios is important since their outcomes may either reinforce or offset each other. The Economic Growth uncertainty shows significant impact. In light of this, please note that FEI's method for developing the quantitative inputs for this uncertainty represents a proxy only to estimate the potential impact of different economic growth climates. The Fuel Switching and District Energy lever from the Non-Price Carbon Policy Action critical uncertainty has the highest individual impact. This illustrates the significance for annual demand of this backstop that FEI included in the 2017 LTGRP scenario analysis.

Figure B1-11: 2036 Annual Demand Sensitivity to High/Low Critical Uncertainties – All Sectors



1.3 Conclusion

Section 2 of the Application discusses how the 2017 LTGRP is embedded within the context of a complex and partially uncertain planning environment. In response, the 2017 LTGRP builds on the end-use forecast method scenario analysis from the 2014 LTRP and includes a significant range of critical uncertainties to account for potential changes in the planning environment across the planning period.

These uncertainties range from economic growth and natural gas price, via carbon price and non-price carbon policy action, to the impact of emerging markets, such as RNG and NGT as well as the potential impact of large new industrial point loads, such as LNG export terminals. FEI used a rigorous process for developing the inputs for each critical uncertainty and for implementing these into the 2017 LTGRP forecast model. In doing so, FEI drew on the expertise of its internal LTGRP working groups, its forecast consultant (Posterity), and the experience of stakeholders in the RPAG and across FEI's community engagement workshops.

The resulting critical uncertainty data and implementation accounts for a wide range of possible alternate future scenarios and enables FEI to account for planning environment risks in its 2017 LTGRP analysis. The critical uncertainties also serve as signposts for FEI to evaluate which future scenarios may be unfolding as it proceeds through the planning period.

Appendix B-2

END-USE DEMAND FORECAST METHODS ANALYSIS

boreas consulting ltd.

FortisBC Energy Inc.

Long Term Demand Forecasting

Benchmarking Study on End-Use Methods

Industry Practices Review

Prepared by: **Boreas Consulting Ltd.**

4 January 2017

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1. EXECUTIVE SUMMARY

In the regulatory proceeding reviewing the 2014 Long Term Resource Plan for FortisBC Energy Utilities (2014 FEU LTRP), FEU was asked by the BC Utilities Commission ('the Commission') whether it had compared its End-Use forecasting model with forecasting models used by other utilities. The Commission and interveners expressed some reservations about FEU's end-use model including the complexity and associated cost of updating the model. Accordingly, the Commission directed FEU to "provide a detailed analysis of the relative benefits/shortcomings of their particular End-Use Method as compared to other end-use methods". As a result, FEU retained Boreas Consulting (Boreas) to review long term forecasting practices of North American gas utilities to determine whether there is a preferred method for conducting demand forecasts for use in integrated resource planning activities.

Boreas completed a comparison of long-term (over 10 years) annual demand forecasting activities among gas distribution utilities in North America – particularly in Canada, the U.S. Pacific Northwest and California.

Boreas completed this work by reviewing publicly available documents from 30 gas utilities and one utility regulator. These documents primarily consisted of regulatory filings by the utilities and included Integrated Resource Plans (IRPs), Capacity Supply Plans, Energy Efficiency Plans, Rate Applications, and Testimonies. Furthermore, Boreas identified the person and/or people responsible for forecasting at some utilities and interviewed them to obtain more detailed insight into their forecasting methods.

Companies with forecasting horizons of 10 years or more often use their long term forecast as part of their IRP, which often has a longer term horizon.

Approximately 44% of the companies that use long term forecasts of 10 years or more use some form of end-use modeling combined with econometric modeling. The end-use models are often used to forecast use per account, while econometric models are used to forecast growth in the number of accounts. The rationale being that as energy efficiency becomes more important, end-use modeling provides a much more detailed understanding of the impact of efficiency improvements on the energy use and long term forecasts, particularly in new construction and replacement of old equipment.

Some of the jurisdictions that are leaders in energy efficiency policy and regulation have used end-use modeling since the introduction of energy efficiency regulation over 20 years ago and continue to do so. The one regulatory body that prepares its own long term forecasts for the state and the utilities in the state has used end-use forecasting models since 1975.

In most cases, annual demand forecasts for residential and commercial customer classes are developed by multiplying the forecasted number of customers in each rate class by the average use per account for that rate class. Economic forecasts from government agencies or other organizations are used to forecast the growth in number of customers. Average use per account forecasts are based on either econometric models or end use models. Econometric models often use weather normalized historical consumption data and apply regression modeling to the data to forecast average use per account. End-use models often use end-use data from end-use surveys to forecast average use per account based on different end-uses.

End-use models tend to be much more data intensive than econometric models. However, the companies that use them believe as energy efficiency policies and standards become more important, end-use modeling provides them the level of detail required to assess the impact of energy efficiency standards and regulations. Similar to econometric models, the parameters used in end-use forecasting models vary from company to company, but in most cases, include energy prices, saturation levels of different end-uses, saturation levels of different energy sources, vintage or age of dwellings, dwelling type, dwelling size, and vintage or age of different end-use equipment. This data is often collected from end-use surveys.

Most jurisdictions, among those investigated, with high levels of DSM activity and IRPs use end-use modeling for their long-term forecasting. All end-use models require a medium to high degree of data intensiveness and can examine end-use trends within different scenarios, which in turn allow the utilities to show how changes to model inputs affect the results. Most utilities perform some form of testing of the forecasts against actual data. However, because long-term forecasts are based on forecasts of many input parameters, such as whether, energy prices, economic conditions, employment levels, new construction activity, etc. a straight comparison of forecasts to actuals without any adjusting for the input parameters does not necessarily reflect the effectiveness of the forecasting model. Thus, comparison of the forecast results to actuals may be quite resource intensive.

2. Introduction

In the regulatory proceeding reviewing the 2014 Long Term Resource Plan for FortisBC Energy Utilities (2014 FEU LTRP), FEU was asked by the BC Utilities Commission ('the Commission') whether it had compared its End-Use forecasting model with forecasting models used by other utilities. FEU provided a high level description of forecasting models from eight other utilities and characterized their approaches as one of: "top-down", "bottom-up statistical", "bottom-up engineering". In its Decision, the Commission agreed that FEU's intention to discontinue using a traditional method and to move towards an end-use forecasting approach had merit, but expressed reservations about the added expense related to further development of a model for forecasting the annual demand when it is the peak demand forecast that is the primary driver for infrastructure planning purposes. The Commission and interveners also expressed reservations regarding the complexity and associated cost of updating the FEU End-Use model, as well as with the lack of testing with historical data to ascertain the accuracy of the model. Accordingly, the Commission directed FEU to "provide a detailed analysis of the relative benefits/shortcomings of their particular End-Use Method as compared to other end-use methods".

As a result, FEU retained Boreas Consulting (Boreas) to review long term forecasting practices of North American gas utilities to determine whether there is a preferred method for conducting demand forecasts for use in integrated resource planning activities. Specifically, FEU desires:

- A comparison of long-term (~20 year) annual demand forecasting activities among gas utilities in North America – particularly in Canada, the U.S. Pacific Northwest and California.
- A characterization of forecasting methods as either top-down (aggregated trends) or bottom-up (end-use based), or as based on some alternative characterization.
- A survey of the granularity of forecasts. In other words, are forecasts typically presented on a yearly basis, using milestone years (i.e. every 5 years), or on some other frequency?
- A survey of the variables and parameters altered in order to develop alternative forecast scenarios, such as different customer growth scenarios, use per customer scenarios, or economic and climate change scenarios.
- When possible, an assessment of the costs for updating and maintaining various forecasting models (within ranges).
- Depending on the information available, assess how different models have performed against historical data.
- Where possible, a description of how other utilities link their long-term annual demand to their long-term peak demand forecasts.

3. FortisBC Model

FEU's end-use forecasting model was developed by ICF International Canada (formerly known as ICF/Marbek). The model is built on top of the model that was used to develop the Conservation Potential Review (CPR), which allows for applying energy efficiency measures to a reference case

FEU's long term annual demand forecast starts by developing a detailed annual demand forecast for the base year. The base year demand forecast is built on demand forecasts for geographic regions, sectors and subsectors, rate classes, and different end-uses. FEU's annual demand forecast considers saturation levels of different end-uses, the market share of natural gas, and energy consumption for various end-uses. The base year forecast is then calibrated against FortisBC's sales, using the most recent data available.

The forecast is built from the base year by growing the number of accounts based on FortisBC's 20-year forecast number of accounts by rate class. FEU's end-use model forecasts new accounts based on the most recent vintage of buildings and building codes; it incorporates anticipated efficiency improvements (such as natural replacement of furnaces with condensing units), as well as anticipated changes in saturation and gas share for specific end uses.

The model makes use of saturation levels of different end-uses, natural gas market share, the vintage of buildings, rate class, dwelling type, and number of accounts.

4. Method

Boreas completed a comparison of long-term (over 10 years) annual demand forecasting activities among gas distribution utilities in North America – particularly in Canada, the U.S. Pacific Northwest and California.

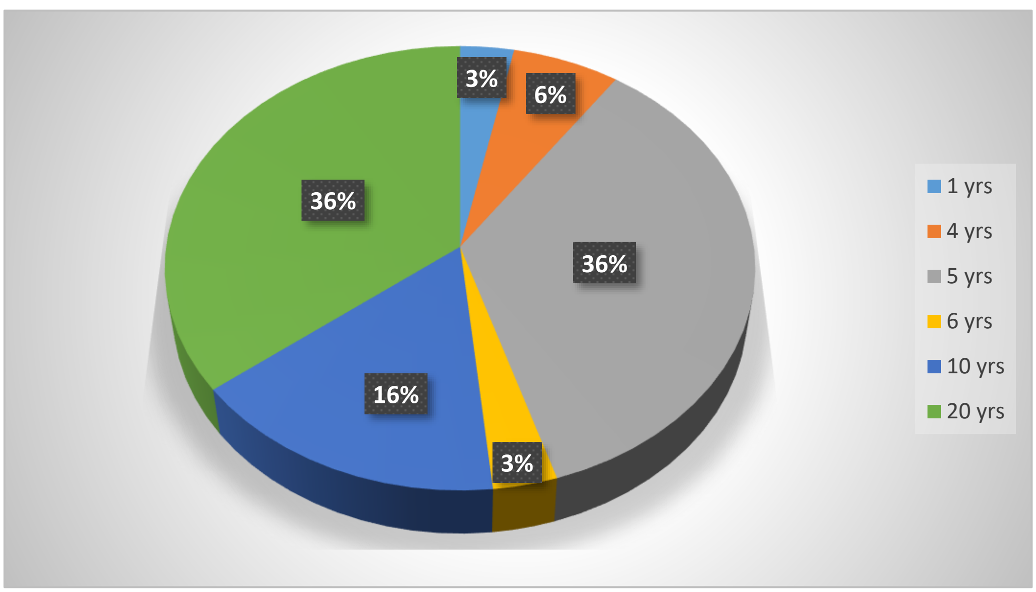
Boreas completed this work by reviewing publicly available documents from 30 gas utilities and one utility regulator. These documents primarily consisted of regulatory filings by the utilities and included Integrated Resource Plans (IRPs), Capacity Supply Plans, Energy Efficiency Plans, Rate Applications, and Testimonies. Furthermore, Boreas identified the person and/or people responsible for forecasting at some utilities and interviewed them to obtain more detailed insight into their forecasting methods.

5. Findings

Boreas' findings are summarized in this section, with detailed findings included in Appendix A.

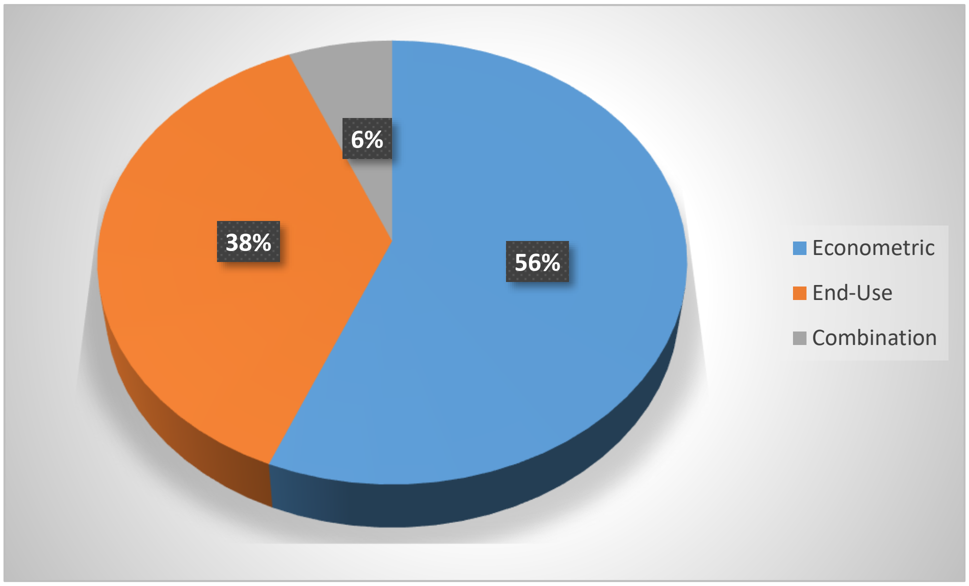
As illustrated by Figure 1, the companies are relatively evenly distributed among those that prepare long term forecasts of 10 years or more and those that prepare forecasts of less than 10 years. The companies with forecasting horizons of less than 10 years often prepare their forecast for supply planning purposes or rate applications, while companies with forecasting horizons of 10 years or more often use their long term forecast as part of their IRP, which often has a longer term horizon.

Figure 1. Distribution of Forecast Horizon



As illustrated by Figure 2, approximately 44% of the companies that use long term forecasts of 10 years or more use some form of end-use modeling combined with econometric modeling. The end-use models are often used to forecast use per account, while econometric models are used to forecast growth in the number of accounts. The rationale being that as energy efficiency becomes more important, end-use modeling provides a much more detailed understanding of the impact of efficiency improvements on the energy use and long term forecasts, particularly in new construction and replacement of old equipment.

Figure 2. Distribution of Forecasting Method for Companies w/ Forecast Horizon Over 10 yrs



Some of the jurisdictions that are leaders in energy efficiency policy and regulation have used end-use modeling since the introduction of energy efficiency regulation over 20 years ago and continue to do so. The one regulatory body that prepares its own long term forecasts for the state and the utilities in the state has used end-use forecasting models since 1975.

In most cases, annual demand forecasts for residential and commercial customer classes are developed by multiplying the forecasted number of customers in each rate class by the average use per account for that rate class. Economic forecasts from government agencies or other organizations are used to forecast the growth in number of customers. Average use per account forecasts are based on either econometric models or end use models. Econometric models often use weather normalized historical consumption data and apply regression modeling to the data to forecast average use per account. End-use models often use end-use data from end-use surveys to forecast average use per account based on different end-uses.

Most companies build their annual demand forecast for their large industrial customers from individual customer forecasts, which are often based on historical trends with adjustments that are based on customer feedback and future plans.

The parameters used in econometric forecasting models vary from company to company but in most cases include energy prices, GDP growth, population growth, household growth, income, and employment levels. Some econometric models also include an energy efficiency index, which takes into account improvements in energy efficiency standards and building codes.

End-use models tend to be much more data intensive than econometric models. However, the companies that use them believe as energy efficiency policies and standards become more important, end-use modeling provides them the level of detail required to assess the impact of energy efficiency standards and regulations. Similar to econometric models, the parameters used in end-use forecasting models vary from company to company, but in most cases, include energy prices, saturation levels of different end-uses, saturation levels of different energy sources, vintage or age of dwellings, dwelling type, dwelling size, and vintage or age of different end-use equipment. This data is often collected from end-use surveys.

Irrespective of the type of forecasting model used, most companies run a number of forecast scenarios. The forecast scenarios typically include a base case, which is the mostly likely scenario, plus a high and low case, which are based on high and low growth. Some companies also run forecast scenarios to assess the potential impact of climate change and carbon taxes.

The companies with long-term forecasts, where the forecast horizons are 10 years or more, provide annual demand forecasts for either every year or every five years during the forecast period.

Most companies evaluate the performance of their forecasting model by comparing forecasted annual demand to actuals. However, this may sometimes be challenging because of the number of adjustments that may have to be done to parameters, such as weather, energy prices, and economic conditions as these parameters can have a significant impact on the output from the model. In general, performance of the models is assessed by comparing the long term average of the adjusted actuals to forecast over several years.

Most end-use models are developed by external resources but are operated by internal resources. Because econometric models often use regression analysis techniques, they are sometimes developed internally.

Most companies use their annual demand forecast to develop their peak-day demand forecast. Some of the common methods used in developing peak-day demand forecasts is to start with the annual demand forecast and to apply the load factor of the different customer classes to the average-day demand for the applicable class, applying load shapes for different customer classes or end uses to the annual demand, and adjusting the average-day demand for the peak-day weather conditions.

Table 1 summarizes the characteristics of the end-use models for the utilities and organizations that use end-use modeling in their long-term forecasting.

Most jurisdictions with high levels of DSM activity and IRPs use end-use modeling for their long-term forecasting. All end-use models require a medium to high degree of data intensiveness and can examine end-use trends and different scenarios, which in turn allow the utilities to show how changes to model inputs affect the results. Most utilities perform some form of testing of the forecasts against actual data. However, because long-term forecasts are based on forecasts of many input parameters, such as whether, energy prices, economic conditions, employment levels, new construction activity, etc. a straight comparison of forecasts to actuals without any adjusting for the input parameters does not necessarily reflect the effectiveness of the forecasting model. Thus, comparison of the forecast results to actuals may be quite resource intensive.

Table 1. End-Use Model Characteristics

Utility End-use Forecasting Model	No. of Gas Customers	Utility Ownership	DSM Activity	Degree of Data Intensiveness	Degree of Customization	Ability to Examine End-use Trends/Scenarios	Ability to Show How Changes to Model Inputs Affect Results	Informs both Annual and Peak Demand	Cost to Maintain	Forecast Tested Against Actuals
So-Cal Gas (2016 CGR)	5.9 million	IOU	High	High	High	Yes	Medium	Yes	Moderate	Some
Manitoba Hydro (2012 Gas Forecast)	275,000	Crown	High	Moderate	High	Yes	Medium	No	Moderate	Yes
San Diego Gas & Electric (2016 CGR)	873,000	IOU	High	High	High	Yes	Medium	Yes	Moderate	Some
Colorado Springs Utilities (2011 IRP)	192,000	Municipal	Low	Moderate	High	Yes	High	Yes	N/A	Yes
Pacific Northern Gas (2015 IRP)	40,000	IOU	Low	Moderate	High	Yes	High	Yes	Moderate	Some
Black Hills Energy (2014 EE Report)	N/A	IOU	Medium	High	High	Yes	Low	No	N/A	N/A
California Energy Commission (2015 IEPR)	--	Regulator	High	High	High	Yes	Medium	Yes	Moderate	Yes
FEI (2014 LTRP)	1.1 million	IOU	High	High	High	Yes	Yes	No*	Moderate	Not Yet**

Notes:

* Linkage with peak demand is being addressed as part of the ongoing improvement to the forecasting model.

** To date there has not been enough actual history to compare to the end-use demand forecast. Once enough historic data is available, FEI plans to compare end-use demand forecast to actual consumption.

Appendix A. LONG TERM DEMAND FORECASTING PRACTICES

1. Southern California Gas Company and San Diego Gas & Electric[1]

1.1. Overview

The companies are investor owned utilities that are owned by the same parent and often share forecasting resources. Although the two companies develop individual forecasts for each company, they use the same models to develop their long term forecasts.

One of the companies is one of the largest natural gas distribution utilities and serves 21.6 million consumers through 5.9 million meters in more than 500 communities, with a service territory encompassing approximately 20,000 square miles in diverse terrain throughout Central and Southern California, from Visalia to the Mexican border.

The other company is combination gas and electric utility that provides energy service to 3.6 million people through 1.4 million electric meters and 873,000 natural gas meters in southern California with a service area that spans 4,100 square miles.

The companies forecast total annual gas demand across all market sectors, including residential, commercial, and industrial sectors, to decline from 2013 to 2035. The decline in annual demand is due to modest economic growth, mandated energy efficiency (EE) standards and programs, renewable electricity goals, increases in the marginal gas rates, high costs of compliance with environmental regulations, conservation savings linked to Advanced Metering Infrastructure (AMI), and the expected implementation of regulations to aggressively reduce CO_2 emissions by effectively increasing the gas commodity price for many large industrial customers.

1.2. Forecasting Method

Prior to 2013 the companies used both econometric and end-use modeling to forecast gas demand. However, in their 2013 cost allocation proceedings the companies stopped using econometric modeling and only used the end-use modeling. The companies switched to only using end-use modeling, which include an equipment choice module, in their regulatory filings for the following reasons:

1. End-use models with an equipment choice module are a more effective forecasting tool in an environment that is focused on energy efficiency
2. To save resources
3. End-use models are the basis for long term gas demand forecasting for the companies' California Gas Reports

[1] 2014 California Gas Report – Prepared by the California Gas and Electric Utilities

4. End-use models are used by the California Energy Commission for its long-term energy demand forecasts

The companies use End Use Forecaster (EU Forecaster), formerly known as Quant.sim to prepare their forecast. It is a market segmentation, competitive assessment, and sales projection application developed to respond to market needs and overcome the limitations of existing demand forecasting and market planning tools. The application, originally developed in 1993, is constructed using SAS software.

EU Forecaster has a sufficiently generic structure that could readily be applied to specific market segments for each company so that the companies could separate the specific underlying data needs from a general methodology. As a result, the companies can maintain and support gas demand forecasting capability for both companies by using the underlying data for each company. Furthermore, the structure embedded in EU Forecaster is readily adaptable to addressing questions related to the growing emphasis on incorporating energy efficiency policy goals and emissions regulation into demand forecasts, thereby making end-use modeling more effective.

The companies' econometric models produced forecasts that relied on historical data to fit an equation. The fitted equation was used to explain how changes in the independent variables drove changes in the dependent variable. The models forecasted future demand by extrapolating the same relationship over the forecast period and assumed that there were no structural changes in the fitted relationship into the future. Improvements in energy efficiency were included in econometric models by including an efficiency index as an explanatory variable. This efficiency index was only a proxy that accounted for the downward trend in gas use because of energy efficiency improvements. In prior econometric work, the companies used end-use models to develop the energy efficiency index.

EU Forecaster tracks energy use (e.g., natural gas or electricity) by simulating customers' energy consumption into two key steps:

1. Simulates the choices in the selection of end-use equipment from two fuel types (gas or electric), and various equipment efficiency levels and then
2. Forecasts the energy use derived from the customers' end-uses from the set of customers' equipment.

The model takes into account the age of the equipment to determine when the equipment is replaced. As the model iterates from one year to the next, it distinguishes, in each year, between the load added due to new meters in addition to changes in the load due to existing customers replacing old equipment with newer, more energy efficient appliances or other equipment. Historical accounts are segmented into the total number of accounts in the base year and their distribution among the historical vintages. The model produces a forecast over the planning horizon by applying a forecast of equipment capital costs, energy consumption, and fuel price forecasts to the customer choice parameters. It calculates energy use for each customer type by optimizing the underlying customer choices.

EU Forecaster's structure is designed to keep track of energy use for each market segment, each end use and for each vintage as the model steps through the entire forecast time horizon. In contrast, the companies' previously-used econometric models stepped through the forecast period by using the same structure for predicting energy consumption from the independent variables (e.g., energy prices, employment levels, meter counts), from one year to the next.

The companies use five residential segment types: single family, small and large multi-family customers, master meter and sub-metered customers and 14 commercial sectors identified by the customer's NAICS codes.

1.3. Forecasting Parameters

The companies use data from End Use Surveys conducted by the California Energy Commission in their forecasting model. The parameters used in the forecasting model include:

- Equipment usage equation forecast drivers
- Coefficients describing how usage varies by weather, customer characteristics, prices, and other variables
- Choice forecast drivers, including capital costs for equipment in existing, conversion, and new construction buildings, plus future availability of each equipment type
- Average and marginal market shares for existing, conversion, and new customers
- Fuel, product, or service price forecasts in native units
- Decay functional form indicator and parameters for existing, conversion, and new accounts
- Number of existing accounts, non-accounts on main, and non-accounts off main
- Forecast of new construction (economic activity driving demand), capture rates, units per account, and number of units (i.e., units are a scale of measurement consistent with results of the usage forecast, such as buildings, square footage, apartments, etc.)
- Mean age of end uses by historical vintage in the baseline (i.e., 0th) year of the forecast, used to initialize the age dimension in the turnover/vintage module
- Decay functional form indicator and parameters for equipment (end-uses) in existing, conversion, and new buildings
- Saturation (percentage of accounts that have the equipment) independent of fourth dimension market shares
- Total actual sales in base year
- Exogenous parameters that change market shares for existing, conversion, and/or new customers through 'what if' intervention strategies

- Exogenous parameters that adjust product usage through 'what if' convention strategies

1.4. Forecasting Scenarios

Forecasting scenarios included sensitivity to temperatures and non-cogeneration electric generation.

Core demand forecasts are prepared for two design temperature conditions – average and cold – to quantify changes in space heating demand due to weather. The cold design temperature conditions are based on a statistical likelihood of occurrence of 1-in-35 on an annual basis, with a typical recurrence period of 35 years.

The average year HDDs were calculated as the simple average of annual HDD's from 1994 to 2013.

The non-cogeneration EG forecasts are prepared for two hydro conditions – average and dry. The dry hydro case refers to gas demand in a 1-in-10 dry hydro year.

1.5. Forecast Period and Update Frequency

As part of the California Gas Report, the companies prepare a 20-year forecast of customers, annual demand, peak-day demand every two years. While the companies prepare a forecast for each year during the forecast period, they only report forecasts in five year intervals.

1.6. Forecast Evaluation

The companies find evaluating the performance of their long term forecast to be very difficult as there are numerous assumption and inputs into the model. As result, there is no formal evaluation process in place. However, they do compare their forecast for annual demand to actuals.

1.7. Forecast Resources

The companies share forecasting resources. While the team responsible for forecasting consists of four analysts who are responsible for long and short term forecasts as well as other tasks, approximately 1.5 of an FTE is responsible for long term forecasting.

1.8. Peak-Day Demand Forecast vs. Annual Demand Forecast

The companies use their annual demand forecast and apply peak day design temperature to forecast their peak-day demand.

The peak-day design temperature conditions are based on a statistical likelihood of occurrence of 1-in-35 on an annual basis, with a typical recurrence period of 35 years.

2. California Energy Commission[2]

2.1. Overview

Since 1975 the organization has been responsible for forecasting electricity and natural gas (and other fuels) demand for the primary purpose of insuring adequate, but not excessive, electricity supplies. These include forecasts of statewide and regional electricity and natural gas consumption; annual and seasonal peak demand; factors contributing to projected demand growth; and the impacts of electricity and natural gas efficiency, load management and other demand response activities.

Residential and commercial natural gas consumption in California has remained relatively flat for the past two decades despite increases in population, jobs, and gross state product. This has been attributed to increasingly stringent California Building Energy Efficiency Standards and increasing investments in statewide utility energy efficiency programs have.

California Building Energy Efficiency Standards are advancing toward a goal of Zero Net Energy buildings by 2020. California's Senate Bill 350 requires the doubling of energy efficiency savings by 2030 for electricity and natural gas combined. Natural gas end-use assessments are expected to evolve over time toward a similar level of granularity as in the electricity forecast to support the provisions of Senate Bill 350.

A critical part of the demand forecast is estimating energy savings from DSM activities. The organization is required to include all such demand reductions which are "reasonably expected to occur" during the forecast period in its forecasts.

2.2. Forecasting Method

The organization forecasts natural gas demand in California as part of each Integrated Energy Policy Report (IEPR) cycle. The organization uses end-use and econometric models structured along utility planning area boundaries for the residential, industrial, commercial, agricultural, transportation, communications, and utilities sectors.

End-use modeling is used for forecasting residential and commercial demand, while econometric/trend modeling is used for forecasting industrial and agricultural demand.

Residential use is forecasted for different building arch-types based on demographic and economic data and the forecasted number of households in each geographic area from Moody's. Vintage of the dwellings is used to adjust for changes in building code and standards.

Commercial use is forecasted for different building types by building gross area.

End-use surveys are used to collect average use per appliance, saturation levels, and equipment and building vintages. These are conducted every four to five years.

[2] 2015 Integrated Energy Policy Report

End-use energy consumption estimates are developed using analytical engineering and econometric techniques for extracting information from customer use data. The early generation end-use models were developed using primarily engineering methods. As better data became available, disaggregate econometric techniques were incorporated into the model.

End-use modeling is used rather than other forecasting techniques because of its ability to better explain how energy is actually used and how various factors effect changes in energy use. For example, models involving different levels of end-use detail are used to characterize how efficiency programs affect both energy requirements and peak demand.

Table 2 lists the end use and consumer characteristics of each of the sectoral models used.

Table 2. Characteristics of Forecast Sectoral Models

Sector	Consumer Type/NAICS Code	End uses Covered
Residential	Residential consumers 3 housing types	24 major appliance and space conditioning categories
Commercial	12 building types 21 NAICS codes	10 equipment and space conditioning categories
Transportation, Communications and Utilities (TCU)	NAICS codes 221, 48 (excluding 48841), 49, 513, 56151, 56152, 562, 62191, and 92811	Consumption is estimated for aggregated of the ten NAICS codes, not for specific end uses
Industrial	Process, extraction, and assembly industries included in NAICS 1133, 21, 23; 31-33, 511, and 516	Thermal processes, HVAC, process steam, and cogeneration.
Agriculture	Crop production, livestock, and related commodities.	Irrigation pumping, building heating, crop drying

Planning area forecasts are developed by aggregating county data to the planning area level. For example, county-level housing construction, population and income estimates form the basis of a planning-area residential consumption forecast. Each county is apportioned to one or more of sixteen climate zones and each climate zone is assigned to a planning area.

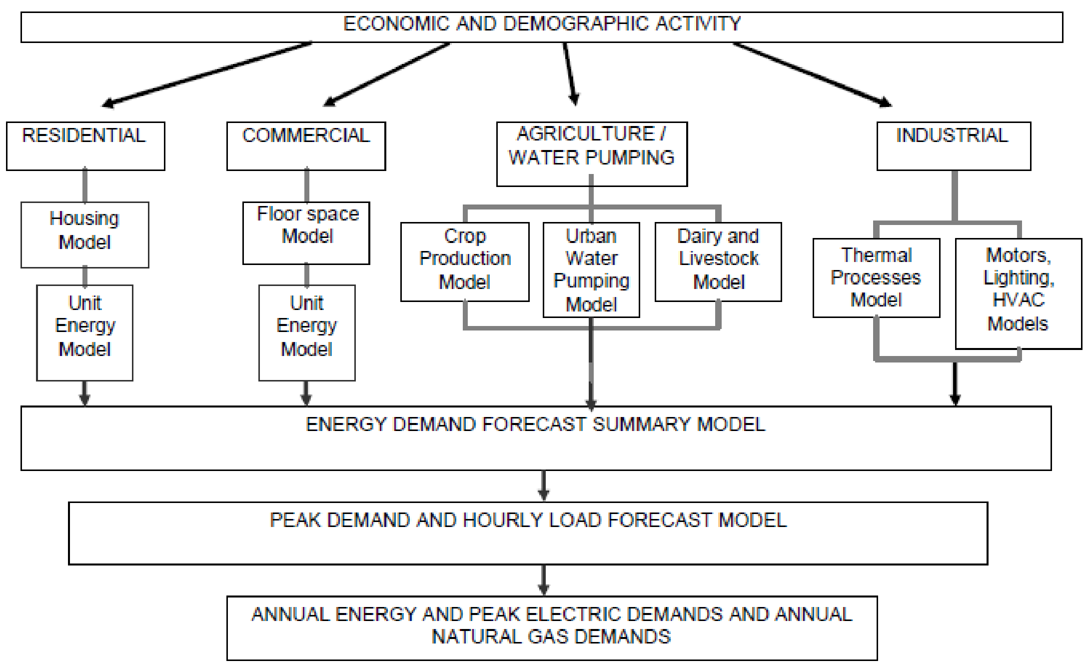
The same models are used to forecast electricity and natural gas demand.

The aggregate demand for energy services increases with growth in economic activity and population and as new energy services become available due to technological development.

In addition, updated forecasts must reflect the penetration rates at which more efficient equipment and new energy services come into use. In addition to the energy and peak demand sectoral models that forecast final demand, the organization sometimes develops models that generate the values of economic variables used to drive the energy or peak sectoral models. This work has been necessary because suitable specific variables have not been readily available.

Figure 3 illustrates a schematic diagram of the major elements of the energy and peak demand forecasting models. The results from the energy forecasting models flow directly into the peak demand forecasting model.

Figure 3. Framework for Energy Demand Forecast Models



Source: California Energy Commission staff, May 2005

2.2.1. Residential Energy Demand Forecast Model

The residential model forecasts energy demand for 24 end uses, three housing types and three fuel types.

End uses include space heaters, air conditioners, refrigerators, color televisions, lighting, water heating, etc. Electricity and natural gas consumption are fully modeled for all relevant end uses, while saturations are maintained for other fuels (principally wood, liquid propane gas, and solar).

Three housing types single-family, multi-family, and mobile homes are modeled; these are further grouped by climate zone. Sixteen climate zones are modeled; these are intended to capture differences in residential energy use for space conditioning across the state's microclimates.

Five vintages of housing construction are used to represent the eras in which building codes and revisions significantly influenced the thermal characteristics of residential buildings.

The residential model forecasts energy demand in three principal components:

1. The number of households of each housing type is forecasted.
2. The saturation of appliances for each of three fuel types is projected
3. The model determines the amount of energy expected to be used by each end use appliance; this depends, in part, on the age profile of the appliance stock.

Total residential energy consumption is the product of projected households, the number of households possessing a particular appliance, and the yearly average energy use for that appliance, summed over all end uses.

2.2.2. Commercial Energy Demand Forecast Model

The commercial energy forecasting model is similar to the residential model with respect to the degree of disaggregation. The model first forecasts the amount of building floor-space and vacancy rates for twelve different building types. The model then determines the fraction of floor-space in each building with commercial equipment for each of three fuel types. The nature of the energy-using equipment in each building type determines the commercial end uses (for example, restaurants contain ovens and stoves, therefore, cooking is a principle end use for that building type). The amount of energy required per square foot of floor-space is then determined for each fuel type. Total commercial energy demand is the product of these three factors and summed for all end uses and building types. The model considers the effects on energy use of changes in floor space, vacancy rates, energy prices, building and appliance standards, and other major efficiency programs.

The commercial model uses end use intensities (EUIs), which are the energy use estimates per square foot by building type with corresponding end uses and equipment.

2.2.3. Industrial Energy Demand Forecast Model

The industrial sector is divided into process and assembly groups.

Projections of industrial energy demand for most sectors except extraction industries are driven by forecasts of GDP. For extraction industries forecasts of employment are used because the volatility of the prices of such commodities as oil, natural gas and precious metals leads to volatility in values of shipments or GDP.

To forecast annual electricity and natural gas demand, the organization used to use the Industrial End-Use Forecasting Model (INFORM), developed by the Electric Power Research Institute (EPRI) until 2014. However, because EPRI does not support the model any longer, the organization decided to develop a new model for its 2014 report based on the INFORM method. The INFORM program accounted for energy use trends, price effects, and exogenous improvement in efficiency by end use and industry.

The major end uses in the model are motors, thermal processes, lighting, HVAC and miscellaneous. The organization used to use the model to forecast demand for electricity, natural gas and other fuels for these five major end uses over a 12-year period.

The new model forecasts industrial energy demand based on a number of factors, including:

- Projected growth in dollar output or employment for 28 categories
- Projected average industrial rates
- Changes in end-use characteristics, including energy intensities, which measures energy use per dollar of output

The marginal impact of economic growth on energy use in each of the 28 categories is estimated using regression analysis. Estimated coefficients are applied to the appropriate economic indicator to provide "business as usual" forecast for each industrial category. This forecast is adjusted for rate increases, using price elasticities estimated in the sector econometric models. Finally, the forecast is adjusted to account for changes in end-use energy intensity.

Since a full statewide industrial end use survey has not been completed for more than 20 years, recent data on industrial end-use energy intensities and other characteristics to fully populate the model are not available for California. As a result, the organization started to populate end-use characteristics in the model using national data and smaller-scale state surveys. However, the organization expects the new model will require a full California industrial end-use survey to reach its full potential as a forecasting tool.

2.2.4. Energy Demands Summary Forecast Model

Individual sectoral model energy demand forecasts are processed by the Energy Demands Summary Forecast Model in order to calculate planning area total forecasts. The summary model adjusts the sectoral forecasts for weather and DSM program savings. The results are calibrated using recorded energy consumption.

Energy demand for weather sensitive end uses is adjusted to accommodate the deviation between actual weather and normal weather for each climate zone in the planning area. After the weather adjustment, minor adjustments are performed to account for DSM programs that have not been incorporated into the input data used in the sectoral models. The final adjustment to the forecasts is to calibrate the results using the recorded energy consumption.

2.3. Forecasting Parameters

The latest historical natural gas consumption data are used for the forecast.

Factors that affect natural gas supply and demand include production, population growth, pipeline capacity, economic outlook, weather, national and global markets, environmental concerns, and the effects of energy policies. Supply and demand, in turn, affect natural gas prices.

Four classes of data are needed as inputs to disaggregated forecast models:

- Consumer characteristics data such as end use appliance saturations, dwelling size and age, occupants' income and demographic makeup, utility bills for the residential sector, and equipment saturations, hours of operation, etc. for the commercial sector
- Aggregated energy consumption data for the non-residential sectors (most notably the industrial sector) classified by the North American Industry Classification (NAIC) codes devised by the federal government
- Disaggregated economic and fuel price projections at a level of detail matching the customer sectors of the energy forecasting models
- Characteristics of demand side management programs

Customer surveys are the principle source of information on consumer characteristics. These surveys are used to collect data on customer electric and natural gas use, which form the core data needed for the end use forecasting models.

A major secondary data source on consumer attributes are federal activities under the Bureau of the Census.

Acquisition of reliable commercial floor-space data remains a difficult and unresolved problem for forecasters.

Monthly consumption data for different NAICS codes are used in the sector models.

Essential inputs into the forecasting models are economic and fuel price projections for each planning area annually for 10 years into the future. Several translation models are used to convert available economic data into the actual "energy driver variables" which are used in the models to forecast energy use. For example, in the commercial sector, the key energy driver is floor space by building type, while the economic variables are employment of various types, taxable sales, and various groupings of population.

The sector-specific economic variables used in developing the forecast are summarized in Table 3.

Table 3. Economic Variables Used in Forecast Models

Sector	Energy Driver	Economic Variable	Constructed Economic Variable
Residential	• Fuel Prices	• Population • Personal income • Households	• Household population • Persons per household • Group quarters • Income per capita
Commercial	• Floor-space, by building type • Fuel prices	• Employment • Retail sales • Population	
Industrial	• Output by industry • Fuel prices	• Output by industry • Employment (extraction sectors only)	
Agriculture	• Crop production • Rainfall • Electricity price • Diesel price • Cooling degree days • Dairy and livestock production	• Personal income • Population • Households	• Total households • Persons per household • Income per capita

2.4. Forecasting Scenarios

The organization develops high, mid, and low use scenarios. These scenarios are developed using various natural gas prices and committed efficiency program impacts. Statewide and major planning area results are shown with and without estimates of incremental achievable efficiency, referred to as baseline and adjusted forecasts, respectively. The three future energy demand scenarios are:

- Business-as-usual or mid demand case – mid population, income, and energy prices
- A high demand case – high population and income, and low energy prices.
- A low demand case – low population and income, and high energy prices

The mid demand case represents a future in which the economy and commercial activity remain consistent with trends experienced over the last several years. The high demand and low demand cases are created by altering assumptions, which move natural gas prices. The assumptions that are varied included economic growth, technology improvements, renewable portfolio standards, coal-fired generation retirements, natural gas supply cost curves, demand, and the production cost environment.

The mid case includes potential climate changes in the forecast, while the high and low cases do not include the impact of potential climate changes. This results in mid case demand being lower than the low case in some instances.

2.5. Forecast Period and Update Frequency

The forecast provides annual demand forecast for every year over the 10-year forecast period. It is updated every year as part of each Integrated Energy Policy Report (IEPR) cycle.

2.6. Forecast Evaluation

The new forecasts begin at a higher point in 2015, as actual natural gas consumption in California was higher in 2015 than forecasted in the CED 2013 mid case. This was attributed to an expected steep increase in forecasted prices that did not materialize.

The organization evaluates the performance of its forecasts by having an expert panel review the forecasts. It also examines annual demand compared to subsequent actual consumption at the statewide level. In addition, it compares model backcasts, or predictions of historical outcomes, to historical consumption.

The organization also compared CED 2013 Final end-user natural gas results for 2024 by major planning area and statewide with those from a full econometric forecast. Differences range from around five percent higher for the econometric forecast to over 11 percent higher. Most of the differences are in the residential sector, reflecting increases in efficiency impacts not fully reflected in the econometric results.

2.7. Forecast Resources

Although the original model was developed externally, the forecasts are prepared by internal resources.

Two full time equivalent (FTE) staff prepare the forecast for both gas and electricity in the residential sector.

One FTE prepares the forecast for both gas and electricity in the commercial sector.

One FTE prepares the forecast for both gas and electricity in the industrial sector.

One FTE prepares the forecast for both gas and electricity in the agricultural sector.

One FTE prepares the forecast summary for both gas and electricity for all sectors.

2.8. Peak-Day Demand Forecast vs. Annual Demand Forecast

The organization uses hourly load shapes for each end-use and applies the load shapes to the annual demand forecast from the end-use model to determine the hourly demand for each end-use. It then aggregates all the hourly demand for all the end-use to forecast the peak-day demand.

2.9. The Impacts of Climate Change

The potential incremental impacts of climate change on both energy consumption and peak demand are incorporated into the forecast using temperature simulations developed by the Scripps Institution of Oceanography (Scripps).

The effect on annual energy consumption is estimated through projected changes in the number of annual heating and cooling degree days, while the impact on peak demand is estimated using increases in annual maximum daily average temperatures.

Heating degree days in California in the last few decades have been declining. HDD in some areas has declined by approximately 15% percent from 1960 to 2014. Since approximately 88% of natural gas consumption in the residential sector is weather-dependent, the decline in HDD should result in significant decline in demand.

3. Pacific Gas & Electric[3]

3.1. Overview

The company provides natural gas and electric service to approximately 16 million people throughout a 70,000-square-mile service area in northern and central California. The company has 42,141 miles of natural gas distribution pipelines and 6,438 miles of transportation pipelines. It serves 5.4 million electric customer accounts and 4.3 million natural gas customer accounts.

The company has experienced declining growth rate in its annual demand in the core market and forecasts this decline in annual growth rate to continue primarily due to increasing emphasis on energy efficiency.

3.2. Forecasting Method

The company's gas demand forecasts for the residential, commercial, and industrial sectors are developed using econometric models. Forecasts for other sectors (Natural Gas Vehicle (NGV), wholesale) are developed based on market information. Forecasts of gas demand by power plants are developed by modeling the electricity market using the MarketBuilder software.

The company uses the current levels of energy efficiency programs included in its latest Integrated Energy Policy Report in the forecast.

3.3. Forecasting Parameters

While variations in short-term gas use depend mainly on prevailing weather conditions, longer term trends in gas demand are driven primarily by changes in customer usage patterns influenced by underlying economic, demographic, and technological changes, such as growth in population and employment, changes in prevailing prices, growth in electricity demand and in electric generation by renewables, changes in the efficiency profiles of residential and commercial buildings and the appliances within them, and the response to climate change.

[3] 2016 California Gas Report

3.4. Forecasting Scenarios

The company uses alternative demand forecasts to assess the possible variations in gas demand that result from changes in various factors such as weather, economic activity, appliance saturation, and efficiencies.

For the high demand scenario, the company forecasts total gas demand with the weather conditions set to match the conditions that have an approximately 1-in-10 likelihood of occurrence.

Space heating accounts for a large portion of the gas use by the company's residential and commercial customers. In previous forecasts, the company used the average of observed temperatures during the past 20 years. However, the company is now building into its forecast an assumption of climate change. The climate change scenario is developed from work done at the National Center for Atmospheric Research, downscaled to the company's service area.

Annual water runoff for hydroelectric plants has varied by 50 percent above and below the long-term annual average. The company also assesses the impact of 1-in-10 dry conditions, which impacts hydro power generation and in turn demand for natural gas power generation.

Since gas prices and rate assumptions are important for forecasting gas demand, especially in price sensitive sectors such as industrial sectors and electric generation, the company models the impact of gas commodity prices in its forecast scenarios.

3.5. Forecast Period and Update Frequency

As part of the California Gas Report, the company prepares a 20-year forecast of customers, annual demand, peak-day demand every two years. While the company prepares a forecast for each year during the forecast period, it reports forecast results for every year for the first five years of the forecast period and at five year intervals after that.

3.6. Forecast Evaluation

This information was not available.

3.7. Forecast Resources

This information was not available.

3.8. Peak-Day Demand Forecast vs. Annual Demand Forecast

The company uses a 1-in-90-year cold-temperature event as the design criterion for its peak-day demand forecast. The core market peak-day demand forecast is developed using the observed relationship between historical daily weather and core usage data. This relationship is then used to forecast the core load under peak-day conditions.

4. Enbridge Gas

4.1. Overview

The company is an investor owned utility that serves over two million customers.

Residential average use per customer has declined steadily over the period of 2005 through 2014, at an average rate of 1.1% per year.

4.2. Forecasting Method

The company prepares a five-year forecast, which it files with the regulator. It also prepares five to 30 year forecasts for internal use, but these are not filed with the regulator. Forecasts are prepared for different rate classes.

The company uses an econometric model for forecasting. The same model is used for preparing short and long term forecasts. While the company prefers to use an end-use model for forecasting demand, it does not have the resources to develop and collect the data required for an end-use model for forecasting.

The company moved to a more objective forecasting methodology starting in the 2001 budget year in order to address the regulator's concern with the systemic bias attributed to the grassroots forecasting process[4]. This forecasting methodology removes systemic or subjective bias by developing regression models to forecast average use for the company's residential and small commercial customers.

For the residential and small commercial customers, the forecast is derived using forecasted number of customers and normalized average use per customer forecast generated from the average use forecasting models. The company's econometric model allows the company to produce separate forecast for each rate class. While the forecasting model does not use specific end-uses in determining average use per account, it includes bundles of end-uses grouped together. The model uses historical data to forecast annual demand for each rate class using regression techniques. The model determines average use per account for each bundle of end-uses and allows the company to adjust for efficiency improvements within the bundle.

For large customers, the model can provide forecasts for different sectors.

The forecast incorporates economic assumptions from the Economic Outlook documents from government agencies.

4.3. Forecasting Parameters

The parameters used in the forecasting model include:

[4] The '**grassroots forecasting process**' is based on the concept of asking the people who are close to the eventual consumer, such as sales representatives.

- Gas prices
- Historical annual demand
- Weather
- Vintage for residential customers
- Employment
- Real GDP
- Vacancy rates
- Time trend

The vintage variable is constructed to reflect the impact that new homes, associated with more energy efficient gas equipment and enhanced building codes, have on average use.

The time trend, including the dynamic variable in the regression model, captures the historical actual average trend of the sectorial average use, conservation initiatives originated by customers themselves or promoted by government programs, stock turnover, and other historical impact not reflected in the mentioned driver variables.

4.4. Forecasting Scenarios

The company develops a number of alternative forecast scenarios based their requirements in a given year. Alternative forecasts are developed using different customer growth rates and extensions to new communities, cold and warm weather scenarios, changes in gas prices, different economic conditions, improved energy efficiency standards, and a cap & trade mechanism for emissions.

4.5. Forecast Period and Update Frequency

The forecast is typically updated annually but the forecast period varies.

When changes to the building code and efficiency standards are introduced, the company updates its forecast to reflect the improved energy performance of buildings and appliances.

The company provides a forecast for each year during the forecast period.

4.6. Forecast Evaluation

The company evaluates the performance of its forecasting model by comparing forecasted annual demand to actuals. In general, the difference between the forecasted annual demand and actual annual demand has been less than 1% for residential and small to medium commercial customers.

4.7. Forecast Resources

The company only uses internal resources in preparing its forecast. The forecasting department consists of three FTE and approximately 1/3 of FTE is dedicated to preparing the long term forecast.

4.8. Peak-Day Demand Forecast vs. Annual Demand Forecast

The company applies the load factor for each rate class to the annual demand forecast to determine the peak-day demand forecast for each rate class. It then sums up the peak-day demand for each customer class to forecast the peak-day demand for the system.

5. Manitoba Hydro

5.1. Overview

The company is a crown corporation that serves approximately 567,000 electricity customer and 275,000 gas customers.

5.2. Forecasting Method

The company prepares both a natural gas and an electricity demand forecast using the same model. It includes fuel switching in its forecast.

The company uses a combination of end-use modeling and econometric modeling for forecasting its annual demand. It uses an end-use model for forecasting annual demand for its residential customers and an econometric model for forecasting annual demand for its core market commercial and industrial customers. It forecasts annual demand for its largest industrial customers individually in the short term and as a group using trend analysis in the long term.

The company conducts a REUS approximately every five years to collect data, which it then uses in its end-use forecasting model. It uses REUS to collect data on end-use saturation levels, detailed information on newly constructed dwellings, and appliance age distributions and their expected lifetimes. It uses the results of the REUS together with conditional demand analysis in its forecasting model to forecast the average use per account. The company uses economic forecasts from government agencies to forecast the number of customers.

The end use assumptions used in the model include current usage information and efficiency improvement information. The number of appliances and their estimated usage are multiplied together to calculate an energy forecast for each end use. All uses are then combined to calculate the total use for the residential end-use forecast.

The company forecasts the number of small commercial gas customers based on economic forecasts from government agencies. It forecast the average use per account based on historical average use per account for each rate class. Since commercial rate classes are based on annual gas use, the average use per account for the commercial rate classes is relatively stable, as customers whose gas use changes move to the appropriate rate class based on their gas use.

The effect of weather is determined in any class by regressing the last two years of actual monthly energy use against the actual HDD for the month. This results in a m^3 per HDD effect for that particular sector. These effects are additive as they are estimated from a linear model.

Annual demand forecast for the company's approximately 140 large industrial customers is based on each customer's average annual demand over the previous three-year period and is kept constant over the forecast period.

the forecast reflects future DSM savings associated with the company's energy efficiency programs. Savings due to DSM programs to date are embedded in the historical data that is the basis for the forecast. The current level of past achieved DSM savings is assumed to remain in place throughout the future. Future DSM savings arising from future energy efficiency programs and market engagement above those already achieved are included in the forecast as outlined in the company's DSM plan.

5.3. Forecasting Parameters

The parameters used in the forecasting model include:

- End use saturation rates
- Detailed information on newly constructed dwellings
- Dwelling type
- Appliance age distributions
- Appliance expected lifetimes

5.4. Forecasting Scenarios

The company only prepares a base case forecast for its natural gas annual demand forecast. In the past, the company used to include scenarios that considered different weather conditions.

The company prepares its forecast with the goal of being an unbiased and accurate predictor of future volumes. It expects the forecast to have a 50% chance of exceeding actual annual demand and 50% chance of being lower than actual annual demand.

The company presents a probability-based estimate of how much future actual volumes might vary from forecast. This can be used to produce forecasts with a specific probability of occurrence, or can be used to determine the probability of specific volumes occurring. The company determines the standard deviation and correlation coefficient of historical weather adjusted volume and applies to the forecast to give an estimate of the width of the volume confidence bands. It used 10% and 90% confidence bands (-/+ 1.28 standard deviations) to represent a low and high scenario. This calculation gives the variability due to economic effects and the year-to-year variation in natural gas use. It does not include variability due to weather which was removed through the use of weather adjusted volumes.

5.5. Forecast Period and Update Frequency

The company prepares a 10-year annual demand forecast, which it updates annually and prepares a forecast for each year during the forecast period.

The company also prepares 20-year annual demand forecast, which it uses internally for financial planning.

5.6. Forecast Evaluation

The company evaluates its model regularly by comparing the forecasted annual demand for the first two years of the forecast period to actuals and has found that over the long term after accounting for heating value and weather the absolute average variance is within 1% in the first year and within 2.6% in the second year.

5.7. Forecast Resources

The company's forecasting department included seven full time staff including the manager. Approximately three FTE prepare the forecast over a four-month period. The other staff members work on the surveys and maintaining the databases.

The economic forecast is provided by the Economic Analysis Department, who purchase the documents.

5.8. Peak-Day Demand Forecast vs. Annual Demand Forecast

The company does not prepare a long term peak-day demand forecast as it is only used for gas purchase planning. As a result, the peak-day demand forecast is based on the previous year's peak-day demand.

6. Union Gas

6.1. Overview

The company is an investor owned utility that serves over 1.4 million natural gas customers in over 400 communities.

The company does not prepare a long term annual demand forecast. It only prepares a four-year forecast, which included the current year. The company is however, exploring the possibility of preparing long term forecasts. The company has not settled on the forecasting horizon for a long term forecast, if it decides to prepare a long term forecast, however, a 10-year forecasting period is a possible time horizon for a long term forecast.

6.2. Forecasting Method

The company uses an econometric model in preparing its forecast for the residential and commercial sectors. It uses the most recent annual demand for its less than 500, large contract customers.

The company's econometric model for residential and commercial customers uses actual monthly average use per account for each rate class for the previous 10 years and runs a regression analysis of the data against demographic and econometric indicators. The regression model includes an "efficiency index", which represents a weighted average efficiency of furnace efficiencies from the company's REUS. The company conducts a REUS annually.

For the less than 500 large contract customers, the company's forecast uses the most recent annual demand for each customer. These customers have dedicated key account managers, who then review the forecasts for their customers and adjust the forecasts if the customers have advised them of any changes to their expected gas use.

6.3. Forecasting Parameters

The parameters used in the forecasting model include:

- Efficiency Index, which represents the weighted average furnace efficiency from the company's REUS
- Number of people per household
- Total gas bill in dollars
- Weather

The company evaluates its model annually and in some years some parameters used in the model may be replaced.

6.4. Forecasting Scenarios

The company runs sensitivity analysis on its forecast for the residential and commercial sectors. It runs alternative scenarios to assess elasticity of demand in response to changes in gas prices, weather and number of customers.

6.5. Forecast Period and Update Frequency

The company does not prepare a long term annual demand forecast. It only prepares a four-year forecast, which included the current year. The company is however, exploring the possibility of preparing long term forecasts. The company has not settled on the forecasting horizon for a long term forecast, if decides to prepare a long term forecast, however, a 10-year forecasting period is a possible time horizon for a long term forecast.

The company updates its forecast annually and prepares a forecast for each year during the forecast period.

6.6. Forecast Evaluation

The company evaluates its model annually. It has a good understanding of the impact of each parameter on it forecasts. It compares the forecasted annual demand to actuals and has found that over the long term the actuals are within 2.5% of the forecasted demand.

In 2003/04 the company was directed by the regulator to retain a consultant to evaluate its forecasting method. The consultant found the company's method to be acceptable and in line with other forecasting practices.

6.7. Forecast Resources

The company only uses internal resources in preparing its forecast. The forecast is prepared by 2 FTEs one prepares the forecast for residential and commercial customers and the second prepares the forecast for large contract customers.

6.8. Peak-Day Demand Forecast vs. Annual Demand Forecast

The company forecasts its peak-day demand by applying a weather factor to the average daily demand from annual demand forecast.

7. SaskEnergy & TransGas

7.1. Overview

The company is a crown corporation and owns and operates a natural gas distribution system that serves over 385,000 residential, farm, commercial and industrial customers through its natural gas distribution systems. Through one of its subsidiaries, the company's operates natural gas transmission system with over 14,000 kilometres of high pressure natural gas pipelines and gas storage sites as well as serve the large industrial customers.

The transmission company uses its forecasts primarily to assess load requirements, urban growth, which may encroach on its assets and result in potential relocation of the assets.

7.2. Forecasting Method

The gas distribution company does not prepare a long term annual demand forecast. However, the company's subsidiary that operates the gas transmission system prepares a long term forecast, which includes the demand from the distribution company.

The distribution company uses a top-down qualitative model to prepare its forecast for each rate class. This model is based on an econometric model that uses economic forecasts from government agencies.

The forecast for growth in the number of accounts is based on economic forecasts and most recent historical trends.

The forecast for average use per account for residential and small commercial customers is based on weather normalized historical data, while the annual demand forecast for large commercial customers is based on the annual demand from the previous year.

Since the transmission company's customers are large industrial customers and the distribution company, its annual demand forecasts are based on forecasts provided by customers. When it receives new service requests, it includes a probability of the customer coming online during the forecast period.

The transmission company also works with the electric utility to assess conversion of coal-fired power plants to natural gas plants over 20 to 30 years.

7.3. Forecasting Parameters

The company's econometric model uses a number of parameters, which include:

- Economic forecasts from various government agencies
- Input from builders to assess housing starts
- Economic and housing starts forecasts from CMHC and Statistics Canada

7.4. Forecasting Scenarios

The distribution company develops a base case and two alternative scenarios based on warm weather and cold weather with two standard deviations from the base case forecast.

The transmission company develops a base case, which is based on the probability of new customer additions coming online. In addition, it also develops a high case scenario.

7.5. Forecast Period and Update Frequency

The distribution company prepares an annual demand forecast every year.

The transmission company prepares five to 10-year forecasts with results for each year across the forecast horizon and updates these annually as part of its budget planning cycle. However, most of its forecasts are five year forecasts.

The transmission company also works with the electric utility to assess conversion of coal-fired power plants to natural gas plants over 20 to 30 years.

7.6. Forecast Evaluation

The distribution company evaluates the performance of its forecasting model by comparing weather normalized actual annual demand to weather normalized forecasted annual demand. Forecasts are generally within one to two percent of actuals.

The transmission company evaluates the performance of its forecasting model by comparing its budgeted annual demand to its actual throughput. Forecasts are generally within one to two percent of actuals.

7.7. Forecast Resources

The distribution company only uses internal resources to develop its annual demand forecast and estimates approximately ¼ of an FTE is required in preparing the forecast.

The transmission company only uses internal resources to develop its annual demand forecast. While four people from different departments are involved in preparing the forecast, it estimates approximately one FTE is required.

7.8. Peak-Day Demand Forecast vs. Annual Demand Forecast

The distribution company does not prepare a peak-day demand forecast. The peak-day demand forecast is provided by the transmission company.

The transmission forecasts the maximum daily demand for its customers based on historic customer demand and customer feedback. It then compares the correlation of the peak-day demand to annual demand for each customer to other customers in the same sector based on the sector load factor. Its peak-day demand is generally 20% higher than its average daily demand.

8. Pacific Northern Gas

8.1. Overview

The company serves approximately 40,000 customers. The company used end-use forecasting in its most recent long term forecast, which was part of its long term resource plan.

The company has experienced declining use per account in its residential and small commercial sectors, which is likely due to building code improvements and increased appliance efficiencies.

8.2. Forecasting Method

The company uses three different approaches to forecasting annual demand for its three customer classes.

The company forecasts annual demand for its large industrial and commercial customers based on the results of a customer survey. The company sends out a survey to its large customers asking for customers to provide a forecast of their gas use. In cases when a customer forecasts significant change from its historical trend, the company follows up with the customer to verify the customer's forecast.

Forecasts for small commercial customers are based on historical trend analysis coupled with forecasted population growth in the company's service area. Historical trend analysis is used to determine the average use per account, while population growth forecast is based on data from government agencies. The company uses population growth rather than growth in number of housing units because it has found that population growth provides a better correlation to growth in the number of commercial customers.

The company uses an end-use model to forecast the average use per residential customer. The model uses a number of parameters to forecast gas use based on type of dwelling and number of appliances. It uses conditional demand analysis to determine the relationship between the various parameters and gas use per residential customer. The number of residential customers used in the forecast is based on forecasted additions to the number of household in the company's service area provided by government agencies.

The company completed a Residential End Use Survey (REUS) to collect the data on the demographic makeup and consumption behavior of its residential customers. It used this data together with historical customer billing data as key inputs into its residential forecasting model. The model accounts for building code improvements in new homes as well as replacement of appliances with more efficient appliances as customers replace appliances at the end of their useful life. The company used conditional demand analysis techniques to develop end-use models for single family dwellings (SFD), duplexes (DUP), multi-family dwellings (MFD) such as triplexes and townhouses, apartments and condominiums in vertical subdivisions (VS), and mobile homes (MH). It takes into account various characteristics of the natural gas consumption by residential customers such as the distribution of annual demand, the penetration rate and portion of the overall demand of each end-use based on the results of the REUS.

8.3. Forecasting Parameters

The parameters used in the company's residential forecasting model for forecasting average use per residential customer include:

- Dwelling type
- Type of construction
- Number of gas appliances in the home
- Type of gas appliances in the home
- Behaviour of the residents

The company collected this data from its REUS.

8.4. Forecasting Scenarios

The company prepared a base case forecast as well as a high case and a low case for its forecast. These were based on the addition or loss of a large customer and different average use per account for the residential sector based on the REUS.

Alternative demand scenarios were developed to provide some indication of the sensitivity of the demand forecasts to changes in forecast economic and climatic conditions as well as to provide a range of demands that could reasonably be expected. The sensitivity analysis reflected increase in electricity prices and the carbon tax. The scenarios were based on changes to the residential and small commercial demand resulting from changes in the penetration of natural gas versus electricity as the fuel for space and water heating applications. The underlying growth in households and small commercial enterprises remains the same in the base case and competitive electricity price, while the capture rates were adjusted to reflect varying degrees of probability that new households and commercial enterprises use natural gas. Additional growth was reflected in the competitive gas price scenario to account for growth.

8.5. Forecast Period and Update Frequency

The company updates its long term forecast when it files its resource plan. PNG expects to file its resource plan with the BC Utilities Commission every four years.

The company prepares a forecast for each year during the forecast period.

8.6. Forecast Evaluation

The company does not explicitly evaluate the performance of its long term forecast model by using the actual number of customers in the model and adjusting for different assumptions used in the model, however, it does compare actual annual demand to forecasted annual demand. It has found that the forecasts are reasonable and there are no significant variations.

8.7. Forecast Resources

The company was using external resources to prepare its long term forecast, but plans to use internal resources, which are estimated at approximately one third of an FTE.

8.8. Peak-Day Demand Forecast vs. Annual Demand Forecast

The company has determined the load factor for each customer class using regression analysis of energy consumption against HDD. It then applies the load factor to the annual demand forecast for each customer class to forecast the peak-day demand for each customer class. As a final step in forecasting peak-day demand, the company sums up the peak-day demand for each customer class and adds the forecast for company gas use to forecast the peak-day demand for the system.

The company used a 50-year period in determining the design day demand.

9. Colorado Springs Utilities[5]

9.1. Overview

The company is municipally owned utility that provides water, electricity, and natural gas. The city has a population of approximately 416,000 and its economy is based substantially on employment attributable to service industries, retail businesses, construction industries, military installations, the high technology

[5] 2011 – Gas Integrated Resource Plan (GRIP)

industry and tourism. The company serves over approximately 192,000 gas customers and 217,000 electricity customers

The company's forecasts were developed as part of its 2011 Gas Integrated Resource Plan (GIRP). The 2011 GIRP included an annual demand forecast, a peak-day demand forecast, and a peak-hour demand forecast.

The annual demand forecast was used to prepare revenue budgets and develop long term natural gas procurement plans, while the peak-day and peak-hour demand forecasts were used to assess the adequacy of its transportation capacity, storage deliveries, the need for new capacity, and on-system propane-air production against future demand.

Over the past two decades the company's annual use per residential customer has declined by approximately 25% and is forecasted to decline further and then stabilize in the future due to replacement of older furnaces with higher efficiency furnaces and higher efficiency standards. The company forecasted efficiency standards for water heaters and clothes dryers to also contribute to declining use per residential customer.

The company forecasted that its use per non-residential customer to decrease slightly in the near term in response to price increases and more efficient buildings. It forecasted that longer term, gas use per non-residential customer to stabilize because of increasing average building size to accommodate more employees.

9.2. Forecasting Method

The company's annual demand forecast uses a combination of econometric and end-use (or engineering) modeling. The company's traditional econometric models were based on historical data and the interactions of different economic indicators. With the introduction of Federal efficiency standards, the company believed that the historical relationship could change. The company accounted for these new appliance efficiency standards by using an end-use model to adjust the results of the econometric model for the residential sector. The company continues to use the econometric approach for the commercial sector.

The primary driver of overall demand forecast for the company is the customer count. The second factor in the overall demand forecast is the use per customer.

The company bases its customer count forecast on the population and employment forecasts developed by the state agencies. It also uses other economic variables from Moody's Economics forecast for the U.S. and local economies.

The company bases its residential use per customer forecast on an end use model. The end use model accounts for the effects of appliance efficiency standards, which subsequently impact the forecasted use per customer. The company accounts for the impact of more efficient furnaces, water heaters, range/ovens and clothes dryers in its forecast.

9.3. Forecasting Parameters

The company considers the following parameters in developing its demand forecast:

- Population
- Employment trends
- Inflation
- Traffic area zones (TAZ) based on government planning information
- Construction trends and housing permits, and
- New use development (e.g. natural gas vehicles).
- Average daily temperatures data dating back to 1946, and determined -13 °F average daily temperature to be a one in twenty-year occurrence.
- Wind speed
- Customer growth rate
- Demand response of existing residential, commercial, and industrial customers

9.4. Forecasting Scenarios

The company uses a number of demand scenarios, which included:

- Expected
- High Growth
- Low Growth
- Get the Green Back
- Supply Constraints

These demand scenarios do not represent the maximum bounds of possible demands, but offered a broad range of potential outcomes.

“Expected” demand is based on normal weather and growth. It represents the most likely scenario. The company aligns its long-term strategies to support this scenario. Since the company’s interruptible customers have the option of converting to firm service, the demand scenarios assume that interruptible customers are not curtailed except for two power plants.

9.5. Forecast Period and Update Frequency

The company prepares a forecast which includes the annual demand forecast for every year during the 20-year forecast period.

9.6. Forecast Evaluation

The company uses a separate analysis using single and multiple factor linear regression to validate the corporate sales and load forecast for peak-day and peak-hour forecasts. The company's separate analysis demonstrated statistical agreement with the corporate sales and load forecast.

9.7. Forecast Resources

This information was not available.

9.8. Peak-Day Demand Forecast vs. Annual Demand Forecast

The company uses peak-day and peak-hour demand forecasts to determine the adequacy of existing supply resources, or the timing for new resource acquisitions or capital investments required to meet customers' natural gas needs during a peak event. The company has determined that these peak conditions occur once every 20 to 30 years and typically last no more than 3 consecutive days.

Prior to the 2011 GIRP the demand forecast was developed through multiple linear regression analysis. The key inputs into this model included daily load, customer count, and temperature data from multiple years for loads greater than 160,000 Mscf/day.

In February 2011, the company experienced a significant cold weather event, which revealed gaps in the company's demand modeling methodology. As a result, the company revised its forecasting method to better correlate forecasts with an actual peak-day and peak-hour event. The improvements included:

- Widening the data set with hourly load data
- Eliminating weekend data from the data set
- Including wind effects and
- Switching to a use per customer approach to determine daily peak loads for temperatures less than 50° F

Based on actual peak events, the company determined a multiplier that it applied to peak-day load to determine peak-hour load forecasts.

10. Black Hills Energy – Iowa[6]

10.1. Overview

The company operates natural gas and electric utilities that serve 1.2 million customers in eight states: Arkansas, Colorado, Iowa, Kansas, Montana, Nebraska, South Dakota and Wyoming.

[6] Black Hills Energy Natural Gas Energy-Efficiency Plan 2014-2018: Appendices E-H

Forecasts were developed as part of its 2014 to 2018 Natural Gas Energy Efficiency Plan. The company developed an annual demand forecast and a peak-day demand forecast for each customer class.

10.2. Forecasting Method

In its filing, the company stated that it used a combination of econometric and end-use models to forecast monthly and peak-day demand. However, the description of their models does not clearly describe how the company used an end use model. Further review of the company's supporting documents submitted as part of its 2008 filing, including a file with the common assumptions, showed that the company used hourly load shapes for various end uses to determine end use forecasts. This model may be what the company referred to in its 2014 to 2018 Natural Gas Energy Efficiency Plan.

The company developed separate forecasts for each of the major customer classes, which included residential, commercial, industrial, transportation, and other.

The company's models quantify the impact of the significant factors that determine residential, commercial and industrial annual demand and peak-day demand. Econometric/end-use class sales models were developed to take into consideration as many of the important factors as possible.

The company used its most current historic data over a four-year period in the models for residential, commercial, and industrial classes to determine the factors which could significantly impact the monthly demand and peak-day demand. Monthly HDD was used to capture the effect of weather variation on seasonal gas usage. The company also used economic and natural gas price variables together with a heating index (end-use efficiencies and market shares).

The company's annual demand forecast included the impact of previous improvements in energy efficiency and shows a declining annual use per customer for the following five years. Impacts of future energy efficiency programs are not included in the forecast.

The company's residential use per customer was based on actual monthly use per customer explained by weather and historical trends, while annual demand growth in commercial, industrial, and transportation classes were affected by the state's real GDP, natural gas prices, and customer class migration.

The company used monthly data in its class end-use models to better capture the weather impact on monthly demand.

10.3. Forecasting Parameters

The data used to develop the annual demand forecasts included the monthly number of customers, sales volumes, use per customer, and gas prices over the most recent four-year period for each customer class.

Actual HDD and normal HDD from NOAA for four weather stations, weighted by usage were used to normalize the forecast for weather.

The key assumptions used to develop demand forecasts for each customer class included:

1. In the short run, appliance stocks are fixed. Consumption arises from the varying utilization rates.
2. Appliance utilization rates are determined by the price of natural gas, real personal income, housing size, and heating degree days.
3. In the long run, the equipment stock is not fixed and energy-efficient equipment can be installed by households and firms.

The primary factors that impact demand forecast were:

- Customer Growth
- Personal Income Growth
- Price of natural gas and elasticity
- Price of alternate fuels
- Real state GDP for gas utility service area

10.4. Forecasting Scenarios

The company conducted sensitivity analysis to quantify margins of error for two major peak-day demand assumptions:

1) growth in the number of households and
2) growth in commercial, industrial and transportation demand forecasts

The sensitivity analysis presented the relative impact of changes in the number of residential customers, as well as high and low gas prices on peak-day demand.

The company developed a base case, a low case, and a high case for its annual demand forecast and its peak-day demand forecast. In the high case, the number of customers and use per customer were forecasted to grow at higher rates than in the base case forecast; and in the low case, the number of customers and use per customer were forecasted to grow at lower rates, or decline, compared to the base case forecast.

10.5. Forecast Period and Update Frequency

The company's forecast period was from 2013 to 2017. The company developed forecasts for each year during this period.

10.6. Forecast Evaluation

This information was not available.

10.7. Forecast Resources

This information was not available.

10.8. Peak-Day Demand Forecast vs. Annual Demand Forecast

Peak-day demand forecast was based on the peak weather experienced in the last twenty years.

The forecast for peak-day demand was based on an analysis of historical actual peak-day total throughput and actual HDD on dates when peak-days occurred.

11. Avista Utilities[7]

11.1. Overview

The company is an investor owned utility that serves more than 600,000 electric and natural gas customers. Its service territory covers 30,000 square miles in eastern Washington, northern Idaho and parts of southern and eastern Oregon, with a population of 1.5 million.

The company's forecasts were developed as part of its 2014 GIRP. The company developed an annual demand forecast and a peak-day demand forecast.

The company uses annual average demand forecast to prepare revenue budgets, develop natural gas procurement plans, and prepare purchased gas adjustment filings. It uses its peak-day demand forecast to determine the adequacy of existing resources or the timing for acquiring new resources to meet customers' needs in extreme weather conditions.

The company's recent usage data indicated that long run use per customer has been declining. The company attributes this to a confluence of factors including high unemployment, increased investments in energy efficiency measures, building code improvements, behavioral changes, and heightened focus on consumers managing their household budgets.

11.2. Forecasting Method

The company uses an econometric model to prepare its annual demand forecast.

The primary drivers of the company's overall demand forecast are customer growth and use per customer.

The company forecasts the number of customers for each customer class using national economic forecasts and then drills down into regional economies. US GDP growth, US and regional employment growth, and regional population growth forecasts are the key drivers in regional economic forecasts and are used to estimate the number of customers. The company combines this data with local knowledge

[7] 2014 Gas IRP

about sub-regional construction activity, age and other demographic trends, and historical data to develop its 20-year customer forecasts.

The company forecasts its use per customer using regression modeling. The company develops base and weather sensitive demand coefficients that are combined and applied to HDD weather parameters to determine average use per customer.

The company uses historical daily gas flow data from all of its city gate stations. It uses city gate data over revenue data because of the high correlation between weather and demand. The company's revenue system does not capture daily data; therefore, it could not be used in the daily regression modeling. The company, however, reconciles city gate station data against revenue data to ensure the total demand is properly captured. The company uses three years of historical data in its regression modeling and to derive the use per customer coefficients. The company also considered using five years of historic data in its regression modeling and found that five years of data resulted in slightly lower use per customer, which may understate demand as the economy recovers and customer usage pattern return to pre-recession patterns. The regression modeling is performed for each of the company's service territories and temperature zones.

The base usage calculation uses three years of July data to derive coefficients. The base usage coefficient is determined by dividing the average usage in these months by the average number of customers. The company performs this calculation for each area and each customer class.

The company defines eight distinct demand areas in its IRP. These areas are structured around the pipeline transportation and storage resources that serve them.

The company uses the most current 20 years of daily weather data from the NOAA as the base weather forecast to prepare the annual average demand forecast.

The company analyzes an alternate planning standard using the coldest temperature in the last 20 years.

As a final step, the company checks the reasonableness of its coefficient by applying the coefficients to actual customer count and weather data to backcast demand. This compares to actual demand with satisfactory results.

Figure 4 below illustrates the company's method in developing its forecast.

Figure 4. Forecasting Method

Financial Planning and Analysis (FPA) Gas Forecast

Accounting revenue reports for ID, WA, and OR customer count and load data.

Forecast Drivers: HDD, GDP, IP, non-farm employment, and population.

Update spreadsheet with new data each month.

Gas forecast is done twice a year, in June and December. During IRP years, one of these forecasts will be extended to produce the long-run customer projections. The FPA forecast is largely based on an ARIMA based approach with historical billed load data.

Generate a monthly forecast of customers and load by rate schedule. The forecast is 5-years out non-IRP years and 20-years out in IRP years. All forecasts assume average weather using a 20-yer moving average of HDD.

FPA customer forecasts sent to Gas Supply. Customer forecasts are used in Sendout® to (1) generate an aggregate load forecast for firm customers and (2) verify that it lines up with the annual aggregated load forecast from FPA. This process is a cross verification of both forecasts and ensures there are no material differences between the forecasts used for financial forecasting and gas purchase decisions. A 20-year moving average also applied in the Sendout®. forecast.

Sendout® and FPA forecasts are sent to Resource Accounting. The FPA firm load forecast is converted into load shares by schedule, and these shares are applied to the Sendout® forecast to generate the load forecast by firm class and schedule. The forecast is allocated from the Sendout® total to capture the unbilled portion that is not present in the billed data used by FPA. The forecasted loads are converted to revenues that reflect both billed and unbilled dollars. Forecasts for transportation and interruptible schedules come directly from the FPA forecast, and not Sendout®.

The final revenue forecast from Resource Accounting is sent back to FPA for use in the company's earnings model.

11.3. Forecasting Parameters

Weather is the most significant factor influencing demand. Other factors that the company uses include population, employment trends, age and income demographics, construction trends, conservation technology, new uses (e.g. natural gas vehicles), and use-per-customer trends.

The company also analyzes factors that could influence natural gas prices and demand through price elasticity, as customers may adjust consumption in response to changes in price. These include:

- **Supply Trends:** shale gas, Canadian supply availability, and export LNG.
- **Infrastructure Trends:** regional pipeline projects, national pipeline projects, and storage.
- **Regulatory Trends:** subsidies, market transparency/speculation, and carbon legislation.
- **Other Trends:** thermal generation and energy correlations (i.e. oil/gas, coal/gas, liquids/gas).

11.4. Forecasting Scenarios

The company recognizes that historical energy use trends may fundamentally change. The company developed a dynamic demand forecasting model that is flexible to changing assumptions. This helps the company examine a range of potential outcomes.

The company uses a reference case based on historical data and conducted sensitivity analysis on key demand drivers. The company uses this information and input from a technical advisory committee to create several alternate demand scenarios for detailed analysis.

The company groups the demand drivers into two categories:

- Demand Influencing Factors, which directly influence natural gas consumption of core customers.
- Price Influencing Factors, which indirectly influence natural gas consumption of core customers through a price elasticity response.

The company analyzes 17 demand sensitivities to determine the results relative to the reference case. These are summarized in Table 4.

Table 4. Demand Sensitivities and Sensitivity Analysis

Scenario	Influence	Weather	Growth	Use per Customer	Price Curve	Carbon Adder	LNG Adder	DSM	New Markets	Elasticity
Reference Case	Direct	Normal	Expected	3 year	Expected	No	No	No	No	No
Reference Case plus Peak Weather	Direct	Peak	Expected	3 year	Expected	No	No	No	No	No
High Growth Case	Direct	Peak	High	3 year	Expected	No	No	No	No	No
Low Growth Case	Direct	Peak	Low	3 year	Expected	No	No	No	No	No
Alternate Use per Customer	Direct	Peak	Expected	5 year	Expected	No	No	No	No	No
New Markets Case	Direct	Peak	Expected	3 year	Expected	No	No	No	Yes	No
DSM	Direct	Normal	Expected	3 year	Expected	No	No	No	No	No
Peak plus DSM	Direct	Peak	Expected	3 year	Expected	No	No	Yes	No	No
Alternate Weather Planning Standard	Direct	Coldest in 20	Expected	3 year	Expected	No	No	Yes	No	No
Expected Elasticity	Indirect	Peak	Expected	3 year	Expected	No	No	No	No	Yes
Low Price	Indirect	Peak	Expected	3 year	Low	No	No	No	No	No
High Price	Indirect	Peak	Expected	3 year	High	No	No	No	No	No
Carbon Legislation - Low	Indirect	Peak	Expected	3 year	Expected	Yes	No	No	No	No
Carbon Legislation - Medium	Indirect	Peak	Expected	3 year	Expected	Yes	No	No	No	No
Carbon Legislation - High	Indirect	Peak	Expected	3 year	Expected	Yes	No	No	No	No
Exported LNG	Indirect	Peak	Expected	3 year	Expected	No	Yes	No	No	No

After testing the sensitivities, the company groups them into meaningful combinations of demand drivers to develop demand forecasts representing scenarios. These demand scenarios include:

- Average case – this case represents the case used for normal planning purposes, such as corporate budgeting, procurement planning, and General Rate Cases
- Expected case – this case reflects the demand forecast Avista believes is most likely given peak weather conditions
- High growth, low price case – this case represents high customer growth and low future prices
- Low growth, high price case – this case represents low customer growth and high future prices
- Alternate weather standard – this case utilizes the coldest day in Avista's service territories in the last 20 years

The company also analyzes three carbon sensitivities and their impact on the demand forecasts based on different levels of carbon tax to assess the impacts of uncertain carbon legislation.

11.5. Forecast Period and Update Frequency

The company's IRP planning period was from 2014 to 2033. The company developed forecasts for each year during this period.

Even though the company publishes an IRP every two years, it updates its forecast with new information and developments in the years between IRP filings.

11.6. Forecast Evaluation

As a final step in its forecasting process, the company checks the reasonableness of the coefficients from its regression model by applying the coefficients to actual customer count and weather data to backcast demand. This compares to actual demand with satisfactory results.

11.7. Forecast Resources

This information was not available.

11.8. Peak-Day Demand Forecast vs. Annual Demand Forecast

The company uses a five-day cold weather event to forecast its peak-day demand. The peak-day demand forecast includes adjustments to average weather to reflect a five-day cold weather event. This consists of adjusting the middle day of the five-day cold weather event to the coldest temperature on record for a service territory, as well as adjusting the two days on either side of the coldest day to temperatures slightly warmer than the coldest day.

The company develops a super peak coefficient to capture gas use in extreme weather conditions because in extreme weather conditions demand can begin to flatten out relative to the linear relationships at less extreme temperatures.

The model for deriving super peak coefficients is derived by averaging the heat coefficients for December, January and February. Because of the lack of sufficient data points to develop a strong linear relationship, the company continues to test this theory and monitor trends.

11.9. Global Warming

In previous IRP's the company adjusted NOAA weather data to incorporate estimates for global warming. This adjustment was based on analysis of historical weather data in each of the areas served. In its 2014 IRP, the company moved away from adjusting the weather data and moved from a rolling 30-year average to a 20-year average. The company moved to a 20-year average because NASA climate studies indicated that the distribution of temperatures in North America began to shift upwards significantly about 20 years ago and although a 10-year moving average captures turning points in climate trends more quickly than 15, 20 or 30-year averages, it will do so at the cost of larger year-to-year changes in the measurement of normal weather.

The company was unable to find any definitive evidence to support a peak-day warming trend. After discussion with the TAC, the company decided to discontinue global warming trend adjustments to the peak day weather events in the HDD forecast. Therefore, the modeling and analysis with respect to peak day planning is unaffected by global warming.

12. Cascade Natural Gas Corporation[8]

12.1. Overview

The company serves more than 272,000 customers in 96 communities in western and central Washington and central and eastern Oregon.

The company developed a long-term forecast of natural gas demand in its service territory as part of its 2011 IRP. The company uses an econometric model to develop its demand forecast.

Residential and commercial load growth is primarily a result of increased customer counts.

The forecast is used in short-term (annual budgeting) and long-term (distribution and integrated resource planning) planning processes.

The number of residential and commercial customers is expected to increase faster than energy use per customer. Factors that have resulted in lower user per customer are believed to be soft conservation (such as behavioural changes), building codes, and heat pump penetration. The reduction in use per account is more prevalent among residential customers than commercial.

12.2. Forecasting Method

The company retained a consultant to develop its forecasting model. The model is based on an Excel spreadsheet. However, the forecasting department is seeking budget approval to acquire a commercial forecasting software.

The company starts its forecast process by developing separate econometric models representing the company's three main core customer classes (residential, commercial and industrial) for each of the company's 15 districts for a total of 45 models. These models forecast the number of customers for each of the three main core customer classes. These customer count forecasts are designed to reflect both demographic trends and economic conditions both in the short and long term in each district.

The models are built up from the district level, because it is the smallest level where consistent raw data is available. This is a change from previous years where certain models were built from the town level and others from the district. The company expected to improve the reliability of its forecast by unifying its forecasting method. The district models are rolled up into zones based on the pipelines serving the districts and weather.

In addition to these 45 customer count forecasting models, a separate and parallel set of 45 models are used to estimate energy use per customer for each customer class in each district. The use per customer forecasts are developed based on multi-variable regression analysis for each customer class using

8 2011 Integrated Resource Plan

historical weather and energy use data. The historical data used in the regression models extended back to 1980 for customer counts and 1994 for energy use.

The results of the customers count and energy use per customer models are then used to determine the annual gas demand by customer class and district.

These forecasts exclude any saving that may result from the company's energy efficiency programs. The company's energy efficiency and conservation group reviews the forecast and adjusts these forecasts based on the forecasted energy savings from their energy efficiency programs.

The company uses the same model for short term and long term forecasting.

12.3. Forecasting Parameters

The parameters used in the model for forecasting customer count include:

- Employment forecast
- Number of households forecast
- Mortgage rates (for residential customer counts)
- Prime rate (for commercial and industrial customer counts)

The parameters used in the model for forecasting use per account include:

- Median household income forecast
- Weather and
- Natural gas prices

The company uses economic indicator forecasts from Woods & Poole and mortgage rate and prime rate forecasts from Freddie Mac and the Federal Reserve, respectively.

Past weather data is obtained from NOAA and future weather data is based on the company's 20-year normal weather developed for its last rate case.

Natural gas prices are obtained from Wood Mackenzie and equal weights are assigned different price indexes based on the company's general portfolio mix.

These indicators are used over other indicators as they are the most consistent in returning statistically valid results.

12.4. Forecasting Scenarios

The company's customer count and energy use forecasts are augmented by revising the base data and output to create a portfolio of potential scenarios. Low and high growth scenarios are created by altering Woods & Poole's forecasts to reflect the company's strongest and weakest performing decades over the last 30 years. These scenarios, along with the original best-estimate mid case scenario, form a range of most-likely possibilities.

High and low scenarios are created by examining the best and poorest performing years from the historical data period, 1980 to 2009. They provide a range for the annual load and peak-day demand forecasts should the underlying indicators vary from Woods & Poole's long range estimates.

12.5. Forecast Period and Update Frequency

The company develops a 20-year forecast of customers, annual demand, and peak-day demand for each year during the forecast period.

The company develops a 20-year forecast of customers, annual demand, and peak-day requirements for use in short (annual budgeting) and long-term (distribution and integrated resource planning) planning processes each year. Updates to the forecasts may be prepared three to four times per year for use in annual budgets, rate cases, and IRP filings. IRPs are prepared every two years.

12.6. Forecast Evaluation

The company evaluates its forecasting model by using actual weather conditions and actual number of customers in the model and comparing the results to previous forecasts. While the model has performed well overall, it has under-forecasted demand in the winter and over-forecasted demand in mild summers.

12.7. Forecast Resources

The forecasts are prepared internally by the forecasting department which obtains economic forecast reports from Woods & Poole and also consults with other consultants as needed.

One person in the forecasting department maintains the models, while three people in the energy efficiency and conservation department update the forecast prepared by the forecasting department to reflect impact of energy efficiency programs.

12.8. Peak-Day Demand Forecast vs. Annual Demand Forecast

The company develops peak-day forecasts in conjunction with annual demand forecasts to ensure it can meet the demand by its core customers on the coldest days.

Historically the company developed peak-day forecasts based on a 65 HDD day (0°F) to reflect the coldest day in its 60-year weather history. The company's 2008 IRP changed this practice to reflect the coldest day during the past 30 years. The peak-day forecast is developed by adjusting the energy use on the coldest day in recent history upwards to an estimate of what energy use would have been had that day been the coldest day in the past 30 years. The energy use is then applied to each district and escalated into the future at the forecasted annual growth rate for energy use.

This method assumes that core market load shape does not significantly change throughout the forecast period. The company believes that the peak-day forecast conservatively overestimates peak-day demand as the base forecast does not explicitly include future conservation measures implemented by customers.

Appendix B. GLOSSARY

AMI – Advanced Metering Infrastructure

CEC – California Energy Commission

CED – California Energy Demand

CGR – California Gas Report

CMHC – Canada Mortgage and Housing Corporation

CO_2 – Carbon Dioxide

DSM – Demand Side Management

EE – Energy Efficiency

EG – Electricity Generation

EPRI – Electric Power Research Institute

EU – End Use

EUI – End Use Intensity

FTE – Full Time Equivalent

FEU – FortisBC Energy Utilities

GDP – Gross Domestic Product

GHG – Greenhouse Gas

GIRP – Gas Integrated Resource Plan

HDD – Heating Degree Day

HVAC – Heating, Ventilation, and Air Conditioning

IEPR – Integrated Energy Policy Report

IOU – Investor Owned Utility

IRP – Integrated Resource Plan

LNG – Liquefied Natural Gas

LTRP – Long Term Resource Plan

m^3 – Cubic Metre

MFD – Multifamily Dwelling

MH – Mobile Home

Mscf – Million Standard Cubic Feet

MURB – Multi-Unit Residential Building

NAICS – North American Industry Classification System

NAMGas Model – North American Market Gas-Trade Model

NASA - National Aeronautical and Space Agency

NGV – Natural Gas Vehicle

NOAA – National Oceanic and Atmospheric Administration

PNG – Pacific Northern Gas

PSE – Puget Sound Energy

REUS – Residential End Use Survey

SFD – Single Family Dwelling

TAC – Technical Advisory Committee

UPC – Use Per Customer

UPA – Use Per Account

VS – Vertical Subdivisions

ZNE – Zero Net Energy

Appendix B-3

TRADITIONAL ANNUAL DEMAND FORECAST

APPENDIX B-3: TRADITIONAL ANNUAL DEMAND FORECAST

This appendix provides further background on and key results from the Traditional Annual Method. Just like the end-use method, the Traditional Annual Method uses a 2015 base year.

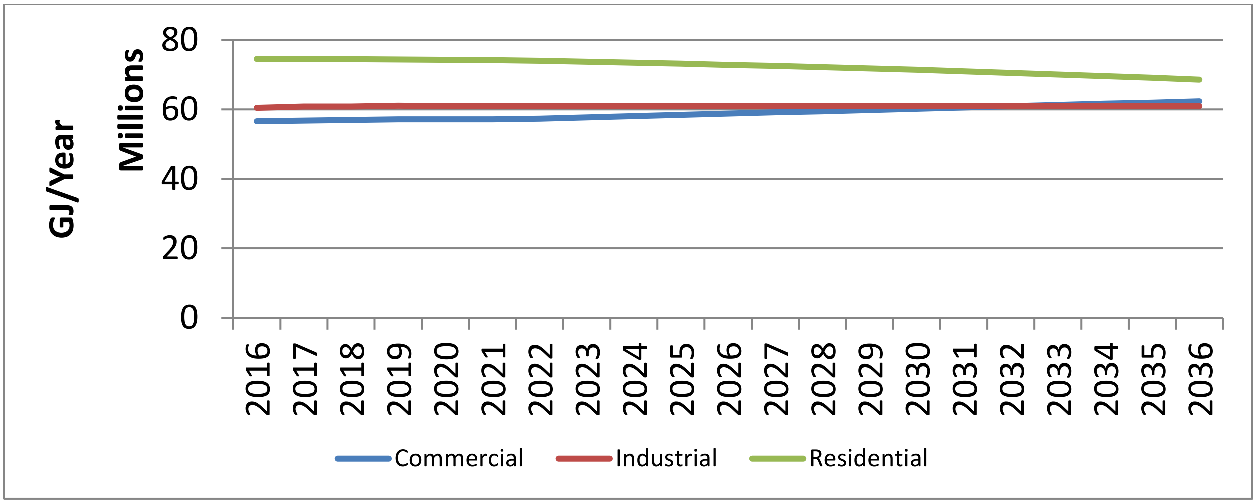
1.1 Traditional Annual Demand Method – Residential, Commercial and Industrial

The Company's Traditional Annual Method for forecasting residential and commercial demand involved determining a forecast natural gas Use per Customer (UPC) and multiplying it by the number of customers forecasted for each year of the study period. UPC was determined by examining weather normalized historical actual demand. A regression analysis was used to identify any significant trends in the use rates. These trends implicitly included the impact of broad changes in consumption patterns that might have been caused by such factors as energy efficiency, economic activity, policies and equipment standards up to the time of the most recently available annual usage data. The analysis was conducted for each residential and commercial rate class, based on the most recent three years of data. The trends were then extended into the next 20 years for the purposes of providing a long term forecast.

FEI utilized the results of the annual industrial customer survey to identify expected changes in industrial customer demand. The survey was conducted as part of FEI's short term demand forecasting process used for gas supply planning, revenue requirements and other BCUC submissions. The intentions of industrial customers over the next five years were held constant over the LTRP planning horizon as this represents the best available information using the Traditional Annual Method.

The annual demand in each year of the forecast for each rate class in each customer category (i.e. residential, commercial, industrial) was then summed to determine the total overall residential, commercial and industrial demand. The result is a Reference Case demand scenario using the Company's Traditional Annual Method. Figure B3-1 shows the Traditional Annual Method Reference Case demand for each of the rate class categories and is followed by a general description of the forecast results for each category.

Figure B3-1: Long Term Annual Demand by Customer Category – Traditional Annual Method



1.1.1 RESIDENTIAL DEMAND

Declining residential UPC in the FEI service territories is resulting in an overall decline in residential annual demand, even though the Company continues to add residential customers through the forecast period. This decline in residential UPC is now a common occurrence affecting mature natural gas utilities across North America. Declining use rates are driven by a number of factors, such as efficiency improvements, changes in building stock, changes in appliance uptake and switching between energy sources (from gas to electricity). Efficiency improvements include the retrofit of older, less efficient appliances with new high efficiency units, and also upgrades to insulation, window, doors, and more generally speaking, building shells. Efficiency improvements are driven by a number of factors such as technological advances, construction of smaller, less energy-intensive multifamily dwellings, public policies and programs and the state of the economy. This declining trend is expected to continue through the planning period.

1.1.2 COMMERCIAL DEMAND

In the Traditional Annual Method forecast, the recent demand increases seen in the commercial rate classes are assumed to continue into the long term and thus, commercial demand grows over the 20 year planning horizon.

1.1.3 INDUSTRIAL DEMAND

Overall industrial demand is forecast to be stable through the planning horizon.

1.2 Conclusion

The Traditional Annual Method represents an extension across the planning period of intrinsic end-use trends from the most recent three years (in relation to the base year). The resulting annual demand forecast is largely flat with moderate growth in the commercial sector. Section 2 of the 2017 LTGRP discusses an uncertain and complex planning environment. Projecting existing end-use trends across the long term planning period may be unsuitable to account for uncertainty in such a complex planning environment. For this reason, FEI discusses the end-use forecast method in Section 3 of the Application. This method enables FEI to prepare a Reference Case end-use annual demand forecast but to also plan to alternate future scenarios.

Appendix B-4

ANNUAL DEMAND FORECAST TABLES

APPENDIX B-4: ANNUAL DEMAND FORECAST TABLES[1]

Reference Case

Year End Customers by Rate Schedule

Rate Class	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
RATE1	888,135	900,173	911,695	923,246	934,801	946,344	957,278	967,265	976,711	985,789	995,170	1,004,674	1,014,004	1,023,382	1,032,635	1,041,739	1,050,681	1,059,431	1,068,060	1,076,512	1,084,705	1,092,647
RATE2	85,075	86,388	87,699	89,013	90,323	91,636	92,950	94,229	95,541	96,805	98,073	99,355	100,645	101,920	103,204	104,488	105,756	107,059	108,339	109,615	110,891	112,170
RATE2_1	458	453	453	453	453	453	453	453	453	453	453	453	453	453	453	453	453	453	453	453	453	450
RATE2_2	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
RATE3	5,287	5,315	5,339	5,365	5,393	5,417	5,443	5,479	5,515	5,559	5,596	5,646	5,695	5,748	5,814	5,881	5,956	6,034	6,116	6,205	6,297	6,397
RATE4	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
RATE5	241	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	238
RATE6	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
RATE7	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
RATE22	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48
RATE23	1,722	1,740	1,757	1,776	1,794	1,811	1,830	1,847	1,866	1,881	1,899	1,917	1,937	1,953	1,970	1,983	2,002	2,016	2,033	2,043	2,059	2,074
RATE25	561	553	553	553	553	553	553	553	553	553	553	553	553	553	553	553	553	553	553	553	553	553
RATE27	107	106	106	106	106	106	106	106	106	106	106	106	106	106	106	106	106	106	106	106	106	106
RATE46	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Grand Total	**981,701**	**995,082**	**1,007,956**	**1,020,866**	**1,033,777**	**1,046,674**	**1,058,967**	**1,070,286**	**1,081,099**	**1,091,500**	**1,102,204**	**1,113,058**	**1,123,747**	**1,134,469**	**1,145,089**	**1,155,557**	**1,165,861**	**1,176,006**	**1,186,014**	**1,195,841**	**1,205,418**	**1,214,750**

Annual Use Rate per Customer by Rate Schedule (GJ)

Rate Class	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
RATE1	83.7	82.9	81.9	81.0	80.1	79.2	78.5	77.8	77.1	76.5	75.9	75.4	74.8	74.3	73.8	73.3	72.9	72.4	72.0	71.6	71.2	70.8
RATE2	329.1	328.1	326.7	325.6	324.4	323.4	322.4	321.6	320.8	320.0	319.2	318.4	317.6	316.9	316.2	315.5	314.8	314.1	313.4	312.8	312.2	311.6
RATE2_1	484.7	484.0	482.7	481.7	480.5	479.5	478.6	477.8	477.0	476.1	475.2	474.4	473.5	472.7	471.8	470.9	470.0	469.1	468.2	467.3	466.4	466.1
RATE2_2	9,274.8	9,265.4	9,244.6	9,230.4	9,213.3	9,200.7	9,188.9	9,179.5	9,170.1	9,160.7	9,151.3	9,142.0	9,132.8	9,123.5	9,114.4	9,105.2	9,096.1	9,087.1	9,078.0	9,069.0	9,060.0	9,051.1
RATE3	3,626.9	3,615.5	3,600.9	3,589.6	3,575.9	3,565.9	3,555.0	3,545.7	3,535.3	3,523.0	3,514.0	3,505.0	3,493.3	3,485.4	3,470.2	3,460.4	3,448.6	3,436.6	3,424.3	3,416.4	3,405.6	3,394.4
RATE4	5,696.8	5,699.1	5,694.8	5,695.5	5,703.7	5,715.9	5,729.5	5,745.7	5,763.0	5,759.0	5,755.2	5,751.6	5,748.2	5,745.0	5,734.2	5,723.8	5,713.5	5,703.5	5,693.7	5,683.9	5,674.2	5,664.4
RATE5	9,542.6	9,518.5	9,480.4	9,449.5	9,414.9	9,385.1	9,356.3	9,330.1	9,304.1	9,279.1	9,254.3	9,229.6	9,205.1	9,180.8	9,156.5	9,132.5	9,108.6	9,084.9	9,061.3	9,037.8	9,014.5	8,992.3
RATE6	4,242.7	4,247.5	4,247.0	4,250.0	4,248.1	4,248.7	4,249.8	4,252.2	4,254.9	4,252.8	4,250.9	4,249.1	4,247.4	4,245.8	4,242.9	4,240.2	4,237.7	4,235.4	4,233.3	4,231.2	4,229.2	4,227.2
RATE7	28,034.8	27,939.5	27,810.5	27,703.5	27,592.0	27,495.4	27,401.9	27,316.5	27,232.1	27,170.5	27,109.5	27,049.2	26,989.4	26,930.3	26,887.2	26,844.5	26,802.3	26,760.5	26,719.2	26,677.9	26,636.8	26,595.8
RATE22	771,870.1	770,317.6	767,860.4	765,990.9	763,651.4	761,725.1	759,897.3	758,302.0	756,745.4	755,020.4	753,314.2	751,627.4	749,958.7	748,309.8	746,579.6	744,871.9	743,185.6	741,520.1	739,875.5	738,241.5	736,618.2	735,005.4
RATE23	4,972.4	4,954.8	4,928.4	4,910.0	4,888.8	4,868.9	4,857.6	4,841.6	4,827.5	4,816.3	4,806.9	4,788.5	4,769.5	4,760.1	4,746.1	4,739.8	4,717.8	4,705.5	4,693.0	4,687.6	4,679.2	4,669.7
RATE25	24,718.6	24,742.8	24,640.0	24,557.3	24,464.5	24,385.7	24,310.4	24,242.9	24,177.0	24,125.7	24,075.5	24,026.3	23,978.2	23,931.2	23,894.0	23,857.8	23,822.6	23,788.4	23,755.1	23,722.5	23,690.5	23,659.1
RATE27	66,882.9	66,726.7	66,489.8	66,305.7	66,052.1	65,835.7	65,628.9	65,443.4	65,262.1	65,172.8	65,085.7	65,000.8	64,918.1	64,837.6	64,767.3	64,699.3	64,633.5	64,569.8	64,508.3	64,447.9	64,388.5	64,330.2
RATE46	37,471.6	37,377.5	37,238.7	37,126.6	37,002.8	36,897.3	36,795.1	36,702.4	36,610.0	36,518.0	36,426.2	36,334.8	36,243.7	36,152.9	36,062.6	35,972.7	35,883.1	35,793.7	35,704.7	35,616.1	35,527.7	35,439.6

Annual Demand by Rate Schedule (GJ)

Rate Class	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
RATE1	74,379,270	74,579,659	74,662,138	74,805,331	74,868,580	74,974,925	75,130,739	75,253,932	75,350,446	75,430,212	75,533,121	75,703,893	75,867,631	76,037,096	76,202,189	76,362,195	76,555,037	76,738,549	76,917,592	77,088,535	77,246,914	77,392,346
RATE2	27,994,803	28,340,278	28,651,469	28,982,497	29,301,124	29,634,357	29,969,034	30,304,766	30,648,228	30,975,855	31,303,091	31,635,506	31,969,070	32,298,588	32,631,876	32,962,195	33,290,097	33,627,312	33,957,516	34,288,142	34,619,227	34,949,492
RATE2_1	222,002	219,267	218,654	218,203	217,652	217,211	216,793	216,434	216,078	215,682	215,287	214,894	214,503	214,114	213,705	213,299	212,895	212,493	212,093	211,694	211,297	209,754
RATE2_2	64,924	64,858	64,712	64,613	64,493	64,405	64,322	64,256	64,190	64,125	64,059	63,994	63,929	63,865	63,800	63,737	63,673	63,609	63,546	63,483	63,420	63,358
RATE3	19,175,310	19,216,213	19,225,225	19,258,171	19,284,582	19,316,655	19,349,663	19,427,052	19,497,299	19,584,601	19,664,388	19,789,064	19,894,339	20,034,057	20,175,511	20,350,776	20,540,097	20,736,165	20,943,255	21,198,935	21,444,911	21,714,243
RATE4	148,116	148,177	148,064	148,083	148,296	148,612	148,966	149,388	149,838	149,734	149,634	149,541	149,452	149,369	149,090	148,818	148,551	148,290	148,036	147,782	147,528	147,276
RATE5	2,299,775	2,274,913	2,265,824	2,258,427	2,250,153	2,243,042	2,236,157	2,229,894	2,223,676	2,217,705	2,211,773	2,205,879	2,200,022	2,194,205	2,188,415	2,182,667	2,176,957	2,171,284	2,165,648	2,160,041	2,154,463	2,140,175
RATE6	50,912	50,970	50,964	51,000	50,977	50,984	50,997	51,027	51,059	51,034	51,010	50,989	50,968	50,950	50,915	50,883	50,853	50,825	50,800	50,775	50,750	50,727
RATE7	168,209	167,637	166,863	166,221	165,552	164,972	164,411	163,899	163,392	163,023	162,657	162,295	161,936	161,582	161,323	161,067	160,814	160,563	160,315	160,068	159,821	159,575
RATE22	37,049,763	36,975,247	36,857,300	36,767,565	36,655,268	36,562,804	36,475,069	36,398,498	36,323,778	36,240,981	36,159,082	36,078,116	35,998,016	35,918,869	35,835,819	35,753,853	35,672,910	35,592,966	35,514,022	35,435,591	35,357,673	35,280,258
RATE23	8,562,540	8,621,274	8,659,214	8,720,233	8,770,562	8,817,530	8,889,344	8,942,388	9,008,083	9,059,492	9,128,315	9,179,478	9,238,567	9,296,506	9,349,745	9,398,979	9,444,960	9,486,188	9,540,769	9,576,776	9,634,552	9,684,982
RATE25	13,867,113	13,682,748	13,625,929	13,580,161	13,528,894	13,485,300	13,443,640	13,406,337	13,369,860	13,341,509	13,313,737	13,286,556	13,259,941	13,233,926	13,213,363	13,193,362	13,173,902	13,154,975	13,136,582	13,118,537	13,100,839	13,083,486
RATE27	7,156,470	7,073,026	7,047,920	7,028,404	7,001,521	6,978,586	6,956,665	6,936,997	6,917,780	6,908,318	6,899,084	6,890,087	6,881,314	6,872,783	6,865,332	6,858,124	6,851,147	6,844,398	6,837,879	6,831,473	6,825,181	6,819,002
RATE46	599,546	598,040	595,819	594,025	592,045	590,357	588,721	587,239	585,761	584,287	582,819	581,357	579,899	578,447	577,002	575,563	574,129	572,700	571,276	569,857	568,443	567,033
Grand Total	**191,738,754**	**192,012,307**	**192,240,096**	**192,642,932**	**192,899,700**	**193,249,740**	**193,684,523**	**194,132,108**	**194,569,468**	**194,986,558**	**195,438,057**	**195,991,649**	**196,529,588**	**197,104,356**	**197,678,086**	**198,275,517**	**198,916,020**	**199,560,318**	**200,219,329**	**200,901,688**	**201,585,020**	**202,261,704**

[1] All tables in this appendix display results from the end-use annual demand forecast method and exclude Renewable Natural Gas (RNG), the impact of Conservation and Energy Management Programs (C&EM), and the Woodfibre LNG Project example.

Scenario A

Year End Customers by Rate Schedule

Rate Class	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
RATE1	888,135	900,173	912,103	924,108	936,155	948,223	959,712	970,278	980,325	990,020	1,000,035	1,010,186	1,020,175	1,030,220	1,040,150	1,049,938	1,059,572	1,069,020	1,078,353	1,087,512	1,096,417	1,105,076
RATE2	85,075	86,388	87,774	89,171	90,572	91,981	93,396	94,781	96,202	97,579	98,965	100,365	101,775	103,171	104,580	105,990	107,384	108,816	110,223	111,629	113,035	114,444
RATE2_1	458	453	458	463	471	478	486	492	501	511	515	523	531	538	547	556	567	570	576	588	596	604
RATE2_2	7	7	7	7	7	7	7	7	7	7	7	7	7	8	8	8	8	8	9	9	9	9
RATE3	5,287	5,315	5,349	5,389	5,426	5,468	5,505	5,558	5,609	5,666	5,724	5,789	5,855	5,924	6,011	6,096	6,187	6,284	6,386	6,491	6,595	6,721
RATE4	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
RATE5	241	239	241	244	246	250	252	256	259	264	268	273	276	280	286	290	294	295	301	306	311	315
RATE6	12	12	12	12	12	12	12	12	12	13	13	13	13	14	14	14	14	14	14	14	15	15
RATE7	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
RATE22	48	48	48	48	48	48	48	49	49	50	50	52	52	54	57	57	58	58	59	61	61	61
RATE23	1,722	1,740	1,764	1,789	1,813	1,837	1,865	1,888	1,917	1,944	1,971	1,999	2,025	2,050	2,077	2,103	2,126	2,160	2,180	2,206	2,230	2,258
RATE25	561	553	561	569	576	583	592	601	609	616	625	636	644	654	664	673	682	689	705	719	728	738
RATE27	107	106	107	108	108	111	112	113	114	115	117	120	121	122	124	127	127	129	131	135	138	139
RATE46	16	16	16	16	16	16	16	17	17	18	19	19	19	19	19	20	20	20	20	20	20	20
Grand Total	**981,701**	**995,082**	**1,008,472**	**1,021,956**	**1,035,482**	**1,049,046**	**1,062,035**	**1,074,084**	**1,085,653**	**1,096,835**	**1,108,341**	**1,120,014**	**1,131,525**	**1,143,086**	**1,154,569**	**1,165,904**	**1,177,071**	**1,188,095**	**1,198,989**	**1,209,722**	**1,220,187**	**1,230,432**

Annual Use Rate per Customer by Rate Schedule (GJ)

Rate Class	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
RATE1	83.7	82.9	82.0	81.3	80.6	80.0	79.6	79.1	78.8	78.4	78.1	77.8	77.5	77.3	77.0	76.7	76.5	76.3	76.1	76.0	75.8	75.6
RATE2	329.1	329.2	328.9	328.8	328.9	329.4	330.3	331.4	332.6	333.7	334.9	336.0	337.2	338.3	339.5	340.6	341.8	342.9	344.0	345.2	346.3	347.4
RATE2_1	484.7	486.2	485.9	485.8	486.6	486.7	488.6	490.5	491.1	491.4	493.5	493.8	494.9	498.0	500.7	501.2	502.1	503.4	504.0	506.9	507.3	507.7
RATE2_2	9,274.8	9,273.3	9,271.7	9,270.6	9,275.8	9,287.2	9,304.2	9,323.2	9,342.8	9,362.3	9,381.8	9,400.8	9,418.9	9,775.0	9,790.0	9,804.6	9,818.9	9,832.6	9,512.3	9,529.7	9,546.6	9,562.5
RATE3	3,626.9	3,633.1	3,632.0	3,631.5	3,636.3	3,645.4	3,660.8	3,673.1	3,691.2	3,708.4	3,722.1	3,738.6	3,757.2	3,775.5	3,785.1	3,798.4	3,817.0	3,831.9	3,846.2	3,858.9	3,872.0	3,894.4
RATE4	5,696.8	5,741.2	5,755.7	5,776.8	5,815.5	5,859.6	5,912.8	5,969.6	6,028.2	6,063.8	6,099.2	6,133.7	6,166.4	6,198.2	6,220.6	6,241.9	6,262.6	6,282.2	6,300.8	6,318.2	6,334.6	6,349.5
RATE5	9,542.6	9,571.6	9,556.0	9,542.6	9,548.1	9,556.4	9,590.0	9,618.1	9,656.8	9,733.8	9,754.6	9,803.2	9,847.6	9,867.3	9,909.3	9,955.7	10,001.4	10,060.0	10,088.7	10,158.2	10,220.5	10,269.8
RATE6	4,242.7	4,260.6	4,276.0	4,297.4	4,321.6	4,350.5	4,387.1	4,426.4	4,466.9	4,432.8	4,466.8	4,500.3	4,532.6	4,428.6	4,457.1	4,485.0	4,512.5	4,539.3	4,565.4	4,590.7	4,557.6	4,580.3
RATE7	28,034.8	28,625.9	28,597.0	28,595.6	28,637.4	28,706.2	28,820.3	28,951.4	29,089.2	29,253.3	29,420.4	29,586.2	29,745.0	29,900.7	30,069.5	30,234.5	30,397.3	30,555.4	30,709.1	30,857.8	31,001.7	31,139.4
RATE22	771,870.1	790,986.1	792,149.8	791,001.7	790,089.2	789,401.3	789,038.5	778,647.0	778,467.6	803,687.9	803,119.3	806,412.2	805,979.1	801,693.8	801,932.4	801,233.2	791,740.5	791,010.3	781,515.1	770,006.3	769,229.6	768,396.2
RATE23	4,972.4	4,993.9	4,983.9	4,983.7	4,977.1	4,990.0	5,005.4	5,017.9	5,034.6	5,052.7	5,068.7	5,083.8	5,096.2	5,110.1	5,127.9	5,154.3	5,166.1	5,207.2	5,220.0	5,236.0	5,246.9	5,270.2
RATE25	24,718.6	25,353.4	25,209.2	25,061.8	25,103.7	25,000.0	25,117.1	25,018.4	24,920.4	25,068.8	24,956.4	25,222.8	25,248.0	25,171.0	25,395.8	25,333.4	25,275.8	25,394.1	25,384.5	25,339.0	25,399.8	25,343.9
RATE27	66,882.9	68,408.9	68,391.5	68,280.0	68,177.9	67,648.7	67,874.0	67,849.0	67,558.1	67,627.9	67,264.0	67,372.9	67,443.3	67,371.6	68,982.4	68,804.4	68,868.6	68,813.0	68,468.4	67,954.5	67,985.8	68,017.6
RATE46	37,471.6	37,442.0	37,413.0	37,415.7	37,459.9	37,539.1	37,667.2	38,748.4	38,908.1	37,682.4	36,895.7	37,056.7	37,213.8	37,370.9	37,527.8	38,586.9	38,745.5	38,898.9	39,047.4	39,190.8	39,329.2	39,460.8

Annual Demand by Rate Schedule (GJ)

Rate Class	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
RATE1	74,379,270	74,624,717	74,805,228	75,113,371	75,470,178	75,866,499	76,345,548	76,795,183	77,225,271	77,641,422	78,086,259	78,590,073	79,084,633	79,587,590	80,086,161	80,576,224	81,097,606	81,606,512	82,108,678	82,602,728	83,082,523	83,545,692
RATE2	27,994,803	28,439,506	28,868,125	29,315,082	29,792,778	30,302,125	30,851,976	31,412,551	31,993,774	32,561,209	33,141,368	33,727,273	34,316,913	34,906,789	35,500,880	36,100,706	36,699,446	37,312,002	37,921,026	38,531,492	39,144,131	39,757,654
RATE2_1	222,002	220,259	222,544	224,931	229,195	232,650	237,473	241,349	246,066	251,123	254,140	258,280	262,811	267,921	273,857	278,644	284,668	286,960	290,296	298,084	302,340	306,636
RATE2_2	64,924	64,913	64,902	64,894	64,930	65,010	65,130	65,262	65,399	65,536	65,673	65,806	65,932	78,200	78,320	78,437	78,551	78,661	85,610	85,768	85,919	86,062
RATE3	19,175,310	19,309,790	19,427,410	19,570,244	19,730,313	19,933,302	20,152,945	20,414,936	20,704,177	21,011,831	21,305,337	21,642,873	21,998,425	22,366,216	22,752,337	23,154,752	23,615,958	24,079,497	24,562,051	25,048,412	25,535,570	26,174,259
RATE4	148,116	149,272	149,648	150,196	151,204	152,351	153,733	155,211	156,733	157,660	158,580	159,476	160,326	161,154	161,735	162,291	162,827	163,336	163,821	164,274	164,699	165,088
RATE5	2,299,775	2,287,612	2,303,008	2,328,399	2,348,843	2,389,100	2,416,673	2,462,238	2,501,104	2,569,725	2,614,230	2,676,275	2,717,950	2,762,833	2,834,066	2,887,151	2,940,409	2,967,705	3,036,703	3,108,413	3,178,562	3,234,983
RATE6	50,912	51,127	51,311	51,569	51,859	52,206	52,645	53,117	53,603	57,626	58,069	58,504	58,923	62,000	62,399	62,790	63,175	63,550	63,916	64,270	68,364	68,704
RATE7	168,209	171,756	171,582	171,574	171,825	172,237	172,922	173,708	174,535	175,520	176,522	177,517	178,470	179,404	180,417	181,407	182,384	183,333	184,255	185,147	186,010	186,836
RATE22	37,049,763	37,967,334	38,023,188	37,968,080	37,924,282	37,891,262	37,873,846	38,153,703	38,144,914	40,184,395	40,155,966	41,933,433	41,910,915	43,291,467	45,710,147	45,670,291	45,920,948	45,878,597	46,109,392	46,970,386	46,923,003	46,872,167
RATE23	8,562,540	8,689,396	8,791,523	8,915,795	9,023,439	9,166,565	9,335,148	9,473,816	9,651,276	9,822,361	9,990,478	10,162,514	10,319,753	10,475,768	10,650,590	10,839,570	10,983,160	11,247,586	11,379,561	11,550,604	11,700,618	11,900,089
RATE25	13,867,113	14,020,433	14,142,356	14,260,147	14,459,749	14,575,009	14,869,348	15,036,077	15,176,513	15,442,397	15,597,759	16,041,707	16,259,688	16,461,833	16,862,814	17,049,349	17,238,076	17,496,548	17,896,048	18,218,767	18,491,080	18,703,771
RATE27	7,156,470	7,251,343	7,317,889	7,374,236	7,363,208	7,509,005	7,601,891	7,666,940	7,701,628	7,777,204	7,869,885	8,084,749	8,160,644	8,219,337	8,553,814	8,738,165	8,746,314	8,876,881	8,969,355	9,173,851	9,382,035	9,454,441
RATE46	599,546	599,071	598,608	598,651	599,358	600,625	602,675	658,723	661,437	678,282	701,019	704,078	707,063	710,048	713,029	771,737	774,910	777,979	780,949	783,816	786,583	789,216
Grand Total	**191,738,754**	**193,846,528**	**194,937,321**	**196,107,170**	**197,381,162**	**198,907,946**	**200,731,952**	**202,762,816**	**204,456,431**	**208,396,291**	**210,175,286**	**214,282,556**	**216,202,447**	**219,530,560**	**224,420,566**	**226,551,514**	**228,788,433**	**231,019,146**	**233,551,659**	**236,786,010**	**239,031,438**	**241,245,597**

Scenario B

Year End Customers by Rate Schedule

Rate Class	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
RATE1	888,135	900,173	912,103	924,108	936,155	948,223	959,712	970,278	980,325	990,020	1,000,035
RATE2	85,075	86,388	87,774	89,171	90,572	91,981	93,396	94,781	96,202	97,579	98,965
RATE2_1	458	453	458	463	471	478	486	492	501	511	515
RATE2_2	7	7	7	7	7	7	7	7	7	7	7
RATE3	5,287	5,315	5,349	5,389	5,426	5,468	5,505	5,558	5,609	5,666	5,724
RATE4	26	26	26	26	26	26	26	26	26	26	26
RATE5	241	239	241	244	246	250	252	256	259	264	268
RATE6	12	12	12	12	12	12	12	12	12	13	13
RATE7	6	6	6	6	6	6	6	6	6	6	6
RATE22	48	48	48	48	48	48	48	49	49	50	50
RATE23	1,722	1,740	1,764	1,789	1,813	1,837	1,865	1,888	1,917	1,944	1,971
RATE25	561	553	561	569	576	583	592	601	609	616	625
RATE27	107	106	107	108	108	111	112	113	114	115	117
RATE46	16	16	16	16	16	16	16	17	17	18	19
Grand Total	**981,701**	**995,082**	**1,008,472**	**1,021,956**	**1,035,482**	**1,049,046**	**1,062,035**	**1,074,084**	**1,085,653**	**1,096,835**	**1,108,341**

Rate Class	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
RATE1	1,010,186	1,020,175	1,030,220	1,040,150	1,049,938	1,059,572	1,069,020	1,078,353	1,087,512	1,096,417	1,105,076
RATE2	100,365	101,775	103,171	104,580	105,990	107,384	108,816	110,223	111,629	113,035	114,444
RATE2_1	523	531	538	547	556	567	570	576	588	596	604
RATE2_2	7	7	8	8	8	8	8	9	9	9	9
RATE3	5,789	5,855	5,924	6,011	6,096	6,187	6,284	6,386	6,491	6,595	6,721
RATE4	26	26	26	26	26	26	26	26	26	26	26
RATE5	273	276	280	286	290	294	295	301	306	311	315
RATE6	13	13	14	14	14	14	14	14	14	15	15
RATE7	6	6	6	6	6	6	6	6	6	6	6
RATE22	52	52	54	57	57	58	58	59	61	61	61
RATE23	1,999	2,025	2,050	2,077	2,103	2,126	2,160	2,180	2,206	2,230	2,258
RATE25	636	644	654	664	673	682	689	705	719	728	738
RATE27	120	121	122	124	127	127	129	131	135	138	139
RATE46	19	19	19	19	20	20	20	20	20	20	20
Grand Total	**1,120,014**	**1,131,525**	**1,143,086**	**1,154,569**	**1,165,904**	**1,177,071**	**1,188,095**	**1,198,989**	**1,209,722**	**1,220,187**	**1,230,432**

Annual Use Rate per Customer by Rate Schedule (GJ)

Rate Class	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
RATE1	83.7	82.2	80.6	79.0	77.4	75.7	74.2	72.7	71.2	69.5	67.9
RATE2	329.1	326.3	323.0	319.1	313.7	308.3	303.8	298.7	293.1	286.7	280.5
RATE2_1	484.7	480.6	475.3	469.2	461.2	452.3	445.6	437.8	427.9	416.6	407.2
RATE2_2	9,274.8	9,227.4	9,164.5	9,091.1	8,976.7	8,863.0	8,775.3	8,684.8	8,582.1	8,465.1	8,352.4
RATE3	3,626.9	3,589.5	3,548.0	3,498.7	3,433.7	3,367.6	3,312.1	3,248.4	3,179.6	3,100.2	3,019.0
RATE4	5,696.8	5,667.9	5,637.6	5,610.8	5,577.2	5,532.3	5,494.3	5,453.6	5,401.4	5,311.1	5,231.0
RATE5	9,542.6	9,429.9	9,291.5	9,128.6	8,921.9	8,704.7	8,521.5	8,315.3	8,084.1	7,854.4	7,581.7
RATE6	4,242.7	4,210.8	4,173.5	4,132.3	4,070.5	4,004.6	3,947.8	3,888.6	3,818.0	3,677.9	3,586.5
RATE7	28,034.8	27,664.7	27,262.3	26,832.2	26,296.8	25,717.0	25,189.0	24,642.0	23,998.8	23,280.5	22,582.4
RATE22	771,870.1	767,874.9	763,689.6	760,633.9	755,733.7	748,895.9	742,548.4	726,450.8	718,825.7	732,536.6	724,426.2
RATE23	4,972.4	4,920.5	4,856.3	4,794.8	4,701.7	4,618.6	4,543.6	4,455.0	4,356.0	4,244.5	4,136.8
RATE25	24,718.6	24,602.4	24,273.9	23,955.8	23,717.4	23,288.2	23,074.7	22,638.6	22,152.6	21,819.5	21,290.0
RATE27	66,882.9	66,437.5	65,989.7	65,635.4	65,090.6	64,000.7	63,570.9	62,882.5	61,838.8	60,974.2	59,856.0
RATE46	37,471.6	37,023.7	36,503.5	35,929.0	35,188.8	34,433.0	33,774.9	34,101.5	33,249.3	31,277.4	29,360.2

Rate Class	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
RATE1	66.3	64.6	62.9	61.0	59.0	56.9	54.7	52.2	49.6	46.7	43.8
RATE2	274.0	268.5	262.3	255.9	249.2	242.3	234.9	227.4	220.0	212.7	206.5
RATE2_1	395.9	387.0	377.6	368.3	357.0	344.8	333.2	321.0	310.1	297.6	285.6
RATE2_2	8,237.5	8,159.2	8,519.2	8,437.4	8,351.1	8,262.6	8,171.6	7,438.4	7,341.8	7,244.7	7,150.3
RATE3	2,936.1	2,867.0	2,787.8	2,699.9	2,611.4	2,522.4	2,425.2	2,327.3	2,228.1	2,129.8	2,061.1
RATE4	5,150.6	5,077.0	4,994.3	4,893.0	4,782.5	4,660.0	4,524.2	4,376.5	4,217.1	4,042.2	3,857.3
RATE5	7,321.5	7,082.3	6,809.1	6,546.8	6,264.4	5,970.5	5,674.6	5,333.2	5,069.6	4,845.5	4,627.6
RATE6	3,491.6	3,403.9	3,180.8	3,075.5	2,962.0	2,839.4	2,704.6	2,561.7	2,414.6	2,216.6	2,065.4
RATE7	21,863.5	21,210.1	20,503.6	19,780.2	19,025.5	18,237.4	17,410.1	16,536.2	15,616.2	14,626.4	13,566.8
RATE22	718,377.7	711,229.5	701,036.7	693,289.3	682,730.9	663,230.4	649,176.9	625,400.8	597,093.0	574,982.0	549,273.7
RATE23	4,024.4	3,921.3	3,809.2	3,696.9	3,586.0	3,457.1	3,341.8	3,199.4	3,056.4	2,905.6	2,780.3
RATE25	21,084.7	20,705.6	20,218.5	19,930.2	19,372.6	18,768.1	18,246.2	17,469.3	16,723.8	15,996.8	15,134.8
RATE27	59,155.9	58,533.8	57,610.7	58,194.8	57,077.4	55,979.9	54,577.7	52,835.2	50,707.4	48,764.6	46,576.2
RATE46	28,462.1	27,652.2	26,756.2	25,845.0	25,358.2	24,311.1	23,181.8	22,010.2	20,792.2	19,535.5	18,348.4

Annual Demand by Rate Schedule (GJ)

Rate Class	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
RATE1	74,379,270	74,020,776	73,560,646	73,042,069	72,470,434	71,780,327	71,224,993	70,568,693	69,771,166	68,847,283	67,937,825
RATE2	27,994,803	28,184,570	28,346,911	28,450,544	28,411,123	28,353,931	28,370,622	28,314,996	28,198,042	27,979,412	27,755,924
RATE2_1	222,002	217,713	217,684	217,241	217,212	216,196	216,575	215,401	214,356	212,889	209,729
RATE2_2	64,924	64,592	64,152	63,638	62,837	62,041	61,427	60,794	60,075	59,256	58,467
RATE3	19,175,310	19,077,935	18,978,322	18,854,457	18,631,507	18,414,085	18,233,006	18,054,371	17,834,431	17,565,925	17,280,905
RATE4	148,116	147,366	146,579	145,881	145,008	143,840	142,851	141,794	140,438	138,089	136,005
RATE5	2,299,775	2,253,741	2,239,261	2,227,378	2,194,783	2,176,174	2,147,417	2,128,721	2,093,774	2,073,558	2,031,908
RATE6	50,912	50,529	50,082	49,588	48,846	48,056	47,374	46,663	45,816	47,813	46,625
RATE7	168,209	165,988	163,574	160,993	157,781	154,302	151,134	147,852	143,993	139,683	135,494
RATE22	37,049,763	36,857,995	36,657,103	36,510,429	36,275,215	35,947,002	35,642,324	35,596,087	35,222,461	36,626,831	36,221,308
RATE23	8,562,540	8,561,623	8,566,578	8,577,908	8,524,180	8,484,392	8,473,838	8,410,972	8,350,403	8,251,340	8,153,597
RATE25	13,867,113	13,605,113	13,617,640	13,630,862	13,661,236	13,577,000	13,660,240	13,605,822	13,490,938	13,440,797	13,306,263
RATE27	7,156,470	7,042,379	7,060,902	7,088,621	7,029,789	7,104,075	7,119,940	7,105,724	7,049,620	7,012,037	7,003,157
RATE46	599,546	592,379	584,057	574,864	563,020	550,929	540,398	579,726	565,238	562,993	557,843
Grand Total	**191,738,754**	**190,842,700**	**190,253,489**	**189,594,474**	**188,392,972**	**187,012,350**	**186,032,139**	**184,977,616**	**183,180,751**	**182,957,904**	**180,835,051**

Rate Class	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
RATE1	66,951,884	65,918,375	64,768,042	63,457,372	61,971,147	60,341,508	58,466,528	56,325,350	53,906,971	51,184,445	48,370,609
RATE2	27,499,057	27,329,211	27,058,156	26,763,729	26,416,448	26,017,013	25,557,084	25,066,335	24,561,977	24,038,749	23,629,716
RATE2_1	207,072	205,512	203,167	201,442	198,503	195,482	189,931	184,868	182,327	177,347	172,530
RATE2_2	57,663	57,115	68,153	67,499	66,809	66,101	65,373	66,946	66,076	65,202	64,352
RATE3	16,996,988	16,786,160	16,515,028	16,229,178	15,919,352	15,606,354	15,239,693	14,861,947	14,462,656	14,045,880	13,852,618
RATE4	133,916	132,001	129,852	127,218	124,345	121,161	117,630	113,789	109,645	105,097	100,291
RATE5	1,998,765	1,954,723	1,906,553	1,872,394	1,816,667	1,755,329	1,674,012	1,605,290	1,551,289	1,506,939	1,457,686
RATE6	45,391	44,251	44,531	43,057	41,468	39,752	37,864	35,863	33,805	33,249	30,982
RATE7	131,181	127,261	123,021	118,681	114,153	109,425	104,461	99,217	93,697	87,758	81,401
RATE22	37,355,642	36,983,933	37,855,983	39,517,491	38,915,662	38,467,363	37,652,260	36,898,648	36,422,675	35,073,900	33,505,697
RATE23	8,044,730	7,940,705	7,808,844	7,678,527	7,541,365	7,349,811	7,218,300	6,974,730	6,742,326	6,479,539	6,277,878
RATE25	13,409,877	13,334,376	13,222,870	13,233,646	13,037,786	12,799,861	12,571,614	12,315,861	12,024,384	11,645,663	11,169,467
RATE27	7,098,702	7,082,589	7,028,505	7,216,160	7,248,832	7,109,444	7,040,530	6,921,415	6,845,504	6,729,511	6,474,098
RATE46	540,780	525,392	508,368	491,055	507,164	486,221	463,636	440,203	415,843	390,711	366,968
Grand Total	**180,471,646**	**178,421,603**	**177,241,075**	**177,017,448**	**173,919,700**	**170,464,826**	**166,398,916**	**161,910,464**	**157,419,175**	**151,563,990**	**145,554,294**

Scenario C

Year End Customers by Rate Schedule

Rate Class	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
RATE1	888,135	900,173	912,103	924,108	936,155	948,223	959,712	970,278	980,325	990,020	1,000,035	1,010,186	1,020,175	1,030,220	1,040,150	1,049,938	1,059,572	1,069,020	1,078,353	1,087,512	1,096,417	1,105,076
RATE2	85,075	86,388	87,774	89,171	90,572	91,981	93,396	94,781	96,202	97,579	98,965	100,365	101,775	103,171	104,580	105,990	107,384	108,816	110,223	111,629	113,035	114,444
RATE2_1	458	453	458	463	471	478	486	492	501	511	515	523	531	538	547	556	567	570	576	588	596	604
RATE2_2	7	7	7	7	7	7	7	7	7	7	7	7	7	8	8	8	8	8	9	9	9	9
RATE3	5,287	5,315	5,349	5,389	5,426	5,468	5,505	5,558	5,609	5,666	5,724	5,789	5,855	5,924	6,011	6,096	6,187	6,284	6,386	6,491	6,595	6,721
RATE4	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
RATE5	241	239	241	244	246	250	252	256	259	264	268	273	276	280	286	290	294	295	301	306	311	315
RATE6	12	12	12	12	12	12	12	12	12	13	13	13	13	14	14	14	14	14	14	14	15	15
RATE7	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
RATE22	48	48	48	48	48	48	48	49	49	50	50	52	52	54	57	57	58	58	59	61	61	61
RATE23	1,722	1,740	1,764	1,789	1,813	1,837	1,865	1,888	1,917	1,944	1,971	1,999	2,025	2,050	2,077	2,103	2,126	2,160	2,180	2,206	2,230	2,258
RATE25	561	553	561	569	576	583	592	601	609	616	625	636	644	654	664	673	682	689	705	719	728	738
RATE27	107	106	107	108	108	111	112	113	114	115	117	120	121	122	124	127	127	129	131	135	138	139
RATE46	16	16	16	16	16	16	16	17	17	18	19	19	19	19	19	20	20	20	20	20	20	20
Grand Total	**981,701**	**995,082**	**1,008,472**	**1,021,956**	**1,035,482**	**1,049,046**	**1,062,035**	**1,074,084**	**1,085,653**	**1,096,835**	**1,108,341**	**1,120,014**	**1,131,525**	**1,143,086**	**1,154,569**	**1,165,904**	**1,177,071**	**1,188,095**	**1,198,989**	**1,209,722**	**1,220,187**	**1,230,432**

Annual Use Rate per Customer by Rate Schedule (GJ)

Rate Class	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
RATE1	83.7	82.3	80.7	79.2	77.7	76.1	74.7	73.3	71.9	70.5	69.0	67.6	66.1	64.5	62.9	61.2	59.4	57.4	55.3	53.0	50.5	48.1
RATE2	329.1	327.2	325.1	322.8	320.6	318.7	317.0	314.9	312.9	310.8	308.6	306.5	304.3	302.1	299.9	297.7	295.5	293.1	290.8	288.5	286.2	284.0
RATE2_1	484.7	482.6	479.0	475.5	472.4	468.9	466.6	463.5	459.1	454.4	451.7	447.2	443.4	440.6	438.0	433.8	429.2	425.8	421.6	418.7	414.3	410.3
RATE2_2	9,274.8	9,240.2	9,201.2	9,165.2	9,131.9	9,104.3	9,080.6	9,059.1	9,038.1	9,017.2	8,996.4	8,975.4	8,954.0	9,332.9	9,313.9	9,294.8	9,275.6	9,256.2	8,650.1	8,623.8	8,598.0	8,572.6
RATE3	3,626.9	3,604.1	3,576.8	3,547.7	3,519.4	3,494.0	3,473.0	3,445.8	3,421.9	3,395.5	3,366.0	3,337.6	3,312.0	3,284.8	3,249.7	3,218.2	3,189.8	3,156.3	3,123.0	3,087.9	3,053.4	3,028.4
RATE4	5,696.8	5,700.4	5,695.1	5,695.3	5,708.8	5,726.9	5,751.3	5,778.7	5,807.3	5,813.5	5,819.5	5,824.9	5,829.6	5,833.7	5,829.1	5,823.9	5,818.4	5,812.3	5,805.7	5,798.4	5,790.5	5,781.9
RATE5	9,542.6	9,474.3	9,375.3	9,269.2	9,162.1	9,054.8	8,963.9	8,856.2	8,746.1	8,661.9	8,528.5	8,418.5	8,301.6	8,166.3	8,050.7	7,929.7	7,807.2	7,695.6	7,540.8	7,453.7	7,333.7	7,217.2
RATE6	4,242.7	4,226.5	4,210.4	4,199.5	4,188.6	4,181.7	4,179.8	4,180.3	4,181.7	4,117.3	4,107.8	4,099.4	4,088.2	3,928.3	3,915.1	3,902.5	3,890.4	3,875.6	3,862.0	3,848.4	3,748.7	3,732.4
RATE7	28,034.8	28,155.6	27,920.5	27,711.6	27,528.4	27,368.3	27,238.2	27,122.5	27,012.2	26,927.7	26,846.1	26,764.8	26,680.4	26,595.1	26,524.8	26,453.4	26,381.5	26,307.9	26,232.4	26,154.9	26,075.3	25,992.7
RATE22	771,870.1	781,041.6	780,620.9	779,012.8	777,369.8	776,024.2	774,916.2	764,028.6	763,149.1	787,214.1	785,989.7	788,145.6	787,060.6	782,174.4	782,040.3	780,716.2	770,873.5	769,544.6	759,036.4	747,218.1	745,868.5	744,499.7
RATE23	4,972.4	4,950.4	4,907.7	4,873.1	4,828.0	4,800.4	4,774.1	4,737.0	4,700.5	4,664.3	4,628.4	4,590.7	4,548.5	4,508.0	4,472.3	4,444.6	4,403.7	4,385.8	4,343.4	4,304.6	4,260.5	4,229.4
RATE25	24,718.6	25,002.9	24,768.6	24,536.7	24,476.2	24,272.0	24,267.8	24,048.5	23,824.9	23,838.3	23,592.9	23,719.1	23,599.6	23,390.0	23,470.7	23,282.6	23,094.8	23,076.1	22,822.7	22,642.4	22,568.3	22,382.1
RATE27	66,882.9	67,517.6	67,344.4	67,135.1	66,905.1	66,302.4	66,382.8	66,222.1	65,800.2	65,740.9	65,232.6	65,198.4	65,133.5	64,841.7	66,314.0	66,005.3	65,936.1	65,751.1	65,284.1	64,694.8	64,584.8	64,511.9
RATE46	37,471.6	37,131.9	36,777.0	36,453.5	36,152.7	35,882.1	35,644.4	36,486.8	36,194.8	34,705.5	33,366.5	33,126.7	32,859.3	32,603.3	32,363.0	32,729.3	32,470.3	32,172.1	31,892.9	31,618.0	31,350.7	31,090.4

Annual Demand by Rate Schedule (GJ)

Rate Class	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
RATE1	74,379,270	74,057,421	73,639,494	73,194,520	72,711,478	72,144,760	71,695,738	71,160,322	70,511,128	69,760,820	69,026,853	68,241,385	67,403,147	66,471,517	65,408,912	64,203,838	62,886,182	61,360,356	59,614,866	57,639,171	55,410,246	53,103,813
RATE2	27,994,803	28,270,281	28,532,190	28,786,636	29,039,573	29,310,010	29,603,287	29,849,056	30,100,342	30,322,728	30,544,189	30,764,516	30,972,181	31,165,972	31,360,633	31,552,262	31,734,004	31,894,273	32,050,742	32,202,867	32,352,080	32,500,219
RATE2_1	222,002	218,614	219,382	220,156	222,520	224,126	226,752	228,032	230,023	232,195	232,618	233,885	235,468	237,047	239,590	241,181	243,373	242,685	242,836	246,224	246,939	247,828
RATE2_2	64,924	64,681	64,408	64,156	63,923	63,730	63,564	63,414	63,267	63,120	62,975	62,828	62,678	74,663	74,511	74,358	74,205	74,050	77,851	77,614	77,382	77,154
RATE3	19,175,310	19,155,947	19,132,255	19,118,688	19,096,447	19,105,296	19,118,770	19,152,002	19,193,708	19,239,093	19,267,082	19,321,595	19,391,609	19,459,212	19,534,035	19,618,011	19,735,533	19,834,070	19,943,537	20,043,495	20,136,880	20,353,703
RATE4	148,116	148,211	148,071	148,078	148,428	148,900	149,533	150,247	150,991	151,150	151,306	151,446	151,570	151,676	151,556	151,422	151,278	151,119	150,948	150,759	150,554	150,329
RATE5	2,299,775	2,264,357	2,259,454	2,261,677	2,253,878	2,263,695	2,258,897	2,267,188	2,265,238	2,286,736	2,285,645	2,298,242	2,291,251	2,286,577	2,302,493	2,299,606	2,295,321	2,270,201	2,269,778	2,280,838	2,280,767	2,273,432
RATE6	50,912	50,718	50,525	50,395	50,263	50,180	50,157	50,163	50,180	53,524	53,401	53,292	53,147	54,996	54,811	54,635	54,465	54,259	54,068	53,878	56,230	55,986
RATE7	168,209	168,934	167,523	166,270	165,170	164,210	163,429	162,735	162,073	161,566	161,076	160,589	160,082	159,571	159,149	158,720	158,289	157,847	157,395	156,929	156,452	155,956
RATE22	37,049,763	37,489,995	37,469,805	37,392,615	37,313,749	37,249,161	37,195,977	37,437,402	37,394,308	39,360,706	39,299,483	40,983,573	40,927,152	42,237,417	44,576,297	44,500,825	44,710,662	44,633,584	44,783,145	45,580,302	45,497,981	45,414,483
RATE23	8,562,540	8,613,627	8,657,268	8,717,978	8,753,251	8,818,354	8,903,610	8,943,400	9,010,936	9,067,373	9,122,647	9,176,844	9,210,728	9,241,498	9,289,008	9,347,036	9,362,317	9,473,315	9,468,669	9,495,993	9,500,976	9,549,914
RATE25	13,867,113	13,826,583	13,895,207	13,961,407	14,098,298	14,150,556	14,366,547	14,453,172	14,509,338	14,684,374	14,745,558	15,085,374	15,198,125	15,297,068	15,584,538	15,669,218	15,750,685	15,899,427	16,090,018	16,279,912	16,429,692	16,518,018
RATE27	7,156,470	7,156,864	7,205,854	7,250,595	7,225,754	7,359,561	7,434,875	7,483,100	7,501,227	7,560,209	7,632,214	7,823,809	7,881,157	7,910,684	8,222,934	8,382,670	8,373,887	8,481,887	8,552,220	8,733,791	8,912,698	8,967,158
RATE46	599,546	594,110	588,431	583,256	578,443	574,113	570,310	620,275	615,312	624,699	633,964	629,407	624,327	619,462	614,897	654,586	649,406	643,441	637,858	632,359	627,013	621,808
Grand Total	**191,738,754**	**192,080,343**	**192,029,868**	**191,916,426**	**191,721,176**	**191,626,652**	**191,801,445**	**192,020,509**	**191,758,071**	**193,568,295**	**193,219,012**	**194,986,784**	**194,562,621**	**195,367,359**	**197,573,365**	**196,908,369**	**196,179,607**	**195,170,514**	**194,093,931**	**193,574,131**	**191,835,891**	**189,989,802**

Scenario D

Year End Customers by Rate Schedule

Rate Class	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
RATE1	888,135	900,173	911,287	922,384	933,447	944,463	954,844	964,252	973,097	981,558	990,305	999,163	1,007,835	1,016,544	1,025,120	1,033,538	1,041,789	1,049,841	1,057,768	1,065,512	1,072,992	1,080,219
RATE2	85,075	86,388	87,625	88,855	90,075	91,294	92,501	93,678	94,875	96,030	97,184	98,346	99,516	100,666	101,827	102,987	104,127	105,303	106,454	107,600	108,746	109,884
RATE2_1	458	453	446	440	433	427	419	411	403	397	390	381	375	368	359	349	344	335	325	317	309	297
RATE2_2	7	7	7	7	7	7	7	7	7	7	7	6	6	6	6	6	5	5	5	5	5	5
RATE3	5,287	5,315	5,328	5,344	5,357	5,370	5,381	5,398	5,423	5,446	5,472	5,499	5,534	5,575	5,618	5,661	5,724	5,783	5,846	5,911	5,992	6,073
RATE4	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
RATE5	241	239	236	233	231	228	225	220	217	212	208	203	200	195	191	187	183	179	175	170	166	160
RATE6	12	12	12	12	12	12	12	11	11	11	11	10	10	10	10	10	10	10	10	9	9	9
RATE7	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
RATE22	48	48	48	48	48	47	47	46	46	44	44	42	39	39	39	38	37	35	35	35	35	34
RATE23	1,722	1,740	1,752	1,764	1,775	1,784	1,794	1,805	1,812	1,820	1,832	1,842	1,849	1,852	1,861	1,865	1,872	1,878	1,884	1,886	1,896	1,901
RATE25	561	553	548	540	534	524	517	510	501	492	484	471	463	456	446	435	420	409	403	393	382	369
RATE27	107	106	106	103	102	102	100	100	99	95	94	92	90	89	87	86	83	79	79	76	75	75
RATE46	16	16	16	16	16	16	15	14	14	13	13	13	13	13	12	12	12	12	12	12	12	11
Grand Total	**981,701**	**995,082**	**1,007,443**	**1,019,778**	**1,032,069**	**1,044,306**	**1,055,894**	**1,066,484**	**1,076,537**	**1,086,157**	**1,096,076**	**1,106,100**	**1,115,962**	**1,125,845**	**1,135,608**	**1,145,206**	**1,154,638**	**1,163,901**	**1,173,028**	**1,181,958**	**1,190,651**	**1,199,069**

Annual Use Rate per Customer by Rate Schedule (GJ)

Rate Class	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
RATE1	83.7	82.9	82.1	81.4	80.8	80.2	79.8	79.4	79.1	78.8	78.5	78.3	78.1	77.8	77.6	77.4	77.2	77.1	76.9	76.8	76.6	76.5
RATE2	329.1	329.3	329.0	329.0	329.3	329.9	331.0	332.2	333.4	334.7	336.0	337.3	338.6	339.9	341.2	342.4	343.7	344.9	346.2	347.5	348.7	349.9
RATE2_1	484.7	486.3	486.2	486.5	487.9	487.3	489.4	492.4	494.6	495.6	497.9	497.0	497.9	499.2	501.6	503.3	505.6	507.3	504.8	507.8	508.3	511.1
RATE2_2	9,274.8	9,273.8	9,273.1	9,272.7	9,279.0	9,291.6	9,310.2	9,330.6	9,351.7	9,372.7	9,393.7	8,958.8	8,981.7	9,004.0	9,025.8	9,047.0	9,498.6	9,511.4	9,523.6	9,535.3	9,546.5	9,556.9
RATE3	3,626.9	3,634.0	3,634.3	3,636.7	3,644.6	3,655.1	3,671.8	3,691.6	3,709.7	3,729.3	3,748.6	3,770.0	3,787.0	3,802.7	3,824.4	3,846.3	3,857.3	3,875.5	3,895.7	3,915.5	3,924.0	3,940.0
RATE4	5,696.8	5,743.4	5,758.8	5,781.0	5,821.3	5,867.1	5,922.3	5,981.2	6,041.9	6,079.6	6,117.0	6,153.4	6,188.0	6,221.7	6,245.7	6,268.7	6,291.0	6,312.1	6,332.2	6,351.0	6,368.7	6,384.9
RATE5	9,542.6	9,574.3	9,578.6	9,588.3	9,611.6	9,647.3	9,699.1	9,712.4	9,773.6	9,862.6	9,929.6	10,041.8	10,099.2	10,169.5	10,235.4	10,302.9	10,402.3	10,446.4	10,513.5	10,562.6	10,631.9	10,673.3
RATE6	4,242.7	4,261.3	4,277.5	4,299.9	4,325.4	4,355.8	4,394.1	4,446.6	4,491.4	4,530.6	4,569.9	4,780.4	4,819.9	4,858.8	4,894.8	4,930.1	4,964.9	4,998.9	5,032.0	5,127.0	5,160.2	5,192.2
RATE7	28,034.8	28,661.5	28,637.7	28,641.7	28,691.5	28,768.7	28,893.5	29,035.8	29,185.1	29,360.9	29,539.7	29,717.2	29,887.3	30,054.1	30,233.7	30,409.5	30,582.9	30,751.3	30,915.0	31,073.5	31,227.0	31,373.9
RATE22	771,870.1	792,055.6	793,406.6	792,295.8	791,457.2	801,444.1	801,154.6	773,113.8	773,229.8	767,481.9	767,060.2	768,940.1	764,120.0	763,708.1	763,173.4	774,996.2	786,825.3	805,106.4	804,416.5	803,687.0	802,924.6	768,045.4
RATE23	4,972.4	4,995.9	4,988.9	4,989.2	4,997.4	5,008.5	5,025.4	5,043.5	5,061.1	5,082.1	5,108.3	5,130.7	5,151.3	5,176.6	5,204.8	5,224.0	5,246.4	5,267.5	5,288.4	5,308.7	5,330.5	5,353.1
RATE25	24,718.6	25,385.0	25,238.4	25,327.4	25,220.2	25,272.2	25,414.4	25,357.7	25,533.5	25,241.6	25,437.9	25,619.8	25,404.5	25,556.0	25,778.0	25,987.7	25,879.1	26,080.6	26,251.3	26,292.7	26,598.9	26,533.9
RATE27	66,882.9	68,495.9	68,495.1	68,839.2	68,451.6	68,375.1	68,658.5	68,635.1	68,628.9	68,915.3	69,190.8	69,435.5	67,407.0	67,472.3	67,781.2	68,012.1	68,655.4	69,664.7	69,745.1	69,828.4	69,935.1	70,006.6
RATE46	37,471.6	37,445.3	37,422.0	37,430.6	37,483.5	37,572.2	35,904.9	37,629.0	37,801.9	39,322.7	39,498.9	39,674.1	39,845.0	40,016.0	37,963.0	38,125.3	38,284.9	38,439.1	38,588.1	38,731.6	38,870.0	41,268.3

Annual Demand by Rate Schedule (GJ)

Rate Class	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
RATE1	74,379,270	74,637,007	74,780,520	75,054,709	75,381,240	75,741,679	76,187,386	76,599,708	76,990,369	77,364,654	77,765,631	78,223,287	78,669,479	79,122,049	79,568,092	80,004,484	80,470,138	80,921,255	81,364,496	81,798,006	82,215,980	82,615,934
RATE2	27,994,803	28,444,191	28,831,517	29,231,700	29,660,987	30,119,008	30,613,343	31,115,339	31,635,538	32,141,971	32,656,047	33,175,368	33,697,600	34,215,205	34,738,544	35,265,282	35,787,467	36,322,948	36,856,914	37,385,673	37,917,773	38,451,804
RATE2_1	222,002	220,310	216,847	214,053	211,264	208,088	205,059	202,392	199,319	196,752	194,162	189,363	186,708	183,703	180,079	175,665	173,922	169,934	164,054	160,980	157,069	151,792
RATE2_2	64,924	64,916	64,912	64,909	64,953	65,041	65,171	65,314	65,462	65,609	65,756	53,753	53,890	54,024	54,155	54,282	47,493	47,557	47,618	47,677	47,733	47,784
RATE3	19,175,310	19,314,466	19,363,371	19,434,638	19,524,338	19,628,069	19,757,997	19,927,319	20,117,614	20,310,024	20,512,099	20,731,460	20,957,496	21,200,047	21,485,670	21,774,081	22,079,459	22,411,861	22,774,167	23,144,782	23,512,827	23,927,703
RATE4	148,116	149,329	149,730	150,305	151,354	152,544	153,980	155,512	157,089	158,070	159,043	159,989	160,888	161,763	162,389	162,987	163,565	164,114	164,637	165,127	165,586	166,008
RATE5	2,299,775	2,288,268	2,260,545	2,234,068	2,220,277	2,199,592	2,182,304	2,136,738	2,120,882	2,090,864	2,065,357	2,038,492	2,019,842	1,983,058	1,954,960	1,926,643	1,903,615	1,869,911	1,839,865	1,795,647	1,764,896	1,707,728
RATE6	50,912	51,136	51,329	51,599	51,905	52,269	52,730	48,913	49,405	49,836	50,269	47,804	48,199	48,588	48,948	49,301	49,649	49,989	50,320	46,143	46,442	46,730
RATE7	168,209	171,969	171,826	171,850	172,149	172,612	173,361	174,215	175,110	176,165	177,238	178,303	179,324	180,324	181,402	182,457	183,497	184,508	185,490	186,441	187,362	188,243
RATE22	37,049,763	38,018,670	38,083,516	38,030,199	37,989,944	37,667,870	37,654,266	35,563,234	35,568,571	33,769,206	33,750,647	32,295,484	29,800,681	29,784,615	29,763,763	29,449,855	29,112,536	28,178,724	28,154,579	28,129,046	28,102,360	26,113,543
RATE23	8,562,540	8,692,829	8,740,567	8,800,990	8,870,373	8,935,125	9,015,646	9,103,434	9,170,635	9,249,366	9,358,361	9,450,715	9,524,678	9,587,051	9,686,062	9,742,691	9,821,260	9,892,365	9,963,264	10,012,130	10,106,589	10,176,281
RATE25	13,867,113	14,037,905	13,830,634	13,676,802	13,467,586	13,242,620	13,139,257	12,932,421	12,792,275	12,418,848	12,311,939	12,066,932	11,762,281	11,653,519	11,496,971	11,304,659	10,869,226	10,666,984	10,579,288	10,333,037	10,160,793	9,790,993
RATE27	7,156,470	7,260,570	7,260,481	7,090,442	6,982,064	6,974,261	6,865,846	6,863,515	6,794,264	6,546,955	6,503,936	6,388,069	6,066,626	6,005,030	5,896,967	5,849,040	5,698,401	5,503,510	5,509,860	5,306,957	5,245,132	5,250,497
RATE46	599,546	599,125	598,752	598,890	599,736	601,155	538,574	526,806	529,227	511,195	513,485	515,763	517,985	520,208	455,556	457,503	459,419	461,269	463,057	464,780	466,440	453,952
Grand Total	**191,738,754**	**193,950,688**	**194,404,548**	**194,805,156**	**195,348,171**	**195,759,934**	**196,604,920**	**195,414,860**	**196,365,761**	**195,049,513**	**196,083,971**	**195,514,782**	**193,645,678**	**194,699,185**	**195,673,557**	**196,398,931**	**196,819,649**	**196,844,929**	**198,117,608**	**198,976,424**	**200,096,983**	**199,088,993**

Scenario E

Year End Customers by Rate Schedule

Rate Class	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
RATE1	888,135	900,173	911,287	922,384	933,447	944,463	954,844	964,252	973,097	981,558	990,305	999,163	1,007,835	1,016,544	1,025,120	1,033,538	1,041,789	1,049,841	1,057,768	1,065,512	1,072,992	1,080,219
RATE2	85,075	86,388	87,625	88,855	90,075	91,294	92,501	93,678	94,875	96,030	97,184	98,346	99,516	100,666	101,827	102,987	104,127	105,303	106,454	107,600	108,746	109,884
RATE2_1	458	453	446	440	433	427	419	411	403	397	390	381	375	368	359	349	344	335	325	317	309	297
RATE2_2	7	7	7	7	7	7	7	7	7	7	7	6	6	6	6	6	5	5	5	5	5	5
RATE3	5,287	5,315	5,328	5,344	5,357	5,370	5,381	5,398	5,423	5,446	5,472	5,499	5,534	5,575	5,618	5,661	5,724	5,783	5,846	5,911	5,992	6,073
RATE4	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
RATE5	241	239	236	233	231	228	225	220	217	212	208	203	200	195	191	187	183	179	175	170	166	160
RATE6	12	12	12	12	12	12	12	11	11	11	11	10	10	10	10	10	10	10	10	9	9	9
RATE7	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
RATE22	48	48	48	48	48	47	47	46	46	44	44	42	39	39	39	38	37	35	35	35	35	34
RATE23	1,722	1,740	1,752	1,764	1,775	1,784	1,794	1,805	1,812	1,820	1,832	1,842	1,849	1,852	1,861	1,865	1,872	1,878	1,884	1,886	1,896	1,901
RATE25	561	553	548	540	534	524	517	510	501	492	484	471	463	456	446	435	420	409	403	393	382	369
RATE27	107	106	106	103	102	102	100	100	99	95	94	92	90	89	87	86	83	79	79	76	75	75
RATE46	16	16	16	16	16	16	15	14	14	13	13	13	13	13	12	12	12	12	12	12	12	11
Grand Total	**981,701**	**995,082**	**1,007,443**	**1,019,778**	**1,032,069**	**1,044,306**	**1,055,894**	**1,066,484**	**1,076,537**	**1,086,157**	**1,096,076**	**1,106,100**	**1,115,962**	**1,125,845**	**1,135,608**	**1,145,206**	**1,154,638**	**1,163,901**	**1,173,028**	**1,181,958**	**1,190,651**	**1,199,069**

Annual Use Rate per Customer by Rate Schedule (GJ)

Rate Class	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
RATE1	83.7	82.2	80.7	79.1	77.5	75.8	74.3	72.9	71.3	69.7	68.1	66.5	64.9	63.1	61.3	59.3	57.3	55.0	52.5	49.9	47.0	44.0
RATE2	329.1	326.1	322.6	318.2	311.8	305.3	300.0	294.2	287.5	279.8	272.2	264.4	258.0	250.4	242.7	234.5	225.9	216.6	207.3	198.0	188.6	180.6
RATE2_1	484.7	480.3	474.8	468.3	459.4	448.0	440.6	433.3	423.6	411.7	400.7	386.6	376.3	364.3	352.7	340.1	326.9	311.2	293.4	279.0	263.0	246.8
RATE2_2	9,274.8	9,223.9	9,155.5	9,068.8	8,924.1	8,778.3	8,669.7	8,556.0	8,424.5	8,272.3	8,126.1	7,384.1	7,268.9	7,126.5	6,988.4	6,843.0	7,474.4	7,341.6	7,206.4	7,071.3	6,932.0	6,793.7
RATE3	3,626.9	3,587.4	3,543.1	3,489.9	3,415.2	3,336.4	3,271.5	3,203.8	3,122.1	3,027.8	2,934.1	2,837.6	2,753.9	2,656.2	2,557.7	2,453.8	2,338.0	2,218.4	2,099.1	1,978.7	1,853.0	1,753.1
RATE4	5,696.8	5,664.9	5,628.5	5,595.1	5,548.9	5,484.4	5,429.0	5,368.8	5,291.5	5,168.7	5,060.6	4,952.2	4,853.1	4,741.1	4,605.3	4,456.2	4,289.5	4,103.5	3,900.1	3,679.6	3,436.5	3,176.5
RATE5	9,542.6	9,424.6	9,289.2	9,126.4	8,904.3	8,675.6	8,483.4	8,240.0	8,004.9	7,736.3	7,465.1	7,197.7	6,930.6	6,653.6	6,361.7	6,054.8	5,750.7	5,360.3	4,997.6	4,705.7	4,427.8	4,129.0
RATE6	4,242.7	4,207.3	4,164.9	4,115.1	4,037.7	3,953.0	3,881.3	3,816.7	3,725.4	3,609.5	3,495.4	3,512.8	3,401.9	3,273.0	3,130.0	2,972.2	2,798.6	2,606.8	2,398.1	2,210.2	1,984.7	1,759.5
RATE7	28,034.8	27,632.8	27,182.7	26,682.2	26,030.7	25,307.6	24,657.9	23,976.5	23,154.9	22,213.7	21,301.1	20,357.7	19,508.7	18,581.8	17,623.0	16,618.2	15,564.5	14,453.2	13,273.8	12,027.1	10,678.7	9,228.9
RATE22	771,870.1	767,642.8	762,760.7	759,252.3	753,279.2	754,237.6	745,824.4	711,155.2	701,071.5	684,921.3	674,738.8	666,294.8	652,628.6	642,883.9	630,821.6	627,075.3	620,314.7	617,043.1	593,715.2	566,530.1	534,502.9	476,338.4
RATE23	4,972.4	4,917.5	4,849.3	4,778.4	4,682.1	4,577.1	4,486.9	4,388.0	4,273.0	4,141.5	4,018.5	3,886.6	3,773.2	3,645.1	3,513.4	3,365.3	3,207.9	3,039.1	2,861.6	2,677.7	2,486.5	2,312.4
RATE25	24,718.6	24,590.3	24,226.9	24,096.3	23,650.1	23,265.5	23,001.2	22,524.8	22,182.7	21,351.0	20,976.6	20,560.8	19,882.7	19,476.3	19,034.1	18,524.3	17,745.2	17,046.1	16,212.8	15,260.7	14,337.7	13,066.9
RATE27	66,882.9	66,414.6	65,905.6	65,914.5	65,011.1	64,103.5	63,556.1	62,658.6	61,615.4	60,656.8	59,896.6	59,184.4	56,437.3	55,483.6	54,494.6	53,432.6	52,247.2	51,204.1	49,115.3	46,640.5	43,790.5	40,570.2
RATE46	37,471.6	36,992.8	36,428.6	35,772.8	34,881.2	33,958.1	31,589.2	32,034.6	31,075.9	31,256.7	30,139.9	28,962.3	27,950.9	26,782.6	24,185.0	22,962.8	21,663.7	20,275.5	18,796.7	17,236.4	15,603.0	14,104.1

Annual Demand by Rate Schedule (GJ)

Rate Class	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
RATE1	74,379,270	74,020,655	73,517,097	72,950,986	72,328,600	71,586,289	70,977,354	70,268,105	69,417,718	68,441,831	67,481,130	66,445,622	65,369,506	64,178,948	62,830,341	61,309,136	59,646,733	57,743,664	55,578,328	53,138,989	50,400,156	47,574,422
RATE2	27,994,803	28,170,556	28,264,639	28,273,676	28,088,066	27,871,478	27,754,132	27,558,959	27,277,950	26,870,234	26,456,403	25,999,967	25,670,992	25,207,860	24,714,352	24,149,237	23,517,137	22,810,956	22,066,546	21,302,737	20,514,397	19,841,427
RATE2_1	222,002	217,580	211,755	206,050	198,939	191,294	184,611	178,067	170,709	163,461	156,276	147,308	141,121	134,071	126,614	118,686	112,441	104,247	95,363	88,432	81,261	73,302
RATE2_2	64,924	64,567	64,089	63,482	62,468	61,448	60,688	59,892	58,971	57,906	56,883	44,304	43,613	42,759	41,931	41,058	37,372	36,708	36,032	35,356	34,660	33,969
RATE3	19,175,310	19,067,285	18,877,799	18,649,936	18,295,174	17,916,249	17,603,707	17,293,912	16,931,414	16,489,531	16,055,660	15,603,846	15,239,823	14,808,359	14,369,425	13,890,728	13,382,911	12,829,195	12,271,184	11,695,914	11,103,162	10,646,438
RATE4	148,116	147,286	146,342	145,473	144,270	142,595	141,155	139,588	137,580	134,386	131,576	128,756	126,181	123,268	119,738	115,861	111,528	106,691	101,401	95,669	89,349	82,589
RATE5	2,299,775	2,252,469	2,192,259	2,126,442	2,056,890	1,978,034	1,908,768	1,812,792	1,737,061	1,640,105	1,552,750	1,461,143	1,386,129	1,297,447	1,215,082	1,132,247	1,052,382	959,499	874,573	799,973	735,020	660,634
RATE6	50,912	50,488	49,979	49,382	48,452	47,437	46,575	41,984	40,980	39,704	38,450	35,128	34,019	32,730	31,300	29,722	27,986	26,068	23,981	19,892	17,862	15,835
RATE7	168,209	165,797	163,096	160,093	156,184	151,845	147,947	143,859	138,930	133,282	127,807	122,146	117,052	111,491	105,738	99,709	93,387	86,719	79,643	72,163	64,072	55,373
RATE22	37,049,763	36,846,856	36,612,515	36,444,108	36,157,404	35,449,166	35,053,748	32,713,138	32,249,289	30,136,539	29,688,506	27,984,382	25,452,516	25,072,471	24,602,042	23,828,862	22,951,645	21,596,509	20,780,033	19,828,553	18,707,602	16,195,507
RATE23	8,562,540	8,556,387	8,496,032	8,429,070	8,310,676	8,165,614	8,049,429	7,920,353	7,742,634	7,537,536	7,361,804	7,159,134	6,976,586	6,750,778	6,538,456	6,276,281	6,005,200	5,707,480	5,391,197	5,050,220	4,714,494	4,395,964
RATE25	13,867,113	13,598,429	13,276,354	13,011,991	12,629,164	12,191,139	11,891,608	11,487,640	11,113,524	10,504,715	10,152,673	9,684,126	9,205,686	8,881,215	8,489,223	8,058,060	7,452,966	6,971,874	6,533,739	5,997,447	5,476,999	4,821,692
RATE27	7,156,470	7,039,951	6,985,995	6,789,192	6,631,137	6,538,552	6,355,612	6,265,855	6,099,925	5,762,399	5,630,284	5,444,961	5,079,361	4,938,041	4,741,028	4,595,205	4,336,521	4,045,123	3,880,112	3,544,677	3,284,290	3,042,765
RATE46	599,546	591,885	582,858	572,365	558,099	543,330	473,838	448,484	435,063	406,338	391,819	376,509	363,361	348,174	290,220	275,553	259,964	243,306	225,561	206,836	187,236	155,145
Grand Total	**191,738,754**	**190,790,190**	**189,440,809**	**187,872,246**	**185,665,523**	**182,834,472**	**180,649,174**	**176,332,630**	**173,551,747**	**168,317,967**	**165,282,019**	**160,637,333**	**155,205,948**	**151,927,610**	**148,215,489**	**143,920,345**	**138,988,173**	**133,268,039**	**127,937,693**	**121,876,858**	**115,410,562**	**107,595,062**

Natural Gas for Transportation (NGT) Annual Demand by Fuel Type (GJ)

NGT Scenario/NGT Fuel Type	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Reference Case	**1,150,249**	**1,255,538**	**2,141,838**	**3,567,563**	**4,752,438**	**7,801,863**	**13,402,288**	**22,505,713**	**24,044,138**	**35,470,563**	**39,964,988**
Compressed Nat. Gas	496,249	601,538	690,838	946,563	1,032,438	1,132,863	1,233,288	1,333,713	1,434,138	1,534,563	1,634,988
Liquified Nat. Gas	654,000	654,000	1,451,000	2,621,000	3,720,000	6,669,000	12,169,000	21,172,000	22,610,000	33,936,000	38,330,000
Upper Bound	**1,150,249**	**1,255,538**	**2,136,213**	**4,560,088**	**5,963,648**	**8,755,379**	**14,450,203**	**26,978,155**	**66,069,226**	**116,186,459**	**126,411,861**
Compressed Nat. Gas	496,249	601,538	685,213	1,039,088	1,163,648	1,336,379	1,531,203	1,756,155	2,009,226	2,300,459	2,631,861
Liquified Nat. Gas	654,000	654,000	1,451,000	3,521,000	4,800,000	7,419,000	12,919,000	25,222,000	64,060,000	113,886,000	123,780,000
Lower Bound	**1,300,249**	**1,405,538**	**1,909,913**	**3,364,788**	**3,181,978**	**4,559,012**	**5,665,037**	**6,626,071**	**7,720,097**	**7,704,131**	**7,706,165**
Compressed Nat. Gas	496,249	601,538	608,913	618,788	621,978	630,012	636,037	644,071	650,097	658,131	666,165
Liquified Nat. Gas	804,000	804,000	1,301,000	2,746,000	2,560,000	3,929,000	5,029,000	5,982,000	7,070,000	7,046,000	7,040,000

NGT Scenario/NGT Fuel Type	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reference Case	**44,435,413**	**51,135,838**	**54,536,263**	**55,026,688**	**57,652,113**	**61,442,538**	**64,042,963**	**66,733,388**	**73,048,813**	**75,349,238**	**78,339,663**
Compressed Nat. Gas	1,735,413	1,835,838	1,936,263	2,036,688	2,137,113	2,237,538	2,337,963	2,438,388	2,538,813	2,639,238	2,739,663
Liquified Nat. Gas	42,700,000	49,300,000	52,600,000	52,990,000	55,515,000	59,205,000	61,705,000	64,295,000	70,510,000	72,710,000	75,600,000
Upper Bound	**208,159,459**	**329,589,278**	**345,819,352**	**363,292,715**	**381,869,410**	**401,751,487**	**420,543,989**	**442,815,975**	**467,747,531**	**488,812,716**	**516,265,632**
Compressed Nat. Gas	3,009,459	3,439,278	3,929,352	4,487,715	5,124,410	5,851,487	6,678,989	7,620,975	8,697,531	9,922,716	11,320,632
Liquified Nat. Gas	205,150,000	326,150,000	341,890,000	358,805,000	376,745,000	395,900,000	413,865,000	435,195,000	459,050,000	478,890,000	504,945,000
Lower Bound	**7,684,199**	**7,692,233**	**7,698,258**	**7,706,292**	**7,754,326**	**7,762,360**	**7,770,394**	**7,780,437**	**7,788,471**	**7,796,505**	**7,804,539**
Compressed Nat. Gas	674,199	682,233	688,258	696,292	704,326	712,360	720,394	730,437	738,471	746,505	754,539
Liquified Nat. Gas	7,010,000	7,010,000	7,010,000	7,010,000	7,050,000	7,050,000	7,050,000	7,050,000	7,050,000	7,050,000	7,050,000

Appendix B-5

ANNUAL DEMAND FORECAST RESULTS

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Appendix C

DEMAND SIDE RESOURCES

Appendix C-1

BC CONSERVATION POTENTIAL REVIEW REPORT FOR FEI

British Columbia Conservation Potential Review

Prepared for:

FortisBC Energy Inc.

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DISCLAIMER

This report was prepared by Navigant Consulting, Inc. (Navigant) for FortisBC Energy Inc. The work presented in this report represents Navigant's professional judgment based on the information available at the time this report was prepared. Navigant is not responsible for the reader's use of, or reliance upon, the report, nor any decisions based on the report. NAVIGANT MAKES NO REPRESENTATIONS OR WARRANTIES, EXPRESSED OR IMPLIED. Readers of the report are advised that they assume all liabilities incurred by them, or third parties, as a result of their reliance on the report, or the data, information, findings and opinions contained in the report.

EXECUTIVE SUMMARY

FortisBC Energy Inc. (FortisBC Gas) and the other BC Utilities engaged Navigant Consulting, Inc. (Navigant or the team) to prepare a conservation potential review (CPR) for electricity and natural gas across all of British Columbia over a 20-year forecast horizon from 2016 to 2035. The CPR's objective is to assess the energy efficiency potential in the residential, commercial, and industrial sectors by analyzing energy efficiency and peak-load-reduction measures, defining operational and maintenance activities to keep existing devices or equipment in good working order, and improving end-user behaviors to reduce energy consumption. These analysis efforts provide input data to Navigant's Demand Side Management Simulator (DSMSim™) model, which calculates technical and economic savings potential across FortisBC Gas's service territory. FortisBC Gas may use these results as input to their own DSM planning and long term conservation goals, energy efficiency program design, integrated resource planning (IRP), and load forecasting models.

The first stage of this CPR is to estimate technical and economic conservation potential, which is presented in this report. Further analyses, which will be presented in ensuing reports as part of the CPR's Additional Scope Services, include estimation of the province-wide technical and economic potential for electricity and natural gas, achievable market potential for gas savings and potential from fuel switching.

Approach

This section provides an overview of the methods Navigant employed for conducting the 2016 CPR for British Columbia.

Base Year and Reference Case Forecast

Navigant developed the Base Year (2014) Calibration (base year) based on an assessment of energy consumption in each utility's service territory, by customer sector and segment, end-use, fuel, and types of equipment used. The objective of the base year is to establish a profile of energy consumption by utility, which is consistent with the total energy consumption (gas and electricity) reported by each utility. The team used the base year as the foundation to develop the Reference Case Forecast of energy demand through 2035.

The Reference Case Forecast estimates the expected level of energy demand over the CPR period from 2016-2035 absent incremental demand-side management (DSM) activities and absent rate impacts on consumption. The significance of the Reference Case in the context of this CPR study is that it acts as the point of comparison (i.e., the reference) for the calculation of the technical and economic potential scenarios.

The Reference Case Forecast uses the base year calibration as the foundation for analysis. Navigant used two key inputs to construct the Reference Case forecast for each customer sector: building stock growth rates, and end-use intensity (EUI) trends. Applying building stock growth rates to the base year stocks of each customer segment results in a forecast of stocks through 2035. Similarly, applying the EUI trends to the base year EUIs results in a forecast of EUIs through 2035. The final step of this process involves multiplying the stock forecast with the corresponding EUI forecast in order to obtain a consumption forecast.

To construct the Reference Case Forecast, Navigant developed growth projections of residential building stock, commercial floor area, and industrial energy consumption. The team then modeled the potential for energy efficiency based on the resulting stock projections of each sector, while accounting for the changing mix of newly constructed versus existing building stock. The team applied EUI trends to the Base Year EUIs for each customer segment, and used these trends to represent natural change (i.e., naturally occurring increases or reductions in consumption not attributable to DSM programs) in end-use consumption over time.

Navigant compared the forecasts developed as part of the Reference Case for the residential, commercial, and industrial sectors with the long-term load forecast developed by each utility. The team performed this comparison to ensure that the Reference Case forecast is consistent with each utility's current expectations for load growth over the 2015 to 2035 period.

Measure Characterization

Navigant fully characterized over 200 measures across the BC Utility's residential, commercial, and industrial sectors, covering electric and natural gas fuel types. The team prioritized measures with high impact, data availability, and likelihood to be cost-effective as criteria for inclusion into DSMSim™.

The team reviewed current BC program offerings, previous CPR and other Canadian programs, and potential model measure lists from other jurisdictions to identify which energy efficient measures to include in the study. The team supplemented the measure list using the Pennsylvania, Illinois, Mid-Atlantic, and Massachusetts technical resource manuals (TRMs), and partnered with CLEAResult to inform the list of industrial measures. Navigant worked with the BC Utilities to finalize the measure list and ensure it contained technologies viable for future BC program planning activities. Appendix A.2 provides the references to the final measure list and assumptions.

Estimation of Potential

Navigant employed its proprietary DSMSim™ potential model to estimate the technical and economic savings potential for gas energy in FortisBC Gas's service territory.[1] DSMSim™ is a bottom-up technology diffusion and stock-tracking model implemented using a System Dynamics[2] framework. The DSMSim™ model explicitly accounts for different types of efficient measures such as retrofit (RET), replace-on-burnout (ROB), and new construction (NEW) and the impacts these measures have on savings potential. The model then reports the technical and economic potential savings in aggregate by service territory, sector, customer segment, end-use category, and highest-impact measures.

Technical potential is defined as the energy savings that can be achieved assuming that all installed measures can immediately be replaced with the efficient measure, wherever technically feasible, regardless of the cost, market acceptance, or whether a measure has failed (or "burned out") and is in need of being replaced. Technically feasible measures are commercially available measures that are compatible with and may replace the existing baseline technology. Economic potential is a subset of technical potential, using the same assumptions regarding immediate replacement as in technical potential, but limiting the calculation only to those measures that have passed the benefit-cost test chosen for measure screening, in this case the TRC test. Similar to technical potential, economic potential does not represent an achievable level of savings potential because it does not account for market adoption and acceptance, desired customer payback period, etc. The estimation of achievable market potential will be completed as part of this CPR's Additional Scope Services.

Savings reported in this study are "gross", rather than "net," meaning they do not include the effects of natural change (as described in Section 2.3.2). The technical potential results section concludes with a comparison of aggregate potential before consideration of natural change and after including natural change. Providing gross potential is advantageous because it permits a reviewer to more easily calculate net potential when new information about net-to-gross ratios or changing end-use intensities become available.

Findings

Figure ES-1 compares the total technical and economic gas energy savings potential in FortisBC Gas's service territories, and Table D-1 of Appendix D provides the associated data. Technical gas savings potential begins at approximately 46,000 TJ/year in 2016 and increases by 26% to 58,000 TJ/year by 2035. Economic gas savings potential grows by 53% from a 2016 value of 29,000 TJ/year to a 2035 value of 44,000 TJ/year. On average across the study period, 71% of technical potential is cost-effective, as reflected by the economic potential.

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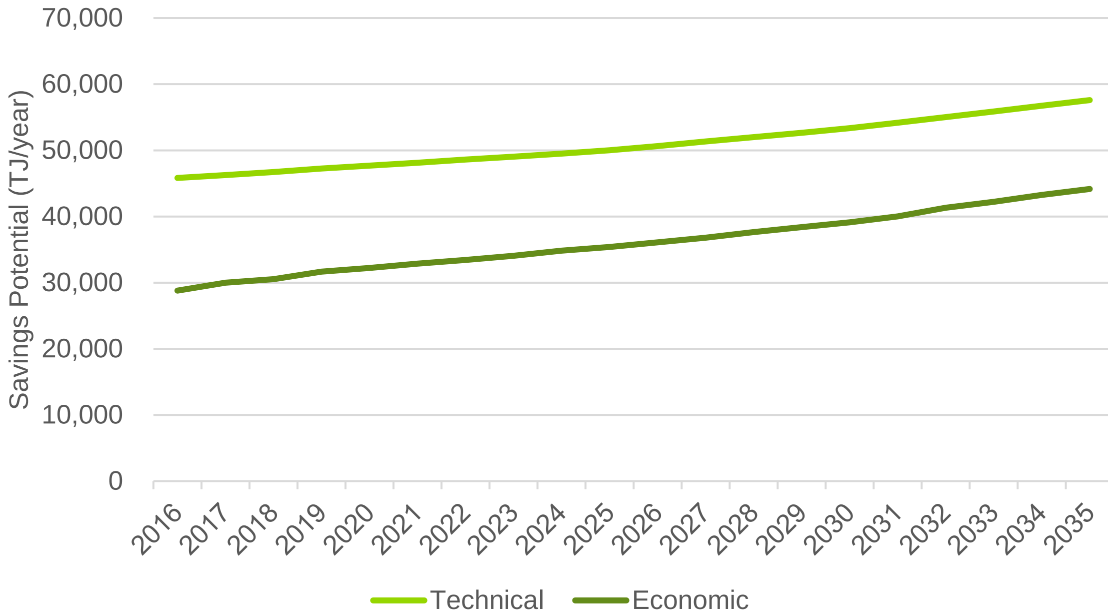
[1] The study also identified the impacts on electric consumption caused by gas measures with either dual-fuel savings or cross-fuel interactive effects. Since the electric impacts are negligible, they are included in Appendix A.1, but not within the body of the report.
[2] See Sterman, John D. *Business Dynamics: Systems Thinking and Modeling for a Complex World*. Irwin McGraw-Hill. 2000 for detail on System Dynamics modelling. Also see http://en.wikipedia.org/wiki/System_dynamics for a high-level overview.

The residential and commercial sectors' contributions to the growth of technical potential are nearly equal, whereas technical potential from the industrial sector declines slightly over the forecast period. The commercial sector drives the majority of the growth in economic potential.

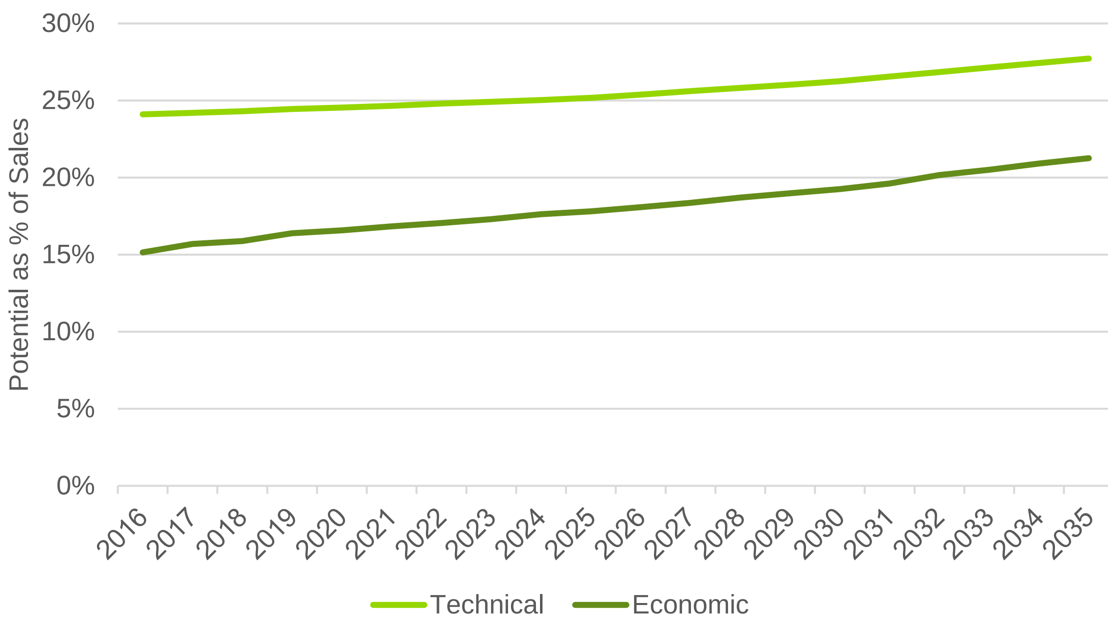
Figure ES-1. Total Gas Energy Savings Potential (TJ/year)



Source: Navigant

Figure ES-2 provides the technical and economic gas savings potential as a percentage of total gas consumption within the FortisBC Gas's service territories, and Table D-2 of Appendix D provides the associated data. The technical savings potential grows faster than the gas consumption forecast, such that the technical potential as a percentage of total gas consumption increases from 24% in 2016 to 28% by 2035. Economic savings potential increases from 15% in 2016 to 21%.

Figure ES-2. Total Gas Energy Savings Potential as a Percent of Total Consumption (%)



Source: Navigant

1. INTRODUCTION

1.1 Conservation Potential Review Background and Goals

The BC Utilities—defined in this report as BC Hydro, FortisBC Inc. (FortisBC Electric), FortisBC Energy Inc. (FortisBC Gas), and Pacific Northern Gas Ltd.—engaged Navigant Consulting, Inc. (Navigant or the team) to prepare a conservation potential review (CPR) for electricity and natural gas across all of British Columbia over a 20-year forecast horizon from 2016 to 2035. The CPR's objective is to assess the energy efficiency potential in the residential, commercial, and industrial sectors by analyzing energy efficiency and peak-load-reduction measures, defining operational and maintenance activities to keep existing devices or equipment in good working order, and improving end-user behaviors to reduce energy consumption. These analysis efforts provide input data to Navigant's Demand Side Management Simulator (DSMSim™) model, which calculates technical and economic savings potential across the BC Utilities' service territories. The BC Utilities may use these results as input to their own DSM planning and long-term conservation goals, energy efficiency program design, integrated resource planning (IRP), and load forecasting models.

1.2 Organization of Report

This report is organized as follows:

Section 2 describes the methodologies and approaches Navigant used for estimating energy efficiency and demand reduction potential, including discussion of base year calibration, Reference Case forecast, the frozen end-use intensity case, and measure characterization.

Section 3 offers the technical potential savings forecast for FortisBC Gas, including the methods for estimating technical potential and the modeling results by customer segment and end-use.

Section 4 offers the economic potential savings forecast for FortisBC Gas, including the methods for estimating economic potential and the modeling results by customer segment and end-use.

Accompanying Appendices provide detailed model results and additional context around modeling assumptions.

1.3 Caveats and Limitations

There are several caveats and limitations associated with the results of this study, as detailed below.

1.3.1 Forecasting Limitations

Navigant obtained future energy sales forecasts from each BC Utility. Each of these forecasts contain assumptions, methodologies, and exclusions which could differ by utility. Navigant has leveraged the assumptions underlying these forecasts, as much as possible, as inputs into the development of the Reference Case stock and energy demand projections. Where sufficient and detailed information could not be extracted, as a result of the granularity of the information available or customer data protection requirements, Navigant developed independent projections of stock for each utility. The team developed these independent projections based on secondary data resources and in collaboration with the utilities. These secondary resources and any underlying assumptions are referenced throughout this report.

1.3.2 Program Design

The results of this study provide a big picture view of the unmet savings potential in each of the BC Utilities’ service territories. However, this study is not considered to be a detailed program design tool, as it does not consider incentive, marketing, advertising and budget levels, nor customers’ willingness to adopt efficient measures. As such, the magnitude of the results should not be interpreted as the savings potential that could be realistically achieved by utility-sponsored energy conservation programs.

1.3.3 Measure Characterization

Efficiency potential studies may employ a variety of primary data collection techniques (e.g., customer surveys, on-site equipment saturation studies, and telephone interviews), which can enhance the accuracy of the results, though not without associated cost and time requirements. The scope of this study did not include primary data collection, but rather relied on data from the BC Utilities, other regional efficiency programs, Natural Resources Canada (NRCan), and technical reference manuals (TRMs) from Pennsylvania, Illinois, Mid-Atlantic, and Massachusetts to inform inputs to DSMSim™.

Furthermore, the team considers the measure list used in this study to appropriately focus on those technologies likely to have the highest impact on savings potential over the potential study horizon. However, there is always the possibility that emerging technologies may arise that could increase savings opportunities over the forecast horizon, and broader societal changes may impact levels of energy use in ways not anticipated in the study.

1.3.4 Measure Interactions

This study models energy efficiency measures independently .[3] As a result, the total aggregated energy efficiency potential estimates may be different from the actual potential available if a customer installs multiple measures in their home or business. Multiple measure installations at a single site generate two types of interactions: within-end-use interactions, and cross-end-use interactions. An example of a within-end-use interaction is when a customer implements an operational program to review and maintain steam traps, but also installs a more efficient boiler. To the extent that the steam trap program reduces heating requirements at the boiler, the savings from the efficient boiler would be reduced. An example of a cross-end-use interaction would be when a homeowner replaces a number of heat producing incandescent light bulbs with efficient LEDs. This impacts the cooling and heating load of the space—however slightly—by increasing the amount of heat required from the HVAC system, and decreasing the amount of cooling required.

[3] A small number of measures accounted for interactions among multiple efficient measures. For measures whose characterization was based on building energy model simulations evaluating bundled measures, interactive effects among those measures were included in the savings estimates (e.g., ENERGY STAR New Homes, Net-Zero New Homes, etc.).

Navigant employed the following methods to account for interactive effects:

- Where measures clearly compete for the same application (e.g., CFL and LED), the team created competition groups to eliminate the potential for double counting savings
- For measures with significant interactions (e.g., industrial process and boilers), the team adjusted applicability percentages to reflect varying degrees of interaction
- Wherever cross-end-use interactions were appreciable (e.g., lighting and HVAC), the team characterized those interactions for both same-fuel (e.g., lighting and electric heating) and cross-fuel (e.g., lighting and gas heating) applications

B.1 provides further discussion on the challenges involved with accurately determining interactive effects.

1.3.5 Measure-Level Results

This report includes a high-level account of savings potential results across the FortisBC Gas's service territories and focuses largely on aggregated forms of savings potential. However, Appendix A.1 provides results at the finest level of granularity, which is at the measure-level within each customer segment. The measure-level data is mapped to the various regions, customer segments and end-use categories to permit a reviewer to easily create custom aggregations

1.3.6 Gross Savings Study

Navigant and BC Utilities agreed to show savings from this study at the gross level, whereby natural change and free ridership, as it relates to program implementation, are not included in the savings estimates but rather are estimated separately. Providing gross potential is advantageous because it permits a reviewer to more easily calculate net potential when new information about changing end-use intensities or net-to-gross ratios become available. However, the team calculated natural change at end-use level, which is available in Appendix A.1. Additionally, each results section concludes with a comparison of aggregate potential before consideration of natural change and after including natural change.

2. APPROACH TO ESTIMATING ENERGY AND DEMAND SAVINGS

This section describes the methodologies Navigant employed for estimating energy and demand savings across the BC Utility's service territories including base year calibration, reference case forecast, the frozen end-use intensity case, and measure characterization.

2.1 Base Year Calibration

Navigant developed a Base Year Calibration (base year) based on an assessment of energy consumption in each utility's service territory, by customer sector and segment, end-use, fuel, and types of equipment used. The objective of the base year is to define a detailed profile of energy consumption by utility which matches the total energy consumption (gas and electricity) reported by each utility. The team used the base year as the foundation to develop the Reference Case Forecast of energy consumption through 2035. Section 2.2 discusses the development of the Reference Case.

Navigant developed the Base Year analysis for the province as a whole relying on data provided by the BC Utilities. This report presents data that is specific to FortisBC Gas. The resources provided by FortisBC Gas included the following data sources:

- Historical gas consumption;
- Residential accounts data;
- Residential and Commercial End-Use Surveys;
- Program evaluation reports, conditional demand analyses (CDA); and
- The 2010 and 2006 CPR reports.

Where utility- or FortisBC-specific information was not available, Navigant utilized data from publicly available sources such as BC Statistics (BC Stats), Statistics Canada (StatsCan), and Natural Resources Canada (NRCan) and the Office of Energy Efficiency (OEE) in addition to internal Navigant data sources. Navigant's review of these sources supported the data provided by FortisBC Gas and to ensure consistency among all data used in the study. In order to develop the final estimates of energy consumption, Navigant compared and calibrated preliminary estimates with actual sales data obtained from FortisBC Gas.

Navigant focused the calibration analysis on volumetric energy (e.g., MWh or GJ) consumed in each region by customer segment, end-use, and equipment type in order to develop the base year energy profile for each utility. Navigant chose not to perform calibration based on peak demand (e.g., MW or GJ/hr.) for several reasons. First, each utility reports sales and self-generation amounts at the level of aggregation required for this analysis (e.g., by residential, commercial, and industrial segments) exclusively by volumetric energy. Second, utilities rarely aggregate and report peak demand data (other than for billing purposes) at the level of aggregation required. Third, each utility had readily available (and granular) volumetric energy data.

2.1.1 Segmentation of Customer Sectors

Navigant disaggregated FortisBC Gas's base year gas consumption by region in the province, sector, and customer segment. Navigant worked with the BC utilities to determine an appropriate level of segmentation for each sector and an acceptable geographic representation resulting in four regions consistent with regional definitions used by FortisBC Gas.
Table 2-1 indicates the relationship between the four utilities' service territories and the regions considered in the CPR.

Table 2-1: Mapping of Utility Service Territories to CPR Regions

	Vancouver Island	Lower Mainland	Southern Interior	Northern BC
BC Hydro (Electric)	✓	✓	✓	✓
FortisBC (Electric)			✓	
FortisBC Energy (Gas)	✓	✓	✓	✓
PNG (Gas)				✓

Source: Navigant

The first major task to develop the base year gas calibration involved the disaggregation of the three main sectors—the residential, commercial, and industrial sectors—into specific customer segments. Each sector was segmented according to several factors including the availability and level of detail of the data provided by each utility, supporting information from secondary resources, level of consumption within segments, and consistency with previous CPRs.

The segmentation also reflects Navigant's modeling approach for representing efficiency measures within the DSMSim™ model. DSMSim™ models energy efficiency measures at the segment level, and tracks building and equipment stocks for each segment within each region and utility. Differences in fuel choices (i.e., space and water heating market shares), types of equipment used (i.e., use of a furnace or boiler for space heating), and equipment and system efficiency levels are all represented within the model for each segment, region, and utility, as required.

This modeling approach represents all measures separately within each customer segment, and does not require the duplication of segments using different space heating sources or different industrial processes. For example, the model represents space conditioning measures separately by heating type (e.g., characterizing thermal envelope measures for homes with electric or gas heat), eliminating the need to define a customer segment with electric heat versus a segment with gas heat.

Table 2-2 shows the segmentation used for the residential, commercial, and industrial sectors, with additional detail provided for each sector in the following sections. Although the streetlights/traffic signals segment is included in the commercial sector in Table 2-2, it has been analyzed and referenced separately throughout this report.

Table 2-2: Customer Segments by Sector

Residential	Commercial	Industrial
Single Family Detached	Accommodation	Agriculture
Single Family Attached/Row	Colleges/Universities	Cement
Apartments =< 4 stories	Food Service	Chemical
Apartments > 4 stories	Hospital	Food & Beverage
Other Residential	Logistics/Warehouses	Greenhouses
	Long Term Care	Mining - Coal
	Office	Mining - Metal
	Other Commercial	LNG Facilities
	Retail - Food	Oil and Gas
	Retail - Non Food	Manufacturing
	Schools	Pulp & Paper - Kraft
	Streetlights/Traffic Signals*	Pulp & Paper - TMP
		Wood Products
		Other Industrial
		Transportation

**Although the streetlights/traffic signals segment is included in the Commercial sector, it is only applicable to the electric utilities.*
Source: Navigant

2.1.1.1 FortisBC Gas Sales

FortisBC Gas supplies natural gas to residential, commercial and industrial customers across the four CPR regions. For internal purposes, FortisBC Gas distinguishes the location of its customers based on seven regions - different to the four CPR regions. As a result, to aggregate the FortisBC Gas sales data according to the four CPR regions, Navigant and FortisBC Gas developed a mapping to allocate sales and customer account data based on the seven FortisBC Gas regions and the four CPR regions.

The seven regions used by FortisBC Gas include Columbia, Fort Nelson, Inland, Lower Mainland, Revelstoke, Vancouver Island, and Whistler. Table 2-3 shows the mapping used to allocate sales to each of the CPR regions.

Table 2-3: Mapping of FortisBC Gas to CPR Regions

Code	Region	Vancouver Island	Lower Mainland	Southern Interior	Northern BC
COL	Columbia			✓	
FTN	Fort Nelson				✓
INL	Inland			✓	✓
LML	Lower Mainland		✓		
RSK	Revelstoke			✓	
VI	Vancouver Island	✓			
WH	Whistler		✓		

Source: Navigant analysis of FortisBC Gas data

A second step was also required in order to allocate FortisBC Gas sales and customers appropriately across customer sectors. This step deals specifically with apartment buildings. In this CPR, apartment buildings have been included in the residential sector. However, for billing purposes, FortisBC Gas includes apartment buildings in the commercial sector. As a result, a fraction of the commercial sector sales –attributed to apartment buildings- has been re-allocated to the residential sector. The fraction of sales attributed to apartment buildings was calculated as part of the analysis of Base Year sales, and is based on the stock of apartment units and the corresponding EUIs. Overall, relative to the initial allocation of sales the resulting residential sales are higher and the commercial sales are lower.

2.1.1.2 Residential Sector

Navigant divided residential customers into five segments based on the type of dwelling they occupied, as shown in Table 2-4.

Table 2-4: Description of Residential Segments

Segment	Description
Single Family Detached/Duplexes	Detached and duplex residential dwellings
Single Family Attached/Row	Attached, row and/or townhouses
Apartments < 4 stories	Apartment units located in low-rise apartment buildings made up of four stories or fewer
Apartments >= 4 stories	Apartment units located in high-rise apartment buildings made up of more than four stories
Other Residential	Manufactured, mobiles or other types of residential dwellings

Source: Navigant

This segmentation is largely consistent with the dwelling types employed in the FortisBC Gas 2010 CPR, with the following three exceptions:

» **Space heating system** - The 2010 CPR duplicated each residential dwelling type in order to model archetypes for different types of heating (e.g., electrically heated homes vs. gas heated homes). Based on Navigant's modelling approach, it is not necessary to duplicate residential segments to analyze dwelling types using different heating fuels.

» **Dwelling vintage** - The 2010 CPR divided the residential sector according to dwelling vintage (e.g., pre-1976 homes, and post-1976 homes). While Navigant recognizes that this approach is meant to reflect differences in gas consumption as a result of different types of equipment found in older and newer homes, Navigant's segmentation does not require this differentiation. These differences in gas consumption and the types of equipment used by different vintage homes can be, and are, captured in Navigant's *DSMSim* model.

» **Apartments -** The 2010 CPR included apartment buildings in the commercial sector, and divided them as large and medium apartment buildings to reflect differences in energy consumption that may appear in low and high rise buildings. For the base year and reference case analysis, this

CPR includes apartment buildings in the residential sector. This CPR also divides apartments based on buildings with less than or equal to 4 stories, and buildings with more than 4 stories. [4]

Navigant developed the breakdown of the residential sector into dwelling types based on FortisBC Gas billing data and supported by BC Hydro apartment unit counts. The team also used the same data sources to divide the total stock of each dwelling type by service region, provided in Table 2-5. While apartment buildings are reported in the residential sector for purposes of the base year analysis and the reference case forecast, they are moved to the commercial sector in the technical and economic potential results. Gas savings from apartment buildings are reported in the commercial sector because FortisBC Gas's conservation programs for apartment buildings are categorized as commercial programs.

Table 2-5: Base Year Housing Stocks (Residential units) – FortisBC Gas

Housing Type	Lower Mainland	Southern Interior	Vancouver Island	Northern BC	Total
Single Family Detached/Duplexes	475,475	170,298	89,448	45,448	780,669
Single Family Attached/Row	53,890	10,417	7,109	2,550	73,965
Apartments < 4 stories	216,678	52,875	59,179	10,195	338,927
Apartments >= 4 stories	158,724	6,853	17,195	1,007	183,779
Other Residential	10,348	8,940	2,198	2,405	23,891
Total	915,115	249,384	175,129	61,604	1,401,231
Apartments Excluded					
Apartments Total	375,402	59,729	76,374	11,202	522,707
Non-Apartments Total	539,713	189,655	98,755	50,402	878,525

The number of apartment units represents individual apartment suites and not single-meter apartment buildings which FortisBC Gas considers and bills as a single account.
Source: Navigant analysis based on data provided by FortisBC Gas and BC Hydro

2.1.1.3 Commercial Sector

Navigant divided the BC commercial sector into twelve (12) segments. The last segment listed below, streetlights and traffic signals, is only applicable to electric utilities.

[4] This CPR analyzes apartments units in the residential sector based on several factors. First, apartment buildings are generally characterized through Residential End Use Surveys (REUS) in parallel with non-apartment residential dwellings (e.g., detached and attached) – as is the case for BC Hydro's REUS studies but not FortisBC Gas. Second, end-use equipment – other than centralized systems for space heating, cooling and water heating – can be characterized in a consistent manner across apartments and non-apartment residential dwellings.

Table 2-6: Description of Commercial Segments

Segment	Description
Accommodation	Short-term lodging including related services such as restaurants and recreational facilities
Colleges/Universities	Post-secondary education facilities such as colleges, universities and related training centers
Food Service	Establishments engaged in preparation of meals, snacks and beverages for immediate consumption including restaurants, taverns, and bars.
Hospital	Diagnostic and medical treatment services such as hospitals and clinics
Logistics/Warehouses	Warehousing/storage facilities for general merchandise, refrigerated goods, and other wholesale distribution
Long Term Care	Residential care, nursing, or other types of long term care
Office	Administration, clerical services, consulting, professional, or bureaucratic work but not including retail sales.
Other Commercial	Establishments, not categorized under any other sector, including but not limited to recreational, entertainment and other miscellaneous activities
Retail - Food	Engaged in retailing general or specialized food and beverage products
Retail - Non Food	Engaged in retailing services and distribution of merchandise but not including food and beverage products
Schools	Primary and secondary schools (K to 12)
Streetlights/Traffic Signals	Roadway lighting and traffic signal loads

Source: Navigant

Navigant selected the commercial segments with the goal that the building types within those segments be reasonably similar in terms of gas and electricity use, operating and mechanical systems, and annual operating hours. This approach allowed for consistency in building characteristics within each segment as required by the measure characterization and modeling processes.

The selection of these commercial segments is similar to those for previous CPRs with the exception that Navigant does not distinguish commercial segments based on the size of facilities (e.g., large vs. medium facilities) as was done in the 2010 CPR. The analysis of gas consumption in the commercial sector is *scaled* based on the stock of commercial floor space in FortisBC Gas's territory. Using this approach, gas consumption is expressed in terms of GJ per square meter (GJ/m^2) of floor space. This approach assumes that the GJ/m^2 intensity within a commercial segment is constant, and independent of building size.[5] Another distinction, relative to the 2010 CPR, is that for the base year and reference case analysis, apartments units are included the residential sector. However, to report technical and economic savings potential results, apartments are moved to the commercial sector for consistency with the way FortisBC Gas delivers programs.

[5] While this CPR's modelling approach is different to the 2010 CPR, each modelling approaches has its own strengths and weaknesses. For example, the archetype-based approach provides increased visibility into the energy usage patterns of large vs. medium buildings. At the same time, the archetype based approach also introduces the risk of skewing energy consumption within a segment should the archetype analysis be based on a commercial building not representative of a segment-wide average. This potential shortcoming is addressed by Navigant's approach since developing a GJ/m2 intensity attempts to reflect segment-wide consumption patterns.

To determine the base year floor space stock for each commercial segment, Navigant applied the end-use intensities (EUIs) of each segment to the gas sales data provided by FortisBC Gas. Appendix B.3 describes in greater detail the methodology used to estimate the commercial EUIs. Table 2-7 summarizes the resulting floor space estimates developed for each commercial segment.

Table 2-7: Base Year Commercial Floor Area (million m^2) – FortisBC Gas

Segment	Lower Mainland	Southern Interior	Vancouver Island	Northern BC	Total
Accommodation	2.55	1.56	0.33	0.25	4.69
Colleges/Universities	4.10	0.39	0.74	0.07	5.30
Food Service	2.17	0.54	0.15	0.08	2.93
Hospital	1.56	0.64	0.05	0.10	2.35
Logistics/Warehouses	10.56	3.30	0.29	0.48	14.64
Long Term Care	2.05	0.87	0.36	0.04	3.33
Office	22.06	7.08	3.84	1.24	34.22
Other Commercial[6]	-	-	-	-	-
Retail - Food	2.10	0.99	0.27	0.11	3.47
Retail - Non Food	7.34	3.08	0.65	0.48	11.55
Schools	5.81	2.03	0.53	0.35	8.71
Total	**60.31**	**20.49**	**7.19**	**3.19**	**91.18**

Source: Navigant analysis of FortisBC Gas Sales and EUIs

[6] The Other Commercial segment was distributed across all other commercial segments proportionally. As a result, the Other Commercial segment does not include any floor area. FortisBC Gas directed Navigant to perform this distribution because of the wide variety of commercial building types reflected in the Other Commercial segment.

2.1.1.4 Industrial Sector

Navigant divided the BC industrial sector into 15 segments as shown in Table 2-8.

Table 2-8: Description of Industrial Segments

Segment	Description
Agriculture	Engaged in growing crops, raising animals, harvesting timber, fish and other animals, including farms, irrigation, ranches, or hatcheries.
Cement	Cement manufacturers and related operations including asphalt and concrete
Chemical	Industrial facilities that produce industrial and consumer chemicals including paints, synthetic materials, pesticides, and pharmaceuticals
Food & Beverage	Food and beverage industrial facilities including breweries, tobacco, meat/dairy and animal food manufacturers
Greenhouses	Engaged in growing nursery stock and flowers, including greenhouses, and nurseries.
Mining - Coal	Thermal and metallurgical coal mines
Mining - Metal	Copper, gold and other metal mines
LNG Facilities	Natural gas liquids processing facilities
Oil and Gas	Industries that explore, operate or develop oil and gas resources including the production of petroleum, mining and extraction of shale oil and oil sands.
Manufacturing	Industrial facilities that engage in light and heavy manufacturing processes including fabricated metal, metal manufacturing, machinery, and textiles.
Pulp & Paper - Kraft	Pulp and Paper industrial facilities dedicated specifically to the chemical kraft process
Pulp & Paper - TMP	Pulp and Paper industrial facilities dedicated to the thermo-mechanical pulp (TMP) process
Wood Products	Industrial facilities that manufacture wood products including lumber, plywood, veneer, boards, panel boards and pellets.
Other Industrial	Other industrial facilities and related production operations not categorized under any other industrial segment, including construction, contracting services, waste management and municipal water.
Transportation	Facilities providing transportation of passengers/cargo/resources and support activities related to common modes of transportation including air, rail, water, road, and pipeline.

Source: Navigant

Navigant selected these industrial segments to group industries with similar manufacturing processes, operations, outputs, and patterns of electricity and gas use. Some sectors such as and Pulp & Paper, which contribute significantly to FortisBC Gas energy sales, were further sub-divided into Pulp & Paper - Kraft and Pulp & Paper -TMP. This subdivision allowed differences in processes or patterns of energy use for each segment to be characterized more accurately than if they were combined into one segment. While this approach attempts to better characterize and analyze energy consumption in certain industrial segments, the proposed segmentation is not intended to accurately represent energy consumption at individual industrial facilities. The team also notes that, in general, the industrial sector exhibits much greater diversity regarding energy usage compared to the commercial or residential sectors.

2.1.2 End-Use Definitions

The next step in the base year calibration analysis involved the establishment of specific end-uses for each customer sector. This CPR defines end-uses as a specific activity or customer need that requires energy, such as space heating or domestic water heating, without specifying the particular type of equipment used to satisfy that need. There are two industrial end-uses, however, that do not align to this definition and represent specific types of industrial equipment; Boilers and Pumps. These two end-uses were defined as specific industrial equipment to better reflect the nature of energy consumption and to enable the model to capture and analyze savings potential arising from these sources.

Table 2-9 presents the list of end-uses by sector used in the CPR, with end-use definitions provided in Appendix B.1. These end-use categories have significant impact on the base year calibration since Navigant calculated the energy consumption for a given baseline measure based on the gas intensity of the end-use to which that measure is assigned. These end-uses also allow Navigant's model to incorporate changes in electric and gas end-use intensity over time.

Table 2-9: End-Uses by Sector

Residential	Commercial	Industrial
Appliances	Cooking	Boilers
Electronics	HVAC Fans/Pumps	Compressed Air
Hot Water	Hot Water	Fans & Blowers
Lighting	Lighting	Industrial Process
Other	Office Equipment	Lighting
Space Cooling	Other	Material Transport
Space Heating	Refrigeration	Process Compressors
Ventilation	Space Cooling	Process Heating
Whole Facility	Space Heating	Product Drying
	Whole Facility	Pumps
		Refrigeration
		Space Heating
		Whole Facility

Source: Navigant

2.1.3 Fuel Share and Equipment Data

Navigant developed fuel share and equipment data for each end-use based on the segmentations defined in the previous sections. The team followed two approaches, depending on sector, as described below:

- **Residential and Commercial Sectors**

  Navigant developed estimates of the distribution of fuel shares for each end-use and the types of equipment that contribute to energy consumption within each end-use based on available data from prior FortisBC Gas end-use surveys. Navigant analyzed FortisBC Gas's *2012 Residential End-Use Survey* (2012 REUS) and *2015 Commercial End-Use Survey* (2015 CEUS). Navigant's review of these resources was supported by data from BC Hydro's *2014 Residential End-Use Survey* (2014 REUS) and *2015 Commercial End-Use Survey* (2015 CEUS). The team also relied on program evaluation reports, conditional demand analysis (CDA) studies, and monitoring surveys provided by both utilities[7]. Appendix B.2 and Appendix B.3 summarize the fuel shares and equipment shares used for the residential and commercial sectors, respectively.

- **Industrial Sector**

  Navigant subcontracted CLEAResult, who has considerable expertise in the industrial sector in BC, to develop an estimate of the distribution of energy consumption by each end-use for each industrial customer segment. CLEAResult determined these estimates based on a detailed database of industrial equipment such as pumps, fans, blowers, motors, compressed air equipment, etc. This database contains information on equipment types, key equipment characteristics including system efficiency and/or equipment efficiency levels, and equipment market shares. CLEAResult developed this database based on *Power Smart* industrial reviews, industrial energy assessments, equipment inventories, and ongoing audit and market assessment work with BC Hydro and FortisBC.

Appendix B.2 and Appendix B.3 provide the information developed for each sector and the resulting estimates of energy intensity.

2.1.4 Calibration Process

This section describes the calibration process Navigant used for the residential, commercial, and industrial sectors.

2.1.4.1 Residential and Commercial Sectors

For the residential and commercial sectors, Navigant developed a base year calibration model to analyze gas consumption at an equipment level, at an end-use level, and at a segment level. The team developed this calibration model to accurately calibrate the estimated gas consumption of each sector to the Fortis Gas sales.

The calibration process began at an equipment level for each of the energy-intensive end-uses—the primary end-uses—and at an end-use level for the less energy-intensive end-uses—the secondary end-uses. Navigant determined the primary end-uses as those that make up more than 15% of gas consumption and for which the availability of equipment data enabled a detailed analysis of equipment data. The calibration model for primary end-uses involved a complete bottom-up buildup of detailed equipment information including various efficiency levels, unit energy consumption (UEC) for each efficiency level, equipment market shares, and fuel types for different equipment. The team extracted these inputs primarily from FortisBC Gas and BC Hydro's REUS and CEUS studies. For the secondary end-uses, calibration focused primarily on analyzing and establishing end-use intensities based on previous CPR studies, CDA reports, and other secondary resources. This process ensured that the segment-level EUIs approximated the sales targets with reasonable precision.

The calibration model used these inputs to aggregate gas consumption by end-uses and by customer segment, and compared the results to the FortisBC Gas sales at the lowest level of disaggregation available. The calibration of the base year was an iterative process to estimate energy consumption from

[7] We note that the BC Utilities provided some data sources on a confidential basis and thus they are not publically available.

the lowest level of granularity (i.e., equipment types) to the sector level. Each calibrated iteration required refining of key variables and inputs such as the market share of equipment types, UECs by equipment, and fuel shares.

Table 2-10 shows an example of the calibration process followed for single family detached/duplexes in the Southern Interior region. The process used to calibrate the estimate of energy use builds on an estimate of the percentage of homes with a particular end-use and fuel type, using a particular type of equipment and efficiency within an end-use. The fuel shares (column B), equipment shares (column E), and an estimated level of energy use for each equipment type (column F) are multiplied to obtain an estimated UEC (column G). In the example below, column G sums the total consumption across all water heating equipment. The team summed the resulting EUCs across end-uses to obtain the segment-level intensity (GJ per year), and then calibrated to match the actual target intensity stemming from FortisBC Gas sales data. Navigant repeated this same process across all residential and commercial segments in each region.

Table 2-10: Example of Calibration Process (Single Family Detached/Duplexes – Southern Interior)

A	B	C	D	E	F	G	H	I
End Use	**Fuel Share (%)**	**Equipment**	**Efficiency**	**Equipment Share (%)**	**Annual Energy Use (GJ)**	**End-Use Weighted Avg. Use (GJ)**	**Total Uncalibrated Consumption (GJ)**	**Total Calibrated Consumption (GJ)**
Space Heating	85%	…	…	…	…	…	51.7	57.7
Water Heating	72%	Gas Water Heater Conventnl	n/a	83%	17.7	12.2	12.2	13.6
		Gas Water Heater Condensing	n/a	13%	13.7			
		Gas DHW Tankless	n/a	4%	10.9			
Cooling	0%	…	…	…	…	…	0.0	0.0
Appliances	100%	…					1.3	1.4
Lighting	0%	…	…	…	…	…	0.0	0.0
Electronics	0%	…	…	…	…	…	0.0	0.0
Other	0%	…	…	…	…	…	2.5	2.8
Ventilation	0%	…	…	…	…	…	0.0	0.0
Estimated Consumption (GJ per year)							67.7	**75.6**
Target Consumption (GJ per year)			- calculated based on Fortis Gas 2014 sales data				75.6	**75.6**
	Uncalibrated vs. Target						**90%**	**100%**

Appliances are assigned a fuel share of 100%. This implies that all gas appliances have a fuel share of 100% gas. Similarly, electric utilities have an appliances fuel share of 100%. The actual penetration of individual gas appliances (e.g., x% of homes have a gas clothes dryer) is represented by the equipment shares column.
Source: Navigant

Navigant developed the calibration process to operate across all of the dimensions of the model as listed below (e.g., energy types, sectors, regions, etc.). The following sections present the key estimates of energy use by end-use, sector, and region. Most inputs to the calibration process, including efficiency levels and shares, equipment types, equipment shares, fuel shares, and EUIs by end-use, segment, and region, are presented in Appendix B.2 for the residential sector and Appendix B.3 for the commercial sector.

Table 2-11: Base Year Calibration Dimensions (Residential and Commercial Sectors)

Element	No. of Dimensions	Dimensions	
Energy Types	2	**Electricity**	**Natural Gas**
Sectors	2	Residential, Commercial	
Regions	4	Lower Mainland Southern Interior Vancouver Island Northern BC	
Utilities	4	BC Hydro FortisBC Inc.	FortisBC Energy Inc. Pacific Northern Gas
Segments	17	Residential (5), Commercial (12)	
End-Uses	17	Residential (8), Commercial (9)	
Equipment Types	<5	Varies by end-use—generally less than five	
Efficiency Levels	>2	Generally two for each equipment type	

Source: Navigant

2.1.4.2 Industrial Sector

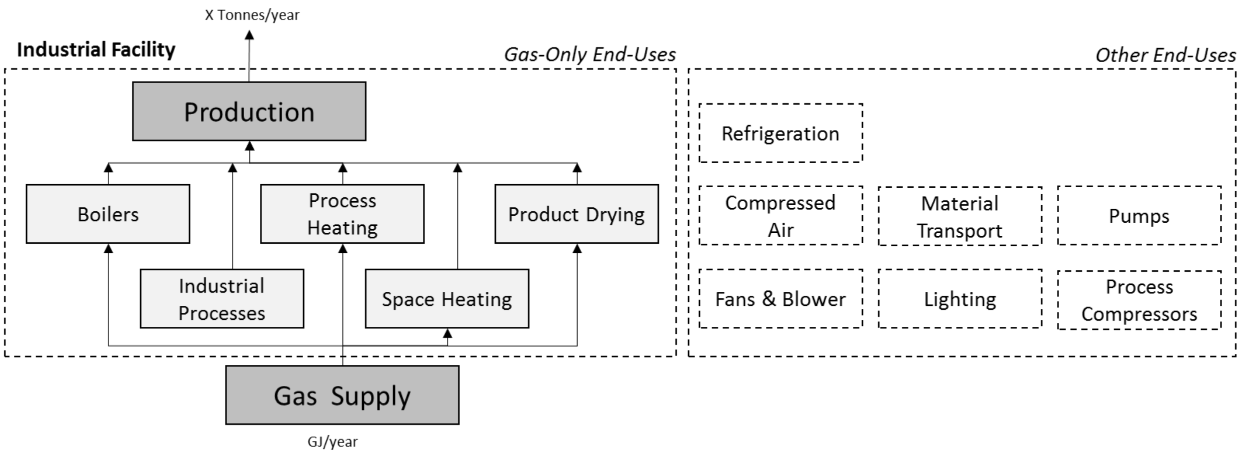
CLEAResult developed estimates of the distribution of energy consumption by end-use for each industrial segment. To calculate the energy consumption by end-use, CLEAResult utilized detailed data on industrial facilities for each of the industrial segments from numerous resources including:

- *BC Hydro* Industrial Electricity Analysis Reviews of industrial customers
- Prior industrial energy assessments performed for BC Hydro and FortisBC
- Detailed energy audits of large industrial facilities in BC
- Inventories of industrial equipment
- CLEAResult professional experience and literature review

Over many years of data collection, CLEAResult has used these resources to build a detailed database of industrial equipment such as pumps, fans, blowers, motors, compressed air equipment, etc. For each equipment type, CLEAResult determined key equipment characteristics including overall system efficiency and/or equipment efficiency levels and equipment market shares, and developed industrial models for BC Hydro and FortisBC. CLEAResult has used these models on a continuous basis to assist BC Hydro and FortisBC with market assessments and DSM program business-case developments. For this CPR, Navigant and CLEAResult aligned the industrial models with up-to-date billing account information broken down into the various industrial segments, and developed end-use allocation factors to estimate the proportion of energy use attributed to each end-use.

CLEAResult's industrial models are broken down into separate sub-models for the major industrial energy end-use categories. Figure 2-1 shows a schematic example of one of these industrial models. As illustrated, a subset of all industrial end-uses are served by natural gas.

Figure 2-1: Schematic of Industrial Model



Source: Navigant schematic of CLEAResult model

The production occurring in each particular segment drives the models for the major energy use industrial segments. A given amount of production requires a certain amount of electricity or natural gas consumption, and this energy can be broken down into each of the end-uses based on the installed equipment.

This detailed modeling approach is not appropriate for certain diverse segments such as food and beverage, manufacturing, and "other" industrial. These three segments involve such a large variety of processes and equipment types that it is not practical to setup an energy model for them. For these industrial segments, the team used end-use information from over 200 facility audits—sponsored by BC Hydro and FortisBC, and including industry groups such as the *BC Food Processors Association* and *Canadian Manufacturers & Exporters*—to estimate the end-use breakdown of each segment. For each of these audits, CLEAResult developed a breakdown of equipment and energy end-use, which Navigant used to develop the end-use breakdown of the food and beverage, manufacturing, and "other" industrial segments.

Table 2-12 shows the resulting end-use consumption percentages developed by CLEAResult, as a distribution of gas consumption by end-use for each industrial segment.

Table 2-12: Industrial End-use Allocation Factors (%)

Segment	Boilers	Compressed Air	Fans & Blowers	Industrial Process	Lighting	Material Transport	Process Compressors	Process Heating	Product Drying	Space Heating	Pumps	Refrigeration	**Total**
Agriculture	50%	0%	0%	0%	0%	0%	0%	0%	0%	50%	0%	0%	**100%**
Cement	4%	0%	0%	0%	0%	0%	0%	90%	4%	2%	0%	0%	**100%**
Chemical	48%	0%	0%	0%	0%	0%	0%	43%	0%	9%	0%	0%	**100%**
Coal Mining	8%	0%	0%	0%	0%	0%	0%	0%	89%	2%	0%	0%	**100%**
Food & Beverage	73%	0%	0%	0%	0%	0%	0%	20%	0%	7%	0%	0%	**100%**
Greenhouses	75%	0%	0%	0%	0%	0%	0%	22%	0%	3%	0%	0%	**100%**
LNG Facilities	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	**0%**
Manufacturing	5%	0%	0%	0%	0%	0%	0%	43%	21%	31%	0%	0%	**100%**
Metal Mining	8%	0%	0%	0%	0%	0%	0%	0%	89%	2%	0%	0%	**100%**
Oil and Gas	5%	0%	0%	75%	0%	0%	0%	10%	0%	10%	0%	0%	**100%**
Pulp & Paper - Kraft	48%	0%	0%	0%	0%	0%	0%	38%	12%	2%	0%	0%	**100%**
Pulp & Paper - TMP	49%	0%	0%	0%	0%	0%	0%	0%	49%	2%	0%	0%	**100%**
Transportation	40%	0%	0%	0%	0%	0%	0%	0%	0%	60%	0%	0%	**100%**
Wood Products	11%	0%	0%	0%	0%	0%	0%	5%	81%	4%	0%	0%	**100%**
Other Industrial	30%	0%	0%	0%	0%	0%	0%	7%	13%	50%	0%	0%	**100%**

Source: CLEAResult

The next step of the industrial sector analysis was to determine the total gas consumption by each segment. Navigant worked with FortisBC Gas to determine the total sales in each industrial segment during the base year. Table 2-13 shows the total gas consumption of each industrial segment region in the base year (2014).

Table 2-13: Base Year Industrial Gas Consumption by Segment (TJ) – FortisBC Gas

Segment	All Regions
Agriculture	1,601
Cement	908
Chemical	1,284
Coal Mining	2,517
Food & Beverage	4,000
Greenhouses	5,473
LNG Facilities	-
Manufacturing	5,710
Metal Mining	10
Oil and Gas	8,761
Pulp & Paper - Kraft	14,585
Pulp & Paper - TMP	3,450
Transportation	921
Wood Products	7,567
Other Industrial	789
Totals	**57,577**

Source: Navigant analysis of FortisBC Gas data

The final step of this analysis was the application of the end-use consumption percentages to the gas consumption corresponding to each industrial segment. Table 2-14 shows the resulting distribution of gas consumption by end-use and by industrial segment.

Table 2-14: Base Year Industrial Gas Consumption by End-use (TJ) – FortisBC Gas

Segment	Boilers	Compressed Air	Fans & Blowers	Industrial Process	Lighting	Material Transport	Process Compressors	Process Heating	Product Drying	Space Heating	Pumps	Refrigeration	Total
Agriculture	800	-	-	-	-	-	-	-	-	800	-	-	**1,601**
Cement	36	-	-	-	-	-	-	817	36	18	-	-	**908**
Chemical	611	-	-	-	-	-	-	557	-	116	-	-	**1,284**
Coal Mining	200	-	-	-	-	-	-	11	2,250	56	-	-	**2,517**
Food & Beverage	2,929	-	-	-	-	-	-	794	-	278	-	-	**4,000**
Greenhouses	4,105	-	-	-	-	-	-	1,204	-	164	-	-	**5,473**
LNG Facilities	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Manufacturing	267	-	-	-	-	-	-	2,471	1,209	1,762	-	-	**5,710**
Metal Mining	1	-	-	-	-	-	-	0	9	0	-	-	**10**
Oil and Gas	438	-	-	6,571	-	-	-	876	-	876	-	-	**8,761**
Pulp & Paper - Kraft	7,001	-	-	-	-	-	-	5,542	1,750	292	-	-	**14,585**
Pulp & Paper - TMP	1,690	-	-	-	-	-	-	-	1,690	69	-	-	**3,450**
Transportation	368	-	-	-	-	-	-	-	-	552	-	-	**921**
Wood Products	799	-	-	-	-	-	-	363	6,097	308	-	-	**7,567**
Other Industrial	234	-	-	-	-	-	-	58	104	393	-	-	**789**
Totals -	**19,480**	**-**	**-**	**6,571**	**-**	**-**	**-**	**12,694**	**13,147**	**5,686**	**-**	**-**	**57,577**

Source: Navigant analysis of FortisBC Gas sales data and CLEAResult data

2.1.5 FortisBC Gas Base Year Consumption

Each of the BC utilities provided Navigant with information on actual sales and customer numbers for the base year (2014). Table 2-15 shows FortisBC Gas's total gas consumption by customer sector in 2014 (the "actual consumption").

Note that for the base year and reference case analysis, Navigant included apartment units in the residential sector. However, to report technical and economic savings potential in Section 3 and 4, apartments are included in the commercial sector. For reference, the second half of Table 2-15 shows the breakdown of the residential segment excluding apartment units.

Table 2-15: Actual Consumption in 2014 (TJ) – FortisBC Gas

Segment	Lower Mainland	Southern Interior	Vancouver Island	Northern BC	Total
Residential	65,227	16,103	6,789	4,949	**93,069**
Commercial	25,595	9,859	2,969	2,211	**40,634**
Industrial	22,019	12,281	8,587	14,690	**57,577**
Total	**112,841**	**38,243**	**18,346**	**21,850**	**191,280**
Apartments Excluded					
Residential (excl. Apts.)	49,192	13,917	5,539	4,469	**73,117**
Apartments	16,035	2,186	1,251	480	**19,952**
Commercial	25,595	9,859	2,969	2,211	**40,634**
Industrial	22,019	12,281	8,587	14,690	**57,577**
Total	**112,841**	**38,243**	**18,346**	**21,850**	**191,280**

Source: Navigant analysis of FortisBC Gas data

2.1.6 Comparison between Base Year and Actual Consumption

Navigant used the calibration process—described in previous sections—along with the actual consumption targets to develop calibrated estimates of gas consumption (the "base year consumption").

Table 2-16 shows the result of the base year calibration by sector and region. This table compares the actual consumption targets (based on FortisBC Gas sales) with the base year consumption (determined through the calibration process). As illustrated by the last column, the base year consumption values developed for the CPR study matches the 2014 actual consumption of each sector and region.

Table 2-16: 2014 Actual Consumption vs. Base Year Consumption (TJ) – FortisBC Gas

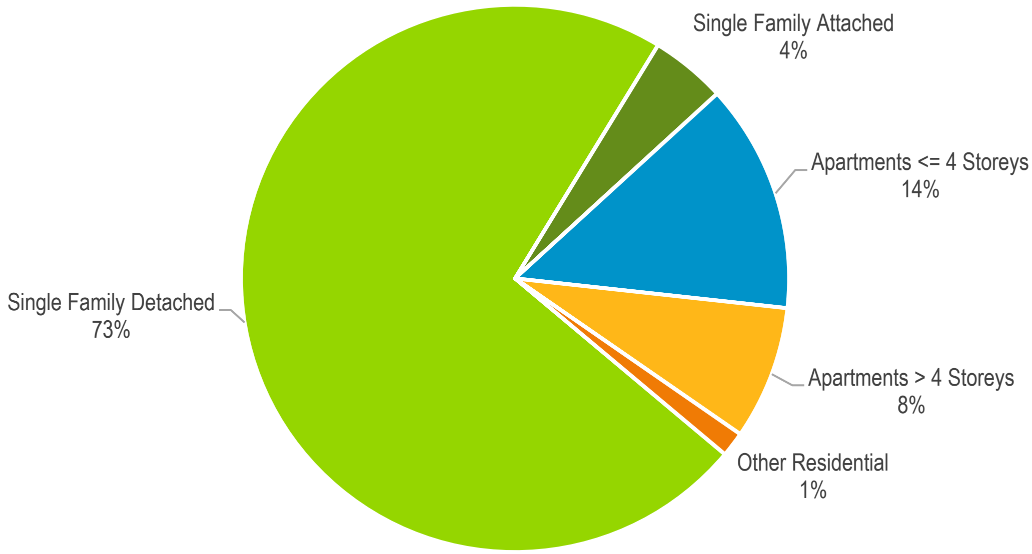
Region	Sect or	Actual Consumption (TJ)	Base Year (TJ)	Difference (%)
Lower Mainland	Residential	65,227	65,227	0.0%
	Commercial	25,595	25,595	0.0%
	Industrial	22,019	22,019	0.0%
Southern Interior	Residential	16,103	16,103	0.0%
	Commercial	9,859	9,859	0.0%
	Industrial	12,281	12,281	0.0%
Vancouver Island	Residential	6,789	6,789	0.0%
	Commercial	2,969	2,969	0.0%
	Industrial	8,587	8,587	0.0%
Northern BC	Residential	4,949	4,949	0.0%
	Commercial	2,211	2,211	0.0%
	Industrial	14,690	14,690	0.0%
Total	**Residential** *(includes apartments)*	**93,069**	**93,069**	**0.0%**
	Commercial	**40,634**	**40,634**	**0.0%**
	Industrial	**57,577**	**57,577**	**0.0%**

Source: Navigant analysis

As part of the development of the base year, Navigant determined the gas consumption for each segment within the residential, commercial, and industrial sectors. The distribution of gas consumption by segment and end-use for each sector is shown by Figure 2-2 through Figure 2-7, and the tabulated results are shown by Table 2-17 (residential) and Table 2-18 (commercial). The industrial results were shown by Table 2-14 in Section 2.1.4.2.

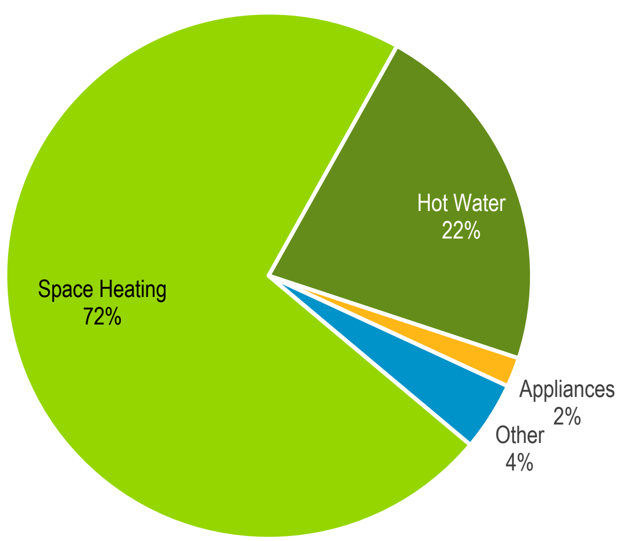
Additional information relating to each segment can be found in Appendix B.2 (for the residential sector), Appendix B.3 (for the commercial sector), and Appendix B.4 (for the industrial sector).

Figure 2-2: Base Year Residential Consumption by Segment (%)



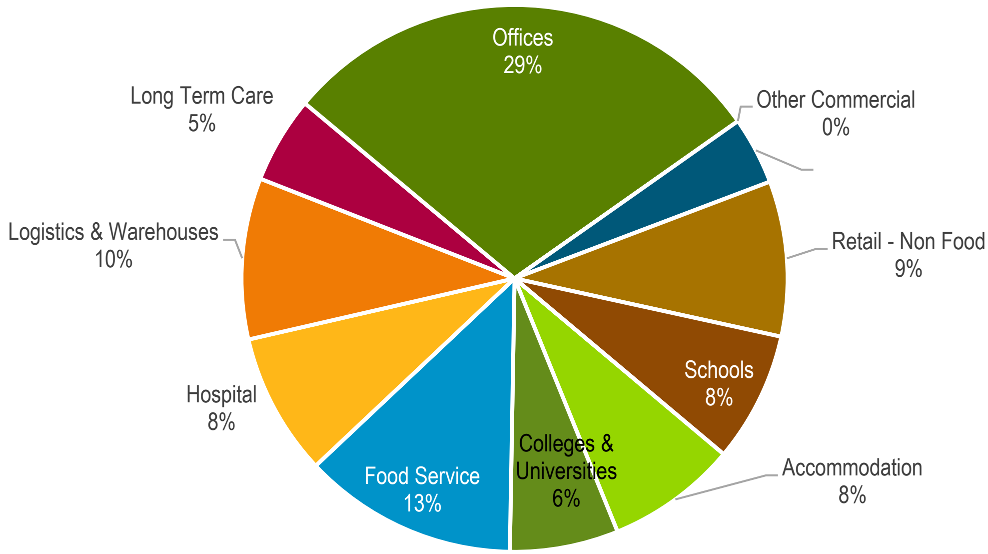
Source: Navigant analysis

Figure 2-3: Base Year Residential Consumption by End-Use (%)



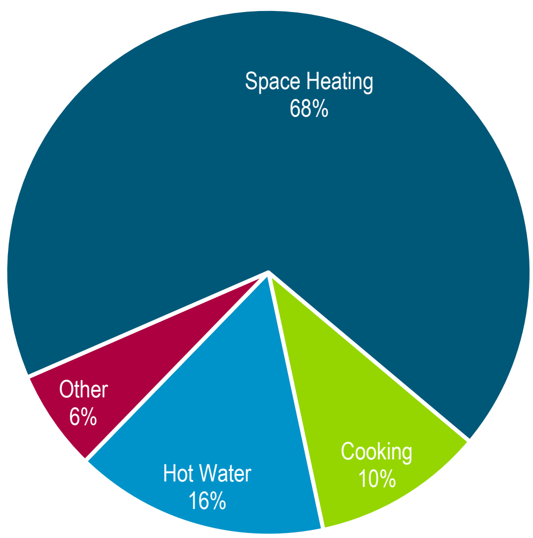
Source: Navigant analysis

Figure 2-4: Base Year Commercial by Segment Consumption (%)



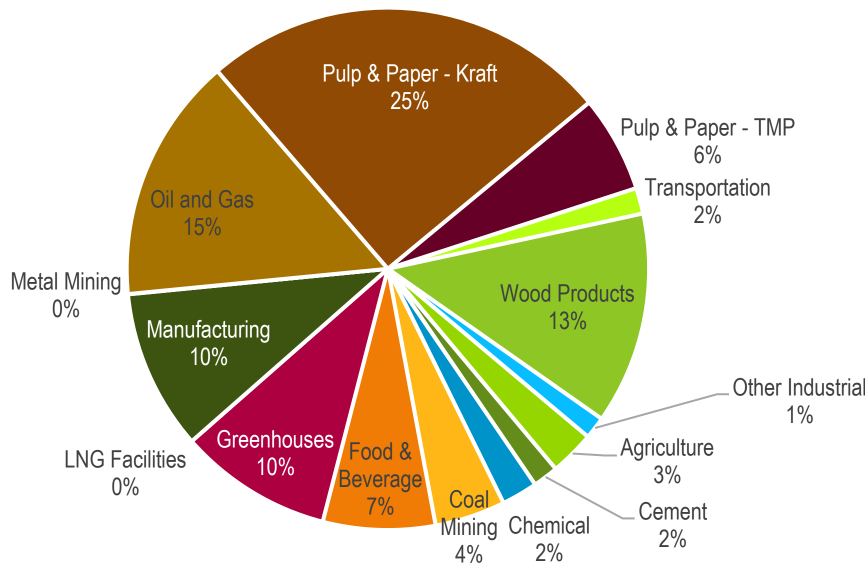
Source: Navigant analysis

Figure 2-5: Base Year Commercial by Segment End-Use (%)



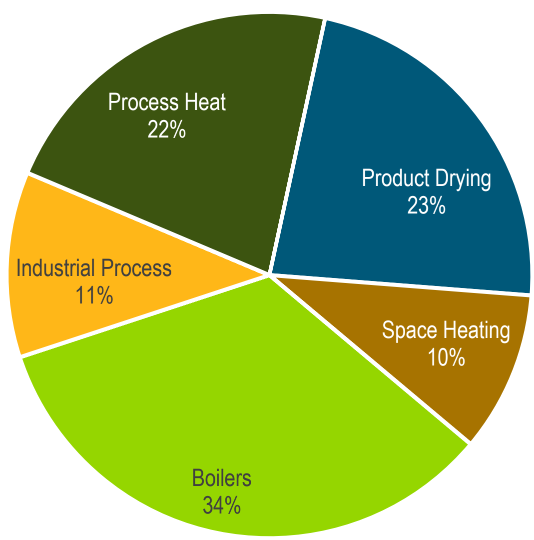
Source: Navigant analysis

Figure 2-6: Base Year Industrial Consumption by Segment (%)



Source: Navigant analysis

Figure 2-7: Base Year Industrial Consumption by End-Use (%)



Source: Navigant analysis

Table 2-17: Base Year Residential Consumption by Segment and End-use (TJ) – FortisBC Gas

Segment	Space Heating	Hot Water	Space Cooling	Appliances	Lighting	Electronics	Other	Ventilation	Total
Single Family Detached/Duplexes	53,132	11,235	-	1,103	-	-	2,129	-	**67,598**
Single Family Attached/Row	3,219	770	-	63	-	-	96	-	**4,148**
Apartments <= 4 stories	6,026	5,214	-	314	-	-	1,043	-	**12,597**
Apartments > 4 stories	3,596	2,944	-	188	-	-	628	-	**7,355**
Other Residential	1,036	287	-	21	-	-	27	-	**1,370**
Totals -	**67,009**	**20,449**	**-**	**1,688**	**-**	**-**	**3,923**	**-**	**93,069**

Source: Navigant analysis

Table 2-18: Base Year Commercial Consumption by Segment and End-use (TJ) – FortisBC Gas[8]

Segment	**Cooking**	**NVAC Fans/Pumps**	**Hot Water**	**Lighting**	**Office Equipment**	**Other**	**Refrigeration**	**Space Cooling**	**Space Hating**	**Total**
Accommodation	368	-	1,201	-	-	262	-	-	1,309	**3,141**
Colleges/Universities	198	-	367	-	-	346	-	-	1,715	**2,625**
Food Service	2,454	-	1,394	-	-	55	-	-	1,253	**5,155**
Hospital	153	-	644	-	-	548	-	-	2,083	**3,428**
Logistics/Warehouses	68	-	265	-	-	273	-	-	3,251	**3,857**
Long Term Care	186	-	517	-	-	217	-	-	1,170	**2,091**
Office	319	-	1,126	-	-	638	-	-	9,800	**11,882**
Other Commercial	-	-	-	-	-	-	-	-	-	**-**
Retail - Food	259	-	225	-	-	65	-	-	1,076	**1,624**
Retail - Non Food	150	-	269	-	-	75	-	-	3,204	**3,698**
Schools	131	-	340	-	-	41	-	-	2,628	**3,140**
Totals -	**4,285**	**-**	**6,348**	**-**	**-**	**2,518**	**-**	**-**	**27,489**	**40,640**

Source: Navigant analysis

[8] Gas sales initially attributed to the *Other Commercial* segment were distributed across all other commercial segments proportionally.

2.2 Reference Case Forecast

This section presents the Reference Case for the CPR study period from 2015 to 2035. The Reference Case estimates the expected level of gas consumption over the CPR period, absent incremental demand-side management (DSM) activities or load impacts from conservation rates. Gas consumption levels in the Reference Case are also based on codes and standards previously included in regulation and reflected in each utility's load forecast.[9] The Reference Case is significant in the context of this CPR study because it acts as the point of comparison (i.e., the reference) for the calculation of the technical and economic potential scenarios.

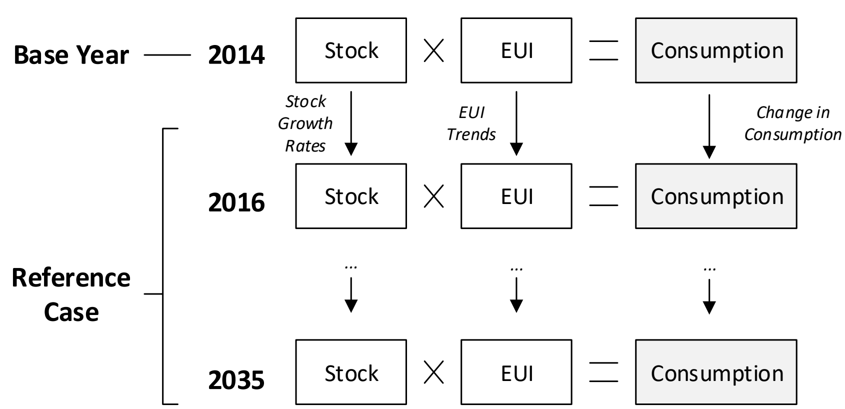
The Reference Case Forecast uses the base year calibration—presented in the previous section—as the foundation for analysis.

Navigant constructed the Reference Case forecast using two different approaches based on sector.

- **Residential and commercial sectors:** For the residential and commercial sectors, Navigant used two key inputs: stock growth rates and EUI trends. Navigant developed stock growth projections of residential accounts and commercial floor area. The team then modeled the potential for energy efficiency based on the resulting stock projections of each customer segment. The team applied EUI trends to the base year EUIs for each customer segment, and used these trends to represent natural change in end-use consumption over time.

  Figure 2-8 illustrates the process used to develop the Reference Case for the residential and commercial sectors. This figure illustrates that applying stock growth rates to the base year stocks of each customer segment results in a forecast of stocks through 2035. Similarly, applying the EUI trends to the base year EUIs results in a forecast of EUIs through 2035. The final step of this process involves multiplying the stock forecast with the corresponding EUI forecast in order to obtain a load forecast.

Figure 2-8: Schematic of Reference Case Development



Source: Navigant

[9] Each utility's load forecast reflects specific effectiveness dates and performance thresholds for codes and standards previously enshrined in regulation. By extension, recently announced performance targets or codes and standards that are not yet enshrined in regulation –such as the target for net zero new construction included in the BC Climate Leadership Plan– are excluded from the analysis.

- **Industrial sector:** The Reference Case for the Industrial sector assumed frozen EUIs over the Reference Case forecast (e.g., frozen EUIs assume that EUIs do not change and are static over time). A more detailed discussion supporting this assumption is presented in Section 2.2.3.3. Based on the frozen-EUI approach, the Industrial Reference Case was established solely by developing energy demand growth assumptions for each industrial segment.

Navigant compared the forecasts developed for the Reference Case for the residential, commercial, and industrial sectors with the long-term load forecast developed by each utility. This comparison ensured that the Reference Case forecast is consistent with each utility's current expectations for load growth over the 2015 to 2035 period.

2.2.1 Approach

This section introduces the overall process for developing the residential and commercial Reference Case. As noted earlier, the Reference Case approach for the industrial sector differed from the residential and commercial sectors.

Navigant's Reference Case started with the base year estimate of stocks and gas consumption for 2014. Two key inputs were the basis for projected change in gas consumption through the CPR study period:

- Stock growth rates
- Gas EUI trends

To develop the Reference Case for each sector, Navigant first developed the stock growth rates based on the CPR segmentation for each sector and region. The second step established appropriate EUI trends that the team applied to each segment and region. Finally, the team applied these two inputs to the base year estimates of stock and EUIs, and projected the results through 2035 to construct the Reference Case.

Navigant developed the growth rates for stock and the EUI trends based primarily on information provided by FortisBC Gas. Secondary sources supported any gaps in these data.

The following two sections provide detailed descriptions of the approach followed to establish stock growth rates and gas EUI trends for each sector.[10] As noted in previous sections, for the base year and reference case analysis apartment units have been included in the residential sector. As such, the following sections will present stock growth rates and EUI trends for apartment units within the residential sector.

[10] For the industrial sector, the stock growth rate section (Section 2.2.2.3) presents the demand forecast established for each industrial customer segment, and the EUI trends section (Section 2.2.3.3) describes the reasoning for a frozen EUI approach.

2.2.2 Stock Growth Rates

This section describes the approach followed to develop stock growth rates for the residential, commercial and industrial sectors.[11]

2.2.2.1 Residential Sector

To develop the residential Reference Case, Navigant first developed and applied growth rates for each residential segment and region over the CPR study period. Navigant established the stock growth rates from household forecasts derived from FortisBC's 2014 Long Term Resource Planning (LTRP) Demand Forecast (as updated)[12]. Based on the residential stock forecasts, average annual growth rates were established for each five-year period in the forecast (e.g., 2015 to 2020, 2021 to 2025, etc.). The team applied these five-year growth rates over the same periods through the end of the CPR study period for each residential segment. A detailed description of the approach used to develop the residential household projections is included in Appendix B.2.

[11] In relation to the natural turnover of commercial floor stock, Navigant's model assumes a stock demolition rate of 0.5% per year for commercial and residential segments and 0% for industrial segments. These demolition rates apply to the existing stock in each year of the analysis. A demolition rate of 0.5% is a conservative assumption used to avoid over-estimation of growth in building stock by recognizing that some new construction is replacing demolished stock and does not add to the total count of building stock. Industrial demolition rates are 0% because industrial facilities are less homogenous than commercial and residential buildings, and the closure of a single plant can represent a significant percentage of a given industrial segment. Given the lack of information about planned closures of industrial facilities, the 0% industrial demolition rate is a more reasonable assumption than representing industrial demolition as a continuous decay of building stock, as is modelled for commercial and residential buildings.

[12] The customer and demand forecast presented in FortisBC Gas's 2014 LTRP was developed from the 2011 year-end actual customer count. A subsequent update was prepared with the only change being the use of the more recent 2012 year-end actual customer count. This update is the most recent long term forecast available and thus has been used in the preparation of the 2016 CPR.

Table 2-19 shows the growth rates employed in the CPR study.

Table 2-19: Annual Growth Rates by Residential Segment and Region (%) – FortisBC Gas

Region	Segment	CPR Period			
		2014-2020	2021-2025	2026-2030	2031-2035
Lower Mainland	Single Family Detached/Duplexes	0.4%	0.2%	0.3%	0.3%
	Single Family Attached/Row	0.8%	0.5%	0.5%	0.5%
	Apartments =< 4 stories	0.6%	0.4%	0.4%	0.5%
	Apartments > 4 stories	0.6%	0.4%	0.4%	0.5%
	Other Residential	0.5%	0.3%	0.4%	0.4%
Southern Interior	Single Family Detached/Duplexes	0.9%	0.6%	0.6%	0.7%
	Single Family Attached/Row	1.3%	1.1%	0.9%	0.7%
	Apartments =< 4 stories	0.7%	0.6%	0.5%	0.5%
	Apartments > 4 stories	0.7%	0.6%	0.5%	0.5%
	Other Residential	1.6%	0.9%	0.9%	0.8%
Vancouver Island	Single Family Detached/Duplexes	0.5%	0.4%	0.4%	0.5%
	Single Family Attached/Row	0.9%	0.6%	0.6%	0.5%
	Apartments =< 4 stories	0.4%	0.2%	0.3%	0.3%
	Apartments > 4 stories	0.4%	0.2%	0.3%	0.3%
	Other Residential	1.0%	0.5%	0.6%	0.8%
Northern Region	Single Family Detached/Duplexes	0.5%	0.3%	0.3%	0.4%
	Single Family Attached/Row	0.7%	0.5%	0.5%	0.5%
	Apartments =< 4 stories	0.4%	0.3%	0.3%	0.3%
	Apartments > 4 stories	0.4%	0.3%	0.3%	0.3%
	Other Residential	1.2%	0.8%	1.1%	0.8%

Source: Navigant analysis of FortisBC Gas's 2014 LTRP

Table 2-20 presents the Reference Case forecast of households by segment and region over time. The team initially based the number of residential dwellings presented in Table 2-20 on the base year residential stock determined for 2014, but adjusted these numbers by applying the growth rates presented above in Table 2-19.

Table 2-20: Number of Residential Dwellings by Segment by Region – FortisBC Gas

Region	Segment	CPR Period				
		2014	2020	2025	2030	2035
Lower Mainland	Single Family Detached/Duplexes	475,475	486,379	492,271	499,539	507,855
	Single Family Attached/Row	53,890	56,388	57,682	59,107	60,645
	Apartments <= 4 stories	216,678	224,205	228,772	233,693	239,023
	Apartments > 4 stories	158,724	164,237	167,583	171,188	175,092
	Other Residential	10,348	10,653	10,806	10,998	11,203
Southern Interior	Single Family Detached/Duplexes	170,298	179,429	185,320	191,223	198,147
	Single Family Attached/Row	10,417	11,282	11,916	12,474	12,933
	Apartments <= 4 stories	52,875	54,993	56,591	58,010	59,346
	Apartments > 4 stories	6,853	7,128	7,335	7,519	7,692
	Other Residential	8,940	9,849	10,318	10,791	11,225
Vancouver Island	Single Family Detached/Duplexes	89,448	92,186	93,847	95,823	98,015
	Single Family Attached/Row	7,109	7,483	7,700	7,916	8,118
	Apartments <= 4 stories	59,179	60,627	61,388	62,210	63,136
	Apartments > 4 stories	17,195	17,616	17,837	18,076	18,345
	Other Residential	2,198	2,336	2,395	2,473	2,577
Northern Region	Single Family Detached/Duplexes	45,448	46,703	47,400	48,200	49,120
	Single Family Attached/Row	2,550	2,652	2,713	2,779	2,853
	Apartments <= 4 stories	10,195	10,436	10,584	10,724	10,896
	Apartments > 4 stories	1,007	1,031	1,045	1,059	1,076
	Other Residential	2,405	2,582	2,689	2,842	2,957
Segment Totals	Single Family Detached/Duplexes	780,669	804,697	818,838	834,784	853,136
	Single Family Attached/Row	73,965	77,804	80,011	82,276	84,549
	Apartments <= 4 stories	338,927	350,261	357,334	364,637	372,401
	Apartments > 4 stories	183,779	190,012	193,800	197,841	202,205
	Other Residential	23,891	25,419	26,208	27,104	27,961
Total		**1,401,231**	**1,448,194**	**1,476,192**	**1,506,641**	**1,540,253**

Source: Navigant analysis of Base Year residential stock and FortisBC Gas's 2014 LTRP

2.2.2.2 Commercial Sector

To develop the commercial Reference Case, the team first selected floor area as the most appropriate driver for gas consumption in the commercial sector. This section describes the development and application of floor space growth rates for each commercial segment and region over the CPR study period. To develop projections of commercial floor area growth by segment, the team relied on three key resources:

- StatsCan's Labour Force Statistics for British Columbia (*BC Labour Force Statistics*)[13]
- NRCan-Office of Energy Efficiency (OEE) Comprehensive Energy Consumption Database
- FortisBC Gas's 2014 LTRP

The primary resource employed to develop stock growth rates was the BC Labour Force Statistics, which tracks labour force levels for 11 commercial segments and 36 commercial sub-segments across seven economic regions in British Columbia. BC Stats uses these statistics for employment forecasting, which represent the most granular publicly available resource reporting commercial sector trends since 2000. The team relied on these data because both employment levels and floor space can serve as the basis for predicting energy demand.[14]

Navigant calculated the statistical relationship between labour force levels and commercial floor space to determine the appropriateness of using labour as a proxy for floor space. The OEE database tracks commercial floor space in BC disaggregated across 10 commercial segments. Since the OEE reports data at a provincial level and not disaggregated across regions, the team summed employment levels across all regions. The team analyzed floor space and labour force levels for the period between 2000 and 2012 for each OEE commercial segment. Table 2-21 below shows the correlation coefficient corresponding to each segment. Most segments show a strong positive correlation with coefficient values ranging between 0.80 and 0.97.

[13] *CANSIM Labor Force Survey Estimates (LFS) (March 2001 to December 2015)* – Table 282-026

[14] For example, vacant floor space can misrepresent the actual stock of floor space in use. As a result, projections of floor space, which account for vacant floor space, can skew energy demand upwards. In Ontario, the Independent Electricity System Operator (IESO) employs a forecasting approach based on employment levels. The IESO utilizes employment figures as an indicator to forecast electricity demand in the near term (i.e., 18-Month Outlook forecasts) and in the long term (i.e., Long Term Energy Plan). The IESO employs non-manufacturing employment levels to forecast demand in the commercial sector, and manufacturing employment for the industrial sector.

Table 2-21: Correlation Coefficient (Floor Space vs. Labor Force) – Commercial Sector

OEE Commercial Segment	Correlation Coefficient (2000 – 2012)
Wholesale Trade	0.80
Retail Trade	0.90
Transportation and Warehousing	(0.27)
Information and Cultural Industries	(0.62)
Offices	0.80
Educational Services	0.87
Health Care and Social Assistance	0.95
Arts, Entertainment and Recreation	0.83
Accommodation and Food Services	0.89
Other Services	0.13

Source: Navigant analysis of OEE and StatsCan data

Three of the commercial OEE segments - Transportation and Warehousing, Information and Cultural Industries, and Other Services - are exceptions with a negative correlation or close to no correlation at all. Two of the commercial segments in this CPR - Logistics and Warehousing and Other Commercial - use employment levels derived from these three OEE segments to establish stock growth rates. To avoid the use of poorly correlated variables, the team adjusted the growth rates for these two segments to follow the growth in commercial gas consumption in each region, determined from Fortis Gas's 2014 LTRP.

Navigant mapped the employment levels of the BC Labour Force Statistics to each of the CPR commercial segments and regions in the Reference Case. The team then analyzed employment growth rates over the 15-year period from 2000 to 2014 to use as a proxy to establish commercial floor space growth rates.

Finally, Navigant analyzed the FortisBC Gas 2014 LTRP to ensure that the stock growth rates applied in the Reference Case aligned with the overall trends in commercial demand projected by FortisBC Gas. The team applied the growth rates derived from the BC Labour Force Statistics to the first five years of the CPR forecast through 2020. For each subsequent five-year period in the forecast, the team applied an adjustment multiplier to the stock growth rates in each region of BC to align with the 2014 LTRP.

For example, the 2014 LTRP projects commercial consumption in the Lower Mainland to grow slightly from 2015 through 2035, with very little incremental demand over time. The team adjusted the Reference Case growth rates established for the Lower Mainland every five-year period to align with these trends in consumption.

Table 2-22 presents the growth rates employed in the CPR study for each segment and across time. The Lower Mainland has the most modest stock growth rates – aligned with the gas sales projections of the load forecast. In general, commercial floor space growth expectations are higher in the Southern Interior, Northern BC, and particularly in Vancouver Island where more aggressive sales projections are forecasted. At a segment level, expectations of commercial floor space growth in the long term care, hospitals, and food service segments are to be at levels significantly higher than the regional average. The following paragraphs provide additional information related to these three segments:

- **Colleges/Universities:** Historical post-secondary enrollment data from StatsCan shows an average annual growth rate of 3.3% across the province.[15] Enrolment in 2000/2001 was reported at 183,000, growing to approximately 278,000 by 2013/2014. BC Labour Force Statistics show that employment growth rates are highest in the Lower Mainland, and slower paced in the Southern Interior, Vancouver Island, and Northern BC.
- **Long Term Care:** BC is experiencing the fastest growth rate of senior citizens across Canada.[16] In absolute numbers, much of this expected growth is in the Lower Mainland and Vancouver Island where retirement homes clusters are most predominant. However, in relative terms, growth rates in the Southern Interior and Northern BC will be higher.[17] BC's Ministry of Health forecasts that demand for long-term care facilities will more than double by 2036 as a result projected growth in the senior population over the next 20 years.[18] Based on BC Labour Force Statistics, employment in nursing and residential care facilities more than doubled in the Southern Interior from 3,700 in 2000 to 9,200 in 2014, at an average annual growth rate of 4.8%.
- **Hospitals:** The Ministry of Health has identified the province's aging hospital infrastructure and current hospital capacity as critical challenges to meet projected provincial demand over the next two decades.[19] Following hospital closures across the province between 2002 and 2004, employment in healthcare has grown from 69,000 in 2005 to 91,700 in 2014, at an annual growth rate of 3.2%.[20] The Ministry of Health forecasts significant increases in demand in all health services through 2036. Projections show hospital floor space growing at rates much higher than each regional average, with highest growth rates in Vancouver Island and Northern BC.

Table 2-23 shows the estimated stock of commercial floor space over time. The base year commercial stock determined for 2014 is the initial basis for the stock of commercial floor space presented in Table 2-23, then the team adjusted future years by applying the growth rates identified in Table 2-22.

Note that as described in Section 2.1.1.3, gas consumption from the Other Commercial segment was distributed across all other commercial segments in proportion to their consumption. Since the base year gas consumption for the Other Commercial segment is zero, growth rates are also zero.

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[15] Statistic Canada. Table 477-0019. Post-secondary enrollments from 2000/2001 to 2013/2014.

[16] British Columbia. Ministry of Health. (2014). Setting priorities for the B.C. health system. Retrieved from http://www.health.gov.bc.ca/library/publications/year/2014/Setting-priorities-BC-Health-Feb14.pdf

[17] Office of the Senior's Advocate. May 2015. *"Senior's Housing in BC"*. Available: https://www.seniorsadvocatebc.ca/wp-content/uploads/sites/4/2015/05/Seniors-Housing-in-B.C.-Affordable-Appropriate-Available.pdf

[18] Marowitz, Ross. June 2015. The Canadian Press. *"Canada's Next Boom Industry? Retirement Homes, Developer Says"*. Available: http://www.huffingtonpost.ca/2015/06/17/quebec-developer-forecast_n_7603704.html

[19] Ministry of Health (2014)

[20] Cohen, March. July 2012. BC Health Coalition. *"Caring for BC's Aging Population".* Available: https://www.policyalternatives.ca/sites/default/files/uploads/publications/BC%20Office/2012/07/CCPABC-Caring-BC-Aging-Pop.pdf

Table 2-22: Annual Growth Rates by Commercial Segment and Region (%) – FortisBC Gas

Region	Segment	CPR Period			
		2014-2020	2021-2025	2026-2030	2031-2035
Lower Mainland	Accommodation	1.4%	1.2%	1.0%	0.8%
	Colleges/Universities	1.8%	1.5%	1.3%	1.1%
	Food Service	1.2%	1.0%	0.9%	0.7%
	Hospital	1.5%	1.3%	1.1%	0.9%
	Logistics/Warehouses	1.6%	1.4%	1.2%	1.0%
	Long Term Care	1.5%	1.3%	1.1%	0.9%
	Office	1.6%	1.3%	1.2%	0.9%
	Other Commercial	-	-	-	-
	Retail - Food	1.0%	0.8%	0.7%	0.6%
	Retail - Non Food	1.0%	0.8%	0.7%	0.6%
	Schools	1.1%	0.9%	0.8%	0.6%
Southern Interior	Accommodation	2.2%	1.9%	1.8%	1.6%
	Colleges/Universities	1.8%	1.5%	1.4%	1.3%
	Food Service	1.6%	1.4%	1.3%	1.2%
	Hospital	2.5%	2.2%	2.0%	1.9%
	Logistics/Warehouses	1.7%	1.5%	1.4%	1.3%
	Long Term Care	4.3%	3.6%	3.4%	3.1%
	Office	1.8%	1.5%	1.4%	1.3%
	Other Commercial	-	-	-	-
	Retail - Food	1.3%	1.1%	1.0%	0.9%
	Retail - Non Food	0.6%	0.5%	0.5%	0.5%
	Schools	0.8%	0.7%	0.6%	0.6%
Vancouver Island	Accommodation	0.3%	0.3%	0.3%	0.3%
	Colleges/Universities	3.1%	3.7%	3.4%	3.0%
	Food Service	0.1%	0.2%	0.2%	0.1%
	Hospital	4.7%	5.6%	5.2%	4.5%
	Logistics/Warehouses	1.2%	1.4%	1.3%	1.1%
	Long Term Care	4.9%	5.9%	5.4%	4.7%
	Office	1.7%	2.1%	1.9%	1.7%
	Other Commercial	-	-	-	-
	Retail - Food	0.2%	0.2%	0.2%	0.2%
	Retail - Non Food	1.8%	2.1%	2.0%	1.7%
	Schools	3.0%	3.6%	3.3%	2.9%
Northern BC	Accommodation	1.6%	1.9%	1.7%	1.5%
	Colleges/Universities	2.6%	3.2%	2.9%	2.6%
	Food Service	0.6%	0.7%	0.6%	0.6%
	Hospital	3.9%	4.7%	4.3%	3.8%
	Logistics/Warehouses	0.5%	0.6%	0.6%	0.5%
	Long Term Care	5.1%	6.1%	5.6%	4.9%
	Office	1.1%	1.3%	1.2%	1.0%
	Other Commercial	-	-	-	-
	Retail - Food	0.9%	1.1%	1.0%	0.9%
	Retail - Non Food	0.7%	0.8%	0.8%	0.7%
	Schools	1.3%	1.6%	1.4%	1.2%

Source: Navigant analysis of StatsCan Labour Market Statistics (CANSIM Table 282-026)

Table 2-23: Commercial Floor Space by Segment by Region (million m^2) – FortisBC Gas

Region	Segment	CPR Period				
		2014	2020	2025	2030	2035
Lower Mainland	Accommodation	2.55	2.78	2.94	3.10	3.23
	Colleges/Universities	4.10	4.55	4.90	5.24	5.52
	Food Service	2.17	2.34	2.46	2.57	2.66
	Hospital	1.56	1.71	1.82	1.93	2.02
	Logistics/Warehouses	10.56	11.61	12.43	13.20	13.84
	Long Term Care	2.05	2.24	2.39	2.52	2.64
	Office	22.06	24.21	25.88	27.45	28.77
	Other Commercial	-	-	-	-	-
	Retail - Food	2.10	2.24	2.33	2.41	2.48
	Retail - Non Food	7.34	7.83	8.16	8.47	8.72
	Schools	5.81	6.21	6.50	6.76	6.98
Southern Interior	Accommodation	1.56	1.77	1.95	2.13	2.31
	Colleges/Universities	0.39	0.43	0.47	0.50	0.54
	Food Service	0.54	0.59	0.63	0.67	0.71
	Hospital	0.64	0.74	0.82	0.91	1.00
	Logistics/Warehouses	3.30	3.67	3.95	4.23	4.50
	Long Term Care	0.87	1.10	1.31	1.55	1.81
	Office	7.08	7.88	8.49	9.10	9.70
	Other Commercial	-	-	-	-	-
	Retail - Food	0.99	1.08	1.14	1.20	1.25
	Retail - Non Food	3.08	3.24	3.33	3.41	3.49
	Schools	2.03	2.15	2.22	2.30	2.36
Vancouver Island	Accommodation	0.33	0.34	0.35	0.35	0.36
	Colleges/Universities	0.74	0.89	1.06	1.26	1.46
	Food Service	0.15	0.15	0.15	0.15	0.16
	Hospital	0.05	0.07	0.09	0.11	0.14
	Logistics/Warehouses	0.29	0.32	0.34	0.36	0.39
	Long Term Care	0.36	0.47	0.62	0.81	1.02
	Office	3.84	4.30	4.77	5.24	5.69
	Other Commercial	-	-	-	-	-
	Retail - Food	0.27	0.28	0.29	0.29	0.29
	Retail - Non Food	0.65	0.73	0.81	0.89	0.97
	Schools	0.53	0.63	0.75	0.89	1.03
Northern BC	Accommodation	0.25	0.28	0.31	0.33	0.36
	Colleges/Universities	0.07	0.08	0.10	0.11	0.13
	Food Service	0.08	0.08	0.08	0.08	0.09
	Hospital	0.10	0.12	0.15	0.18	0.22
	Logistics/Warehouses	0.48	0.50	0.52	0.53	0.55
	Long Term Care	0.04	0.06	0.08	0.10	0.13
	Office	1.24	1.33	1.42	1.51	1.59
	Other Commercial	-	-	-	-	-
	Retail - Food	0.11	0.11	0.12	0.13	0.13
	Retail - Non Food	0.48	0.51	0.53	0.55	0.57
	Schools	0.35	0.38	0.41	0.44	0.46
Segment Totals	Accommodation	4.69	5.17	5.54	5.91	6.25
	Colleges/Universities	5.30	5.95	6.53	7.11	7.64
	Food Service	2.93	3.16	3.32	3.48	3.62
	Hospital	2.35	2.64	2.89	3.14	3.38

Region	Segment	CPR Period				
		2014	2020	2025	2030	2035
	Logistics/Warehouses	14.64	16.11	17.24	18.33	19.28
	Long Term Care	3.33	3.86	4.40	4.98	5.59
	Office	34.22	37.73	40.56	43.30	45.74
	Other Commercial	-	-	-	-	-
	Retail - Food	3.47	3.71	3.87	4.03	4.16
	Retail - Non Food	11.55	12.31	12.83	13.32	13.75
	Schools	8.71	9.37	9.88	10.38	10.83
Totals	**Schools**	**91.18**	**100.01**	**107.06**	**113.97**	**120.24**

Source: Navigant analysis of StatsCan Labour Market Statistics and FortisBC Gas's 2014 LTRP

2.2.2.3 Industrial Sector

To develop the industrial Reference Case, the team developed and applied growth rates of gas demand for each industrial segment and region over the CPR study period. The team derived the demand growth rates from the FortisBC Gas 2014 LTRP.

FortisBC Gas's 2014 LTRP reports industrial sector gas sales as a whole and not broken down into individual industrial segments. To disaggregate the sector-wide forecast into industrial segments, Navigant and FortisBC worked together to develop gas sales projections which aligned with the sector-level forecast established for each region. Appendix B.4 describes the approach used to develop the industrial forecast in more detail.

Using this industrial load forecast, the team calculated average annual growth rates for each segment for each five-year period (e.g., 2015 to 2020, 2021 to 2025). The team applied these five-year growth rates to the same periods through the end of the CPR study period. For industrial segments with no presence in any particular region, the team specified a demand growth rate of zero (0.0%).

Table 2-24 presents the demand growth rates employed in the CPR study. Broadly speaking, the demand growth rates for the industrial sector show a gradual decline in gas sales over time across most segments and across each region. The growth rates presented in Table 2-24 lead to the estimated industrial consumption shown in Table 2-25. The base year consumption is the initial basis for the industrial demand in Table 2-25, which is then adjusted in future years by applying the growth rates identified in Table 2-24.

Table 2-24: Annual Growth Rates by Industrial Segment and Region (%) – FortisBC Gas

Region	Segment	CPR Period			
		2015-2020	2021-2025	2026-2030	2031-2035
Lower Mainland	Agriculture	-0.4%	-0.5%	0.3%	0.6%
	Cement	-1.2%	-1.8%	-0.1%	-0.1%
	Chemical	-2.4%	-1.4%	-0.5%	-0.2%
	Mining - Coal	-1.9%	-2.0%	-1.1%	-0.9%
	Food & Beverage	-1.8%	-2.0%	-1.1%	-0.9%
	Greenhouses	-1.0%	-1.1%	-0.2%	0.0%
	LNG Facilities	0.0%	0.0%	0.0%	0.0%
	Manufacturing	0.6%	0.0%	1.0%	1.2%
	Mining - Metal	-1.9%	-2.0%	-1.1%	-0.9%
	Oil and Gas	-1.9%	-2.0%	-1.1%	-0.9%
	Pulp & Paper - Kraft	0.0%	0.0%	0.0%	0.0%
	Pulp & Paper - TMP	-1.9%	-2.0%	-1.1%	-0.9%
	Transportation	-1.3%	-1.2%	-1.2%	-1.0%
	Wood Products	-0.7%	-0.9%	-0.1%	0.2%
	Other Industrial	2.4%	2.4%	-0.7%	-1.7%
Southern Interior	Agriculture	-0.6%	-0.8%	-0.8%	-0.8%
	Cement	-1.0%	-0.1%	0.7%	0.5%
	Chemical	0.9%	0.7%	0.7%	0.7%
	Mining - Coal	-0.5%	0.2%	-0.3%	-0.3%
	Food & Beverage	1.9%	1.7%	1.7%	1.7%
	Greenhouses	1.8%	1.6%	1.6%	1.6%
	LNG Facilities	0.0%	0.0%	0.0%	0.0%
	Manufacturing	-0.3%	-0.4%	-0.3%	-0.3%
	Mining - Metal	0.3%	0.7%	-4.1%	4.0%
	Oil and Gas	-0.1%	-0.3%	-0.3%	-0.3%
	Pulp & Paper - Kraft	-0.1%	-0.3%	-0.3%	-0.3%
	Pulp & Paper - TMP	-0.1%	-0.3%	-0.3%	-0.3%
	Transportation	1.0%	0.8%	0.7%	0.7%
	Wood Products	-0.3%	-1.0%	-0.6%	-0.6%
	Other Industrial	-2.1%	3.9%	1.8%	1.1%
Vancouver Island	Agriculture	1.1%	0.9%	1.5%	1.5%
	Cement	0.3%	-0.4%	1.0%	0.9%
	Chemical	-1.0%	0.1%	0.7%	0.7%
	Mining - Coal	0.0%	0.0%	0.0%	0.0%
	Food & Beverage	-0.4%	-0.5%	0.0%	0.1%
	Greenhouses	0.5%	0.3%	0.9%	0.9%
	LNG Facilities	0.0%	0.0%	0.0%	0.0%
	Manufacturing	2.1%	1.5%	2.1%	2.1%
	Mining - Metal	-0.4%	-0.6%	0.0%	0.0%
	Oil and Gas	0.0%	0.0%	0.0%	0.0%
	Pulp & Paper - Kraft	0.0%	0.0%	0.0%	0.0%
	Pulp & Paper - TMP	-0.4%	-0.6%	0.0%	0.0%
	Transportation	0.2%	0.3%	0.0%	0.0%
	Wood Products	0.8%	0.5%	1.1%	1.1%
	Other Industrial	3.9%	3.9%	0.4%	-0.8%
Northern BC	Agriculture	1.1%	1.0%	1.0%	1.1%
	Cement	0.3%	-0.3%	0.6%	0.4%
	Chemical	-0.9%	0.1%	0.2%	0.3%
	Mining - Coal	-0.4%	-0.5%	-0.5%	-0.4%
	Food & Beverage	-0.4%	-0.5%	-0.4%	-0.4%
	Greenhouses	0.5%	0.4%	0.4%	0.5%
	LNG Facilities	0.0%	0.0%	0.0%	0.0%
	Manufacturing	2.1%	1.5%	1.7%	1.7%
	Mining - Metal	-0.4%	-0.5%	-0.5%	-0.4%
	Oil and Gas	-0.4%	-0.5%	-0.5%	-0.4%
	Pulp & Paper - Kraft	-0.4%	-0.5%	-0.5%	-0.4%
	Pulp & Paper - TMP	-0.4%	-0.5%	-0.5%	-0.4%
	Transportation	0.2%	0.3%	-0.5%	-0.5%
	Wood Products	0.8%	0.6%	0.6%	0.7%
	Other Industrial	3.9%	3.9%	0.0%	-1.3%

Source: Navigant analysis of FortisBC Gas 2014 LTRP

Table 2-25: Industrial Consumption by Segment by Region (TJ) – FortisBC Gas

Region	Segment	CPR Period				
		2014	2020	2025	2030	2035
All Regions	Agriculture	1,601	1,616	1,627	1,644	1,664
	Cement	908	874	837	837	831
	Chemical	1,284	1,196	1,188	1,188	1,191
	Mining - Coal	2,517	2,443	2,458	2,417	2,378
	Food & Beverage	4,000	3,807	3,658	3,538	3,435
	Greenhouses	5,473	5,384	5,309	5,260	5,219
	LNG Facilities	-	-	-	-	-
	Manufacturing	5,710	6,037	6,215	6,443	6,687
	Mining - Metal	10	10	9	9	9
	Oil and Gas	8,761	8,512	8,310	8,139	7,981
	Pulp & Paper - Kraft	14,585	14,318	13,991	13,702	13,427
	Pulp & Paper - TMP	3,450	3,414	3,384	3,361	3,341
	Transportation	921	897	885	844	805
	Wood Products	7,567	7,606	7,481	7,443	7,421
	Other Industrial	789	921	1,092	1,078	1,006
Total		**57,577**	**57,036**	**56,444**	**55,903**	**55,393**

Source: Navigant analysis of FortisBC Gas 2014 LTRP

2.2.3 EUI Trends

This section discusses the EUI trends across the residential, commercial, and industrial sectors.

2.2.3.1 Residential Sector

To develop EUI trends for the Residential sector Reference Case, Navigant reviewed several resources including the FortisBC Gas 2012 REUS study, the accompanying Residential CDA study, BC Hydro's 2014 REUS, and the NRCan-OEE database. The main resource used to estimate the change in EUIs over time was BC Hydro's 2014 REUS study. BC Hydro's REUS was preferred over FortisBC Gas's REUS because it provided more granularity across individual residential segments. BC Hydro's REUS also provides survey results for gas equipment penetration for various years including 2002, 2003, 2005, 2007, and 2014. The team used the REUS data for each of these years to calculate an average annual rate of change for each EUI. A limitation of this approach is that the REUS data reflects the impact of provincial and federal DSM programs while the objective of this analysis is to trend natural change in EUIs in the absence of DSM impacts.

In certain cases, extrapolating recent trends 20 years into the future is uncertain and can result in implausibly high changes in the EUI over the forecast horizon. Recognizing this, Navigant endeavored to temper short-term trends by assuming a reduction in EUI trends further into the future. To determine these reductions in EUI trends over time, the team analyzed the FortisBC Gas 2014 LTRP. The analysis of the load forecast ensured that the Reference Case residential consumption—determined based on the growing residential stock and the EUI trends—aligned with the forecast of residential consumption reported in FortisBC Gas's load forecast. Navigant made these adjustments to the EUI trends across every five-year period of the CPR analysis horizon.

Based on this analysis, the team applied the EUI trends from the REUS analysis to the first five years of the CPR period, and systematically decreased the magnitude of EUI trends over the subsequent five-year periods. Specifically, the EUI trends decrease by a factor of 20% every five-year period. This 20% reduction enables the Reference Case residential consumption to match the load forecast consumption.[21] These EUI trends implicitly reflect natural changes in residential end-use consumption caused by naturally occurring improvements in end-use equipment efficiency, fuel share changes, saturation levels of energy efficient equipment, existing building retrofit activities, and stock turnover.

Table 2-26 shows the EUI trends determined for each residential segment and end-use over time, and Table 2-27 provides the resulting EUIs for each five-year period in the Lower Mainland. Navigant based the EUIs presented in Table 2-27 on the base year EUIs (for 2014) and adjusted them with the EUI trends identified in Table 2-26. The Reference Case EUIs for the Southern Interior, Vancouver Island and Northern BC are presented in Appendix B.2.

Please note that minor year-to-year changes in EUIs may not be explicitly reflected in the tables due to rounding.

As Table 2-26 indicates, gas consumption by most end-uses is expected to decrease over the CPR period. Current trends show that gas consumption from space heating and water heating are expected to decline over time, while consumption from appliances will increase. In general, the magnitude of the expected annual change in EUIs is greater in the near term and will decrease over time.

- **Space heating** – The use of natural gas for space heating has continued a small downward trend over the past decade—primarily in single detached homes and apartment units—resulting in a decrease in the gas space heating EUI. This trend is driven primarily by the lower penetration of gas space heating in new homes.
- **Water Heating** – Electricity consumption from water heating increases across most segments because of increased penetration of electric water heaters. The trend is most prevalent in single detached and attached homes. As a result, gas consumption for water heating has seen a steady decline across these segments. Survey results also show that apartment buildings are increasingly opting for centralized systems, rather than in-suite water heating units. Although, gas penetration of in-suite units has decreased, overall gas consumption is projected to increase due to centralized systems.
- **Appliances** – Gas consumption for appliances is forecast to increase over time, and at higher rates than space heating and water heating. Although gas clothes dryers are becoming less common, the increased adoption of gas-fired stoves and ranges has offset the impact of dryers and is expected to continue increasing gas consumption for appliances.

As noted for some of these end-uses, changing fuel shares for individual residential segments cause change in gas consumption over time.

[21] For example, if the EUI trend determined from the 2014 REUS was a 1.0% decrease in EUI per year, the team applied 1.0% per year from 2015 through 2020, 0.8% per year from 2021 through 2025, 0.64% per year from 2026 through 2030, and 0.51% per year from 2031 through 2035.

Table 2-26: Residential Gas Intensity Trends (%) – Five-Year Trends

Residential Segment	End-Use	CPR Period			
		2015-2020	2020-2025	2025-2030	2030-2035
Single Family Detached	Space Heating	-1.8%	-1.4%	-1.1%	-0.9%
	Water Heating	-0.9%	-0.7%	-0.6%	-0.4%
	Cooling	-	-	-	-
	Appliances	1.3%	1.1%	0.9%	0.7%
	Lighting	-	-	-	-
	Electronics	-	-	-	-
	Other	-1.3%	-1.0%	-0.8%	-0.7%
	Ventilation	-	-	-	-
Single Family Attached/Row	Space Heating	-1.5%	-1.2%	-1.0%	-0.8%
	Water Heating	-0.7%	-0.6%	-0.5%	-0.4%
	Cooling	-	-	-	-
	Appliances	1.3%	1.0%	0.8%	0.7%
	Lighting	-	-	-	-
	Electronics	-	-	-	-
	Other	-1.1%	-0.9%	-0.7%	-0.6%
	Ventilation	-	-	-	-
Apartments =< 4 stories	Space Heating	-2.0%	-1.6%	-1.3%	-1.0%
	Water Heating	0.4%	0.3%	0.3%	0.2%
	Cooling	-	-	-	-
	Appliances	1.7%	1.4%	1.1%	0.9%
	Lighting	-	-	-	-
	Electronics	-	-	-	-
	Other	-0.8%	-0.6%	-0.5%	-0.4%
	Ventilation	-	-	-	-
Apartments > 4 stories	Space Heating	-2.0%	-1.6%	-1.3%	-1.0%
	Water Heating	0.4%	0.3%	0.3%	0.2%
	Cooling	-	-	-	-
	Appliances	1.7%	1.4%	1.1%	0.9%
	Lighting	-	-	-	-
	Electronics	-	-	-	-
	Other	-0.8%	-0.6%	-0.5%	-0.4%
	Ventilation	-	-	-	-
Other Residential	Space Heating	-1.7%	-1.4%	-1.1%	-0.9%
	Water Heating	-1.2%	-1.0%	-0.8%	-0.6%
	Cooling	-	-	-	-
	Appliances	1.0%	0.8%	0.6%	0.5%
	Lighting	-	-	-	-
	Electronics	-	-	-	-
	Other	-1.5%	-1.2%	-0.9%	-0.8%
	Ventilation	-	-	-	-

Source: Navigant analysis of BC Hydro's 2014 REUS

Table 2-27: Residential Gas Intensity (GJ/household) – Lower Mainland

Residential Segment	End-Use	CPR Period				
		2015	2020	2025	2030	2035
Single Family Detached	Space Heating	77	69	64	61	58
	Hot Water	15	14	14	13	13
	Cooling/Refrigeration	-	-	-	-	-
	Appliances	1	1	2	2	2
	Lighting	-	-	-	-	-
	Electronics	-	-	-	-	-
	Other	3	2	2	2	2
	Ventilation	-	-	-	-	-
	Total	95	87	82	78	75
Single Family Attached/Row	Space Heating	47	43	40	38	37
	Hot Water	10	10	10	9	9
	Cooling/Refrigeration	-	-	-	-	-
	Appliances	1	1	1	1	1
	Lighting	-	-	-	-	-
	Electronics	-	-	-	-	-
	Other	1	1	1	1	1
	Ventilation	-	-	-	-	-
	Total	59	55	52	50	48
Apartments =< 4 stories	Space Heating	21	19	17	16	15
	Hot Water	17	18	18	18	19
	Cooling/Refrigeration	-	-	-	-	-
	Appliances	1	1	1	1	1
	Lighting	-	-	-	-	-
	Electronics	-	-	-	-	-
	Other	3	3	3	3	3
	Ventilation	-	-	-	-	-
	Total	43	41	40	39	38
Apartments > 4 stories	Space Heating	21	19	17	16	15
	Hot Water	17	17	18	18	18
	Cooling/Refrigeration	-	-	-	-	-
	Appliances	1	1	1	1	1
	Lighting	-	-	-	-	-
	Electronics	-	-	-	-	-
	Other	4	3	3	3	3
	Ventilation	-	-	-	-	-
	Total	43	41	39	39	38
Other Residential	Space Heating	45	40	38	36	34
	Hot Water	13	12	12	11	11
	Cooling/Refrigeration	-	-	-	-	-
	Appliances	1	1	1	1	1
	Lighting	-	-	-	-	-
	Electronics	-	-	-	-	-
	Other	1	1	1	1	1
	Ventilation	-	-	-	-	-
	Total	60	55	51	49	47

Source: Navigant analysis of BC Hydro's 2014 REUS

2.2.3.2 Commercial Sector

The next step in building the commercial sector Reference Case involved the development and application of EUI trends over the CPR study period. Navigant reviewed several resources including FortisBC Gas's 2015 CEUS, the NRCan-OEE database for British Columbia, and BC Hydro's 2014 CEUS to develop these trends. The main resource for EUI trends in the commercial sector was BC Hydro's 2014 CEUS. The team preferred BC Hydro's 2014 CEUS to FortisBC's 2015 CEUS because it provides detailed survey results for each commercial segment in each region.

BC Hydro's 2014 CEUS surveyed commercial customers in relation to upgrades made to end-use equipment in the past 5 years.[22] Based on the incidence of equipment upgrades made to specific end-uses (e.g., space cooling vs. space heating), Navigant estimated the potential reduction in energy consumption from higher efficiency equipment. This approach is described in more detail in Appendix 0. A limitation of this approach is that the CEUS data reflects the impact of provincial and federal commercial DSM programs, while the objective of this analysis is to trend natural change in EUIs in the absence of DSM impacts. The impact of this limitation on the study is that the EUI trends established for these commercial end-uses may be overstated, which may affect the overall results of this study. Additionally, this EUI trending approach inherently reflects both new and existing buildings because the CEUS customer pool included both new and existing buildings.

This analysis resulted in EUI trends for all the end-uses for which equipment upgrade information was reported in 2014 CEUS. [23] This included the following end-uses:

- Lighting
- Water heating
- Space cooling
- HVAC fans/pumps
- Space heating

Two of these end-uses—water heating and space heating—are applicable to gas consumption. The 2014 CEUS did not report the necessary information to develop EUI trends for the *cooking* and *other* gas end-uses, so the team assumed they would remain flat.

Similar to the residential sector, Navigant analyzed FortisBC Gas's 2014 LTRP to establish changes in the magnitude of commercial EUI trends every five years over the entire CPR analysis period. This ensured that the Reference Case commercial consumption—determined based on the commercial floor space stock and the EUI trends—aligned with the forecast of commercial consumption reported in the 2014 LTRP.

Based on this analysis, the commercial EUI trends determined from the CEUS analysis are applied to the first five years of the analysis, decreasing slightly over the subsequent five-year periods. Specifically, the EUI trends decrease by a factor of 30% every five-year period. This 30% reduction in EUI trends enables the Reference Case commercial consumption to match the load forecast consumption.

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[22] For example, the incidence of water heating equipment upgrades within the past 5 years was 23% across the entire commercial sector. However, the incidence of water heating upgrades varied across commercial segments (e.g., 38% in Colleges & Universities, 12% in Offices).
[23] The 2014 CEUS did not report equipment upgrade information for the cooking, refrigeration, and office equipment end-uses.

Table 2-28 shows the EUI trends for each commercial segment and end-use, and Table 2-29 shows the resulting EUIs over five-year intervals for the Lower Mainland. The EUIs presented in Table 2-29 were initially derived from the base year EUIs (for 2014) and have been adjusted by applying the EUI trends identified in Table 2-28. The Reference Case EUIs for the Southern Interior, Vancouver Island and Northern BC are presented in Appendix B.3.

As seen in Table 2-28, gas consumption for water heating and space heating is expected to decrease over the CPR period.

These changes in EUIs over time implicitly reflect natural changes in gas end-use consumption caused by naturally occurring improvements in end-use equipment efficiency and saturation levels, fuel switching, and retrofit activities. For example, energy efficient improvements driven by initiatives like ENERGY STAR and the Leadership in Energy and Environmental Design (LEED) certification are expected to influence EUI trends. Although the impact of these two energy performance initiatives remains limited thus far, the initiatives are likely to increase adoption of commercial envelope measures and higher efficiency space heating, lighting and cooking equipment.

Table 2-28: Commercial Gas Intensity Trends (%) – Five-Year Trends

Commercial Segment	End-Use	CPR Period			
		2015-2020	2020-2025	2025-2030	2030-2035
Accommodation	Cooking	0.0%	0.0%	0.0%	0.0%
	HVAC Fans/Pumps	-	-	-	-
	Hot Water	-0.8%	-0.6%	-0.4%	-0.3%
	Lighting	-	-	-	-
	Office Equipment	-	-	-	-
	Other	0.0%	0.0%	0.0%	0.0%
	Refrigeration	-	-	-	-
	Space Cooling	-	-	-	-
	Space Heating	-1.7%	-1.2%	-0.8%	-0.6%
Colleges/ Universities	Cooking	0.0%	0.0%	0.0%	0.0%
	HVAC Fans/Pumps	-	-	-	-
	Hot Water	-1.1%	-0.8%	-0.5%	-0.4%
	Lighting	-	-	-	-
	Office Equipment	-	-	-	-
	Other	0.0%	0.0%	0.0%	0.0%
	Refrigeration	-	-	-	-
	Space Cooling	-	-	-	-
	Space Heating	-1.9%	-1.3%	-0.9%	-0.6%
Food Service	Cooking	0.0%	0.0%	0.0%	0.0%
	HVAC Fans/Pumps	-	-	-	-
	Hot Water	-1.1%	-0.8%	-0.5%	-0.4%
	Lighting	-	-	-	-
	Office Equipment	-	-	-	-
	Other	0.0%	0.0%	0.0%	0.0%
	Refrigeration	-	-	-	-
	Space Cooling	-	-	-	-
	Space Heating	-2.0%	-1.4%	-1.0%	-0.7%
Hospital	Cooking	0.0%	0.0%	0.0%	0.0%
	HVAC Fans/Pumps	-	-	-	-
	Hot Water	-0.7%	-0.5%	-0.3%	-0.2%
	Lighting	-	-	-	-
	Office Equipment	-	-	-	-
	Other	0.0%	0.0%	0.0%	0.0%
	Refrigeration	-	-	-	-
	Space Cooling	-	-	-	-
	Space Heating	-1.8%	-1.2%	-0.9%	-0.6%
Logistics/ Warehouses	Cooking	0.0%	0.0%	0.0%	0.0%
	HVAC Fans/Pumps	-	-	-	-
	Hot Water	-0.7%	-0.5%	-0.4%	-0.3%
	Lighting	-	-	-	-
	Office Equipment	-	-	-	-
	Other	0.0%	0.0%	0.0%	0.0%
	Refrigeration	-	-	-	-
	Space Cooling	-	-	-	-
	Space Heating	-1.3%	-0.9%	-0.7%	-0.5%
Long Term Care	Cooking	0.0%	0.0%	0.0%	0.0%
	HVAC Fans/Pumps	-	-	-	-
	Hot Water	-1.0%	-0.7%	-0.5%	-0.3%
	Lighting	-	-	-	-
	Office Equipment	-	-	-	-
	Other	0.0%	0.0%	0.0%	0.0%
	Refrigeration	-	-	-	-
	Space Cooling	-	-	-	-
	Space Heating	-1.8%	-1.3%	-0.9%	-0.6%
Office	Cooking	0.0%	0.0%	0.0%	0.0%

Commercial Segment	End-Use	CPR Period			
		2015-2020	2020-2025	2025-2030	2030-2035
	HVAC Fans/Pumps	-	-	-	-
	Hot Water	-0.4%	-0.3%	-0.2%	-0.1%
	Lighting	-	-	-	-
	Office Equipment	-	-	-	-
	Other	0.0%	0.0%	0.0%	0.0%
	Refrigeration	-	-	-	-
	Space Cooling	-	-	-	-
	Space Heating	-1.8%	-1.2%	-0.9%	-0.6%
Other Commercial	Cooking	0.0%	0.0%	0.0%	0.0%
	HVAC Fans/Pumps	-	-	-	-
	Hot Water	-0.4%	-0.3%	-0.2%	-0.1%
	Lighting	-	-	-	-
	Office Equipment	-	-	-	-
	Other	0.0%	0.0%	0.0%	0.0%
	Refrigeration	-	-	-	-
	Space Cooling	-	-	-	-
	Space Heating	-1.8%	-1.2%	-0.9%	-0.6%
Retail - Food	Cooking	0.0%	0.0%	0.0%	0.0%
	HVAC Fans/Pumps	-	-	-	-
	Hot Water	-0.9%	-0.6%	-0.4%	-0.3%
	Lighting	-	-	-	-
	Office Equipment	-	-	-	-
	Other	0.0%	0.0%	0.0%	0.0%
	Refrigeration	-	-	-	-
	Space Cooling	-	-	-	-
	Space Heating	-2.2%	-1.5%	-1.1%	-0.7%
Retail – Non Food	Cooking	0.0%	0.0%	0.0%	0.0%
	HVAC Fans/Pumps	-	-	-	-
	Hot Water	-0.9%	-0.6%	-0.4%	-0.3%
	Lighting	-	-	-	-
	Office Equipment	-	-	-	-
	Other	0.0%	0.0%	0.0%	0.0%
	Refrigeration	-	-	-	-
	Space Cooling	-	-	-	-
	Space Heating	-2.2%	-1.5%	-1.1%	-0.7%
Schools	Cooking	0.0%	0.0%	0.0%	0.0%
	HVAC Fans/Pumps	-	-	-	-
	Hot Water	-0.6%	-0.4%	-0.3%	-0.2%
	Lighting	-	-	-	-
	Office Equipment	-	-	-	-
	Other	0.0%	0.0%	0.0%	0.0%
	Refrigeration	-	-	-	-
	Space Cooling	-	-	-	-
	Space Heating	-1.8%	-1.2%	-0.9%	-0.6%

Source: Navigant analysis of BC Hydro 2014 CEUS

Table 2-29: Commercial Gas Intensity (MJ/m2) – Lower Mainland

Commercial Segment	End-Use	CPR Period				
		2015	2020	2025	2030	2035
Accommodation	Cooking	80	80	80	80	80
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	258	246	239	234	230
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	56	56	56	56	56
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	252	228	215	206	200
	Total	646	609	589	576	567
Colleges/ Universities	Cooking	37	37	37	37	37
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	69	65	62	61	60
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	65	65	65	65	65
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	310	276	259	247	239
	Total	481	444	424	410	401
Food Service	Cooking	839	839	839	839	839
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	476	446	430	418	411
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	19	19	19	19	19
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	425	376	351	334	323
	Total	1,759	1,680	1,638	1,610	1,591
Hospitals	Cooking	65	65	65	65	65
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	274	263	257	253	250
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	233	233	233	233	233
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	758	682	641	614	596
	Total	1,330	1,243	1,197	1,165	1,144
Logistics/ Warehouses	Cooking	5	5	5	5	5
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	18	17	17	17	16
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	19	19	19	19	19
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	201	185	177	171	167
	Total	242	226	217	211	207
Long Term Care	Cooking	56	56	56	56	56
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	156	147	142	138	136
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-

Commercial Segment	End-Use	CPR Period				
		2015	2020	2025	2030	2035
	Other	65	65	65	65	65
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	337	301	282	270	262
	Total	613	569	545	530	519
Office	Cooking	9	9	9	9	9
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	33	32	32	31	31
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	19	19	19	19	19
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	263	237	223	213	207
	Total	324	297	282	273	266
Other Commercial	Cooking	15	15	15	15	15
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	26	26	25	25	25
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	13	13	13	13	13
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	276	248	233	223	217
	Total	330	301	286	276	269
Retail - Food	Cooking	75	75	75	75	75
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	65	61	60	58	57
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	19	19	19	19	19
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	311	273	253	240	231
	Total	469	428	406	391	381
Retail – Non Food	Cooking	13	13	13	13	13
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	23	22	21	21	21
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	6	6	6	6	6
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	256	225	208	197	190
	Total	299	266	249	237	230
Schools	Cooking	15	15	15	15	15
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	39	38	37	36	36
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	5	5	5	5	5
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	277	249	234	224	218
	Total	336	307	291	280	273

Source: Navigant analysis of FortisBC Gas's 2014 LTRP, and BC Hydro 2014 CEUS

2.2.3.3 Industrial Sector

Discussions between Navigant and CLEAResult concluded “natural” change in industrial energy efficiency would be minimal over the study horizon. This assumption is consistent with past CPRs, which forecasted very small changes in industrial EUIs over a 20-year forecast horizon (typically only a few percent over 20 years)[24]. Given the expected small magnitude of natural change in industrial EUIs, inherent EUI forecasting uncertainty, and limited historical data availability for industrial EUIs, this study assumes that EUIs in the industrial sector will remain constant in the absence of conservation programs.

The study represents industrial production levels as an index that begins at 1.0 in 2014 and grows or declines in accordance with expected trends in production. These production levels are analogous to building stocks and are multiplied by EUIs to determine consumption in a given year.

The outline below details key considerations for the industrial consumption forecast.

- **Resource-extraction industries** are much more sensitive to primary cost drivers (timber prices, labor costs), suggesting their consumption is not strongly dependent on electricity and gas prices. The prime reason for upgrading equipment is for increasing production, market expansion, or new product lines, rather than to increase energy efficiency.
- **Non-resource-extraction industries** are unlikely to experience significant changes in EUIs. Many of these customers—particularly food & beverage and manufacturing customers—operate smaller facilities and the tendency is not to invest capital upgrading older facilities but rather in expanding or building new plants.
- The **pulp & paper and wood products** consumption has been declining steadily over the past decade, as is evident by mill shutdowns. By and large, these industrial segments are projected to continue declining through 2020, particularly in other regions where much of the industry is concentrated. Capital constraints in this segment limit the opportunities for energy efficiency. These industries—in addition to the chemical and cement sector—consist mainly of older plants where customers have shown reluctance to upgrade to more efficient equipment due to uncertain market conditions.

2.2.4 Reference Case Forecast and Comparison with Utility Forecast

This section provides the final Reference Case forecast and compares the sector-level results of the Reference Case forecast with FortisBC Gas’s load forecast.

2.2.4.1 Reference Case Forecast

Table 2-30 summarizes the results of the Reference Case for each sector and customer segment. Navigant computed these results by applying the stock growth rates and the EUI trends established in previous sections for each customer segment to the base year results.

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[24] The base year analysis did not characterize industrial consumption on a per-unit basis, as was done for the residential sector (i.e., kWh or GJ *per* household) and commercial sector (i.e., kWh or GJ *per* m2). Industrial EUIs are expressed directly in electric or gas units of consumption (i.e., kWh or GJ).

Table 2-30: Reference Case Forecast by Segment (TJ)

Sector	Segment	CPR Period				
		2015	2020	2025	2030	2035
Residential	Single Family Detached	67,598	63,730	61,177	59,574	58,711
	Single Family Attached/Row	4,148	4,212	4,249	4,318	4,406
	Apartments =< 4 stories	12,597	12,774	12,911	13,108	13,352
	Apartments > 4 stories	7,355	7,502	7,606	7,747	7,915
	Other Residential	1,370	1,366	1,353	1,358	1,369
	Total	**93,069**	**89,584**	**87,296**	**86,105**	**85,752**
Commercial	Accommodation	3,141	3,261	3,381	3,523	3,667
	Colleges/Universities	2,625	2,715	2,847	3,004	3,161
	Food Service	5,155	5,313	5,451	5,610	5,761
	Hospital	3,428	3,600	3,808	4,055	4,312
	Logistics/Warehouses	3,857	3,950	4,054	4,186	4,317
	Long Term Care	2,091	2,257	2,466	2,718	2,995
	Office	11,882	11,986	12,241	12,614	13,006
	Other Commercial	-	-	-	-	-
	Retail – Food	1,624	1,582	1,567	1,571	1,584
	Retail - Non Food	3,698	3,502	3,411	3,378	3,375
	Schools	3,140	3,081	3,083	3,122	3,176
	Street Lights	-	-	-	-	-
	Total	**40,640**	**41,248**	**42,308**	**43,781**	**45,351**
Industrial	Agriculture	1,601	1,616	1,627	1,644	1,664
	Cement	908	874	837	837	831
	Chemical	1,284	1,196	1,188	1,188	1,191
	Mining – Coal	2,517	2,443	2,458	2,417	2,378
	Food & Beverage	4,000	3,807	3,658	3,538	3,435
	Greenhouses	5,473	5,384	5,309	5,260	5,219
	LNG Facilities	-	-	-	-	-
	Manufacturing	5,710	6,037	6,215	6,443	6,687
	Mining – Metal	10	10	9	9	9
	Oil and Gas	8,761	8,512	8,310	8,139	7,981
	Pulp & Paper - Kraft	14,585	14,318	13,991	13,702	13,427
	Pulp & Paper - TMP	3,450	3,414	3,384	3,361	3,341
	Transportation	921	897	885	844	805
	Wood Products	7,567	7,606	7,481	7,443	7,421
	Other Industrial	789	921	1,092	1,078	1,006
	Total	**57,577**	**57,036**	**56,444**	**55,903**	**55,393**
Total		**191,286**	**187,867**	**186,048**	**185,789**	**186,497**

Source: Navigant analysis

2.2.4.2 Comparison between Reference Case and Utility Forecast

In this section, Navigant compares the Reference Case forecast with FortisBC Gas's 2014 LTRP. Since most of the demand growth assumptions underlying the load forecast were used as inputs to develop the stock growth rates in the Reference Case, the two forecasts are largely consistent.

Table 2-31 compares the projected gas sales in 2035 between the Reference Case and the Load Forecast.

Table 2-31: Reference Case Forecast

Class/Sector	Average Annual Growth Rate (%)		2035 Sales (TJ)		Difference (%)
	Reference Forecast	FortisBC Gas Forecast	Reference Forecast	FortisBC Gas Forecast	
Residential	-0.4%	-0.4%	85,752	85,752	0.0%
Commercial	0.5%	0.5%	45,351	45,351	0.0%
Industrial	-0.2%	-0.2%	55,393	55,393	0.0%
Total	**-0.1%**	**-0.1%**	**186,497**	**186,497**	**0.0%**

Source: Navigant analysis

2.3 Frozen End-use Intensity Case and Natural Change

Navigant's model uses the building stock projections from the Reference Case forecast to calculate technical and economic potential, but does not use the reference case's time-changing end-use intensities. Rather, it freezes the end-use intensities from the Reference Case forecast at 2016 levels and holds them fixed over time. This section describes the reasons for this approach and the method by which the team links the frozen EUI case back to the reference case using "natural change."

2.3.1 Frozen EUI Case

The Reference Case includes many embedded assumptions derived from observed trends in the market and forward-looking expectations. The Reference Case allows end-use intensities to change over time as a function of:

- Changing mix of efficient versus inefficient equipment
- Changing use of building space (e.g., open plan office spaces)
- Changing mix of commercial activities (e.g., decrease in manufacturing and increase in service industries)
- New trends in consumption (e.g., increase in use of home electronics)
- Fuel switching (e.g., switching from electric appliances to gas appliances, or vice versa)

Modelling these considerations at the *measure* level would require a detailed adoption forecast for every measure in each customer segment. Typically, potential studies forecast measure-level adoption when looking at achievable market potential in the context of utility-sponsored energy efficiency programs. The achievable market potential hinges on expected levels of incentives, program budgets, and marketing/advertising levels, and there is adequate industry experience to provide substance to these forecasts. Conversely, it is notoriously difficult to estimate retrospectively what would have happened with measure adoption in the absence of energy efficiency programs (typically estimated through "net-to-gross" ratio studies), and it is even more difficult and uncertain to *forecast* such "natural" behavior at the measure level. Since program design is outside the scope of this study, and considering the inherent uncertainty in forecasting natural adoption at the measure level, Navigant did not pursue and create detailed measure adoption forecasts for technical and economic potential. Rather, the study uses a "frozen EUI" approach to estimate technical and economic potential combined with an estimation of aggregate end-use intensity trends to calculate the natural change expected at the end-use level.

Navigant calculated technical and economic potential assuming that EUIs are frozen at 2016 levels, ensuring consistency between modelled energy sales and measure characterization. For example, measure characterization assumes a fixed mix of efficient and inefficient measures over time—absent any energy efficiency programs—implying that end-use intensities do not change over time when calculating technical and economic potential. However, building stock changes (e.g., growth in the residential customer count or commercial floor space) can increase overall energy sales and assumed total equipment counts, which would impact the estimates for technical and economic potential.

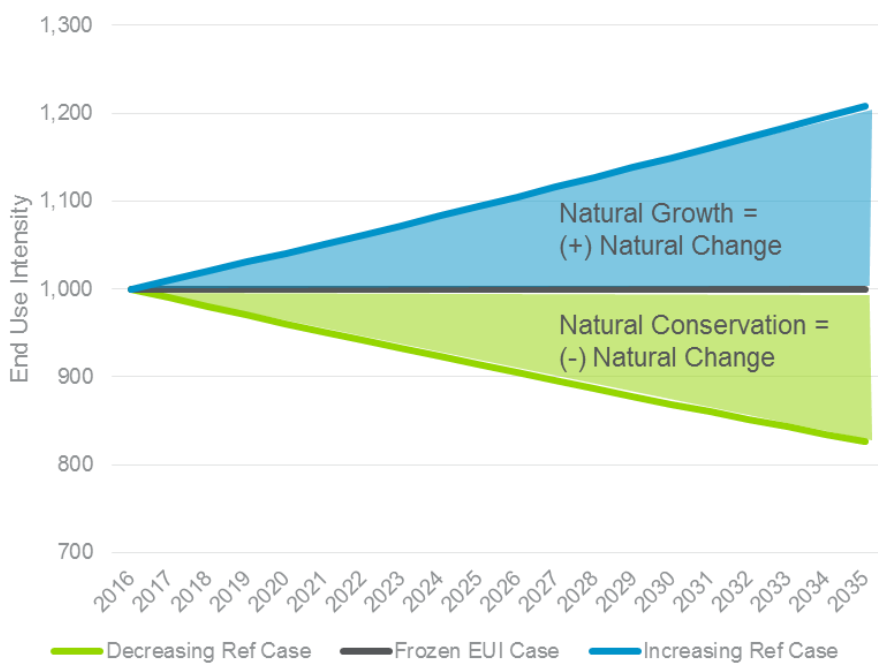
If end-use intensities are changing in the Reference Case, Navigant calculates what this study refers to as the "natural change"—defined in section 2.3.2—of EUIs over time. The team then applies this natural change to the technical and economic potential results using the frozen EUI to estimate the shift in potential savings.

2.3.2 Natural Change

Navigant's definition of "natural change" stems from two related concepts: natural conservation and natural growth. Natural *conservation* is a well-established concept in demand side management programs, and typically refers to actions taken by utility customers—in absence of utility-sponsored programs—to improve energy efficiency and reduce consumption. These actions are occurring naturally, with no influence from utilities or program administrators. Natural *growth* refers to actions taken by utility customers to *increase consumption* without the involvement of utility-guided programs. An example of natural growth is home electronics, where customers may be increasing their electric consumption (e.g., through addition of more televisions, computers, etc.) and causing an increase in the electronics end-use intensity.

This study captures the effects of natural conservation as well as natural growth within the end-use intensities, and defines these effects as "natural change." When natural change is positive for an end-use category, it reflects growth. When natural change is negative, it reflects conservation. Figure 2-9 illustrates this concept of natural change as it relates to the Reference Case end-use intensities as compared with the frozen EUI case.

Figure 2-9. Natural Change in Context of End-use Intensity



Source: Navigant

Navigant calculated natural change by subtracting the energy consumption in the frozen EUI case from the energy consumption in the Reference Case (see Table 2-32). Positive natural change results indicate a quantity of consumption missing from the frozen EUI case, whereas negative natural change indicates an overestimate of consumption in the frozen EUI case. Since Navigant estimates technical and economic potential based on the frozen EUI case, any missing consumption (i.e., positive natural change) is not included in the technical and economic results. Conversely, the model overestimates technical and economic potential when natural change is negative. Natural change helps provide a bound for the technical and economic potential forecasts, as it reflects one component of the uncertainty in energy savings from end-uses with expected changes to intensities over time.

Table 2-32. Illustrative Calculation of Natural Change

Year	Building Stock (homes)	Reference Case EUI (GJ/year-home)	Frozen Case EUI (GJ/year-home)	Reference Case Consumption (GJ/year)	Frozen EUI Case Consumption (GJ/year)	Natural Change (GJ/year)
	A	B	C	D = A x B	E = A x C	F = D - E
2016	1,000	70	70	70,000	70,000	0
2020	1,082	69	70	74,808	75,770	-962
2025	1,195	68	70	81,351	83,656	-2,305
2030	1,319	67	70	88,412	92,364	-3,952
2035	1,457	66	70	96,162	101,977	-5,815

Source: Navigant

Calculating technical and economic potential that includes natural change at the measure level would require measure-level adoption forecasts. As mentioned in section 2.3.1, Navigant's calculation of technical and economic potential does not involve forecasting adoption at the measure level. However, the team does estimate upper and lower bounds on the technical and economic potential inclusive of natural change at the end-use level.[25]

Navigant refined the frozen EUI technical potential by estimating savings potential percentages for natural change. The team calculated the technical potential as a percentage of consumption within a given end-use category, and applied that percentage to the natural change occurring within that end-use. For example, if the model concludes that technical potential for gas appliances is 30% of the total consumption from gas appliances, Navigant can apply that 30% to the natural change occurring within the appliance end-use to find a midway estimate between the technical potential and the upper or lower bound.

Table 2-33 builds off the example in Table 2-32 by estimating adjusted technical potential for the frozen EUI case by applying the example of 30% savings to the natural change estimates.

[25] Adding consumption from natural change directly to savings potential—instead of adding the expected savings from the natural change—typically exaggerates the upper or lower bound results.

Table 2-33. Illustrative Calculation of Bounds on Technical Potential (GJ/year)

Year	Frozen EUI Case Consumption	Natural Change	Tech Potent @ 30% Savings	Tech Potent + Nat Change	Tech Potent + 30% Nat Change
	A	B	C = A x 30%	D = B + C	E = B x 30% + C
2016	70,000	0	24,500	24,500	24,500
2020	75,770	-962	26,520	25,558	26,231
2025	83,656	-2,305	29,280	26,975	28,588
2030	92,364	-3,952	32,327	28,375	31,142
2035	101,977	-5,815	35,692	29,877	33,948

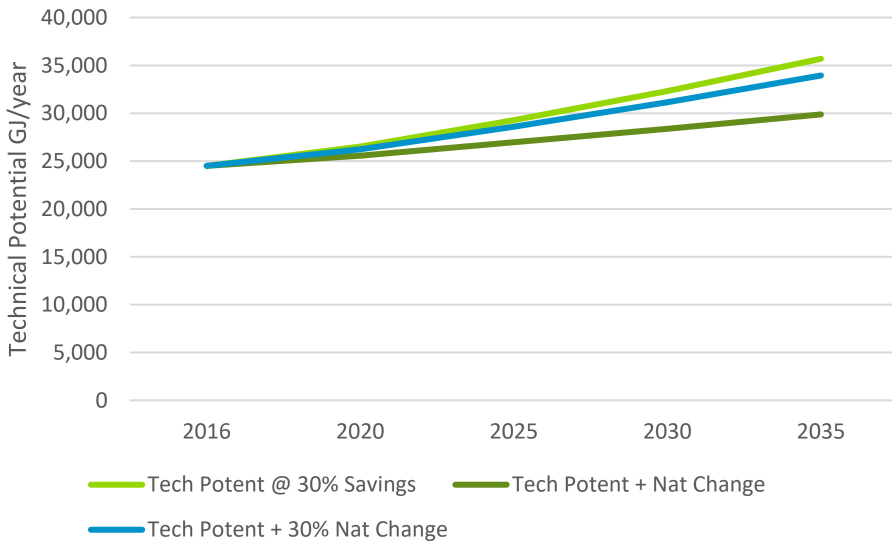
Source: Navigant

Where:

- **Frozen EUI Case Consumption** – the consumption forecast from the frozen EUI case
- **Natural Change** – the natural change between the frozen EUI case and the Reference Case
- **Tech Potent @ 30% Savings** – the technical potential assuming that efficient measures, in aggregate, lead to 30% savings as a percentage of the frozen EUI case's consumption
- **Tech Potent + Nat Change** – the sum of technical potential and natural change. Because natural change is negative, it reduces the total technical potential and indicates an extreme lower bound. This lower bound is overly conservative because it reduces the technical potential by the total natural change, rather than reducing potential by the overestimation of savings from natural change.
- **Tech Potent + 30% Nat Change** – the sum of technical potential and 30% of the natural change. Instead of reducing the technical potential by the total natural change, we reduce the potential by an estimate of the savings from natural change. The savings from natural change is a rough estimate based on the same 30% savings as a percentage of consumption used to estimate the technical potential. In reality, the percentage savings from natural change could be different from the 30% aggregate technical savings for the end-use.

Figure 2-10 plots the illustrative results from Table 2-33.

Figure 2-10. Illustrative Example of Technical Potential and Bounds Derived from Natural Change



Source: Navigant

At the end-use level, the technical potential plus the adjusted natural change (i.e., "Tech Potential + 30% Nat Change") will always fall between the technical potential and the bound created by adding natural change directly to the potential. At the sector level, however, this may not always be the case due to the aggregation of various end-use categories that may have positive or negative natural change. The natural change and estimated savings from natural change can be positive or negative and will cancel each other out, which leads to aggregate natural change and aggregate savings from natural change that can be in different proportions than was calculated at the end-use level. After aggregation, the technical potential plus the adjusted natural change may or may not fall between the technical potential and the bound.[26]

2.4 Measure Characterization

Navigant fully characterized over 200 measures across the BC Utilities' residential, commercial, and industrial sectors, covering electric and natural gas fuel types. The team prioritized measures with high impact, data availability, and most likely to be cost-effective as thresholds for inclusion into DSMSim™.

2.4.1 Measure List

Navigant developed a comprehensive measure list of energy efficiency measures likely to contribute to economic potential. The team reviewed current BC program offerings, previous CPR and other Canadian programs, and potential model measure lists from other jurisdictions to identify EE measures with the highest expected economic impact. The team supplemented the measure list using the Pennsylvania, Illinois, Mid-Atlantic, and Massachusetts technical resource manuals (TRMs), and partnered with CLEAResult to inform the list of industrial measures. Navigant worked with the BC Utilities to finalize the

[26] The effects of natural change by end-use category and customer segment are available in Appendix A.1.

measure list and ensure it contained technologies viable for future BC program planning activities. Appendix A.2 provides the final measure list and assumptions.

Working sessions with the BC Utilities revealed topics of note regarding the following measures:

- **Multi-Unit Residential Building (MURB) measures –** Navigant characterized both in-suite and common area measures for MURBs. In-suite measures are similar to other residential measures such as LED light bulbs, power strips, and televisions. Common area measures include space heating and hot water heating measures such as make-up air units, HVAC controls, central boilers, and roof deck insulation
- **Showerheads for MURBs –** The model currently uses material and labor costs for showerheads assuming the customer installs the measure themselves. However, BC Utilities offer a direct install program for showerheads in the MURB customer segment and may purchase showerheads at a wholesale price. Since the measure is already cost-effective without the direct install cost adjustments, this issue does not impact the technical and economic potential results. This issue would impact any further analysis of achievable potential, but that is outside of the scope of this study.

2.4.2 Measure Characterization Key Parameters

The measure characterization effort consisted of defining nearly 50 individual parameters for each of the 200 measures included in this study. This section defines the top 10 key parameters and how they impact technical and economic potential savings estimates.

1. **Measure Definition**: The team used the following variables to qualitatively define each characterized measure:
    - ***Replacement Type****:* Replacing the baseline technology with the efficient technology can occur in three variations:
        1. Retrofit (RET): where the model considers the baseline to be the existing equipment, and uses the energy and demand savings between the existing equipment and the efficient technology during technical potential calculations. RET also applies the full installed cost of the efficient equipment during the economic screening.
        2. Replace On Burnout (ROB): where the model considers the baseline to be the code-compliant technology option, and uses the energy and demand savings between the current code option and the efficient technology during technical potential calculations. ROB also applies the incremental cost between the efficient and code-compliant equipment during the economic screening.
        3. New Construction (NEW): where the model considers the baseline to be the least cost, code-compliant option, and uses the energy and demand savings between this specific current code option and the efficient technology during technical potential calculations. NEW also applies the incremental cost between the efficient and code-compliant equipment during the economic screening.
    - ***Baseline Definition***: Describes the baseline technology (e.g., the existing equipment).
    - ***EE Definition***: Describes the efficient technology set to replace the baseline technology.
    - ***Unit Basis***: The normalizing unit for energy, demand, cost, and density estimates.

2. **Regional, Sector, and End-use Mapping:** The team mapped each measure to the appropriate end-uses, customer segments, sectors, and climate regions across the BC Utility's service territory. Section 2.1 describes the breakdown of customer segments with each sector in greater detail. Navigant characterized weather dependent measures into four regions: Lower Mainland, Southern Interior, Vancouver Island, and Northern BC to account for changes in climate that impact energy savings.
3. **Annual Energy Consumption:** The annual energy consumption in kilowatt-hours (kWh) or mega joules (MJ) for each of the base and energy-efficient technologies
4. **Coincident Electric Demand**: The peak coincident demand in kilowatts (kW) for each of the base and energy-efficient technologies
5. **Fuel Type Applicability Multipliers**: Assigns the percentage of electric fuel type to measures with electric fuel type such as water heaters and space heating equipment
6. **Measure Lifetime:** The lifetime in years for the base and energy-efficient technologies. The Base and EE lifetime only differ in instances where the two cases represent inherently different technologies, such as light-emitting diodes (LEDs) or compact fluorescent lamp (CFL) bulbs compared to a baseline incandescent bulb.
7. **Incremental Costs:** The incremental cost between the assumed baseline and efficient technology, using the following variables:
    - ***Base Costs***: The cost of the base equipment, including both material and labor costs
    - ***EE Costs:*** The cost of the energy-efficient equipment
8. **Technology Densities**: This study defines "density" as the penetration or saturation of the baseline and efficient technologies across the BC Utility's territory. For residential measures, these saturations are on a per home basis, for commercial they are per 1,000 square meters of building space, and for industrial they are based on energy consumption.[27]
    - ***Base Initial Saturation***: The saturation of the baseline equipment in a territory for a given customer segment
    - ***EE Initial Saturation:*** The saturation of the efficient equipment in a territory for a given customer segment
    - ***Total Maximum Density***: The total number of both the baseline and efficient units in a territory for a given technology
9. **Technology Applicability:** The percentage of the base technology that can be reasonably and practically replaced with the specified efficient technology. For instance, occupancy sensors are only practical for certain interior lighting fixtures (an applicability less than 1.0), while all existing incandescent exit signs can be replaced with efficient LED signs (an applicability of 1.0).
10. **Competition Group**: The team combined efficient measures competing for the same baseline technology density into a single competition group to avoid the double-counting of savings. (Section 3.1.3 provides further explanation on competition groups.)

2.4.3 Measure Characterization Approaches and Sources

This section provides approaches and sources for the main measure characterization variables. The BC Utilities and Technical Advisory Committee reviewed Navigant's measure assumptions for each sector

[27] Navigant sourced density estimates from the residential end-use survey (REUS), commercial end-use survey (CEUS), BC Utility program data, and other related secondary resources.

and provided inputs to refine measure assumptions. Navigant also worked with CLEAResult to further customize industrial measures.

2.4.3.1 Energy and Demand Savings

Navigant took three general bottom-up approaches to analyzing residential and commercial measure energy and demand savings:

1. **TRM Standard Algorithms:** Navigant used TRM standard algorithms for unit energy savings and demand savings calculations for the majority of measures. FortisBC Gas provided coincidence factors for the residential sector.
2. **Program Evaluation Data:** Where available, Navigant used measure specific program evaluation data from the BC Utilities to inform energy savings.
3. **Engineering Analysis:** Navigant used appropriate engineering algorithms to calculate energy savings for any measures not included in BC Utility programs or available TRMs.

2.4.3.2 Incremental Costs

Navigant relied primarily on BC Utility provided program data and TRM data for incremental cost data. Navigant conducted secondary research and used other publicly available cost data sources such as the Database for Energy Efficient Resources (DEER), ENERGY STAR®, RSMeans, and the Michigan Energy Measures Database (MEMD) for all other cost data.[28]

2.4.3.3 Building Stock and Densities

The residential end-use survey (REUS) and commercial end-use survey (CEUS) provided building stock data for the BC Utility's service territory, enabling Navigant to characterize residential and commercial measures. The measure characterization workbooks include full documentation of assumptions applied to each measure. Navigant also used the REUS and CEUS reports to develop measure densities by customer segment. For measures not included in REUS and CEUS, Navigant reviewed other data sources such as NRCan for estimates.

2.4.3.4 Industrial Measures

The industrial sector measure characterization deploys a top-down approach, which differs from the residential and commercial sectors. Navigant characterized industrial measures as a percentage reduction of the customer segment and/or end-use consumption. CLEAResult evaluated past and recent project data from the BC Utilities to estimate the energy savings and incremental cost for all industrial measures.

[28] For example, measure costs for new construction whole-building measures were gathered from a variety of sources. For residential measures, Navigant received data from the BC Utilities, and performed secondary research for measures where data was not provided. For Commercial whole-building new construction measures, Navigant leveraged RSMeans new construction cost data for Vancouver, BC and supplemented those costs with data from LEED and green building reports that reported incremental costs associated with higher energy savings. Navigant determined energy savings and costs for the discrete new construction measures in their entirety without analyzing what bundles of other CPR measures would make up a new construction measure.

2.4.4 Codes and Standards Adjustments

Natural Resources Canada publishes all energy efficiency regulations. Amendment 14[29] states that the intent of the amendment is to "align with energy efficiency standards in force or soon to be in force in the U.S." The U.S. Department of Energy (DOE) Technical Support Documents (TSD)[30] contains information on energy and cost impact of each appliance standard. Engineering analysis is available in Chapter 5 of the TSD; energy use analysis is available in Chapter 7, and cost impact is available in Chapter 8.

As these codes and standards take effect, the energy savings from existing measures impacted by these codes and standards diminishes. Navigant accounts for the impact of codes and standards by baseline energy and cost multipliers—sourced from the DOE's analysis—which reduce the baseline equipment consumption starting from the year a particular code or standard takes effect.[31] The baseline cost of an efficient measure impacted by codes and standards will often increase upon implementation of the code. Technical and economic savings potential presented in the model results includes savings potential from codes and standards, and measure-level results show their contribution to overall potential. Savings potential results do not consider fuel switching.[32]

The City of Vancouver By-Law (VBBL) varies from the National Building Code for insulation measures and water heating equipment. Navigant did not estimate the impact of the VBBL as the model segmentation does not drill down to city level granularity. City specific stock and sales data are not available to estimate the impact of the VBBL. Navigant expects the impact of VBBL to be small compared to the EE potential of the entire province. The majority of energy efficient savings from Part 9 buildings come from existing buildings in the near future. The VBBL does not require a specific upgrade level if the retrofit project is less than $5,000, which represents most residential measures in the model. Part 3 Buildings from VBBL references the National Building Code and ASHRAE 90.1 standards. The model assumes the National Building Code as the baseline for Part 3 buildings, therefore, the discrepancy in impact is minimal for commercial buildings.

29 Natural Resources Canada Amendment 14 to the Energy Efficiency Regulations. Access at: http://www.nrcan.gc.ca/energy/regulations-codes-standards/18437

30 Appliance standards rulemaking notices and Technical Support Documents can be found at: http://energy.gov/eere/buildings/current-rulemakings-and-notices

31 Navigant uses a similar method of applying multipliers for changes in measure economics over time if sufficient data exists for extrapolating such changes, e.g. reducing measure costs over time for Commercial High Efficiency Gas-Fired Condensing Rooftop Units (RTU).

32 For example, if a natural gas heated new home is upgraded from the code-mandated performance level to an R-2000 home, the savings potential analysis assumes that this home remains natural gas heated.

3. TECHNICAL POTENTIAL FORECAST

This section describes Navigant's approach to calculating technical potential and presents the results for FortisBC Gas's service territory.

3.1 Approach to Estimating Technical Potential

This study defines technical potential as the total energy savings available assuming that all installed measures can *immediately* be replaced with the "efficient" measure/technology—wherever technically feasible—regardless of the cost, market acceptance, or whether a measure has failed and must be replaced.

Navigant used its DSMSim model to estimate the technical potential for demand side resources in the regions considered for this study. Navigant's modelling approach considers an energy-efficient measure to be any change made to a building, piece of equipment, process, or behaviour that could save energy. The savings can be defined in numerous ways, depending on which method is most appropriate for a given measure. Measures like condensing water heaters are best characterized as some fixed amount of savings per water heater; savings for measures like commercial automated building controls are typically characterized as a percentage of customer segment consumption; and measures like industrial ventilation heat recovery are characterized as a percentage of end-use consumption. The model can appropriately handle savings characterizations for all three methods.

The calculation of technical potential in this study differs depending on the assumed measure replacement type. Technical potential is calculated on a per-measure basis and includes estimates of savings per unit, measure density (e.g., quantity of measures per home) and total building stock in each service territory. The study accounts for three replacement types, where potential from retrofit and replace-on-burnout measures are calculated differently from potential for new measures. The formulae used to calculate technical potential by replacement type are shown below.

3.1.1 New Construction Measures

The cost of implementing new construction (NEW) measures is incremental to the cost of a baseline (and less efficient) measure. However, new construction technical potential is driven by equipment installations in new building stock rather than by equipment in existing building stock.[33] New building stock is added to keep up with forecast growth in total building stock and to replace existing stock that is demolished each year. Demolished (sometimes called replacement) stock is calculated as a percentage of existing stock in each year, and this study uses a demolition rate of 0.5% per year for residential and commercial stock and 0% for industrial stock. New building stock (the sum of growth in building stock and replacement of demolished stock) determines the incremental annual addition to technical potential, which is then added to totals from previous years to calculate the total potential in any given year. The equations used to calculate technical potential for new construction measures are provided below.

Equation 1. Annual Incremental NEW Technical Potential (AITP)

$AITP_{YEAR}$ = New $Buildings_{YEAR}$ (e.g., buildings/year[34]) X Measure Density (e.g., widgets/building) X $Savings_{YEAR}$ (e.g., GJ/widget) X Technical Suitability (dimensionless)

Equation 2. Total NEW Technical Potential (TTP)

$$TTP = \sum_{YEAR=2016}^{YEAR=2035} AITP_{YEAR}$$

3.1.2 Retrofit and Replace-on-Burnout Measures

Retrofit (RET) measures, commonly referred to as advancement or early-retirement measures, are replacements of existing equipment before the equipment fails. Retrofit measures can also be efficient processes that are not currently in place and that are not required for operational purposes. Retrofit measures incur the full cost of implementation less a deferred replacement credit, rather than incurring a cost incremental to some other baseline technology or process because the customer could choose not to replace the measure and would therefore incur no costs.[35] In contrast, replace-on-burnout (ROB) measures, sometimes referred to as lost-opportunity measures, are replacements of existing equipment that have failed and must be replaced, or they are existing processes that must be renewed. Because the failure of the existing measure requires a capital investment by the customer, the cost of implementing replace-on-burnout measures is always incremental to the cost of a baseline (and less efficient) measure.

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[33] In some cases, customer-segment-level and end-use-level consumption are used as proxies for building stock. These consumption figures are treated like building stock in that they are subject to demolition rates and stock-tracking dynamics.

[34] Units for new building stock and measure densities may vary by measure and customer segment (e.g., 1,000 square meters of building space, number of residential homes, customer-segment consumption, etc.)

[35] This study's approach subtracts a deferred replacement credit from the full cost of implementation whenever the average remaining useful life of currently installed measures can be reasonably approximated. This methodology leads to a similar outcome as subtracting a salvage value from the full incremental cost. For more discussion of deferred replacement credits, see "Retrofit Economics 201: Correcting Commons Errors in Demand-Side Management Cost-Benefit Analysis" by Rachel Brailove, John Plunkett, and Jonathan Wallach.

Retrofit and replace-on-burnout measures have a different meaning for technical potential compared with new construction measures. In any given year, we use the entire building stock for the calculation of technical potential.[36] This method does not limit the calculated technical potential to any pre-assumed rate of adoption of retrofit measures. Existing building stock is reduced each year by the quantity of demolished building stock in that year and does not include new building stock that is added throughout the simulation. For retrofit and replace-on-burnout measures, annual potential is equal to total potential, thus offering an *instantaneous* view of technical potential. The equation used to calculate technical potential for retrofit and replace-on-burnout measures is provided below.

Equation 3. Annual/Total RET/ROB Technical Savings Potential

Total Potential = Existing Building Stock$_{YEAR}$ (e.g., buildings[37]) X Measure Density (e.g., widgets/building) X Savings$_{YEAR}$ (e.g., GJ/widget[38]) X Technical Suitability (dimensionless)

3.1.3 Competition Groups

Navigant's modelling approach recognizes that some efficient technologies will compete against each other in the calculation of potential. The study defines "competition" as an efficient measure competing for the same installation as another efficient measure. For instance, a consumer has the choice to install a condensing or a near-condensing water heater, but not both. These efficient technologies compete for the same installation.

General characteristics of competing technologies used to define competition groups in this study include the following:

- Competing efficient technologies share the same baseline technology characteristics, including baseline technology densities, costs, and consumption
- The total (baseline plus efficient) measure densities of competing efficient technologies are the same
- Installation of competing technologies is mutually exclusive (i.e., installing one precludes installation of the others for that application)
- Competing technologies share the same replacement type (RET, ROB, or NEW)

To address the overlapping nature of measures within a competition group, Navigant's analysis only selects one measure per competition group to include in the *summation* of technical potential across measures (e.g., at the end-use, customer segment, sector, service territory, or total level). The measure with the largest energy savings potential in a given competition group is used for calculating total technical potential of that competition group. This approach ensures that the aggregated technical potential does not double-count savings. However, the model still calculates the technical potential for

[36] In some cases, customer-segment-level and end-use-level consumption/sales are used as proxies for building stock. These consumption/sales figures are treated like building stock in that they are subject to demolition rates and stock-tracking dynamics.
[37] Units for building stock and measure densities may vary by measure and customer segment (e.g., 1,000 square meters of building space, number of residential homes, customer-segment consumption/sales, etc.).
[38] To determine energy savings, Navigant consistently applies one measure-specific baseline across the entire measure life of each respective measure.

each individual measure outside of the summations.

3.2 Technical Potential Results

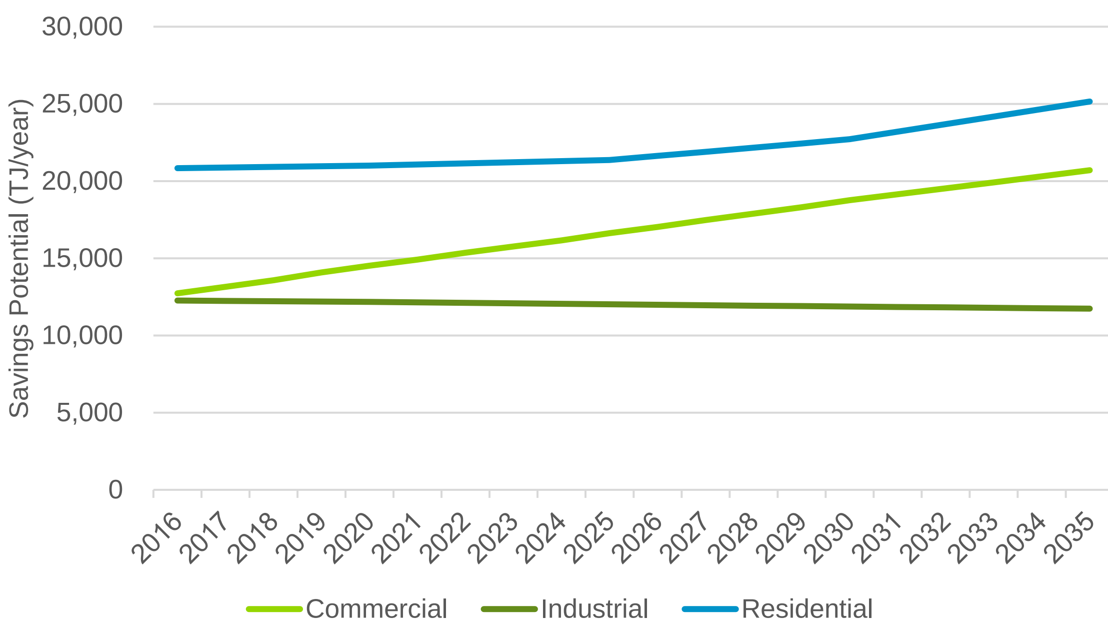
This section provides the technical savings potential calculated by the model at varying levels of aggregation. Results are shown by sector, customer segment, end-use category, and highest-impact measures. The section concludes with a review of natural change and its impacts on technical potential.

3.2.1 Results by Sector

Figure 3-1 shows the total gas energy technical savings potential split by sector, and Table D-3 in Appendix D provides the associated data. As noted in previous sections, although apartments were included in the residential sector for the Base Year and Reference Case analyses, technical and economic savings potential from apartments are reported with the commercial sector to align with FortisBC Gas's categorization for conservation programs.

The increased rate of growth in residential technical potential beginning around 2025 is due to improvements in whole-building energy efficiency practices for single-family detached homes. The upward trend in the commercial sector stems largely from high-impact whole-building new construction measures as well. Of the largest contributing industrial customer segments, reductions in potential from greenhouses and food and beverage outpace the increase in potential from manufacturing, leading to a slight decrease in industrial potential over the forecast period.

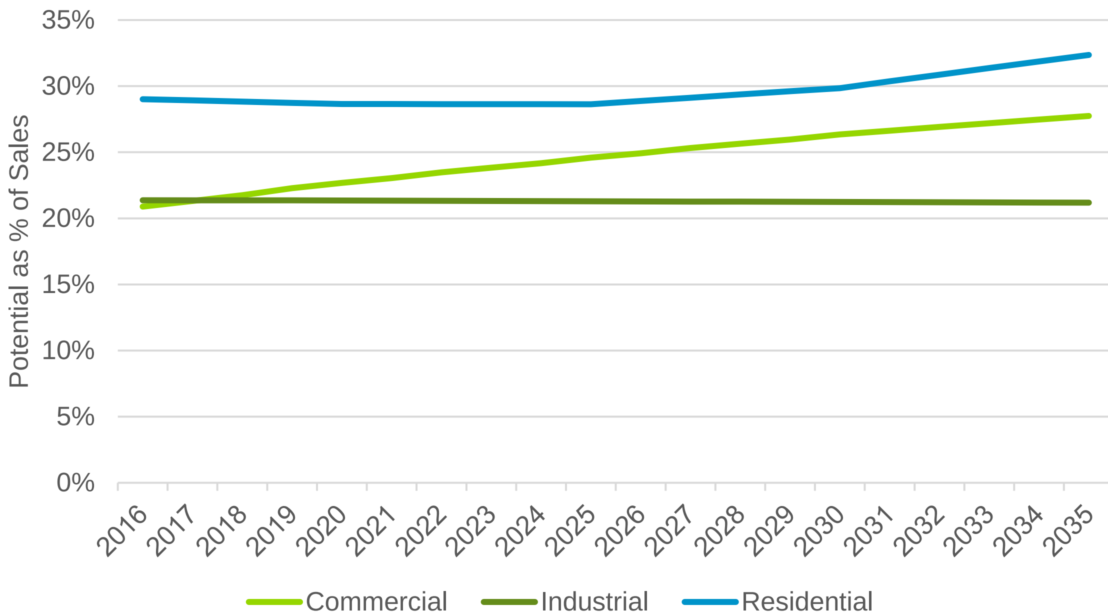
Figure 3-1. Gas Energy Technical Savings Potential by Sector (TJ/year)



Source: Navigant

Figure 3-2 shows the gas energy technical savings potential as a percentage of each sector's total forecasted consumption. Table D-4 in Appendix D provides the associated data. The percentages reflect a weighted average savings among measures applicable to existing building stock and new building stock constructed during the study period. As such, upward-sloping sectors indicate that savings opportunities—on a percentage of consumption basis—are larger in new construction than existing construction. Although growth in total residential consumption declines over time, the high impact new construction measures—several of which were not available until later years—help the residential percentages recover an upward trend by 2026. The commercial sector benefits from new construction measures with significant savings. New construction opportunities in the industrial sector are limited because many of the customer segments show no growth in the consumption forecasts. As such, the vast majority of savings from the industrial sector come from existing facilities rather than facilities constructed during the forecast period.

Figure 3-2. Gas Energy Technical Savings Potential by Sector as a Percent of Sector Consumption (%)

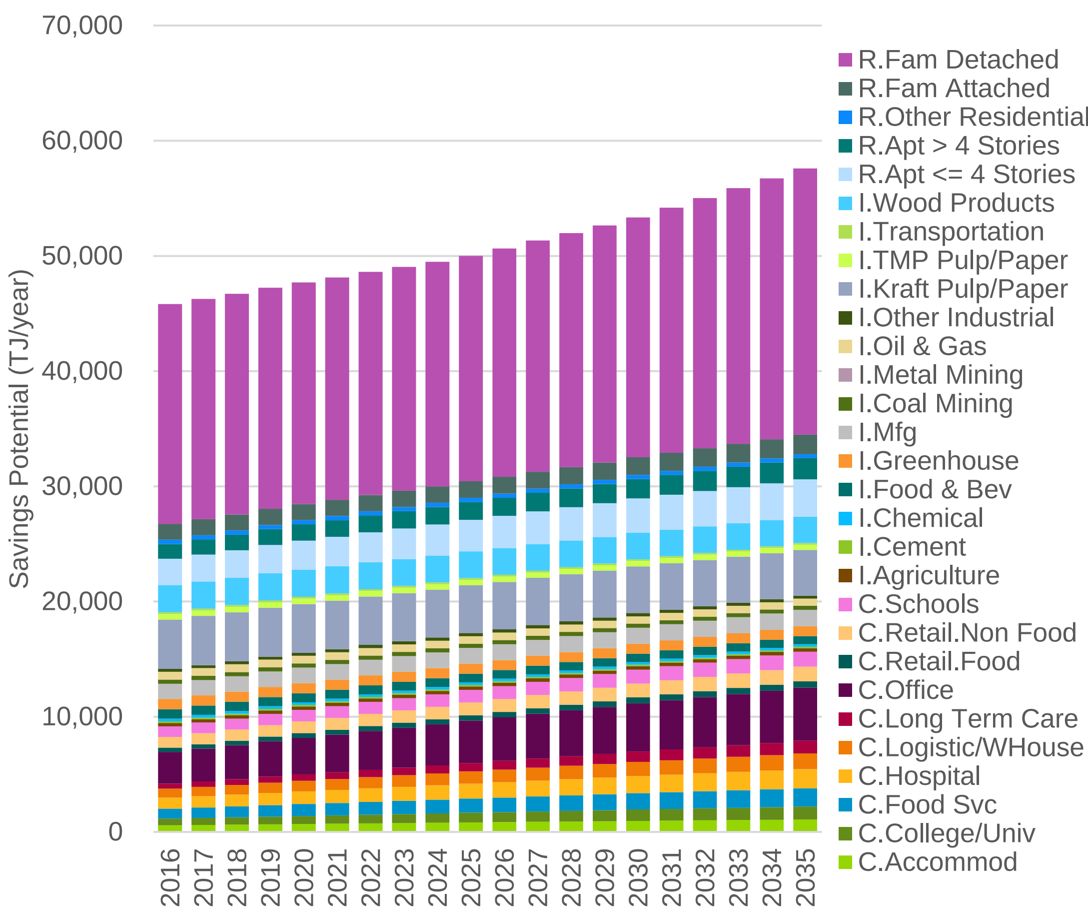


Source: Navigant

3.2.2 Results by Customer Segment

Figure 3-3 shows the gas energy technical savings potential across all customer segments, and Table D-5 in Appendix D provides the associated data.[39] This figure highlights the large savings potential of the residential detached single-family home customer segment relative to other customer segments. The growth in potential for the detached single-family home segment is the largest contributor to the increase in savings potential in the last ten years of the study. This coincides with the improvements to efficient home construction practices that reach maturity toward the end of the forecast. The savings opportunities from new construction buildings (45% above code) boost potential for most commercial segments. [40]

Figure 3-3. Gas Energy Technical Savings Potential by Customer Segment (TJ/year)



Source: Navigant

[39] The LNG segment does not appear in this figure because FortisBC Gas does not supply natural gas to LNG facilities. Gas sales to LNG facilities are zero across the Reference Case forecast, hence, the savings potential is also zero.

[40] Note that whole-building, new construction measures do not necessarily align with provincial energy *step* codes. For example, while the new construction 30% and 45% better than code measures were selected to broadly align with step codes, savings attributed to these measures are calculated based on overall energy consumption, and not based on a particular building code requirement stated in the step codes.

Figure 3-4, Figure 3-5, and Figure 3-6 break out the gas energy technical savings potential for each sector by customer segment. For the residential sector, detached single-family homes represents the largest savings potential of any customer segment by far, accounting for 91% of the total savings potential. Offices and apartments provide approximately half of the savings in the commercial sector. In general, the distribution of savings among customer segments aligns well with the distribution of gas consumption among segments. In the industrial sector, kraft pulp and paper accounts for the largest share of energy savings at 35%. Wood products and manufacturing also provide significant savings among industrial segments.

Figure 3-4. Residential Gas Energy Technical Potential Customer Segment Breakdown in 2025

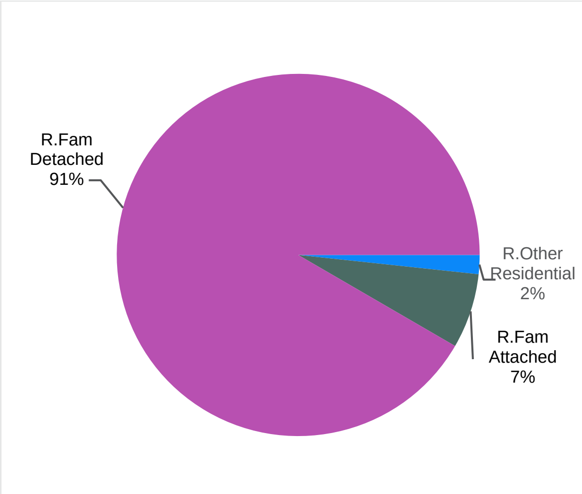


Figure 3-5. Commercial Gas Energy Technical Potential Customer Segment Breakdown in 2025

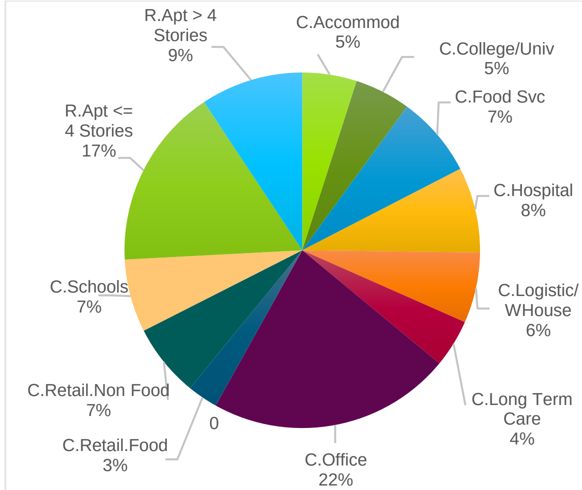
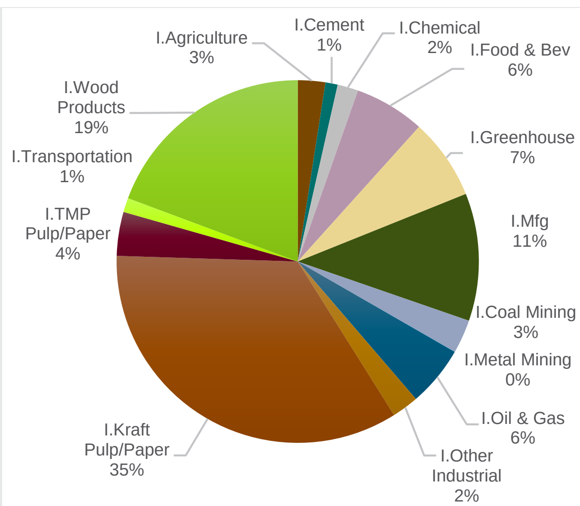


Figure 3-6. Industrial Gas Energy Technical Potential Customer Segment Breakdown in 2025

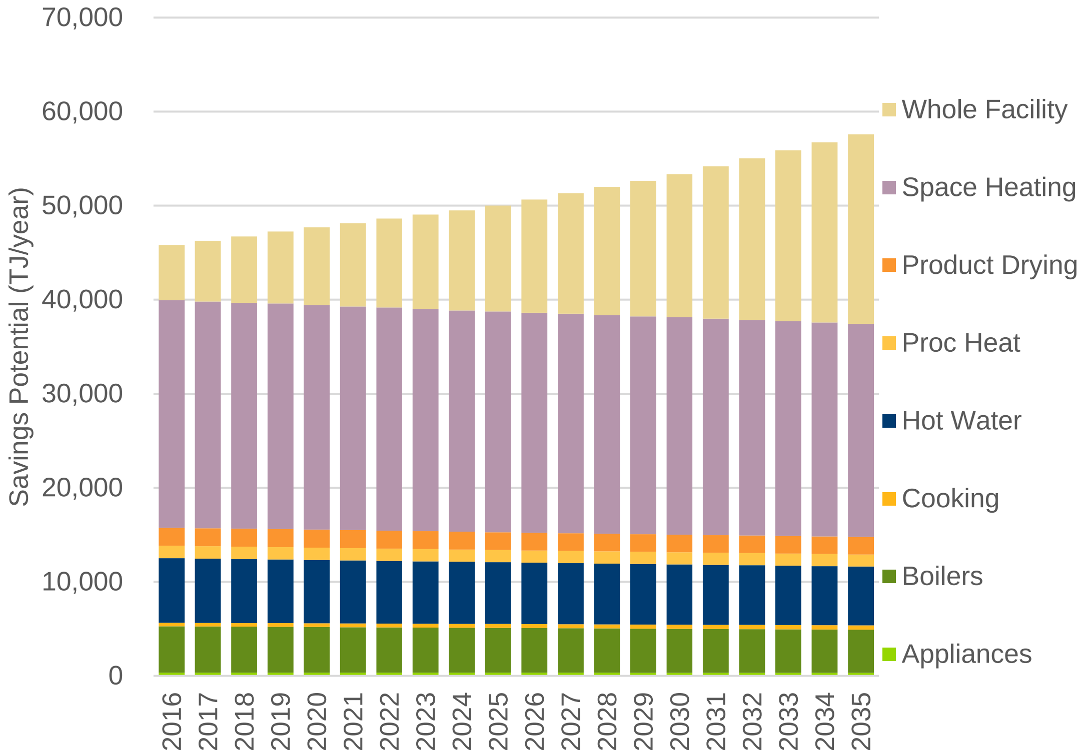


Source: Navigant

3.2.3 Results by End-use

Figure 3-7 shows the gas energy technical savings potential across end-uses. The data used to generate the figure are in Table D-6 in Appendix D. The dominant end-uses are space heating and whole facility. The bulk of savings potential in the space heating end-use come from smart thermostats. The whole facility end-use primarily consists of savings from comprehensive whole-facility new construction practices and energy management programs. As such, these whole-facility savings implicitly include savings from multiple end-uses.

Figure 3-7. Gas Energy Technical Savings Potential by End-Use across sectors (TJ/year)



Source: Navigant

Figure 3-8, Figure 3-9, and Figure 3-10 break out the gas energy technical savings potential for each sector. The space heating and hot water end-uses dominate the residential sector, together accounting for 87% of the total savings potential. In the residential sector, smart thermostats and efficient fireplaces are the two largest space heating measures, while condensing and non-condensing gas tankless water heaters contribute significantly to the hot water end-use's savings.[41] In the commercial sector, the space heating and whole facility end-uses account for roughly 89% of the total technical savings potential. Savings in commercial space heating come largely from wall insulation, HVAC control upgrades, and condensing make-up air units. Boilers measures, which are included in the hot water and space heating end-uses account for roughly 13% of the technical potential. The whole-facility end-use's savings are driven by new building construction practices that are at least 45% above code. While the appliances end-use is not inherent to the commercial sector, the inclusion of apartment buildings in the commercial sector means that savings from appliances are also reported in the commercial sector. In the industrial sector, the boiler end-use plays the largest role, consisting of high savings measures like process boiler load control and heat recovery systems.

[41] Note that efficient fireplaces and envelope upgrade measures are classified as space heating measures.

Figure 3-8. Residential Gas Energy Technical Potential End-Use Breakdown in 2025

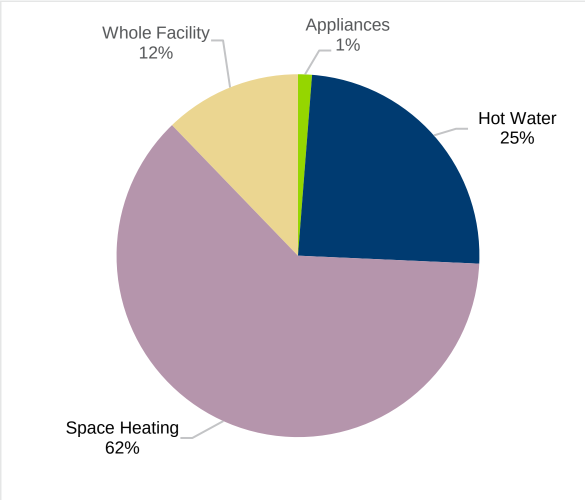


Figure 3-9. Commercial Gas Energy Technical Potential End-Use Breakdown in 2025

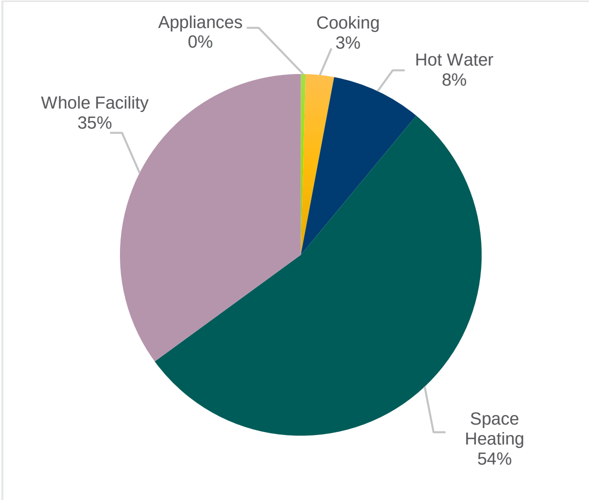
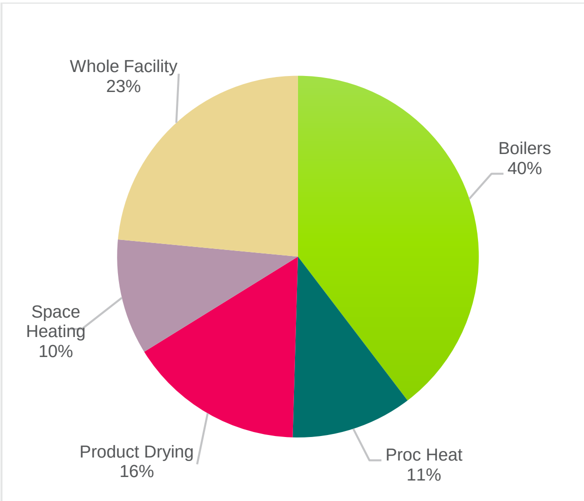


Figure 3-10. Industrial Gas Energy Technical Potential End-Use Breakdown in 2025[42]



Source: Navigant

3.2.4 Results by Measure

The measure-level savings potential shown in Figure 3-11 is prior to adjustments made to competition groups. Some of the measures shown here are not included in the customer segment, end-use, sector and portfolio totals because they are not the measures with the greatest savings potential for their respective competition group.

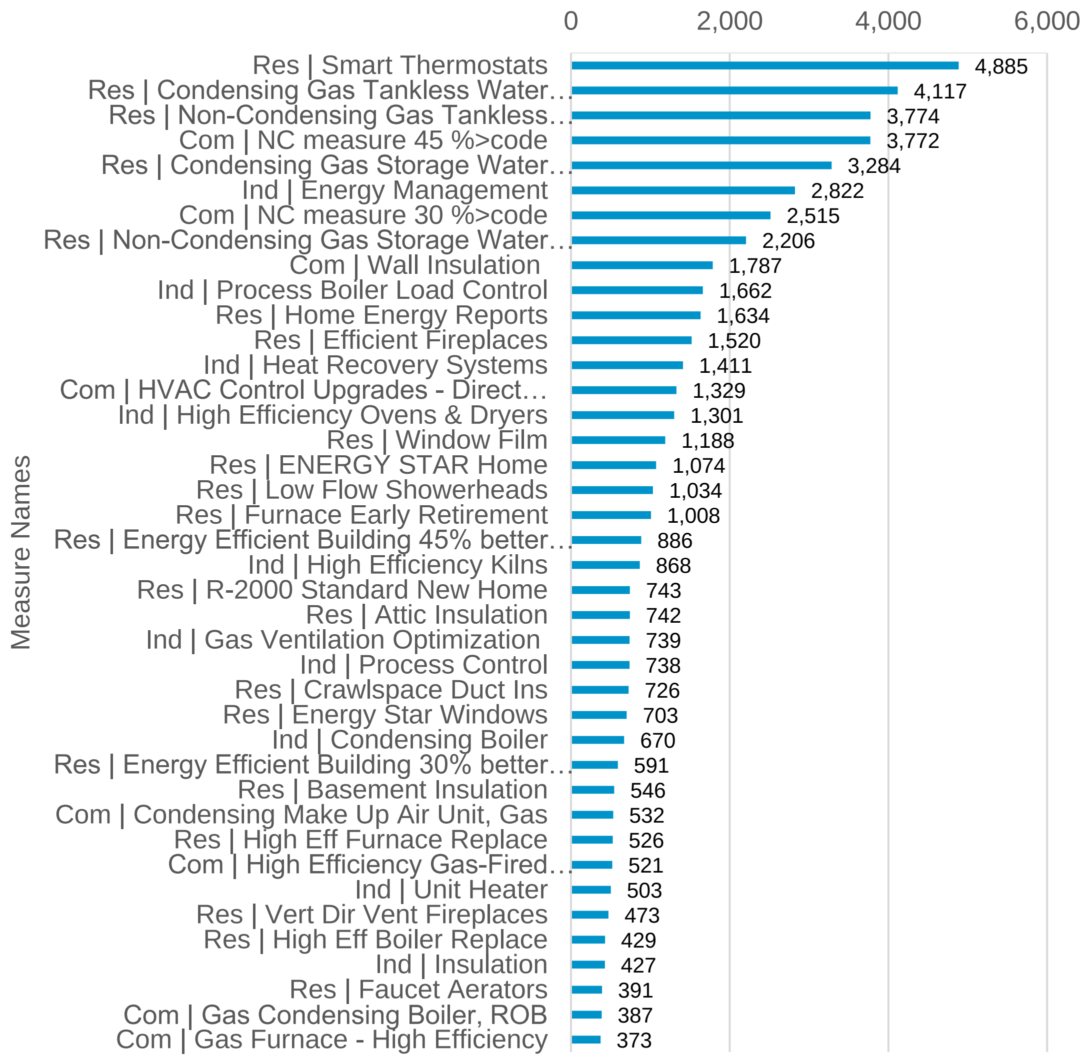
[42] Note that no natural gas energy savings measures are assigned to the *industrial process* end use. As a result, no energy savings potential is reported for this end use.

The figure presents the top forty measures ranked by their gas energy technical savings potential in 2025. Wherever a group of measures were similar in nature, Navigant consolidated their potential into a representative measure name to produce a more succinct view at the measure level. For example, the energy management potential in the figure represents the technical savings potential for industrial energy management and commercial energy management, which encompass energy savings opportunities unique to each sector.

When code-change measures become applicable, they “steal” savings potential from other related measures that may display significant savings in absence of the code. In this way, the sum of the total savings potential between the code and the related energy-efficient measure is the same before and after a code takes effect. This ensures there is no double counting of savings from codes and the energy efficient measures impacted by the code.

The top ten measures come from the space heating, whole-facility, and hot water end-uses. However, non-condensing gas tankless water heaters, new construction building practices at least 30% better than code, and condensing storage water heaters are in competition with other higher impact measures, so their savings do not contribute to aggregate potential results. Smart thermostats and energy management are two of the top ten measures that provide savings in multiple sectors. Thermostats contribute to residential and commercial savings.

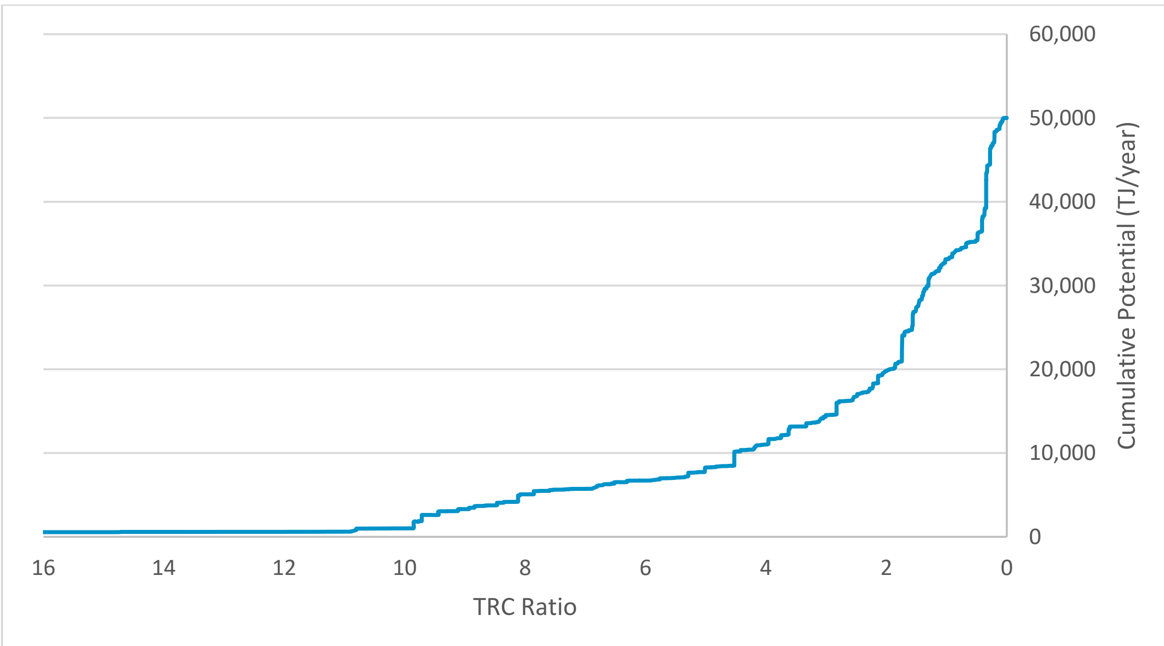
Figure 3-11. Top 40 Measures for Gas Energy Technical Savings Potential in 2025 (TJ/year)



Source: Navigant

Figure 3-12 provides a supply curve of technical savings potential versus the TRC ratio for all measures considered in the study. Navigant truncated this curve only to show TRC ratios below 16, although the full curve would extend well beyond this ratio. Much of the potential with TRC ratios larger than 16 come from new codes and standards measures, which the team modelled as having zero costs and infinite TRC ratios. There is a distinct “elbow” in the supply curve at a TRC ratio of about 4.0, indicating the majority of savings coming from measures with TRC ratios less than 4.0. For TRC ratios below 4.0, cumulative potential increases to about 33,000 TJ/year at a ratio of 1.0. Measures with TRC ratios less than 1.0 are non-cost-effective and do not appear in the economic potential.

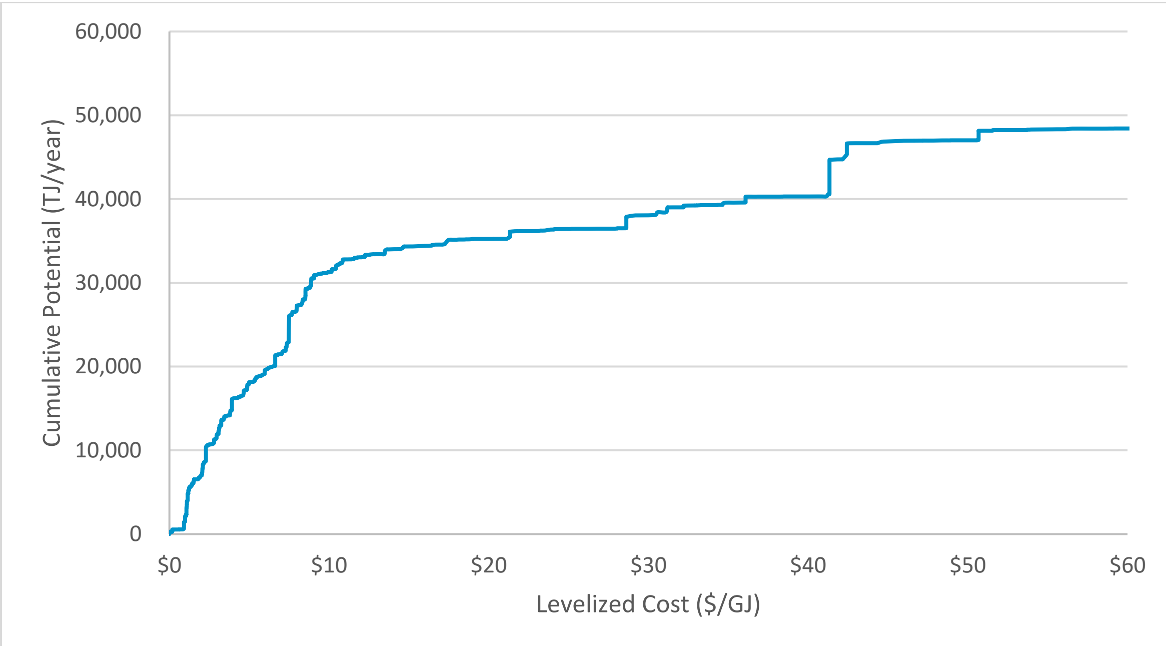
Figure 3-12. Supply Curve of Gas Energy Technical Potential (TJ/year) vs. TRC Ratio (ratio) in 2025



Source: Navigant

Figure 3-13 provides a supply curve of savings potential versus levelized cost of savings in $/GJ for all measures considered in the study. Navigant truncated this curve to show only those measures with a levelized cost less than $60/GJ, though the full curve would extend beyond this to measures with costlier savings. The savings potential having a cost of $0/GJ is due to code-change measures, which Navigant modelled as having zero costs. Total cumulative savings potential increase steadily to just over 48,000 TJ/year at a cost of $60/GJ, beyond which costlier modes of savings add minimal cumulative potential.

Figure 3-13. Supply Curve of Gas Energy Technical Potential (TJ/year) vs. Levelized Cost of Savings ($/GJ) in 2025



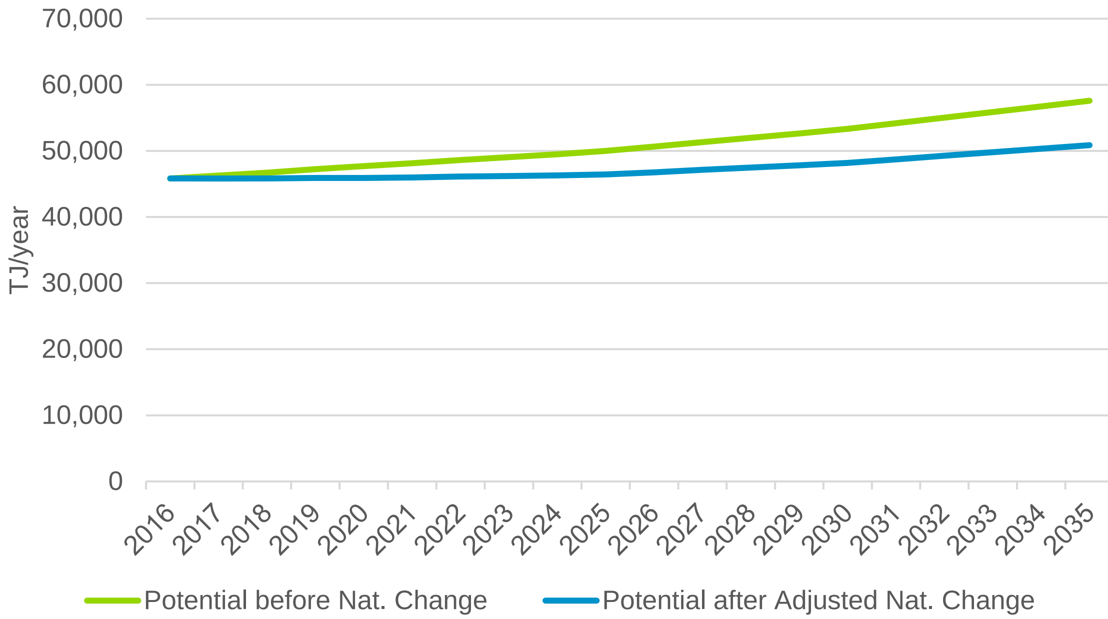
Source: Navigant

3.2.5 Adjustments for Natural Change

As discussed in section 2.3.2, Navigant estimated natural change to account for differences in end-use consumption in the Reference Case compared to the frozen EUI case. Natural change accounts for changes in consumption that are naturally occurring and are not the result of utility-sponsored programs or incentives. Adding natural change to the frozen EUI case required adjusting the technical potential forecasts accordingly.

Figure 3-14 shows the total technical potential across all sectors before and after adjusting for natural change. The total natural change across all sectors is negative in all years, indicating an overall natural tendency toward increased energy conservation rather than growth. The adjusted natural change is computed by accounting for the percentage of the gross natural change that could reasonably be attributed to energy savings for each end-use. On average across the study period, the technical potential after adjusted natural change is roughly 7% lower than the potential prior to natural change.

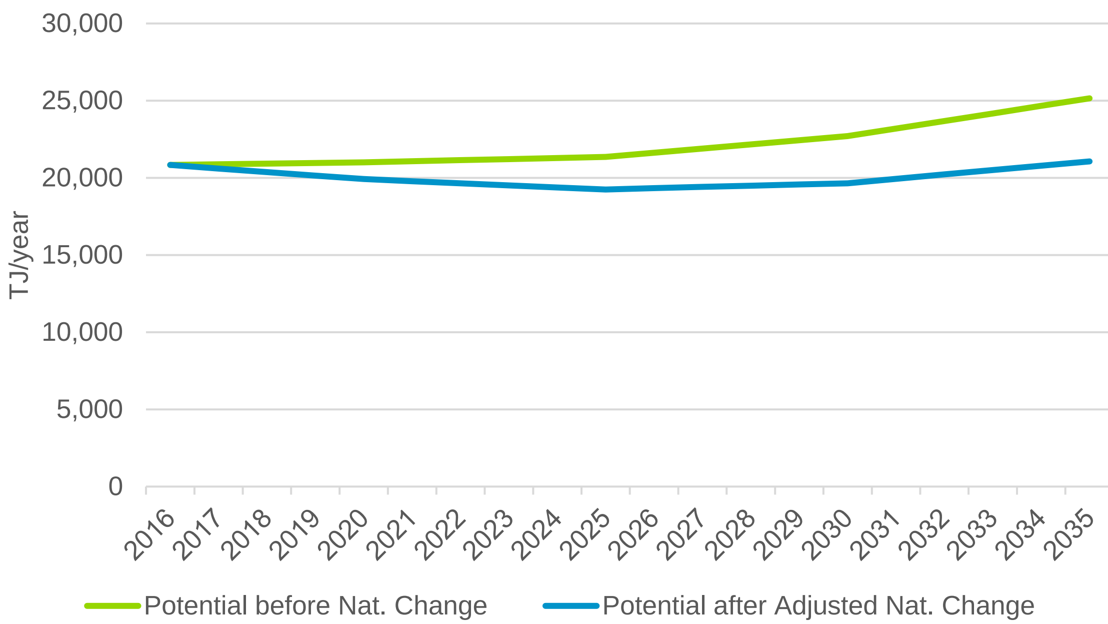
Figure 3-14. Gas Energy Technical Savings Potential with Natural Change – All Sectors (TJ/year)



Source: Navigant

Figure 3-15 shows the effect of adjustments for natural change in the residential sector. Space heating and hot water end-uses account for significant natural conservation. In contrast, appliances account for a minor amount of natural growth. When aggregated to the sector level, natural conservation has a much larger effect than natural growth. On average across the study period, the residential technical potential after adjusted natural change is roughly 10% lower than the potential prior to natural change.

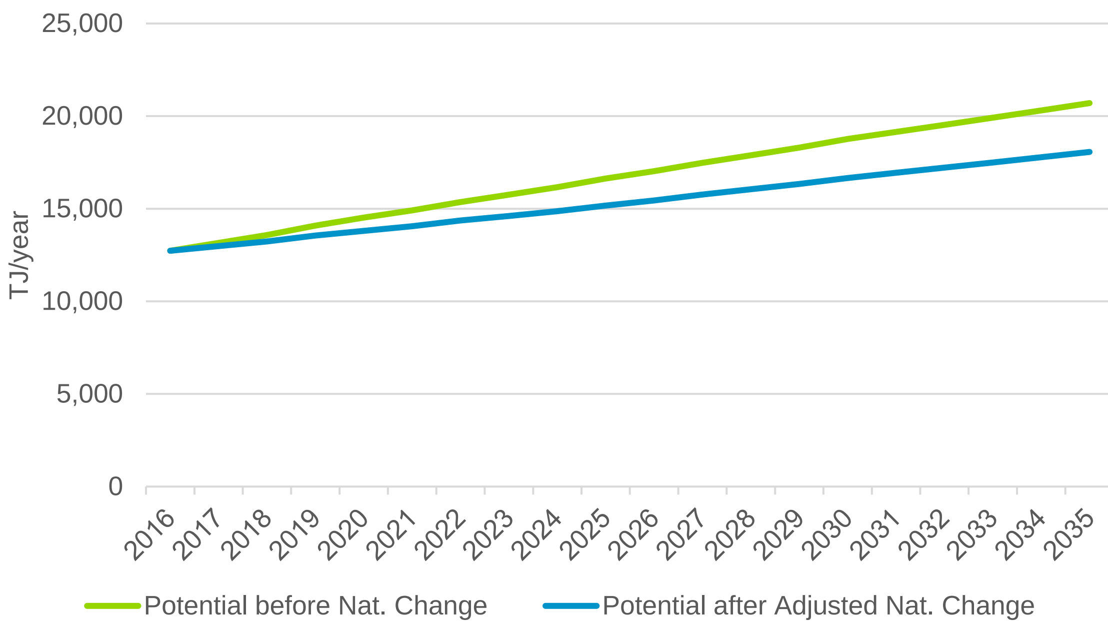
Figure 3-15. Residential Gas Energy Technical Savings Potential with Natural Change (TJ/year)



Source: Navigant

The effect of adjustments for natural change on the commercial sector's technical potential is slightly less than for the residential sector, as seen in Figure 3-16. Space heating and hot water are the commercial end-uses contributing to natural change, and both exhibit natural conservation. On average across the study period, the commercial technical potential after adjusted natural change is roughly 9% lower than the potential prior to natural change.

Figure 3-16. Commercial Gas Energy Technical Savings Potential with Natural Change (TJ/year)



Source: Navigant

For the industrial sector, there was no forecasted natural change, so adjustments to the technical potential results presented in previous sections were not necessary.

4. ECONOMIC POTENTIAL FORECAST

This section describes the economic savings potential, which is potential that meets a prescribed level of cost effectiveness, available in the BC Utilities' service territories. The section begins by explaining Navigant's approach to calculating economic potential. It then presents the results for economic potential.

4.1 Approach to Estimating Economic Potential

Economic potential is a subset of technical potential, using the same assumptions regarding immediate replacement as in technical potential, but including only those measures that have passed the benefit-cost test chosen for measure screening (in this case the Total Resource Cost (TRC) test, per the BC Utilities' guidance). The TRC ratio for each measure is calculated each year and compared against the measure-level TRC ratio screening threshold of 1.0. A measure with a TRC ratio greater than or equal to 1.0 is a measure that provides monetary benefits greater than or equal to its costs. If a measure's TRC meets or exceeds the threshold, it is included in the economic potential.

The TRC test is a cost-benefit metric that measures the net benefits of energy efficiency measures from combined stakeholder viewpoint of the utility (or program administrator) and the customers. The model calculates the TRC benefit-cost ratio using the following equation:

Equation 4. Benefit-Cost Ratio for Total Resource Cost Test

$$TRC = \frac{PV(Avoided\ Costs + O\&M\ Savings)}{PV(Technology\ Cost + Admin\ Costs)}$$

Where:

- *PV( )* is the present value calculation that discounts cost streams over time;
- *Avoided Costs* are the monetary benefits resulting from gas and electric savings (e.g., avoided costs of infrastructure investments, as well as avoided commodity costs due to gas and/or electric energy conserved by efficient measures);
- *O&M Savings* are the non-energy benefits such as operation and maintenance cost savings;
- *Technology Cost* is the incremental equipment cost to the customer;
- *Admin Costs* are the administrative costs incurred by the utility or program administrator.

Navigant calculated TRC ratios for each measure based on the present value of benefits and costs (as defined above) over each measure's life. Appendix A.3 presents the avoided costs, discount rates, and other key data inputs used in the TRC calculation, and Appendix A.2 provides measure-specific inputs. As agreed upon with the BC Utilities, effects of free ridership are not present in the results from this study, so no net-to-gross (NTG) factor was applied. Providing gross savings results will allow the BC Utilities to easily apply updated NTG assumptions in the future, as well as allow for variations in NTG assumptions by reviewers.

Although the TRC equation includes administrative costs, the study does not consider these costs during the economic screening process because an individual measure's cost effectiveness "on the margin" is the primary focus. Additionally, Navigant excluded administrative costs from this analysis because those costs are largely driven by program design, which is outside of the scope of this evaluation.

Similar to technical potential, only one "economic" measure (meaning that its TRC ratio meets the 1.0 threshold) from each competition group is included in the summation of economic potential across measures (e.g., at the end-use category, customer segment, sector, service territory or total level). If a competition group is composed of more than one measure that passes the TRC test, then the economic measure that provides the greatest gas savings potential is included in the summation of economic potential. This approach ensures that double counting is not present in the reported economic potential, though economic potential for each individual measure is still calculated and reported outside of the summation.

4.2 Economic Potential Results

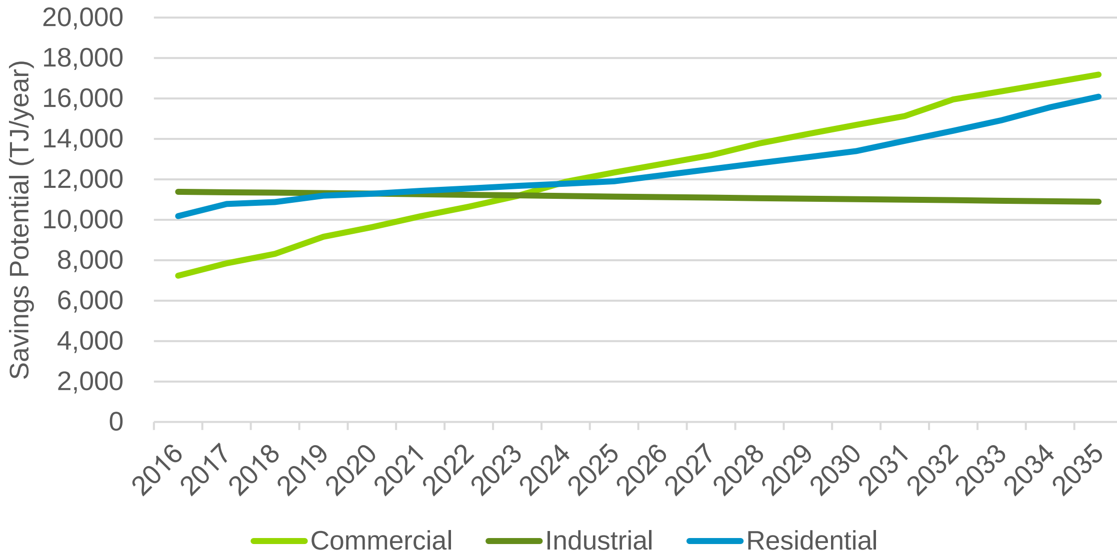
This section provides the results pertaining to economic savings potential at different forms of aggregation. Results are shown by sector, customer segment, end-use category and highest-impact measures.

4.2.1 Results by Sector

Figure 4-1 shows economic gas savings potential across all sectors. The data used to generate the figure are in Table D-7 in Appendix D. In contrast to technical potential, the residential economic potential shows a steady growth through 2035. The commercial economic potential grows nearly twice as fast as the technical potential. The industrial sector's economic potential exhibits similar decay trends as the technical potential. On average across the study period, 57% of residential, 74% of commercial and 93% of industrial technical potential pass the economic screening process.[43]

[43] The BC Utilities Commission (BCUC) allows for the use of a modified-TRC test (mTRC) for evaluating cost-effectiveness of energy efficiency measures. The mTRC test is based on higher avoided energy costs, and produces different results in comparison with the standard TRC test. The use of the mTRC test for economic potential is not in the scope of this portion of the BC CPR.

Figure 4-1. Gas Energy Economic Savings Potential by Sector (TJ/year)



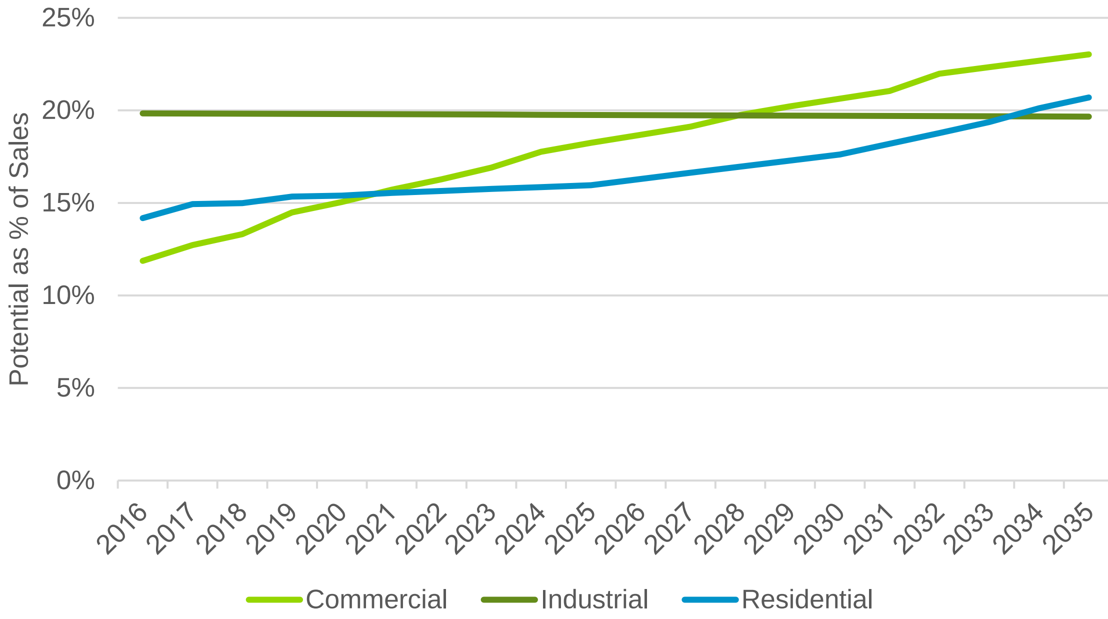
Source: Navigant

The bumps in select years of the residential and commercial economic potential occur whenever one or more measures cross the cost-effectiveness threshold in one or more customer segments. The slope of energy savings over time reflect changes in gas sales and the roll-out of high-efficiency, new construction measures. These measures having TRC ratios slightly less than 1.0 at the beginning of the study period become economically feasible as ***avoided gas costs—which escalate at a faster rate than equipment, operation and maintenance costs***—increase throughout the study the period. For example, smart thermostats become cost-effective in 2017 for the residential sector. The bumps in commercial economic potential prior to 2026 result from HVAC control upgrades using direct digital data control becoming cost-effective in various customer segments and years. When vertical direct-vent fireplaces become economically feasible in 2031, it induces the final visible jump in commercial potential.

Technical and economic energy potential are similar in the industrial sector because the measures included in the study are selected on the premise that they are currently or could become reasonably attractive to industrial customers and have some likelihood of adoption given a wide range of market environments. Considering many industrial customers purchase gas in bulk at rates lower than other customers, market experience has shown industrial customers require measures to be more economic than residential and commercial customers do. Thus, the measures deemed reasonably attractive to industrial customers tend to fair very well in a TRC ratio using the utility's avoided costs, which are often higher than industrial gas retail rates.

Figure 4-2 shows the economic gas savings potential as a percentage of gas consumption, with associated data presented in Table D-8 in Appendix D. Though it had the lowest technical potential as a percentage of consumption, the industrial sector had the highest percentages for economic potential. For the residential sector, the introduction of new whole-home new construction measures allowed the sector to increase economic savings despite the limited growth in residential consumption. Similarly, whole-building new construction practices in the commercial sector enable the increase in savings potential as a percent of commercial-sector consumption over time.

Figure 4-2. Gas Energy Economic Savings Potential by Sector as a Percent of Sector Consumption (%)

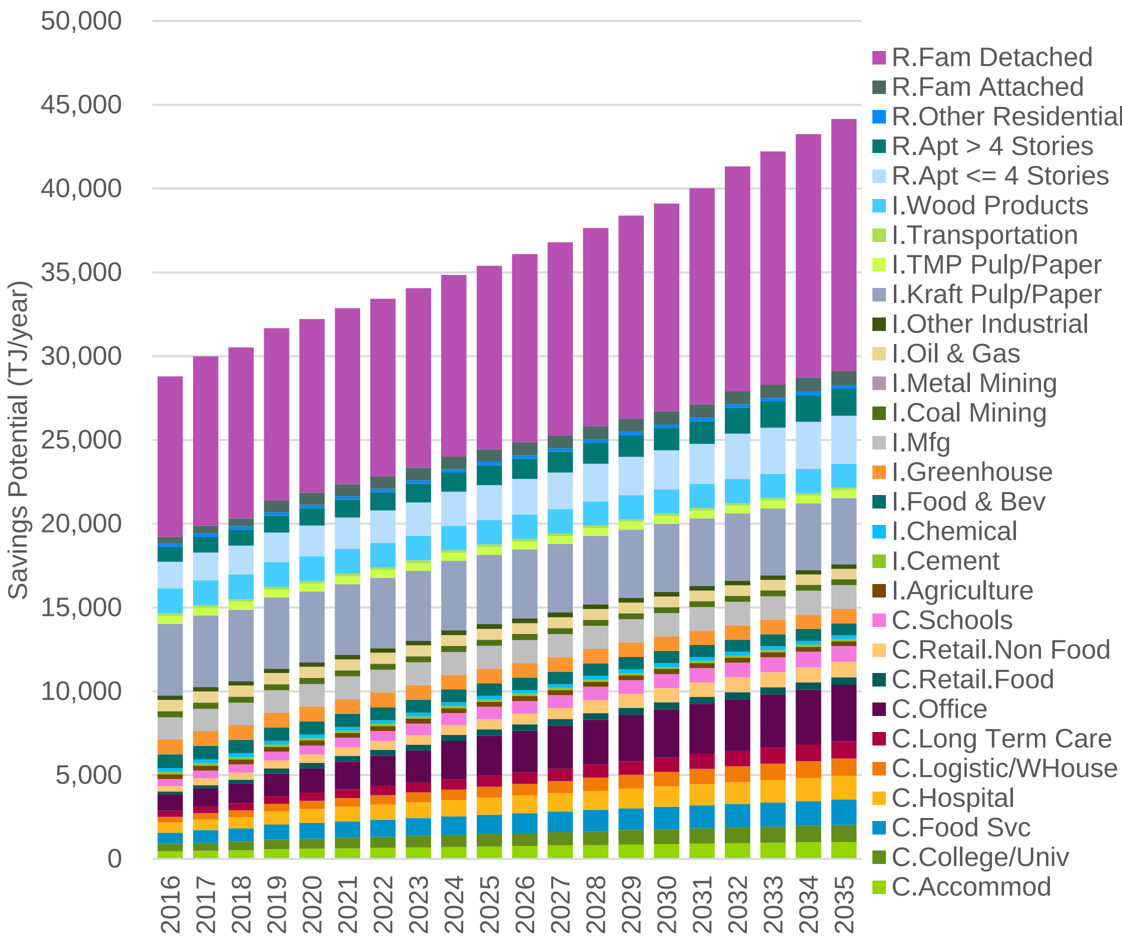


Source: Navigant

4.2.2 Results by Customer Segment

Figure 4-3 depicts the economic energy savings potential for all customer segments, and Table D-9 in Appendix D provides the corresponding data values. Depending on the customer segment, between 49% and 57% of the technical energy potential pass the economic screening threshold within the residential sector. The greatest reduction from technical potential to economic potential appeared in single-family attached homes, while the smallest reduction occurs in single-family detached homes. For the commercial customer segments, the reduction in economic potential relative to technical potential ranges from 59% to 92%. Non-food retail establishments see the greatest loss from non-economic potential, while long term care facilities are the most resilient. In the industrial sector, high-efficiency kilns do not pass the economic screen.

Figure 4-3. Gas Energy Economic Savings Potential by Customer Segment (TJ/year)



Source: Navigant

In general, the mix of economic energy savings from various customer segments within a given sector is similar between economic and technical potential. Detached single-family homes is the segment with the highest fraction of savings potential that are economic, and they provide the largest share of economic savings potential within the residential sector. Similarly, the mix of economic potential from the commercial segments do not change appreciably relative to the technical potential. The wood products segment falls from 19% of the industrial technical potential mix to 13% of the economic potential. Figure 4-4, Figure 4-5 and Figure 4-6 provide a breakdown of economic energy potential by customer segment and sector.

Figure 4-4. Residential Gas Energy Economic Potential Customer Segment Breakdown in 2025

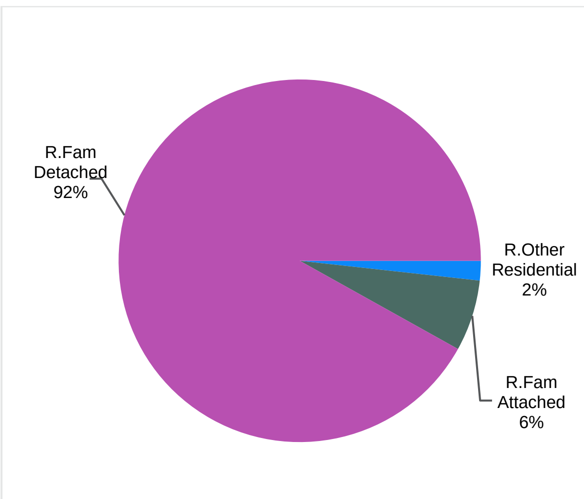


Figure 4-5. Commercial Gas Energy Economic Potential Customer Segment Breakdown in 2025

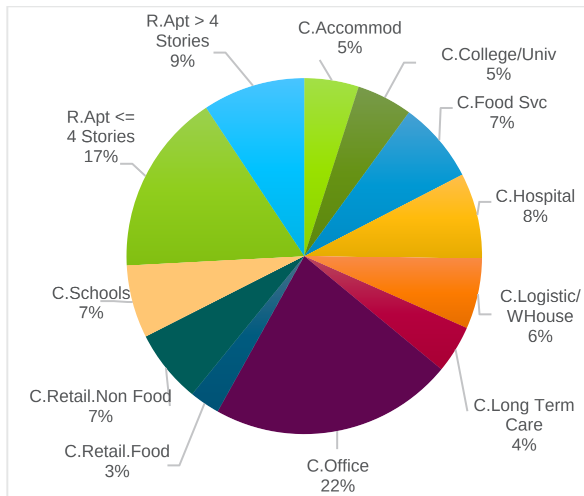
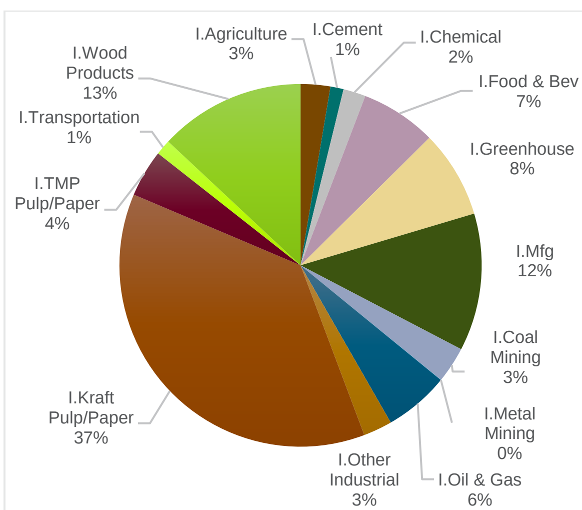


Figure 4-6. Industrial Gas Energy Economic Potential Customer Segment Breakdown in 2025

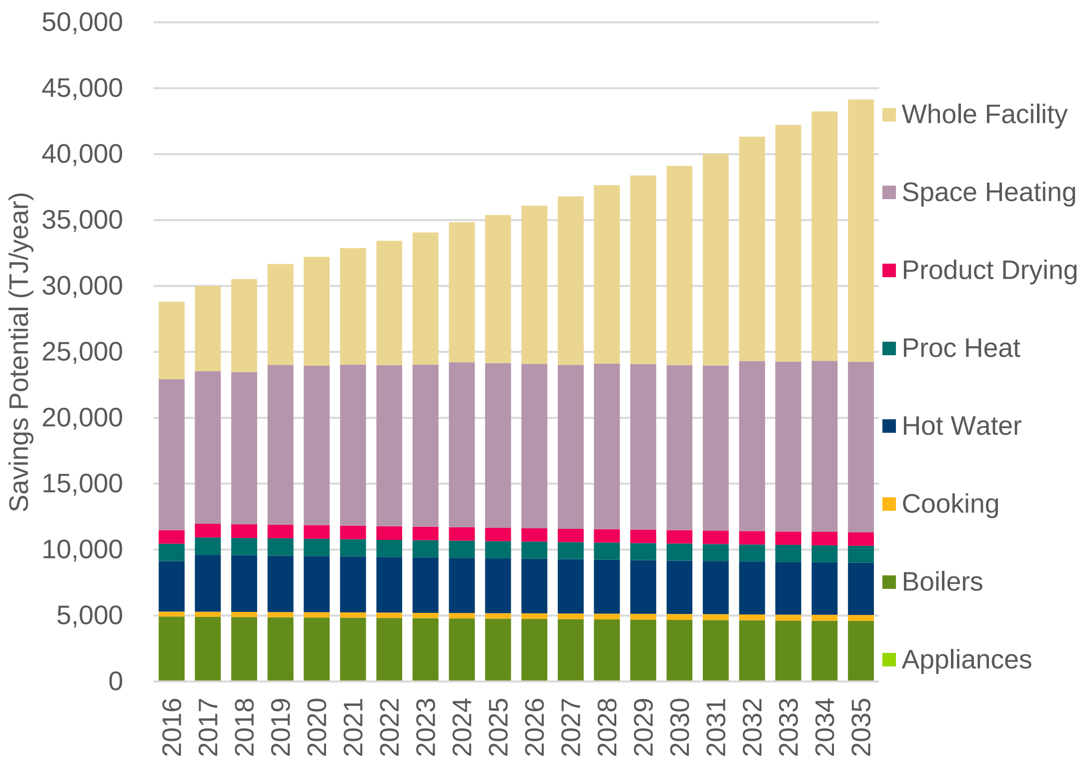


Source: Navigant

4.2.3 Results by End-use

Depending on the end-use category, between 0% and 100% of the technical energy potential is cost-effective. The least economic end-uses across all customer sectors are appliances (0% of technical potential), space heating (53% of technical potential), and product drying (54% of technical potential). Boilers, cooking, and process heat are end-use categories that have economic potential of 100% of technical potential. Figure 4-7, shows the economic gas potential by end-use, with associated data in Table D-10 in Appendix D.

Figure 4-7. Gas Energy Economic Savings Potential by End-Use (TJ/year)



Source: Navigant

Figure 4-8, Figure 4-9 and Figure 4-10 provide the breakdown of economic energy potential by end-use categories within each sector. In the residential sector, space heating decreases from 62% to 52%, while whole facility increases from 12% to 22%. Similarly, in the commercial sector, space heating decreases from 54% to 41% of the total, while whole facility increases from 35% to 47%. Product drying declines by 7 percentage points in the makeup of industrial potential.

Figure 4-8. Residential Gas Energy Economic Potential End-Use Breakdown in 2025

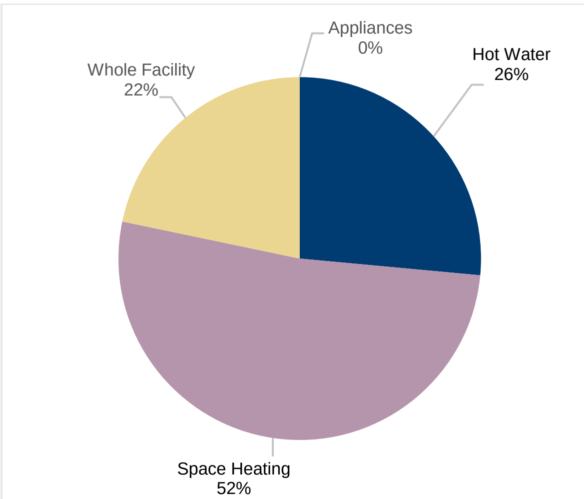


Figure 4-9. Commercial Gas Energy Economic Potential End-Use Breakdown in 2025

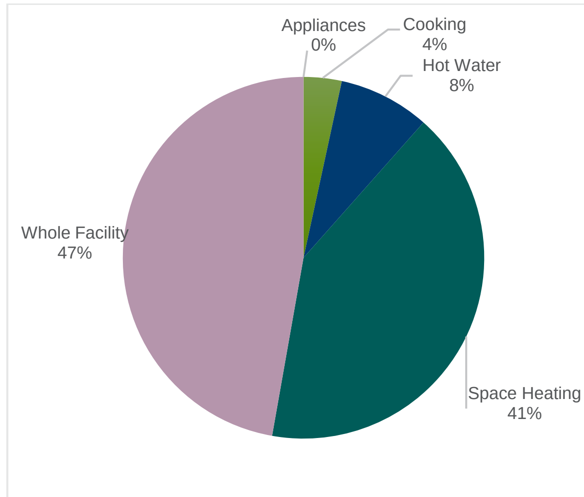
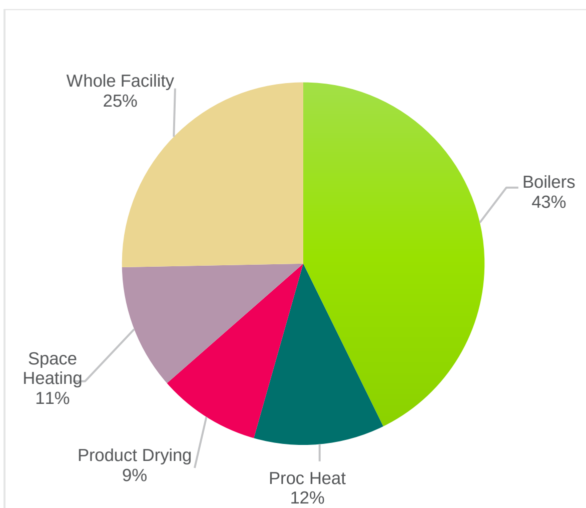


Figure 4-10. Industrial Gas Energy Economic Potential End-Use Breakdown in 2025

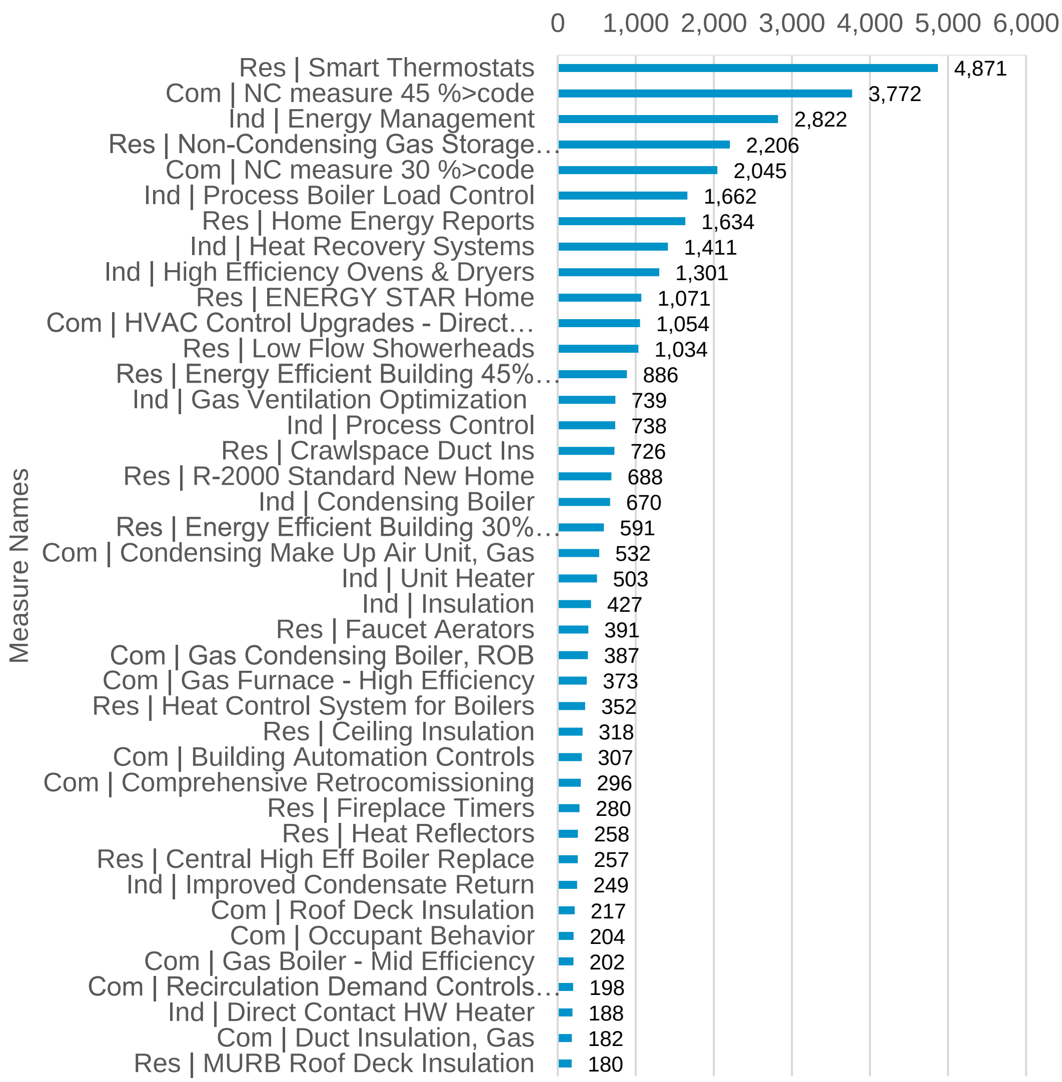


Source: Navigant

4.2.4 Results by Measure

The measure-level economic energy savings potential shown in Figure 4-11 is prior to adjustments made to competition groups as detailed in Section 3.2.4. The figure highlights the economic potential from the top 40 highest-impact measures. When compared with the top 10 technical potential measures, three residential measures (condensing and non-condensing tankless water heaters and condensing storage water heaters), and one commercial measure (wall insulation) are not economic and fall out of the top 40. Measures pertaining to the industrial sector, such as energy management and process boiler load control, move up the rankings due to their economic potential remaining similar to their respective technical potential.

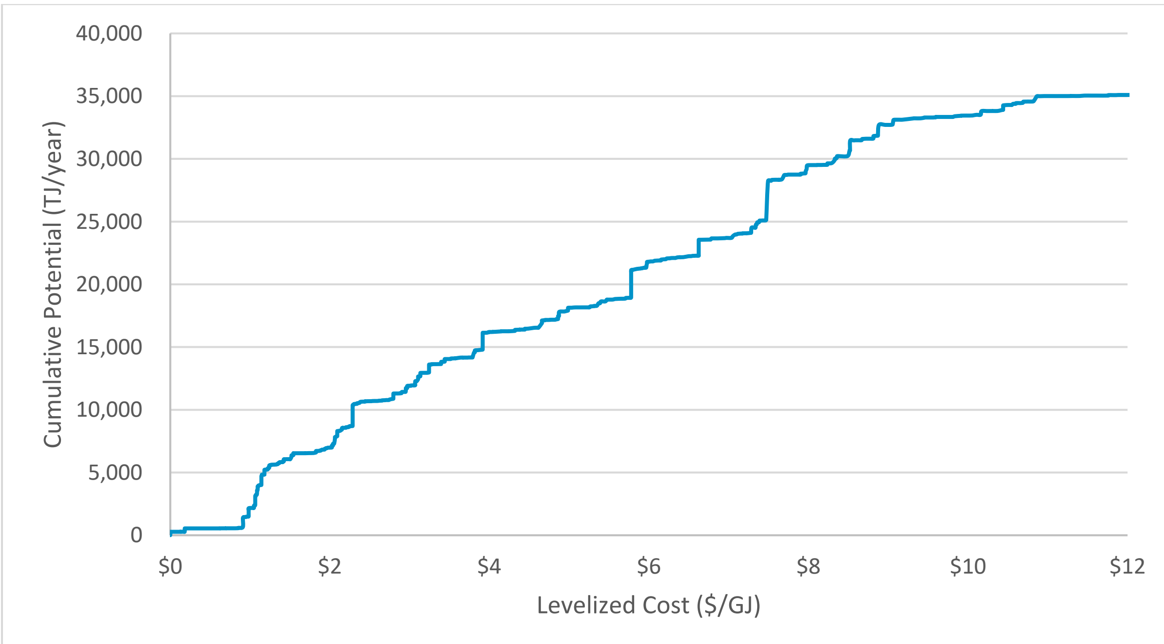
Figure 4-11. Top 40 Measures for Economic Potential in 2025 (TJ/year)



Source: Navigant

Figure 4-12 provides a supply curve of savings potential versus levelized cost of savings in $/GJ for all measures considered in the study. This curve shows only those measures with a levelized cost less than $12/GJ. While the full curve extends beyond the $12/GJ point to measures with costlier savings, savings from these measures is negligible since the curve flattens out. The savings potential seen at a cost of $0/GJ is due to code-change measures, which have zero costs in the model.

Figure 4-12. Supply Curve of Gas Economic Potential (TJ/year) vs. Levelized Cost of Savings ($/GJ) in 2025



Source: Navigant

APPENDIX A. ADDITIONAL MODEL RESULTS AND INPUT ASSUMPTIONS

A.1 Detailed Model Results

See attachment, "FortisGas_Appendix_A1_2017-01-23.xlsx," for granular results from the model.

A.2 Measure List and Characterization Assumptions

See attachment, "FortisGas_Appendix_A2_2017-01-23.xlsx," for granular measure input to the model.

A.3 Other Key Input Assumptions

See attachment, "FortisGas_Appendix_A3_2017-01-23.xlsx," for key assumptions about building stocks, end-use intensities, avoided costs, discount rates, etc. used by the model.

APPENDIX B. APPROACH TO BASELINE CALIBRATION

B.1 End-Use Definitions

Table B-1. Description of End-Uses[44],

Segment	End-Use	Definition
Residential	Appliances	Large/small appliances including ovens, refrigerators, freezers, clothes washers, etc.
	Electronics	Televisions, computers and related peripherals, and other electronic systems
	Water Heating	Heating of water for domestic hot water use
	Lighting	Interior, exterior and holiday/seasonal lighting
	Other	Miscellaneous loads
	Space Cooling	All space cooling, including both central AC and room or portable AC
	Space Heating	All space heating, including both primary heating and supplementary heating
	Ventilation	Ventilation requirements for space heating/cooling including furnace fans
	Whole Facility	The whole facility end-use reflects the total customer load. The residential whole facility end-use is used to characterize new construction and behavioral measures that impact overall energy consumption. In the residential sector this includes as home energy reports, and new construction home/building measures such as ENERGY STAR and Net Zero homes.
Commercial	Cooking	Food preparation equipment including ranges, broilers, ovens, and griddles
	HVAC Fans/Pumps	HVAC auxiliaries including fans, pumps, and cooling towers
	Hot Water	Hot water boilers, tank heaters, and others
	Lighting	Interior, exterior and holiday/seasonal lighting for main building areas and secondary areas
	Office Equipment	Computers, monitors, servers, printers, copiers and related peripherals
	Other	Miscellaneous loads including elevators, gym equipment, and other plug loads
	Refrigeration	Refrigeration equipment including fridges, coolers, and display cases
	Space Cooling	All space cooling equipment, including chillers, and DX cooling.
	Space Heating	All space heating equipment, including boilers, furnaces, unit heaters, and baseboard units
	Whole Facility	The whole facility end-use reflects the total customer load. The commercial whole facility end-use is used to characterize new construction and behavioral measures that impact overall energy consumption. In the commercial sector this includes building automation controls, new construction measures, occupant behavior, and retro-commissioning.
Industrial	Boilers	Boilers for industrial applications
	Compressed Air	Air compressors and related equipment
	Fans & Blowers	Fans and blowers for ventilation, combustion and pneumatic conveyance
	Industrial Process	Industrial processes for various applications including mechanical, electrical, and chemical processes
	Lighting	Interior, exterior, and seasonal lighting loads
	Material Transport	Feedstock and product movement by conveyance or stackers
	Process Compressors	Process compressors
	Process Heating	Process heating including heat treatment and industrial ovens
	Product Drying	Industrial drying equipment and systems
	Space Heating	All non-process space heating equipment (e.g., comfort heating)
	Pumps	Process pump systems
	Refrigeration	Industrial refrigeration

[44] While not all end-uses are applicable to FortisBC Gas, this table shows definitions for all electric and gas end-uses.

Whole Facility	The whole facility end-use reflects the total customer load. The industrial whole facility end-use is used to characterize new construction and behavioral measures that impact overall energy consumption. In the industrial sector this includes energy management, and new plant measures.

Source: Navigant

B.2 Residential Sector – Additional Detail

In order to characterize the residential sector energy usage, Navigant developed a bottom-up analysis based on the mix of fuel shares and the types of equipment used for each end-use. Navigant developed these estimates based on a review of FortisBC Gas's 2012 REUS study and BC Hydro's 2014 REUS. Both of these end-use surveys provides detailed residential household data, and detailed information in relation to each of the end-uses, existing equipment, main and secondary fuel systems, and saturation levels for common energy efficiency measures. Using the data provided by the residential survey, Navigant developed specific fuel share and equipment estimates for each residential segment. The following sections summarized the approach for developing the following:

- **Residential Stock** for each residential segment
- **Fuel shares** and **equipment shares** for each residential segment in each region
- **End-use intensities (EUIs)** for each residential segment in each region

Fuel Shares and Equipment Shares

Using the data provided by the FortisBC 2012 REUS study, Navigant developed specific fuel share and equipment estimates for each residential segment in each region. The translation of data from the 2012 REUS study to Navigant's analysis was relatively straightforward given the granularity of the REUS data. For example, the residential survey reports most information aggregated based on four types of dwellings (Single Detached, Single Attached, Apartments, and Other), which are largely consistent with the residential segments employed for this CPR.

- Table B-2 shows the mix of fuel shares for each residential segment by region[45]
- Table B-3 shows the types of equipment used for the **Space Heating**, and **Water Heating** end-uses by residential segment and region
- Table B-4 shows the types of **Appliance** equipment by residential segment and region

[45] This table shows the gas share of appliances at 100% and the electric share at 0%. This does not mean that all appliances use gas and that no appliances use electricity, but rather reflect the fact that - from the perspective of a gas utility (FortisBC Gas and PNG) - all gas appliances are fueled by gas. For the electric utilities (BC Hydro and Fortis Electric), the opposite is true – all electric appliances are fueled by electricity such that the electric fuel share is 100%.

Table B-2. FortisBC Gas Residential Fuel Shares (Percentage of FortisBC Customers Using Each Energy Type)

Building Type	End-use	Lower Mainland		Vancouver Island		Southern Interior		Northern BC	
		Gas	Electric	Gas	Electric	Gas	Electric	Gas	Electric
Single Family Detached/Duplexes	Space Heating	89%	9%	64%	32%	85%	11%	86%	9%
	Water Heating	84%	15%	70%	29%	72%	27%	75%	24%
Single Family Attached	Space Heating	76%	23%	61%	39%	89%	11%	91%	9%
	Water Heating	69%	30%	66%	34%	85%	15%	79%	21%
Apartments <= 4 Storeys	Space Heating	30%	69%	18%	80%	35%	62%	29%	71%
	Water Heating	69%	30%	50%	48%	64%	36%	63%	37%
Apartments > 4 Storeys	Space Heating	30%	69%	18%	80%	35%	62%	29%	71%
	Water Heating	69%	30%	50%	48%	64%	36%	63%	37%
Other Residential	Space Heating	89%	9%	64%	32%	85%	11%	86%	9%
	Water Heating	89%	3%	82%	10%	79%	13%	81%	11%

Source: Navigant analysis of 2012 REUS

Table B-3. Residential Equipment Shares (%)

End-use	Equipment Type	Fraction of Households Using Equipment Type (%)				
		Single Family Detached	Single Family Attached	Apartments <=4 Storeys	Apartments >4 Storeys	Other Residential
Space Heating	Gas Furnace 0.6 AFUE	8%	8%	4%	4%	1%
	Gas Furnace 0.8 AFUE	27%	28%	14%	14%	5%
	Gas Furnace 0.9 AFUE	36%	29%	13%	13%	66%
	Gas Boiler 0.7 EF	0%	0%	0%	0%	0%
	Gas Boiler 0.8 EF	8%	10%	2%	2%	19%
	Gas Boiler 0.9 EF	4%	5%	17%	17%	11%
	Gas Fireplace	89%	79%	0%	0%	79%
Water Heating	Gas Water Heater Conventional	93%	91%	5%	5%	85%
	Gas Water Heater Condensing	0%	0%	0%	0%	0%
	Gas DHW Tankless	5%	5%	0%	0%	5%

^Note - Equipment types using same energy type add to percentage of homes with end-use. Space heating system may add to >100% due to secondary systems (i.e. fireplaces).
Source: Navigant analysis of 2012 REUS and BC Hydro 2014 REUS

Table B-4. Appliances Equipment (%)

		Percentage of Households with Appliance				
End-Use	Equipment Type	Single Family Detached	Single Family Attached	Apartments <=4 Storeys	Apartments > 4 Storeys	Other Res
Appliances	C. Dryer Gas Low E	7%	7%	4%	4%	7%
	C. Dryer Gas ENERGY STAR®	4%	4%	7%	7%	4%
	Stove Gas	16%	12%	6%	6%	11%

Source: Navigant analysis of BC Hydro 2014 REUS

End-Use Intensities (EUIs)

The next step of the residential calibration to FortisBC Gas's Reference Forecast process required the roll up of the fuel share and equipment share estimates in order to establish EUIs for each residential segment in each region. Based on this approach, Navigant developed bottom-up EUI estimates for Space Heating, Water Heating, and Appliances. The EUIs for the Other end-use was estimated based on the 2010 FortisBC Gas CPR.

Table B-5 shows an example of the calibration process followed for Single Family Detached/Duplexes in the Southern Interior. The process used to calibrate the estimate of energy use builds on an estimate of the percentage of homes with a particular end-use and fuel type, using a particular type of equipment and efficiency within an end-use. The fuel shares (column B), equipment shares (column E), and an estimated level of energy use for each equipment type (column F) are multiplied to obtain an estimated UEC (column G). In the example below, column G sums the total consumption across all water heating equipment. The team summed the resulting EUCs across end-uses to obtain the segment-level intensity (GJ per year), and then calibrated to match the actual target intensity stemming from FortisBC Gas sales data.

This same process is repeated across all residential and commercial segments in each region. Ultimately, EUIs that matched the segment-level sales targets in the base year were determined for each end-use and segment, and across all regions.

With the base year EUIs established, the Reference Case EUIs were determined based on the residential and commercial sector EUI trends. The approach for developing the EUI trends is described in the body of the report.

Table B-7, Table B-8, and Table B-9 show the residential EUIs used in the Reference Case for the Southern Interior, Vancouver Island, and Northern BC regions. The EUIs presented in these tables start with the base year EUIs shown in Table B-6 and adjusted based on the EUI trends. The Lower Mainland EUIs are included the main body of the report.

Table B-5. Example of Calibration Process (Single Family Detached/Duplexes – Southern Interior)

A	*B*	*C*	*D*	*E*	*F*	*G*	*H*	*I*
End Use	***Fuel Share (%)***	***Equipment***	***Efficiency***	***Equipment Share (%)***	***Annual Energy Use (GJ)***	***End-Use Weighted Avg. Use (GJ)***	***Total Uncalibrated Consumption (GJ)***	***Total Calibrated Consumption (GJ)***
Space Heating	*85%*	*…*	*…*	*…*	*…*	*…*	*51.7*	*57.7*
Water Heating	*72%*	*Gas Water Heater Conventnl*	*n/a*	*83%*	*17.7*	*12.2*	*12.2*	*13.6*
		Gas Water Heater Condensing	*n/a*	*13%*	*13.7*			
		Gas DHW Tankless	*n/a*	*4%*	*10.9*			
Cooling	*0%*	*…*	*…*	*…*	*…*	*…*	*0.0*	*0.0*
Appliances	*100%*	*…*					*1.3*	*1.4*
Lighting	*0%*	*…*	*…*	*…*	*…*	*…*	*0.0*	*0.0*
Electronics	*0%*	*…*	*…*	*…*	*…*	*…*	*0.0*	*0.0*
Other	*0%*	*…*	*…*	*…*	*…*	*…*	*2.5*	*2.8*
Ventilation	*0%*	*…*	*…*	*…*	*…*	*…*	*0.0*	*0.0*
Estimated Consumption (GJ per year)							*67.7*	***75.6***
Target Consumption (GJ per year)		*- calculted based on Fortis Gas 2014 sales data*					*75.6*	***75.6***
	Uncalibrated vs. Target						***90%***	***100%***

Appliances are assigned a fuel share of 100%. This implies that all gas appliances have a fuel share of 100% gas. Similarly, electric utilities have an appliances fuel share of 100%. Penetration of gas appliances are represented by equipment shares.
Source: Navigant

Table B-6. Base Year Residential EUIs (GJ/household) by Segment and Region

Building Type	End-Use	Average Use per Household (GJ)			
		Lower Mainland	Southern Interior	Vancouver Island	Northern BC
Single Family Detached/Duplexes	Space Heating	77	58	38	76
	Water Heating	15	14	15	12
	Cooling	-	-	-	-
	Appliances	1	1	2	1
	Lighting	-	-	-	-
	Electronics	-	-	-	-
	Other	3	3	3	2
	Ventilation	-	-	-	-
	Total	95	76	58	91
Single Family Attached	Space Heating	47	39	23	49
	Water Heating	10	12	10	8
	Cooling	-	-	-	-
	Appliances	1	1	1	1
	Lighting	-	-	-	-
	Electronics	-	-	-	-
	Other	1	1	1	1
	Ventilation	-	-	-	-
	Total	59	52	36	59
Apartments <= 4 Storeys	Space Heating	21	18	5	23
	Water Heating	17	15	8	16
	Cooling	-	-	-	-
	Appliances	1	1	1	1
	Lighting	-	-	-	-
	Electronics	-	-	-	-
	Other	3	3	2	3
	Ventilation	-	-	-	-
	Total	43	37	16	43
Apartments > 4 Storeys	Space Heating	21	18	5	23
	Water Heating	17	15	8	15
	Cooling	-	-	-	-
	Appliances	1	1	1	1
	Lighting	-	-	-	-
	Electronics	-	-	-	-
	Other	4	3	2	4
	Ventilation	-	-	-	-
	Total	43	37	16	43
Other Residential	Space Heating	45	43	25	56
	Water Heating	13	11	11	11
	Cooling	-	-	-	-
	Appliances	1	1	1	1
	Lighting	-	-	-	-
	Electronics	-	-	-	-
	Other	1	1	1	1
	Ventilation	-	-	-	-
	Total	60	56	38	69

Source: Navigant analysis of Base Year EUIs, BC Hydro's 2014 REUS, FortisBC Gas Residential Load Forecast

Table B-7. Residential Gas Intensity (GJ/household) – Southern Interior

Residential Segment	End-Use	CPR Period 2015	2020	2025	2030	2035
Single Family Detached/Duplexes	Space Heating	58	52	48	46	44
	Water Heating	14	13	12	12	12
	Cooling	-	-	-	-	-
	Appliances	1	2	2	2	2
	Lighting	-	-	-	-	-
	Electronics	-	-	-	-	-
	Other	3	3	2	2	2
	Ventilation	-	-	-	-	-
	Total	76	69	65	62	60
Single Family Attached/Row	Space Heating	39	36	33	32	31
	Water Heating	12	11	11	10	10
	Cooling	-	-	-	-	-
	Appliances	1	1	1	1	1
	Lighting	-	-	-	-	-
	Electronics	-	-	-	-	-
	Other	1	1	1	1	1
	Ventilation	-	-	-	-	-
	Total	52	48	46	44	43
Apartments =< 4 stories	Space Heating	18	16	14	14	13
	Water Heating	15	15	16	16	16
	Cooling	-	-	-	-	-
	Appliances	1	1	1	1	1
	Lighting	-	-	-	-	-
	Electronics	-	-	-	-	-
	Other	3	3	3	3	3
	Ventilation	-	-	-	-	-
	Total	37	35	34	33	33
Apartments > 4 stories	Space Heating	18	16	15	14	13
	Water Heating	15	15	15	15	16
	Cooling	-	-	-	-	-
	Appliances	1	1	1	1	1
	Lighting	-	-	-	-	-
	Electronics	-	-	-	-	-
	Other	3	3	3	3	3
	Ventilation	-	-	-	-	-
	Total	37	35	34	33	33
Other Residential	Space Heating	43	38	36	34	32
	Water Heating	11	10	10	10	9
	Cooling	-	-	-	-	-
	Appliances	1	1	1	1	1
	Lighting	-	-	-	-	-
	Electronics	-	-	-	-	-
	Other	1	1	1	1	1
	Ventilation	-	-	-	-	-
	Total	56	51	48	45	43

Source: Navigant analysis of Base Year EUIs, BC Hydro's 2014 REUS, FortisBC Gas Residential Load Forecast

Table B-8. Residential Gas Intensity (GJ/household) – Vancouver Island

Residential Segment	End-Use	CPR Period				
		2015	2020	2025	2030	2035
Single Family Detached/Duplexes	Space Heating	38	34	32	30	29
	Water Heating	15	14	14	14	13
	Cooling	-	-	-	-	-
	Appliances	2	2	2	2	2
	Lighting	-	-	-	-	-
	Electronics	-	-	-	-	-
	Other	3	3	3	3	3
	Ventilation	-	-	-	-	-
	Total	58	53	51	48	47
Single Family Attached/Row	Space Heating	23	21	20	19	18
	Water Heating	10	10	10	9	9
	Cooling	-	-	-	-	-
	Appliances	1	1	1	1	1
	Lighting	-	-	-	-	-
	Electronics	-	-	-	-	-
	Other	1	1	1	1	1
	Ventilation	-	-	-	-	-
	Total	36	34	32	31	30
Apartments =< 4 stories	Space Heating	5	4	4	4	4
	Water Heating	8	9	9	9	9
	Cooling	-	-	-	-	-
	Appliances	1	1	1	1	1
	Lighting	-	-	-	-	-
	Electronics	-	-	-	-	-
	Other	2	2	2	2	2
	Ventilation	-	-	-	-	-
	Total	16	16	16	16	16
Apartments < 4 stories	Space Heating	5	5	4	4	4
	Water Heating	8	8	9	9	9
	Cooling	-	-	-	-	-
	Appliances	1	1	1	1	1
	Lighting	-	-	-	-	-
	Electronics	-	-	-	-	-
	Other	2	2	2	2	2
	Ventilation	-	-	-	-	-
	Total	16	16	16	16	15
Other Residential	Space Heating	25	22	21	20	19
	Water Heating	11	11	10	10	9
	Cooling	-	-	-	-	-
	Appliances	1	1	1	1	1
	Lighting	-	-	-	-	-
	Electronics	-	-	-	-	-
	Other	1	1	1	1	1
	Ventilation	-	-	-	-	-
	Total	38	35	33	31	30

Source: Navigant analysis of Base Year EUIs, BC Hydro's 2014 REUS, FortisBC Gas Residential Load Forecast

Table B-9. Residential Gas Intensity (GJ/household) – Northern BC

Residential Segment	End-Use	CPR Period				
		2015	2020	2025	2030	2035
Single Family Detached/Duplexes	Space Heating	76	68	64	60	57
	Water Heating	12	11	11	11	10
	Cooling	-	-	-	-	-
	Appliances	1	1	1	1	1
	Lighting	-	-	-	-	-
	Electronics	-	-	-	-	-
	Other	2	2	2	2	2
	Ventilation	-	-	-	-	-
	Total	91	83	78	74	71
Single Family Attached/Row	Space Heating	49	44	42	40	38
	Water Heating	8	8	8	8	7
	Cooling	-	-	-	-	-
	Appliances	1	1	1	1	1
	Lighting	-	-	-	-	-
	Electronics	-	-	-	-	-
	Other	1	1	1	1	1
	Ventilation	-	-	-	-	-
	Total	59	54	51	49	47
Apartments =< 4 stories	Space Heating	23	20	19	18	17
	Water Heating	16	16	16	17	17
	Cooling	-	-	-	-	-
	Appliances	1	1	1	1	1
	Lighting	-	-	-	-	-
	Electronics	-	-	-	-	-
	Other	3	3	3	3	3
	Ventilation	-	-	-	-	-
	Total	43	41	39	38	38
Apartments > 4 stories	Space Heating	23	20	19	18	17
	Water Heating	15	16	16	16	16
	Cooling	-	-	-	-	-
	Appliances	1	1	1	1	1
	Lighting	-	-	-	-	-
	Electronics	-	-	-	-	-
	Other	4	3	3	3	3
	Ventilation	-	-	-	-	-
	Total	43	41	39	38	38
Other Residential	Space Heating	56	51	47	45	43
	Water Heating	11	10	9	9	9
	Cooling	-	-	-	-	-
	Appliances	1	1	1	1	1
	Lighting	-	-	-	-	-
	Electronics	-	-	-	-	-
	Other	1	1	1	1	1
	Ventilation	-	-	-	-	-
	Total	69	62	58	55	53

Source: Navigant analysis of Base Year EUIs, BC Hydro's 2014 REUS, FortisBC Gas Residential Load Forecast

B.3 Commercial Sector – Additional Detail

To characterize the Commercial sector, Navigant first developed a bottom-up analysis based on the mix of fuel shares and the types of equipment used for each end-use. Navigant developed these estimates based primarily on a review of BC Hydro's 2014 CEUS. BC Hydro's CEUS was preferred over the FortisBC 2015 CEUS given the increased granularity provided by the BC Hydro data. BC Hydro's 2015 CEUS study provides detailed information for several commercial segments across the CPR regions, including commercial building characteristics, main and secondary fuel systems, fuel shares and common commercial equipment, and saturation levels for common energy efficiency measures.

The following sections summarized the approach for developing the following:

- **Fuel Shares** and **Equipment Shares** for each commercial segment
- **End-use intensities (EUIs)** for each commercial segment
- **Commercial Floor Space Stock** for each commercial segment

Fuel Shares and Equipment Shares

Fuel share estimates were developed for end-uses that generally show a split across gas and electricity supply: Cooking, Hot Water, and Space Heating. All other end-uses were treated as electric-only end-uses, with the exception of the Other end-use.

Using the data provided by BC Hydro's 2014 CEUS, Navigant developed fuel share and equipment estimates for each commercial segment. The 2014 CEUS results are disaggregated across each region and are reported for each commercial segment.

Table B-10 and Table B-11Table B-11 shows the space heating equipment shares. The team used these space heating equipment shares to develop space heating EUIs, while EUIs for other end-uses were determined based on the 2010 CPR and did not require equipment shares.

Table B-11 summarize the results of this analysis. These tables show the estimated fuel shares and equipment shares for each commercial segment and climate region.

Table B-10. Commercial Fuel Shares (Percentage of Segment Using Each Energy Type)

Building Type	End-use	Lower Mainland		Vancouver Island		Southern Interior		Northern BC	
		Gas	Electric	Gas	Electric	Gas	Electric	Gas	Electric
Accommodation	Cooking	76%	24%	75%	25%	74%	26%	58%	42%
	Hot Water	71%	29%	69%	31%	78%	22%	55%	36%
	Space Heating	51%	44%	43%	57%	67%	33%	55%	36%
Colleges/ Universities	Cooking	52%	48%	52%	48%	52%	48%	52%	48%
	Hot Water	63%	32%	32%	63%	63%	32%	63%	32%
	Space Heating	53%	42%	48%	48%	53%	42%	63%	32%
Food Service	Cooking	79%	21%	79%	21%	79%	21%	79%	21%
	Hot Water	57%	43%	32%	68%	44%	56%	60%	40%
	Space Heating	63%	37%	19%	81%	47%	41%	75%	25%
Hospitals	Cooking	52%	48%	52%	48%	52%	48%	52%	48%
	Hot Water	93%	7%	93%	7%	93%	7%	93%	7%
	Space Heating	93%	7%	93%	7%	93%	7%	93%	7%
Logistics/ Warehouses	Cooking	0%	100%	0%	100%	0%	100%	0%	100%
	Hot Water	30%	69%	18%	59%	8%	67%	43%	48%
	Space Heating	60%	30%	10%	76%	42%	33%	64%	36%
Long Term Care	Cooking	52%	48%	52%	48%	52%	48%	52%	48%
	Hot Water	88%	12%	46%	46%	50%	38%	67%	28%
	Space Heating	56%	44%	50%	50%	50%	50%	54%	46%
Offices	Cooking	13%	87%	9%	91%	6%	94%	4%	96%
	Hot Water	32%	68%	18%	82%	37%	63%	41%	59%
	Space Heating	54%	44%	24%	75%	59%	39%	53%	43%
Other	Cooking	18%	82%	22%	78%	22%	78%	20%	80%
	Hot Water	42%	54%	19%	77%	44%	48%	46%	45%
	Space Heating	60%	37%	31%	59%	52%	41%	62%	32%
Retail - Food	Cooking	26%	74%	26%	74%	26%	74%	26%	74%
	Hot Water	63%	37%	18%	74%	33%	56%	60%	40%
	Space Heating	67%	27%	24%	72%	63%	25%	50%	50%
Retail - Non Food	Cooking	14%	86%	11%	89%	9%	91%	9%	91%
	Hot Water	34%	58%	16%	81%	36%	64%	36%	64%
	Space Heating	64%	34%	32%	65%	55%	41%	71%	29%
Schools	Cooking	20%	80%	18%	82%	17%	83%	17%	83%
	Hot Water	71%	19%	40%	60%	67%	17%	78%	22%
	Space Heating	75%	25%	54%	46%	80%	20%	90%	10%

Source: Navigant analysis of BC Hydro 2014 CEUS

Table B-11 shows the space heating equipment shares. The team used these space heating equipment shares to develop space heating EUIs, while EUIs for other end-uses were determined based on the 2010 CPR and did not require equipment shares.

Table B-11. Commercial Equipment Shares (%)

End-use	Equipment Type	Percentage of Equip in End-use within Fuel Type^										
		Accommodation	Colleges/ Universities	Food Service	Hospital	Logistics/ Warehouses	Long Term Care	Office	Other Commercial	Retail - Food	Retail - Non Food	Schools
Space Heating	Gas Boiler Low E	35%	40%	6%	73%	4%	34%	8%	10%	1%	1%	40%
	Gas Boiler High E	9%	0%	2%	19%	1%	10%	2%	4%	0%	0%	11%
	Gas Rooftop or Other Forced Air (Low E)	45%	60%	64%	6%	60%	44%	64%	53%	72%	65%	35%
	Gas Rooftop or Other Forced Air (High E)	11%	0%	18%	2%	11%	12%	17%	21%	20%	25%	9%
	Gas Unit Heater (Conventional.)	0%	0%	8%	0%	20%	0%	7%	8%	5%	6%	5%
	Gas Unit Heater (Condensing)	0%	0%	2%	0%	4%	0%	2%	3%	1%	2%	1%

Source: Navigant analysis of BC Hydro 2014 CEUS

End-Use Intensities (EUIs)

The next step of the commercial calibration process required the roll up of the fuel share and equipment share estimates in order to establish EUIs for each commercial segment in each region. Based on this approach, Navigant developed bottom-up EUI estimates for the Space Heating end-use. For other end-uses including Water Heating, Cooking, and Other, EUI estimates were developed based on a review of the 2010 CPR, and adjusted to the base year (2014) according to the EUI trends established for the Reference Case for FortisBC Gas.

Table B-12 presents the EUIs established for each end-use, and commercial segment. With the EUIs established for the base year, the Reference Case EUIs were determined based on the commercial EUI trends. The approach for developing the commercial EUI trends is described in the body of the report.

Table B-12: Base Year Commercial EUIs (MJ/m2) by Segment and Region

Segment	End-Use	Lower Mainland	Southern Interior	Vancouver Island	Northern BC
Accommodation	Cooking	80	76	82	71
	HVAC Fans/Pumps	-	-	-	-
	Hot Water	258	253	261	246
	Lighting	-	-	-	-
	Office Equipment	-	-	-	-
	Other	56	56	56	56
	Refrigeration	-	-	-	-
	Space Cooling	-	-	-	-
	Space Heating	252	305	250	436
	Total	646	690	649	809
Colleges/ Universities	Cooking	37	37	37	37
	HVAC Fans/Pumps	-	-	-	-
	Hot Water	69	69	69	69
	Lighting	-	-	-	-
	Office Equipment	-	-	-	-
	Other	65	65	65	65
	Refrigeration	-	-	-	-
	Space Cooling	-	-	-	-
	Space Heating	310	372	329	811
	Total	481	543	501	982
Food Service	Cooking	839	839	839	839
	HVAC Fans/Pumps	-	-	-	-
	Hot Water	476	476	476	476
	Lighting	-	-	-	-
	Office Equipment	-	-	-	-
	Other	19	19	19	19
	Refrigeration	-	-	-	-
	Space Cooling	-	-	-	-
	Space Heating	425	368	311	1,173
	Total	1,759	1,702	1,645	2,506
Hospitals	Cooking	65	65	65	65
	HVAC Fans/Pumps	-	-	-	-
	Hot Water	274	274	274	274
	Lighting	-	-	-	-
	Office Equipment	-	-	-	-
	Other	233	233	233	233
	Refrigeration	-	-	-	-
	Space Cooling	-	-	-	-
	Space Heating	758	1,037	725	2,062
	Total	1,330	1,609	1,297	2,635
Logistics/ Warehouses	Cooking	5	5	5	5
	HVAC Fans/Pumps	-	-	-	-
	Hot Water	18	18	18	18
	Lighting	-	-	-	-
	Office Equipment	-	-	-	-
	Other	19	19	19	19
	Refrigeration	-	-	-	-
	Space Cooling	-	-	-	-
	Space Heating	201	253	207	483
	Total	242	295	248	525
Long Term Care	Cooking	56	56	56	56
	HVAC Fans/Pumps	-	-	-	-
	Hot Water	156	156	156	156
	Lighting	-	-	-	-
	Office Equipment	-	-	-	-

Segment	End-Use	Lower Mainland	Southern Interior	Vancouver Island	Northern BC
	Other	65	65	65	65
	Refrigeration	-	-	-	-
	Space Cooling	-	-	-	-
	Space Heating	337	374	334	778
	Total	613	651	610	1,054
Offices	Cooking	9	9	9	9
	HVAC Fans/Pumps	-	-	-	-
	Hot Water	33	33	33	32
	Lighting	-	-	-	-
	Office Equipment	-	-	-	-
	Other	19	19	19	19
	Refrigeration	-	-	-	-
	Space Cooling	-	-	-	-
	Space Heating	263	330	275	485
	Total	324	390	336	545
Other Commercial	Cooking	15	14	12	14
	HVAC Fans/Pumps	-	-	-	-
	Hot Water	26	27	28	27
	Lighting	-	-	-	-
	Office Equipment	-	-	-	-
	Other	13	14	16	14
	Refrigeration	-	-	-	-
	Space Cooling	-	-	-	-
	Space Heating	276	347	297	452
	Total	330	402	353	507
Retail – Food	Cooking	75	75	75	75
	HVAC Fans/Pumps	-	-	-	-
	Hot Water	65	65	65	65
	Lighting	-	-	-	-
	Office Equipment	-	-	-	-
	Other	19	19	19	19
	Refrigeration	-	-	-	-
	Space Cooling	-	-	-	-
	Space Heating	311	278	290	639
	Total	469	436	448	797
Retail – Non Food	Cooking	13	13	15	13
	HVAC Fans/Pumps	-	-	-	-
	Hot Water	23	23	23	23
	Lighting	-	-	-	-
	Office Equipment	-	-	-	-
	Other	6	7	7	7
	Refrigeration	-	-	-	-
	Space Cooling	-	-	-	-
	Space Heating	256	315	272	367
	Total	299	357	317	410
Schools	Cooking	15	15	14	14
	HVAC Fans/Pumps	-	-	-	-
	Hot Water	39	39	39	39
	Lighting	-	-	-	-
	Office Equipment	-	-	-	-
	Other	5	5	5	5
	Refrigeration	-	-	-	-
	Space Cooling	-	-	-	-
	Space Heating	277	323	286	623
	Total	336	381	344	680

Source: Navigant analysis

Description of EUI Trending Approach

BC Hydro's 2014 CEUS surveyed commercial customers across each commercial segment in relation to upgrades made to end-use equipment in the past 5 years. The annual incidence of end-use equipment upgrades is then used to estimate the reduction in energy consumption from the adoption of higher efficiency equipment. Table B-13 summarizes an example of the incidence of water heating equipment upgrades.

Table B-13: Incidence of Water Heating Commercial Equipment Upgrades (2014 CEUS)

Segment	Equipment Upgrades	
	Past 5 years (%)	Estimate per year (%)
Accommodation	25.0%	5.0%
Colleges & Universities	33.0%	6.6%
Food Service	32.5%	6.5%
Hospital	20.0%	4.0%
Logistics & Warehouses	22.0%	4.4%
Long Term Care	29.0%	5.8%
Offices	12.0%	2.4%
Other	12.0%	2.4%
Retail - Food	27.0%	5.4%
Retail - Non Food	27.0%	5.4%
Schools	19.0%	3.8%

Source: Navigant analysis of BC Hydro 2014 CEUS

Although the 2014 CEUS did not survey the type of equipment or the efficiency of the upgrades, Navigant estimated the potential reduction in consumption by analyzing the inputs used to characterize conservation measures corresponding to each end-use. For example, the team estimated the average improvement in water heating measure efficiency at approximately 17% such that the efficient consumption is 83% of the base consumption. Navigant determined this improvement from characterization of water heating measures. The difference between the efficient and base consumption of the water heating measures listed below is, on average, 17%:

- Natural Gas On-Demand Water Heaters
- Natural Gas Storage Water Heaters
- Low-Flow Showerheads
- Faucet Aerators
- Natural Gas Hot Water Supply Boilers
- Recirculation Demand Controls for Hot Water

Navigant followed this process across all commercial segments for end-uses for which equipment upgrade information is reported in the 2014 CEUS. This includes the following end-uses:

- Lighting;

- Water Heating;
- Space Cooling;
- HVAC Fans/Pump; and
- Space Heating

Two of these end-uses – water heating and space heating – are applicable to gas consumption. For the remaining gas end-uses – cooking and other – survey information needed to develop EUI trends was not reported and are assumed to remain flat. Table B-14 summarizes the results for each end-use.

Table B-14: Commercial Measure Efficiency – Base vs. EE

End-Use	Improvement in End-Use Efficiency (%)	EE as % of Base consumption (%)
Water Heating	17%	83%
Space Heating	42%	58%

Source: Navigant analysis of measure characterization

Based on this approach, if the Water Heating EUI for the Accommodation segment is estimated at approx. 250 MJ/m2 in 2014, the EUI is estimated to decrease by 0.8% in 2015, down to 248 MJ/m2. This calculation is included below:

$$EUI_{2015} = EUI_{2014} * (EE\ equipment_{\%} * EE\ consumption_{kWh} + Base\ equipment_{\%} * Base\ consumption_{kWh})$$

$$248\frac{MJ}{m2} = 250\frac{MJ}{m2} * (5\% * 83\% + 95\% * 100\%)$$

A limitation of this approach is that the estimated decrease in EUI inherently reflects the impact of DSM programs. Navigant has not attempted to extract the impact of DSM participation from the EUI trends.

Table 2-28 in the main body of this report, shows the EUI trends determined for each end-use and commercial segment.

Table B-15,
Table B-16, and Table B-17, show the commercial EUIs used in the Reference Case for the Southern Interior, Vancouver Island, and Northern BC regions. The Lower Mainland EUIs are included in the main body. The EUIs presented in these tables were initially based on the Base Year EUIs shown in

Table B-12 and then were adjusted based on the EUI trends. The Lower Mainland EUIs are included the main body of the report.

Table B-15: Commercial Gas Intensity (MJ/m2) – Southern Interior

Commercial Segment	End-Use	CPR Period 2015	2020	2025	2030	2035
Accommodation	Cooking	76	76	76	76	76
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	253	241	234	229	226
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	56	56	56	56	56
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	305	276	260	249	242
	Total	690	648	626	611	600
Colleges/ Universities	Cooking	37	37	37	37	37
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	69	65	62	61	60
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	65	65	65	65	65
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	372	332	310	296	287
	Total	543	499	475	460	449
Food Service	Cooking	839	839	839	839	839
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	476	446	430	418	411
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	19	19	19	19	19
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	368	326	304	289	279
	Total	1,702	1,629	1,591	1,565	1,547
Hospitals	Cooking	65	65	65	65	65
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	274	263	257	253	250
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	233	233	233	233	233
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	1,037	933	877	840	815
	Total	1,609	1,494	1,432	1,391	1,363
Logistics/ Warehouses	Cooking	5	5	5	5	5
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	18	17	17	17	16
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	19	19	19	19	19
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	253	234	223	216	211
	Total	295	274	263	256	250

Commercial Segment	End-Use	CPR Period				
		2015	2020	2025	2030	2035
Long Term Care	Cooking	56	56	56	56	56
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	156	147	142	138	136
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	65	65	65	65	65
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	374	335	314	300	291
	Total	651	603	577	560	548
Office	Cooking	9	9	9	9	9
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	33	32	31	31	31
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	19	19	19	19	19
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	330	296	279	267	259
	Total	390	356	338	326	318
Other Commercial	Cooking	14	14	14	14	14
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	27	26	26	26	25
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	14	14	14	14	14
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	347	312	294	281	273
	Total	402	366	347	335	326
Retail - Food	Cooking	75	75	75	75	75
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	65	61	60	58	57
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	19	19	19	19	19
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	278	244	226	214	206
	Total	436	398	378	365	357
Retail – Non Food	Cooking	13	13	13	13	13
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	23	22	21	21	21
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	7	7	7	7	7
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	315	276	256	242	233
	Total	357	318	297	283	274
Schools	Cooking	15	15	15	15	15
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	39	38	37	36	36
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	5	5	5	5	5
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	323	290	273	262	254
	Total	381	347	329	317	309

Source: Navigant analysis of 2014 CEUS, FortisBC Gas 2016 Load Forecast

Table B-16: Commercial Gas Intensity (MJ/m2) – Vancouver Island

Commercial Segment	End-Use	CPR Period				
		2015	2020	2025	2030	2035
Accommodation	Cooking	82	82	82	82	82
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	261	248	241	236	233
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	56	56	56	56	56
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	250	226	213	204	199
	Total	649	612	592	579	570
Colleges/ Universities	Cooking	37	37	37	37	37
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	69	65	62	61	60
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	65	65	65	65	65
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	329	294	275	263	254
	Total	501	461	440	426	416
Food Service	Cooking	839	839	839	839	839
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	476	446	430	418	411
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	19	19	19	19	19
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	311	276	257	245	236
	Total	1,645	1,579	1,544	1,520	1,504
Hospitals	Cooking	65	65	65	65	65
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	274	263	257	253	250
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	233	233	233	233	233
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	725	652	613	587	570
	Total	1,297	1,213	1,168	1,138	1,118
Logistics/ Warehouses	Cooking	5	5	5	5	5
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	18	17	17	17	16
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	19	19	19	19	19
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	207	191	182	176	172
	Total	248	231	222	216	212

Commercial Segment	End-Use	CPR Period				
		2015	2020	2025	2030	2035
Long Term Care	Cooking	56	56	56	56	56
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	156	147	142	138	136
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	65	65	65	65	65
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	334	299	280	268	259
	Total	610	567	543	527	517
Office	Cooking	9	9	9	9	9
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	33	32	32	32	31
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	19	19	19	19	19
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	275	247	232	223	216
	Total	336	307	292	282	275
Other Commercial	Cooking	12	12	12	12	12
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	28	28	27	27	27
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	16	16	16	16	16
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	297	267	251	241	234
	Total	353	323	306	296	288
Retail - Food	Cooking	75	75	75	75	75
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	65	61	60	58	57
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	19	19	19	19	19
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	290	254	235	223	215
	Total	448	409	388	375	366
Retail – Non Food	Cooking	15	15	15	15	15
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	23	22	21	21	20
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	7	7	7	7	7
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	272	238	221	209	202
	Total	317	282	264	252	244
Schools	Cooking	14	14	14	14	14
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	39	38	37	36	36
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	5	5	5	5	5
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	286	257	242	231	225
	Total	344	314	297	287	279

Source: Navigant analysis of 2014 CEUS, FortisBC Gas 2016 Load Forecast

Table B-17: Commercial Gas Intensity (MJ/m2) – Northern BC

Commercial Segment	End-Use	CPR Period				
		2015	2020	2025	2030	2035
Accommodation	Cooking	71	71	71	71	71
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	246	234	227	222	219
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	56	56	56	56	56
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	436	395	372	357	347
	Total	809	755	726	707	693
Colleges/ Universities	Cooking	37	37	37	37	37
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	69	65	62	61	60
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	65	65	65	65	65
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	811	724	677	647	626
	Total	982	891	842	810	788
Food Service	Cooking	839	839	839	839	839
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	476	446	430	418	411
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	19	19	19	19	19
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	1,173	1,039	968	922	891
	Total	2,506	2,342	2,255	2,197	2,158
Hospitals	Cooking	65	65	65	65	65
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	274	263	257	253	250
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	233	233	233	233	233
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	2,062	1,855	1,744	1,671	1,621
	Total	2,635	2,417	2,300	2,222	2,170
Logistics/ Warehouses	Cooking	5	5	5	5	5
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	18	17	17	17	16
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	19	19	19	19	19
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	483	446	425	412	402
	Total	525	486	466	452	442
Long Term Care	Cooking	56	56	56	56	56
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	156	147	142	138	136
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	65	65	65	65	65
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	778	696	652	624	604
	Total	1,054	964	915	883	862

Commercial Segment	End-Use	CPR Period				
		2015	2020	2025	2030	2035
Office	Cooking	9	9	9	9	9
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	32	32	31	31	31
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	19	19	19	19	19
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	485	436	410	393	381
	Total	545	496	469	452	440
Other Commercial	Cooking	14	14	14	14	14
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	27	26	26	26	25
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	14	14	14	14	14
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	452	407	382	366	355
	Total	507	461	436	420	409
Retail - Food	Cooking	75	75	75	75	75
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	65	61	60	58	57
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	19	19	19	19	19
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	639	560	519	492	474
	Total	797	715	672	644	625
Retail – Non Food	Cooking	13	13	13	13	13
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	23	22	21	21	21
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	7	7	7	7	7
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	367	322	298	282	272
	Total	410	363	339	323	312
Schools	Cooking	14	14	14	14	14
	HVAC Fans/Pumps	-	-	-	-	-
	Hot Water	39	38	37	36	36
	Lighting	-	-	-	-	-
	Office Equipment	-	-	-	-	-
	Other	5	5	5	5	5
	Refrigeration	-	-	-	-	-
	Space Cooling	-	-	-	-	-
	Space Heating	623	560	527	505	490
	Total	680	616	582	559	544

Source: Navigant analysis of 2014 CEUS, FortisBC Gas 2016 Load Forecast

B.4 FortisBC Gas Industrial Sector – Additional Detail

This section describes the approach used to develop the Reference Case for the industrial sector.

FortisBC Gas's load forecast reports industrial sector gas sales as a whole and not broken down into individual industrial segments. To disaggregate the sector-wide forecast into industrial segments, Navigant and FortisBC worked together to develop gas sales projections which aligned with the sector-level forecast established for each region.

As a starting point, Navigant applied the electricity demand growth rates established for BC Hydro's Reference Case. FortisBC Gas reviewed those assumptions and directed Navigant to make adjustment to certain industrial segments which did not align with FortisBC Gas projections. These adjusted growth rates were used to estimate a forecast of gas consumption for each segment through 2035. A key aspect of this analysis is that this estimated forecast - determined based on adjusted growth rates – needed to reconcile with FortisBC Gas's sector-level forecast FortisBC Gas.

The steps to develop the Reference Case forecast are outlined below:

- Apply the adjusted growth rates to the base year (2014) consumption and sum the projected sales across each region to obtain a sector-level sales forecast (the "estimated" consumption forecast).
- Compare the estimated consumption across every 5-year period (e.g., 2020, 2025, 2030, and 2035) against the forecast 2035 consumption, and determine the difference (e.g., a surplus or a deficit)
- If the estimated consumption is greater than (or less than) the forecast consumption in each milestone year, reallocate the surplus or deficit across each segment according to each segment's contribution (%) to the regional total (e.g., if Pulp & Paper TMP accounts for 20% of industrial consumption then reallocate 20% of the surplus/deficit to the TMP segment) – this is the "re-adjusted" consumption
- Using the re-adjusted consumption determined in each milestone year, re-calculate the 5-year growth rates of each segment. These re-adjusted growth rates will ensure that the estimated consumption reconciles with the forecast consumption.
- These re-adjusted growth rates are used to develop the industrial sector Reference Case.

APPENDIX C. FORTISBC GAS - INTERACTIVE EFFECTS OF EFFICIENCY STACKING

The results shown throughout the body of this report assume that measures are implemented in isolation from other efficient measures and do not include adjustments for interactive effects of efficiency stacking (with some exceptions).[46] Interactive effects from efficiency stacking are different from cross-end-use interactive effects (e.g., efficient lighting impacts heating/cooling loads), which are present regardless of stacking assumptions and are included in the reported savings estimates. This appendix describes the challenges related to accurately determining the impacts of efficiency stacking, and why Navigant has modelled savings as though measures are implemented independently from others. Although the examples in this appendix focus on gas measures, the concepts are dually applicable to electric measures.

C.1 Background on Efficiency Stacking

When two or more measures that impact the same end-use energy consumption are installed in the same building, the total savings that can be achieved are less than the sum of the savings from those measures independently. For example, in isolation, the installation of a high efficiency boiler might save 11% of gas consumption relative to a baseline (lower efficiency) boiler, while ceiling insulation might save 71% of gas consumption relative to a baseline insulation level. However, if both the boiler and the insulation are installed in the same facility, the savings from the high efficiency boiler decrease due to the reduced need for space heating caused by better insulation.

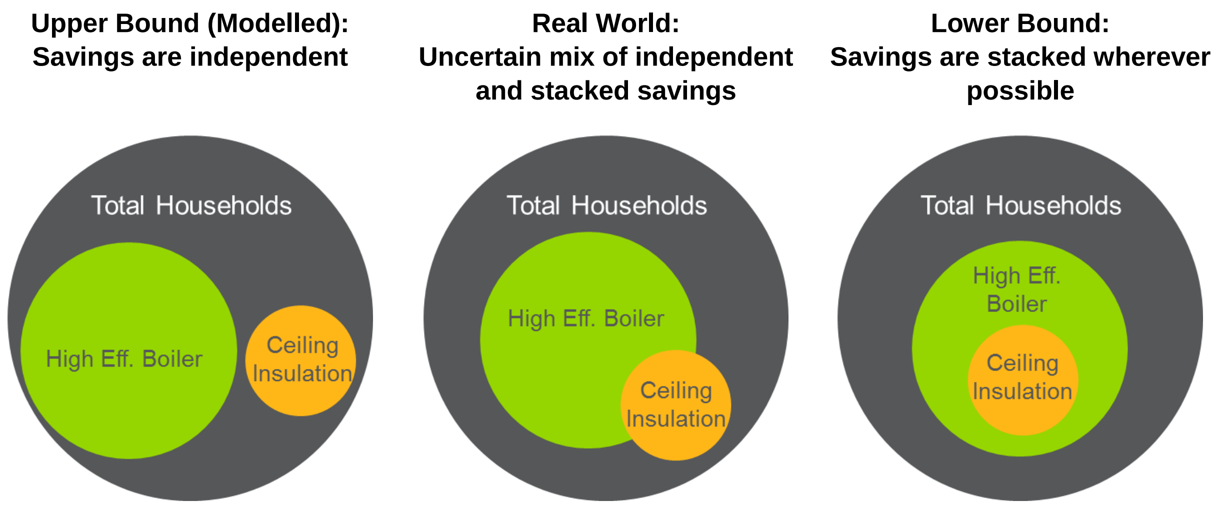
To generalize this concept Navigant refers to measures that actually convert energy as *engines* (boilers, light bulbs, motors, etc.). We refer to measures that impact the amount of energy that engines must convert as *drivers* (insulation, thermostats, lighting controls, etc.). Anytime an engine and driver are implemented in the same building, the expectation is that savings from the engine measure will decrease.[47]

Figure C-1 provides an illustration of three different efficiency stacking approaches. The modelled approach assumes no overlap in measure implementation and no efficiency stacking, which leads to an upper bound on savings potential. The opposite of the modelled approach is to assume all measures are stacked wherever possible, which provides a lower bound on savings. Lastly, there is the real-world approach where some measures are implemented in isolation and others are stacked. Unfortunately, the data is simply not available to accurately estimate the savings from the real-world approach.

[46] Wherever savings were derived from building energy model simulations evaluating bundled measures, interactive effects of efficiency stacking are included in the savings estimates (e.g., ENERGY STAR New Homes, Net-Zero New Homes, etc.).

[47] In practice it does not matter whether one assumes the engine's savings decrease or the driver's savings decrease, as the final savings result is the same. In this discussion, the team has chosen to always reduce the savings from the engine measures, while holding the savings from the driver measures fixed.

Figure C-1. Venn Diagrams for Various Efficiency Stacking Situations



Area of colored circle represents the number of households with a given savings opportunity. Overlapping circles indicate a household has implemented both measures.

C.2 Illustrative Calculation of Savings after Efficiency Stacking

For a very simplistic scenario looking at only two measures, it is possible to determine the stacked savings from the lower bound approach, which assumes efficient measures are stacked wherever possible. To find the high efficiency boiler's savings relative to the baseline after stacking, one must perform several steps:

1. Find the complement of the insulation's savings percentage:

   Insulation Savings Complement = 100% - Insulation Savings
   Insulation Savings Complement = 100% - 71% = 29%

2. Reduce the boiler's unstacked savings by the complement of the insulation's savings:

   Stacked Boiler Savings = Unstacked Boiler Savings x Insulation Savings Complement
   Stacked Boiler Savings =11% x 29% = 3.2%

3. Find the greatest percentage of homes where boiler and insulation stacking is possible:

   % of Homes with Stacking = Homes with Insulation / Homes with Boilers x 100%
   % of Homes with Stacking = 145,300 / 720,200 x 100% = 20.2%

4. Calculate the boiler's weighted average savings across all homes with boilers:

   Weighted Boiler Savings = Stacked Boiler Savings x % of Homes with Stacking +
   Unstacked Boiler Savings x (100% - % of Homes with Stacking)
   Weighted Boiler Savings = 3.2% x 20.2% + 11% x (100% - 20.2%) = 9.4%

Table C-1 provides an example of the technical potential from the boiler and insulation before and after stacking. As expected, the combined savings from the measures treated independently exceeds the combined savings after stacking.

Table C-1. Comparison of Savings Before and After Stacking

	High Efficiency Boiler	Ceiling Insulation	Combined Technical Potential
Applicable Households (households)	720,200	145,300	
Savings treated independently (no stacking)			
Savings Relative to Baseline (%)	11%	71%	
Total Technical Potential in Region (TJ/year)	2,540	1,860	4,400
Savings treated interactively (stacking)			
Savings Relative to Baseline (%)	9.4%	71%	
Total Technical Potential in Region (TJ/year)	2,176	1,860	4,036

C.3 Impetus for Treating Measure Savings Independently

Although it is possible to find the lower bound on savings with just one driver and one engine measure, the process quickly becomes intractable when multiple drivers and engines can be installed in the same facility. Table C-2 lists all of the engine and driver measures included in this study that could have interactive effects within the gas residential space heating end-use (which is just one of many end-uses across multiple sectors where stacking could occur).

Table C-2. Measures with Opportunity for Stacking in Residential Gas Space Heating End-use

Engine Measures	Driver Measures
Boiler Tune Up	Air Infiltration
Central High Eff Boiler Replace	Attic Duct Insulation
Combination System	Attic Insulation
Direct Vent Heaters	Basement Insulation
Efficient Fireplaces	Ceiling Insulation
Furnace Early Retirement	Crawlspace Duct Insulation
High Eff Boiler Replace	Energy Star Windows
High Eff Furnace Replace	Fireplace Timers
Vertical Direct Vent Fireplaces	Heat Reflectors
	Smart Thermostats
	Wall Insulation
	Window Film

Determining the appropriate stacking and correctly weighting the savings percentages from each of the engine measures requires:

- Case-by-case expert judgment about the combinations of driver and engine measures that might realistically be found in the same building, given historic and future construction practices;
- The conditional probability that a building has an inefficient driver “A” and an inefficient engine “B” for all drivers and engines relevant to a given end-use;
- In-depth knowledge of program design and how managers are considering pursuing participants and bundling measure offerings.

Answering the bullets above is beyond the scope of this study.

Lastly, at low levels of customer participation, it’s clear that assuming savings are independent is the best representation of what actual measure stacking would be. When customer participation is high, the “real-world” scenario is the best representation of actual measure stacking. Thus, under the plausible ranges of customer participation, the modelled (upper bound) scenario is likely to be a better representation of actual measure stacking than the lower bound scenario.

As such, this report does not attempt to quantify the impact from efficiency stacking within the modelled service territories.

APPENDIX D. SUPPORTING DATA FOR CHARTS

Table D-1. Total Gas Energy Savings Potential (TJ/year)

	Technical	Economic
2016	45,828	28,797
2017	46,269	29,990
2018	46,717	30,522
2019	47,244	31,666
2020	47,699	32,214
2021	48,128	32,865
2022	48,619	33,430
2023	49,054	34,057
2024	49,496	34,844
2025	50,005	35,389
2026	50,645	36,087
2027	51,335	36,792
2028	51,985	37,645
2029	52,642	38,390
2030	53,348	39,111
2031	54,186	40,025
2032	55,030	41,321
2033	55,879	42,221
2034	56,732	43,248
2035	57,591	44,158

Source: Navigant

Table D-2. Total Gas Energy Savings Potential as Percent of Total Consumption (%)

	Technical	Economic
2016	24.1%	15.1%
2017	24.2%	15.7%
2018	24.3%	15.9%
2019	24.4%	16.4%
2020	24.5%	16.6%
2021	24.7%	16.8%
2022	24.8%	17.1%
2023	24.9%	17.3%
2024	25.0%	17.6%
2025	25.2%	17.8%
2026	25.4%	18.1%
2027	25.6%	18.4%
2028	25.8%	18.7%
2029	26.0%	19.0%
2030	26.3%	19.2%
2031	26.6%	19.6%
2032	26.8%	20.2%
2033	27.1%	20.5%
2034	27.4%	20.9%
2035	27.7%	21.3%

Source: Navigant

Table D-3. Gas Energy Technical Savings Potential by Sector (TJ/year)

	Commercial	Industrial	Residential
2016	12,730	12,262	20,836
2017	13,152	12,240	20,877
2018	13,579	12,219	20,918
2019	14,085	12,198	20,960
2020	14,518	12,179	21,003
2021	14,909	12,145	21,074
2022	15,362	12,111	21,145
2023	15,759	12,079	21,217
2024	16,160	12,047	21,289
2025	16,628	12,016	21,361
2026	17,028	11,987	21,630
2027	17,477	11,958	21,899
2028	17,886	11,930	22,169
2029	18,300	11,903	22,438
2030	18,764	11,876	22,708
2031	19,143	11,847	23,196
2032	19,527	11,818	23,685
2033	19,915	11,790	24,174
2034	20,307	11,763	24,663
2035	20,703	11,736	25,152

Source: Navigant

Table D-4. Gas Energy Technical Savings Potential by Sector as a Percent of Sector Consumption (%)

	All	Commercial	Industrial	Residential
2016	24.1%	20.9%	21.4%	29.0%
2017	24.2%	21.3%	21.4%	28.9%
2018	24.3%	21.7%	21.4%	28.8%
2019	24.4%	22.3%	21.4%	28.7%
2020	24.5%	22.7%	21.4%	28.6%
2021	24.7%	23.0%	21.3%	28.6%
2022	24.8%	23.5%	21.3%	28.6%
2023	24.9%	23.8%	21.3%	28.6%
2024	25.0%	24.2%	21.3%	28.6%
2025	25.2%	24.6%	21.3%	28.6%
2026	25.4%	24.9%	21.3%	28.9%
2027	25.6%	25.3%	21.3%	29.1%
2028	25.8%	25.6%	21.3%	29.4%
2029	26.0%	26.0%	21.3%	29.6%
2030	26.3%	26.3%	21.2%	29.9%
2031	26.6%	26.6%	21.2%	30.4%
2032	26.8%	26.9%	21.2%	30.9%
2033	27.1%	27.2%	21.2%	31.4%
2034	27.4%	27.5%	21.2%	31.9%
2035	27.7%	27.7%	21.2%	32.4%

Source: Navigant

Table D-5. Gas Energy Technical Potential by Customer Segment (TJ/year)[48]

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
C.Accommod	575	602	630	660	688	714	742	768	795	823	849	876	902	929	957	981	1,005	1,030	1,054	1,080
C.College/Univ	588	615	642	672	700	727	757	785	813	844	872	901	929	958	989	1,015	1,041	1,067	1,094	1,121
C.Food Svc	862	903	945	991	1,033	1,071	1,112	1,150	1,188	1,230	1,266	1,306	1,342	1,380	1,420	1,452	1,485	1,518	1,551	1,584
C.Hospital	956	991	1,027	1,066	1,103	1,139	1,177	1,214	1,252	1,292	1,329	1,368	1,406	1,446	1,487	1,523	1,560	1,597	1,636	1,675
C.Logistic/WHouse	772	803	835	878	910	938	975	1,003	1,031	1,069	1,098	1,133	1,162	1,192	1,228	1,254	1,280	1,306	1,333	1,360
C.Long Term Care	438	466	496	528	559	589	622	654	688	724	757	793	828	865	904	939	975	1,012	1,051	1,090
C.Office	2,750	2,847	2,946	3,071	3,171	3,263	3,376	3,469	3,563	3,679	3,773	3,882	3,978	4,074	4,187	4,271	4,357	4,444	4,531	4,619
C.Other Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
C.Retail.Food	376	385	393	406	415	422	433	440	448	459	467	477	485	493	503	510	517	524	531	539
C.Retail.Non Food	930	948	965	995	1,012	1,028	1,053	1,068	1,083	1,109	1,125	1,149	1,166	1,183	1,207	1,221	1,236	1,251	1,266	1,281
C.Schools	922	939	957	986	1,004	1,020	1,046	1,062	1,078	1,104	1,122	1,147	1,165	1,183	1,209	1,225	1,241	1,258	1,274	1,291
C.Streetlights/Signals	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
I.Agriculture	292	292	292	293	293	294	294	294	295	295	295	296	296	297	298	298	299	299	300	301
I.Cement	140	139	139	138	137	136	134	133	132	131	131	131	131	131	131	131	131	130	130	130
I.Chemical	235	233	230	227	224	224	224	223	223	223	223	223	223	223	223	223	223	223	223	223
I.Food & Bev	814	807	800	793	787	780	773	767	761	755	749	744	739	733	728	724	719	715	710	706
I.Greenhouse	893	890	888	885	883	880	878	875	873	870	869	867	865	864	862	860	859	858	856	855
I.LNG Facility	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
I.Mfg	1,317	1,324	1,331	1,338	1,345	1,349	1,353	1,358	1,362	1,366	1,372	1,378	1,383	1,389	1,395	1,401	1,407	1,413	1,420	1,426
I.Coal Mining	366	364	363	361	359	359	360	360	360	360	359	358	357	356	354	353	352	351	350	349
I.Metal Mining	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
I.Oil & Gas	676	673	669	666	663	660	657	653	650	647	645	642	639	637	634	631	629	627	624	622
I.Other Industrial	250	252	255	258	262	266	271	276	281	287	285	284	283	282	281	276	271	266	262	257
I.Kraft Pulp/Paper	4,285	4,272	4,259	4,245	4,232	4,213	4,194	4,174	4,155	4,136	4,119	4,101	4,084	4,067	4,050	4,034	4,018	4,001	3,985	3,969
I.TMP Pulp/Paper	477	477	476	475	474	473	472	472	471	470	469	469	468	467	467	466	466	465	464	464
I.Transportation	157	157	156	155	155	154	154	153	153	152	151	150	148	147	145	144	143	141	140	139
I.Wood Products	2,358	2,360	2,361	2,362	2,363	2,355	2,346	2,338	2,330	2,321	2,318	2,315	2,312	2,309	2,306	2,304	2,302	2,300	2,298	2,296
R.Apt <= 4 Stories	2,284	2,341	2,398	2,454	2,511	2,558	2,606	2,653	2,700	2,747	2,795	2,842	2,890	2,937	2,985	3,034	3,083	3,132	3,180	3,229
R.Apt > 4 Stories	1,278	1,311	1,345	1,378	1,412	1,439	1,466	1,494	1,521	1,548	1,576	1,605	1,633	1,661	1,689	1,718	1,747	1,776	1,805	1,835
R.Other Residential	372	372	371	370	369	368	366	365	364	363	362	361	360	359	358	357	356	355	354	353
R.Fam Attached	1,377	1,381	1,386	1,391	1,396	1,402	1,409	1,415	1,421	1,428	1,448	1,468	1,488	1,509	1,529	1,563	1,597	1,630	1,664	1,698
R.Fam Detached	19,087	19,124	19,162	19,200	19,238	19,304	19,370	19,437	19,503	19,570	19,820	20,070	20,321	20,571	20,822	21,277	21,733	22,189	22,645	23,101

[48] While apartment buildings are prefaced with a "R" (for residential), their savings are grouped into and reported under the commercial sector. Apartments are labelled with an "R" because they are included in the residential sector for purposes of the base year and reference case analysis.

Source: Navigant

Table D-6. Gas Energy Technical Potential by End-use (TJ/year)[49]

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Appliances	343	343	342	341	340	339	338	337	336	335	334	333	332	331	330	329	328	327	327	326
Boilers	4,920	4,904	4,888	4,872	4,857	4,837	4,818	4,800	4,781	4,763	4,745	4,727	4,710	4,693	4,676	4,659	4,642	4,625	4,609	4,592
Cooking	379	384	388	393	398	402	407	411	415	420	424	428	432	437	441	444	448	452	455	459
Hot Water	6,869	6,835	6,801	6,767	6,733	6,699	6,666	6,632	6,599	6,566	6,533	6,501	6,468	6,436	6,404	6,372	6,340	6,308	6,277	6,245
Proc Heat	1,323	1,321	1,319	1,318	1,316	1,313	1,310	1,307	1,304	1,301	1,299	1,298	1,297	1,295	1,294	1,293	1,292	1,290	1,289	1,288
Product Drying	1,915	1,915	1,916	1,916	1,916	1,910	1,905	1,899	1,893	1,888	1,885	1,883	1,880	1,877	1,875	1,873	1,871	1,869	1,867	1,865
Space Heating	24,202	24,105	24,009	23,987	23,887	23,783	23,736	23,629	23,521	23,476	23,384	23,337	23,246	23,156	23,110	23,019	22,929	22,839	22,750	22,662
Whole Facility	5,876	6,463	7,054	7,651	8,253	8,844	9,440	10,040	10,646	11,256	12,040	12,828	13,620	14,417	15,218	16,197	17,181	18,167	19,158	20,153

Source: Navigant

[49] The industrial process end use is not shown in this table because no natural gas measures are assigned to it. As a result, savings are not reported for the industrial process end use.

Table D-7. Gas Energy Economic Savings Potential by Sector (TJ/year)

	Commercial	Industrial	Residential
2016	7,233	11,382	10,181
2017	7,849	11,360	10,781
2018	8,311	11,338	10,872
2019	9,158	11,317	11,192
2020	9,631	11,296	11,287
2021	10,168	11,265	11,432
2022	10,648	11,235	11,547
2023	11,180	11,205	11,672
2024	11,881	11,176	11,787
2025	12,335	11,148	11,907
2026	12,763	11,120	12,204
2027	13,196	11,094	12,502
2028	13,775	11,068	12,801
2029	14,247	11,043	13,100
2030	14,693	11,019	13,398
2031	15,131	10,992	13,901
2032	15,950	10,966	14,405
2033	16,355	10,941	14,925
2034	16,765	10,916	15,568
2035	17,180	10,891	16,087

Source: Navigant

Table D-8. Gas Energy Economic Savings Potential by Sector as a Percent of Sector Consumption (%)

	All	Commercial	Industrial	Residential
2016	15.1%	11.9%	19.8%	14.2%
2017	15.7%	12.7%	19.8%	14.9%
2018	15.9%	13.3%	19.8%	15.0%
2019	16.4%	14.5%	19.8%	15.3%
2020	16.6%	15.0%	19.8%	15.4%
2021	16.8%	15.7%	19.8%	15.5%
2022	17.1%	16.3%	19.8%	15.6%
2023	17.3%	16.9%	19.8%	15.8%
2024	17.6%	17.8%	19.8%	15.9%
2025	17.8%	18.2%	19.7%	16.0%
2026	18.1%	18.7%	19.7%	16.3%
2027	18.4%	19.1%	19.7%	16.6%
2028	18.7%	19.8%	19.7%	17.0%
2029	19.0%	20.2%	19.7%	17.3%
2030	19.2%	20.6%	19.7%	17.6%
2031	19.6%	21.1%	19.7%	18.2%
2032	20.2%	22.0%	19.7%	18.8%
2033	20.5%	22.3%	19.7%	19.4%
2034	20.9%	22.7%	19.7%	20.1%
2035	21.3%	23.0%	19.7%	20.7%

Source: Navigant

Table D-9. Gas Energy Economic Savings Potential by Customer Segment (TJ/year)[50]

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
C.Accommod	456	484	513	579	609	635	662	689	716	744	777	808	835	862	890	914	939	964	989	1,015
C.College/Univ	455	483	511	569	598	626	654	683	713	743	771	800	829	858	888	914	941	967	995	1,023
C.Food Svc	657	751	794	901	944	983	1,022	1,067	1,106	1,146	1,183	1,220	1,257	1,295	1,333	1,366	1,400	1,433	1,467	1,500
C.Hospital	606	643	680	788	827	864	903	942	981	1,023	1,061	1,101	1,141	1,182	1,224	1,262	1,300	1,339	1,378	1,419
C.Logistic/WHouse	334	368	403	449	490	522	554	587	620	653	684	716	794	826	857	923	951	979	1,007	1,035
C.Long Term Care	362	391	421	463	495	526	558	591	625	660	694	729	765	803	846	881	917	955	993	1,033
C.Office	975	1,083	1,197	1,329	1,441	1,647	1,801	1,907	2,275	2,383	2,482	2,583	2,685	2,788	2,892	2,983	3,075	3,168	3,262	3,356
C.Other Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
C.Retail.Food	177	201	211	318	327	336	345	354	362	371	379	388	396	405	413	421	428	436	443	451
C.Retail.Non Food	327	404	426	486	507	527	547	567	588	618	637	656	778	831	850	866	883	900	916	933
C.Schools	412	466	487	511	532	562	582	694	715	735	755	775	795	818	839	857	875	893	912	931
C.Streetlights/Signals	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
I.Agriculture	292	292	292	293	293	294	294	294	295	295	295	296	296	297	298	298	299	299	300	301
I.Cement	140	139	139	138	137	136	134	133	132	131	131	131	131	131	131	131	131	130	130	130
I.Chemical	235	233	230	227	224	224	224	223	223	223	223	223	223	223	223	223	223	223	223	223
I.Food & Bev	814	807	800	793	787	780	773	767	761	755	749	744	739	733	728	724	719	715	710	706
I.Greenhouse	893	890	888	885	883	880	878	875	873	870	869	867	865	864	862	860	859	858	856	855
I.LNG Facility	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
I.Mfg	1,317	1,324	1,331	1,338	1,345	1,349	1,353	1,358	1,362	1,366	1,372	1,378	1,383	1,389	1,395	1,401	1,407	1,413	1,420	1,426
I.Coal Mining	366	364	363	361	359	359	360	360	360	360	359	358	357	356	354	353	352	351	350	349
I.Metal Mining	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
I.Oil & Gas	676	673	669	666	663	660	657	653	650	647	645	642	639	637	634	631	629	627	624	622
I.Other Industrial	250	252	255	258	262	266	271	276	281	287	285	284	283	282	281	276	271	266	262	257
I.Kraft Pulp/Paper	4,285	4,272	4,259	4,245	4,232	4,213	4,194	4,174	4,155	4,136	4,119	4,101	4,084	4,067	4,050	4,034	4,018	4,001	3,985	3,969
I.TMP Pulp/Paper	477	477	476	475	474	473	472	472	471	470	469	469	468	467	467	466	466	465	464	464
I.Transportation	157	157	156	155	155	154	154	153	153	152	151	150	148	147	145	144	143	141	140	139
I.Wood Products	1,479	1,479	1,480	1,480	1,481	1,475	1,470	1,464	1,459	1,453	1,451	1,451	1,450	1,450	1,449	1,450	1,450	1,450	1,450	1,450
R.Apt <= 4 Stories	1,585	1,651	1,711	1,771	1,831	1,882	1,932	1,982	2,033	2,083	2,134	2,185	2,235	2,286	2,337	2,389	2,707	2,757	2,808	2,859
R.Apt > 4 Stories	888	924	959	994	1,029	1,059	1,088	1,117	1,146	1,175	1,205	1,235	1,265	1,295	1,325	1,356	1,535	1,565	1,595	1,625

[50] While apartment buildings are prefaced with a “R” (for residential), their savings are grouped into and reported under the commercial sector. Apartments are labelled with an “R” because they are included in the residential sector for purposes of the base year and reference case analysis.

R.Other Residential	183	204	204	204	205	205	204	204	204	208	208	207	207	207	206	206	206	206	205	208
R.Fam Attached	422	460	470	706	718	723	729	745	750	755	761	766	773	779	786	792	799	805	812	831
R.Fam Detached	9,576	10,117	10,199	10,281	10,364	10,505	10,614	10,724	10,834	10,943	11,236	11,529	11,821	12,114	12,406	12,903	13,400	13,915	14,551	15,047

Source: Navigant

Table D-10. Gas Energy Economic Savings Potential by End-Use (TJ/year)[51]

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Appliances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Boilers	4,920	4,904	4,888	4,872	4,857	4,837	4,818	4,800	4,781	4,763	4,745	4,727	4,710	4,693	4,676	4,659	4,642	4,625	4,609	4,592
Cooking	379	384	388	393	398	402	407	411	415	420	424	428	432	437	441	444	448	452	455	459
Hot Water	3,828	4,317	4,300	4,278	4,257	4,235	4,214	4,199	4,178	4,157	4,136	4,115	4,095	4,074	4,054	4,034	4,013	3,993	3,973	3,954
Proc Heat	1,323	1,321	1,319	1,318	1,316	1,313	1,310	1,307	1,304	1,301	1,299	1,298	1,297	1,295	1,294	1,293	1,292	1,290	1,289	1,288
Product Drying	1,036	1,035	1,035	1,034	1,034	1,031	1,028	1,025	1,023	1,020	1,018	1,018	1,018	1,018	1,018	1,019	1,019	1,019	1,020	1,020
Space Heating	11,440	11,572	11,543	12,121	12,102	12,209	12,224	12,290	12,516	12,496	12,465	12,436	12,549	12,549	12,520	12,519	12,897	12,874	12,974	12,939
Whole Facility	5,871	6,457	7,049	7,650	8,251	8,838	9,430	10,026	10,627	11,233	11,999	12,769	13,544	14,324	15,108	16,058	17,010	17,967	18,927	19,905

Source: Navigant

[51] The industrial process end use is not shown in this table because no natural gas measures are assigned to it. As a result, savings are not reported for the industrial process end use.

British Columbia Conservation Potential Review

Section 5. Market Potential

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DISCLAIMER

This report was prepared by Navigant Consulting, Inc. (Navigant) for FortisBC Energy Inc. The work presented in this report represents Navigant's professional judgment based on the information available at the time this report was prepared. Navigant is not responsible for the reader's use of, or reliance upon, the report, nor any decisions based on the report. NAVIGANT MAKES NO REPRESENTATIONS OR WARRANTIES, EXPRESSED OR IMPLIED. Readers of the report are advised that they assume all liabilities incurred by them, or third parties, as a result of their reliance on the report, or the data, information, findings and opinions contained in the report.

5. MARKET POTENTIAL FORECAST

This section contains details of the market potential analysis that Navigant conducted for FortisBC Gas's service territory, including the following:

- Section 5.1 describes the approach to estimating market potential, including discussion of the model calibration steps and the strategy selected for simulating incentives in the analysis.
- Section 5.2 provides overall gas market potential estimates, as well as savings by sector, customer segment, end use, and certain measures.
- Section 5.3 follows with details of the associated budgets and cost effectiveness results under the TRC test across all sectors, which is consistent with the methodology Navigant used for the economic potential presented in Section 4.
- Section 5.4 provides the economic, market potential, and cost effectiveness results under the modified-TRC (mTRC) test across all sectors.
- Section 5.5 provides the economic, market potential, and cost effectiveness results under the Hybrid mTRC/TRC case (described below).

5.1 Approach to Estimating Market Potential

Market potential is a subset of economic potential that considers the likely rate of DSM acquisition, given factors like the rate of equipment turnover (a function of a measure's lifetime), simulated incentive levels, consumer willingness to adopt efficient technologies, and the likely rate at which marketing activities can facilitate technology adoption. The adoption of DSM measures can be broken down into calculation of the "equilibrium" market share and calculation of the dynamic approach to equilibrium market share, as discussed in more detail below.

Market potential differs from program potential in that market potential does not specifically take into account the various delivery mechanisms that can be used by program managers to tailor their approach depending on the specific measure or market. Rather, market potential represents a high-level assessment of savings that could be achieved over time, factoring in broader assumptions about customer acceptance and adoption rates that are not dependent on a particular program design. Additional effort is typically undertaken by program designers, using the directional guidance from a market potential study, to develop detailed plans for delivering conservation programs.

This report presents market potential results from three distinct approaches to screening measures for cost effectiveness. The objective for assessing these three approaches was to consider various possible cost effectiveness environments over the future of this long-range analysis by incorporating the different cost effectiveness approaches present at the time of the analysis. The regulatory environment for FortisBC Gas at the time of this analysis allowed the utility to spend up to 33% of its entire DSM portfolio on measures or programs that require an mTRC to be cost effective.[1] To date, FortisBC Gas's experience is that, typically, most programs in the residential sector require the mTRC. Since FortisBC Gas uses a

[1] The formulation of the mTRC benefit-cost test is the same as the TRC test, with the exception that the avoided costs stem from a zero emission energy supply alternative (ZEEA) cost and a 15% non-energy benefits adder increases benefits.

combination of TRC and mTRC benefit-cost tests to screen measures and programs within their portfolio, Navigant estimated market potential using the following benefit-cost tests to screen cost effective measures:

1. **TRC only:** This case uses the TRC test across all sectors and presents results consistent with the screening method used in the previous CPR report focusing on technical and economic potential.
2. **mTRC only:** This case uses the mTRC test across all sectors.
3. **Hybrid mTRC/TRC:** This case uses the mTRC test for the residential sector and the TRC test for the commercial and industrial (C&I) sectors, which is most analogous to FortisBC Gas's actual DSM program environment.[2]

Table 5-1 below summarizes the key methodology considerations and decision points informing the analysis in this report, with more detail provided in the report sections noted in the right-hand column of the table. Navigant and FortisBC Gas agreed upon this methodology through discussions about which approach best serves the needs of the utility for understanding market savings potential. Since this study's scope for market potential estimates are not intended to be program-specific and are most reasonable when results are considered in aggregate, the methodology presented here focuses primarily on portfolio-level or sector-level approaches. However, FortisBC Gas selected five high impact measures for measure-level calibration, which is discussed in Section 5.1.6.

[2] Model limitations prevented the team from implementing a strict 33% cap on spending directed towards measures requiring the mTRC screen. However, the cap was approximated by only allowing residential measures to screen the mTRC test for cost-effectiveness.

Table 5-1. Market Potential Methodology Overview

Methodology Parameters	Approach	Report Section
Benefit-cost test screen	Use the TRC as the primary screen for technical, economic, and market potential, with economic and market potential also calculated using the mTRC and a hybrid of mTRC/TRC tests.	5.1
Diffusion parameters	Adjust diffusion parameters within ranges recommended by industry standard data sources to produce savings that are reasonably aligned with FortisBC DSM sector-level historical achievements. Customize the diffusion parameters for the five high impact measures selected in advance by FortisBC Gas in order to align with historic savings at the measure level.	5.1.1, 5.1.2, and 5.1.6
Budget constraints	Do not apply budget constraints.	5.1.4
Incentive strategy	Set incentives as a percent of the incremental cost for all measures pertaining to each sector, such that the simulated percentages of total spending from incentives versus non-incentive costs aligns with historic values across the sector.	5.1.5 and 5.1.7
Treatment of admin and fixed costs	Exclude portfolio-level fixed costs; use a sector-level $/GJ cost derived from historic non-incentive program spending, which includes fixed and variable administrative costs.	5.3.1 and 5.3.2
Net-to-Gross (NTG)	Focus on gross savings within the report, and include discussion on impacts of NTG factors at the sector level for high-level estimates of net savings (consistent with the approach used for technical and economic potential)	5.2.6
Re-participation	Assume 100% of measures re-participate as an efficient measure at the end of their measure life	N/A
Codes and standards	Use the same assumptions about codes and standards as in technical and economic potential	5.2.5

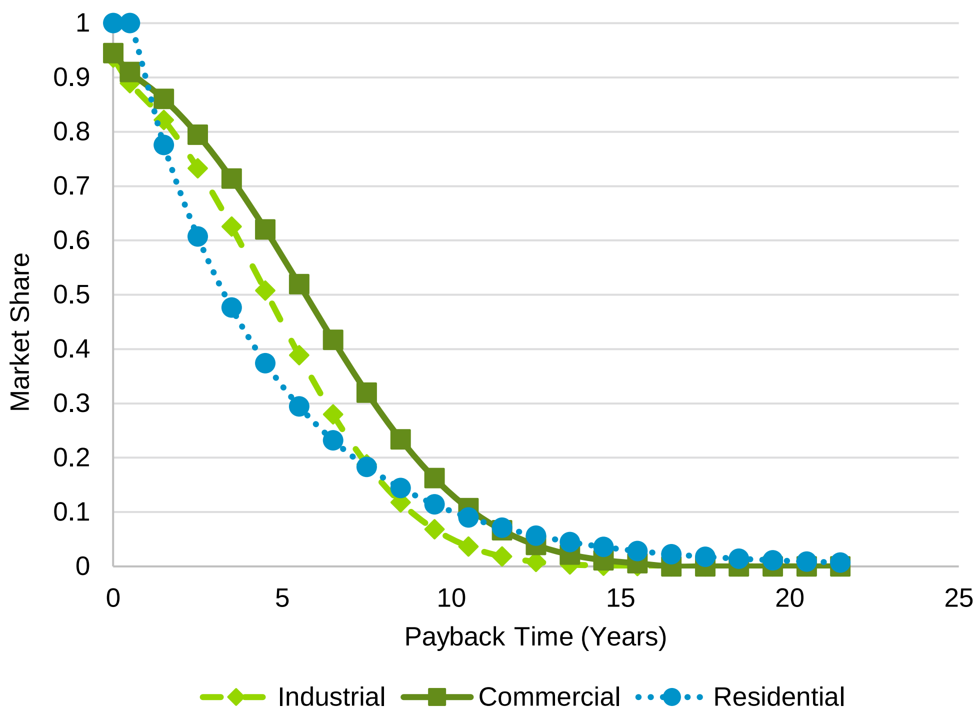
5.1.1 Calculation of "Equilibrium" Market Share

The equilibrium market share can be thought of as the percentage of individuals choosing to purchase a technology provided those individuals are fully aware of the technology and its relative merits (e.g., the energy- and cost-saving features of the technology). For DSM measures, a key differentiating factor between the base technology and the efficient technology is the energy and cost savings associated with the efficient technology. Of course, that additional efficiency often comes at a premium in initial cost. This study calculates an equilibrium market share as a function of the payback time of the efficient technology relative to the inefficient technology. In effect, measures with more favorable customer payback times will have higher equilibrium market share, which reflects consumers' economically rational decision making. While such approaches certainly have limitations, they are nonetheless directionally reasonable and simple enough to permit estimation of market share for the hundreds of technologies appearing in most potential studies.

To inform this CPR, Navigant used equilibrium "payback acceptance" curves that Navigant developed using primary research in the US Midwest in 2012.[3] To develop these curves, Navigant relied on surveys of 400 residential, 400 commercial, and 150 industrial customers. These surveys presented decision makers with numerous "choices" between technologies with low up-front costs, but high annual energy costs, and measures with higher up-front costs but lower annual energy costs. Navigant conducted statistical analysis to develop the set of curves shown in Figure 5-1, which Navigant used in this CPR. Though FortisBC-specific data were not available to estimate these curves, Navigant considers that the nature of the customer decision-making process is such that the data developed using North American customers represents the best industry-wide data available at the time of this study.

As the curves show, the proportion of customers who will accept different payback periods for an energy efficiency investment is different for residential, commercial and industrial customers.[4] The model uses this information to simulate how customers in each sector will accept measures with differing payback periods.

Figure 5-1. Payback Acceptance Curves



Source: Navigant

Since the payback time of a technology can change over time, as technology costs and/or energy costs change over time, the "equilibrium" market share can also change over time. The equilibrium market

[3] A detailed discussion of the methodology and findings of this research are contained in "Demand Side Resource Potential Study," prepared for Kansas City Power and Light, August 2013.

[4] These payback curves represent customer payback acceptance in aggregate across each sector. In practice, customer behavior can vary across sub-sectors. However, there is minimal industry-wide data available on customer payback acceptance at the sub-sector level.

share is therefore recalculated for every year of the forecast to ensure the dynamics of technology adoption take this effect into consideration. As such, “equilibrium” market share is a bit of an oversimplification and a misnomer, as it can itself change over time and is therefore never truly in equilibrium, but it is used nonetheless to facilitate understanding of the approach.

5.1.2 Calculation of the Approach to Equilibrium Market Share

Two approaches are used for calculating the approach to equilibrium market share, one for technologies being modeled as retrofit (RET) measures, and one for technologies simulated as replace-on-burnout (ROB) or new construction (NEW measures).[5] A high-level overview of each approach is provided below.

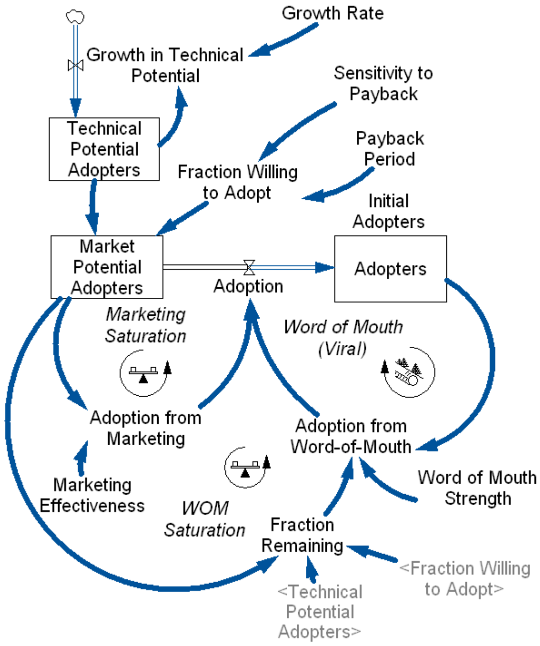
5.1.2.1 Retrofit Technology Adoption Approach

RET technologies employ an enhanced version of the classic Bass diffusion model[6,7] to simulate the S-shaped approach to equilibrium that is observed again and again for technology adoption. Figure 5-2 provides a stock/flow diagram illustrating the causal influences underlying the Bass model. In this diagram, market potential adopters “flow” to adopters by two primary mechanisms – adoption from external influences, such as marketing and advertising, and adoption from internal influences, or “word-of-mouth.” Navigant estimated the “fraction willing to adopt” using the payback acceptance curves illustrated in Figure 5-1.

Navigant estimated the marketing effectiveness and word-of-mouth parameters for this diffusion model by drawing upon case studies where these parameters were estimated for dozens of technologies.[8] Recognition of the positive, or self-reinforcing, feedback generated by the “word-of-mouth” mechanism is evidenced by increasing discussion of the concepts such as social marketing as well as the term “viral,” which has been popularized and strengthened most recently by social networking sites such as Twitter, Facebook and YouTube. However, the underlying positive feedback associated with this mechanism has been ever present and a part of the Bass diffusion model of product adoption since its inception in 1969.

[5] Each of these approaches can be better understood by visiting Navigant’s technology diffusion simulator, available at: http://forio.com/simulate/navigantsimulations/technology-diffusion-simulation.
[6] Bass, Frank (1969). "A new product growth model for consumer durables". Management Science 15 (5): p215–227.
[7] See Sterman, John D. *Business Dynamics: Systems Thinking and Modeling for a Complex World*. Irwin McGraw-Hill. 2000. p. 332.
[8] See Mahajan, V., Muller, E., and Wind, Y. (2000). New Product Diffusion Models. Springer. Chapter 12 for estimation of the Bass diffusion parameters for dozens of technologies.

Figure 5-2. Stock/Flow Diagram of Diffusion Model for New Products and Retrofits



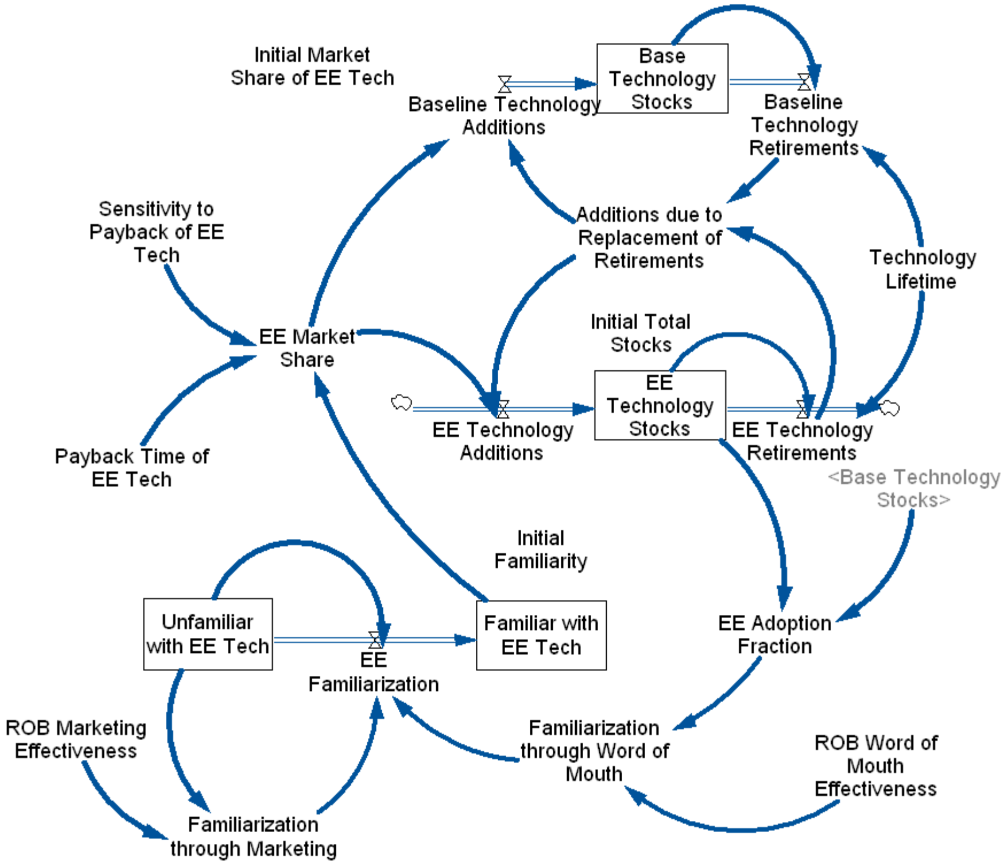
Source: Navigant

The model illustrated above generates the commonly seen S-shaped growth of product adoption and is a simplified representation of that employed in DSMSim™.

5.1.2.2 Replace-on-Burnout Technology Adoption Approach

The dynamics of adoption for ROB technologies are somewhat more complex than for NEW/RET technologies since it requires simulating the turnover of mostly long-lived technology stocks. The DSMSim™ model tracks the stock of all technologies, both base and efficient, and explicitly calculates technology retirements and additions consistent with the lifetime of the technologies. Such an approach ensures that technology “churn” is considered in the estimation of market potential, since only a fraction of the total stock of technologies are replaced each year, which affects how quickly technologies can be replaced. A model that endogenously generates growth in the familiarity of a technology, analogous to the Bass approach described above, is overlaid on the stock tracking model to capture the dynamics associated with the diffusion of technology familiarity. Figure 5-3 graphically illustrates a simplified version of the model employed in DSMSim™.

Figure 5-3. Stock/Flow Diagram of Diffusion Model for ROB Measures



Source: Navigant

5.1.3 Behavioral Measures

Behavior measures typically impose little to no direct costs to the participant[9] and their rate of adoption is highly dependent on the marketing and incentive efforts taken by program administrators. Given these unique characteristics of behavior measures, the payback acceptance curves and technology diffusion models have limited applicability to these types of measures. As such, this study models the adoption of behavior measures in terms of an equilibrium saturation level relative to economic potential and a given amount of time to reach that equilibrium state.

[9] Participants may incur indirect costs through implementation of adjustments to typical operations in response to energy information feedback (e.g., through upgrading a water heater). However, estimating these indirect costs requires additional data on the actions taken by the participant outside of the program and is beyond the scope of this analysis.

This study includes four measures that are distinctly behavioral:

- Commercial Comprehensive Retrocommissioning[10]
- Commercial Occupant Behavior[11]
- Industrial Energy Management[12]
- Residential Home Energy Reports[13]

For each of these measures, the team used multiple sources of information to define the equilibrium saturation level and the duration of time required to reach that level. Figure 5-4 illustrates the saturation trajectory as a percentage of economic potential for each of the behavior measures. Although the adoption of behavior measures is not linked to customers' payback acceptance time, the market potential for behavior measures is still dependent on cost effectiveness by means of the economic potential. As such, the realized market savings from these measures can vary between the TRC and mTRC cases if economic potential varies.

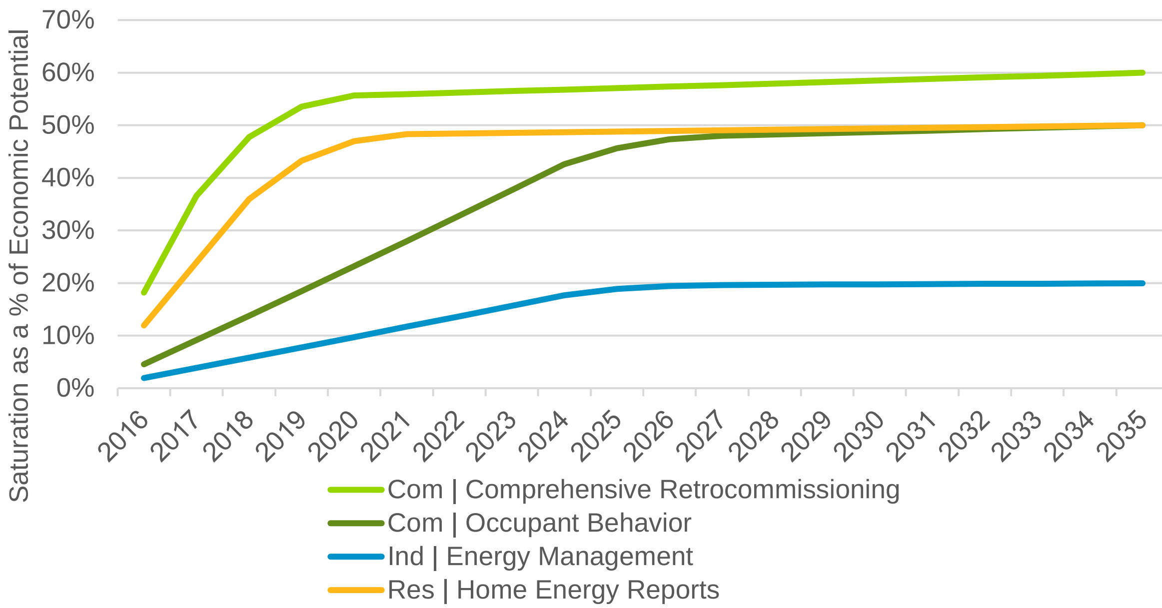
[10] Commercial comprehensive retrocommisioning is similar to FortisBC Gas's Continuous Energy Optimization offering, so the annual ramp rate was trended with historic savings from that measure. Differing from the other behavioral measures, the characterization of retrocommisioning includes some upfront costs to the participant (e.g., paying for a portion of staff training). Since it is uncertain whether comparable training would be available absent program offerings and enrollment efforts, the study treats this measure as a behavior measure that is dependent on on-going support from program administrators.

[11] The team chose the adoption trajectory for the commercial occupant behavior measure after reviewing research conducted for the California Public Utilities Commission on similar measures and after reviewing the trends in historic savings from similar measures within FortisBC Gas's Energy Specialist program.

[12] Navigant designed the rollout of industrial energy management to mimic historical participation levels within BC Hydro's more mature program focusing on industrial energy management. This trajectory implies participation of about nine customers/sites per year, which aligns well with the number of annual customers that participated in BC Hydro's programs, given the different size of each utility's customer base.

[13] The team developed the saturation curves for residential home energy report using information attained through interviews with OPower staff and their experience with typical offerings of these reports. These energy reports encompass many of Fortis Gas's current activities focused on residential behavior.

Figure 5-4. Behavior Measure Market Saturation as a Percentage of Economic Potential (%)



Source: Navigant

5.1.4 Budget Strategy

FortisBC Gas elected to view market potential without imposing any budget constraints on the simulated results. The implication of this decision is that market potential is only constrained by stock turnover and customer willingness to adopt efficient measures. Without future budget constraints, the utility spending falls out naturally from the input assumptions for per-unit-of-savings incentive and administrative costs and a given year's level of market savings, without tying spending to a given budget level. In this case, the per-unit-of-savings incentive and administrative spending levels are fixed at the same levels (in real dollars) over the study horizon. Therefore, changes in spending (in real dollars) only reflect a changing mix and magnitude of savings among measures.

5.1.5 Incentive Strategy

Per FortisBC Gas's guidance, this study calculates measure-level incentives based on a specified percentage of incremental measure costs. For example, if the specified incentive percentage was 50% and a measure's incremental cost was $100, then the calculated incentive for that measure would be $50. The incentive percentage differs by sector and is applied uniformly to all measures within a given sector.[14] Section 5.1.7 discusses how the model calibration process informed the specified incentive percentage in more detail.

[14] Navigant applied incentive percentages at the sector level, as opposed to the measure level, per the focus of this study's scope on sector-level market potential, rather than program-level potential. Actual program design would define incentive levels for each measure.

5.1.6 High Impact Measures

FortisBC Gas selected five measures that merit a more granular measure-level analysis, with the intent that Navigant would perform measure-level calibration customized to each measure's historic savings trajectories. These five high impact measures include:

1. Residential Condensing Storage Water Heater
2. Residential Condensing Tankless Water Heater
3. Residential Efficient Fireplaces
4. Residential Furnace Early Retirement
5. Residential High Efficiency Boiler Replacement

Section 5.1.7 discusses how Navigant customized the calibration of these measures in more detail.

5.1.7 Model Calibration

Any model simulating *future* product adoption faces challenges with "calibration," as there is no future world against which one can compare simulated results to actual results. Engineering models, on the other hand, can often be calibrated to a higher degree of accuracy since simulated performance can be compared directly with performance of actual hardware. Unfortunately, DSM potential models do not have this luxury, and therefore must rely on other techniques to provide both the developer and the recipient of model results with a level of comfort that simulated results are reasonable. For this CPR, Navigant took a number of steps to ensure that forecast model results were reasonable, including:

- Identifying the subset of CPR measures that were included in historic program offerings in order to have a basis for comparison with historic program achievements.
- Ensuring similar trends and magnitudes between average historic sector-level savings between 2013-2015 and simulated sector-level savings from the measure subset in 2016.[15]
- For the five high-impact measures, ensuring similar trends and magnitudes between historic measure-level savings and 2016 simulated savings. Additionally, the team calibrated long-term trends to align reasonably with FortisBC Gas's projections for these measures.
- Seeking general alignment between 2015 historic sector-level incentives as a percentage of total sector-level spending and simulated 2016 values.[16]

Before making comparisons of model results to historic achievements, it was first necessary to identify the CPR measures that were included in historic program offerings. The simulated savings from this subset of CPR measures became the basis for comparing modelled savings to historic savings during the calibration process. It is important to note that although the team reached good alignment in trends between historic and simulated results for this subset of measures, this study's results for *total* market potential significantly exceed the historically achieved program savings. This is because the study includes many additional measures that have historically not been included in programs, and those extra

[15] The team compared simulated savings to 2013-2015 historic averages, rather than a single historic year, because historic savings varied appreciably from one near to the next within each sector.
[16] The team compared the percentage of simulated spending derived from incentives to the 2015 historic percentages because 2015 was deemed to be most representative of expectations about future spending allocations between incentives and non-incentives.

measures contribute significant savings to the total market potential results.

When comparing residential results to historic program achievements, Navigant used results from the mTRC case because they are most analogous to FortisBC Gas's program environment (as described in Section 5.1). When comparing commercial and industrial results to historic program achievements, Navigant used results from the TRC case.

To obtain close agreement with FortisBC Gas's historic savings across a wide variety of metrics, Navigant adjusted incentive levels, technology diffusion coefficients and payback acceptance curves. Calibration required an iterative process of modifying the aforementioned parameters until all goals of calibration were reasonably satisfied. For example, the marketing effectiveness parameters are the key lever for calibrating the magnitude of 2016 savings for each sector, whereas the word-of-mouth parameter strongly influences how rapidly adoption and savings ramp up over time. Navigant varied these diffusion parameters within the commonly observed ranges until simulated savings were trending reasonably compared with historic savings at the sector level.[17]

For the five high impact measures, the team made several custom adjustments to align simulated savings with the historic trends. First, the team automatically included these measures in the market potential (for the mTRC and Hybrid cases, but not the TRC case) regardless of their sub-sector cost effectiveness.[18] The team made this provision to ensure that these measures, which are currently offered through FortisBC Gas's programs, would also appear in the market potential.[19] Second, Navigant customized the marketing effectiveness and payback acceptance curves for these measures to achieve similar magnitudes and trends between modelled savings and historic savings.

Lastly, the team adjusted sector-level incentive levels to be different percentages of incremental costs until the percentage of 2016 total spending attributable to incentives was similar to 2015 historic values. The calibrated incentive levels produce a weighted average incentive percentage of 56% for the simulated portfolio. This calibrated value coincides well with the initial target of having modelled incentives cover roughly 50% of incremental costs across the portfolio.

To summarize, the calibration process ensures that forecast potential is grounded against real-world results considering the many factors that determine likely adoption of DSM measures, including both economic and non-economic factors.

[17] This study uses a value of 0.255 for the word-of-mouth strength, which is the 25th percentile of values observed by Mahajan 2000. The marketing effectiveness parameter varied between 0.010 and 0.053, depending on the sector. These values span from roughly the 25th percentile to 75th percentile of observed marketing effectiveness, per Mahajan 2000.

[18] While these measures are cost effective overall, some measures are not cost effective for certain sub-sectors and regions within the analysis. Since actual programs focus on overall cost effectiveness across the sector, rather than within sub-sectors, Navigant forced the five high impact measures to pass across all sub-sectors to better reflect actual program implementation.

[19] Each of the five high impact measures are currently offered through FortisBC Gas's residential programs. Because programs look at the collective cost effectiveness of a group of measures (e.g., several water heater technologies), it is possible that a technology within the group may not be cost-effective. However, the group as a whole can be cost-effective, and therefore any technology within the group can be offered through programs.

5.2 Market Potential Results

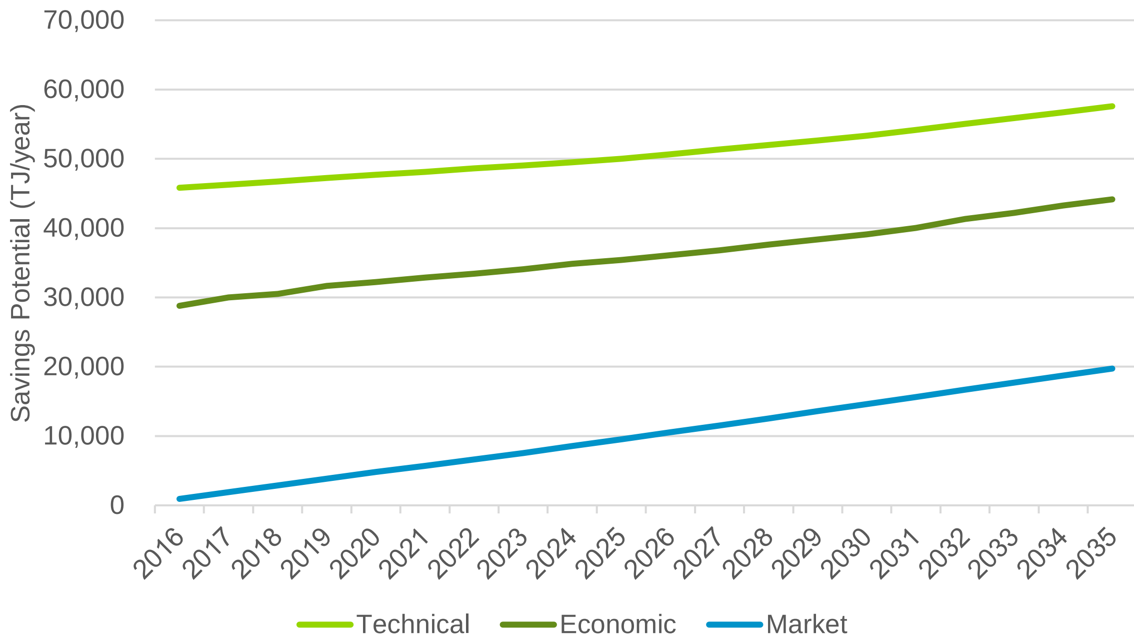
This section provides the market potential results calculated by the model at varying levels of aggregation, using the TRC benefit-cost test as a screen (as consistent with the representation of economic potential in Section 4). Results are shown by sector, customer segment, end-use category, and by highest-impact measures. The section concludes with a review of natural change and its impacts on market potential.

5.2.1 Comparison of Savings by Potential Type

Values shown below for market potential are termed “cumulative market” potential, in that they represent the accumulation of each year’s annual incremental market potential (e.g., an annual incremental market potential of 0.8% per year for ten years would result in a cumulative market potential of 8.0% of forecast consumption). Economic potential, as defined in this study, can be thought of as a bucket of potential from which programs can draw over time. Market potential represents the draining of that bucket, the rate of which is governed by a number of factors, including the lifetime of measures (for ROB technologies), market effectiveness, incentive levels, and customer willingness to adopt, among others. If the cumulative market potential ultimately reaches the economic potential, it would signify that all economic potential in the “bucket”’ had been drawn down, or harvested.

As shown in Figure 5-5 and Table B-1 in Appendix B, the market potential, which accounts for the rate of DSM acquisition, increases steadily throughout the CPR period, reaching 19,736 TJ/year in 2035. By 2035, market potential reaches nearly 46% of the economic potential. Incremental annual market potential added year-over-year to the cumulative potential averages 987 TJ/year over the study horizon.[20]

Figure 5-5. Total Cumulative Gas Savings Potential (TJ/year)

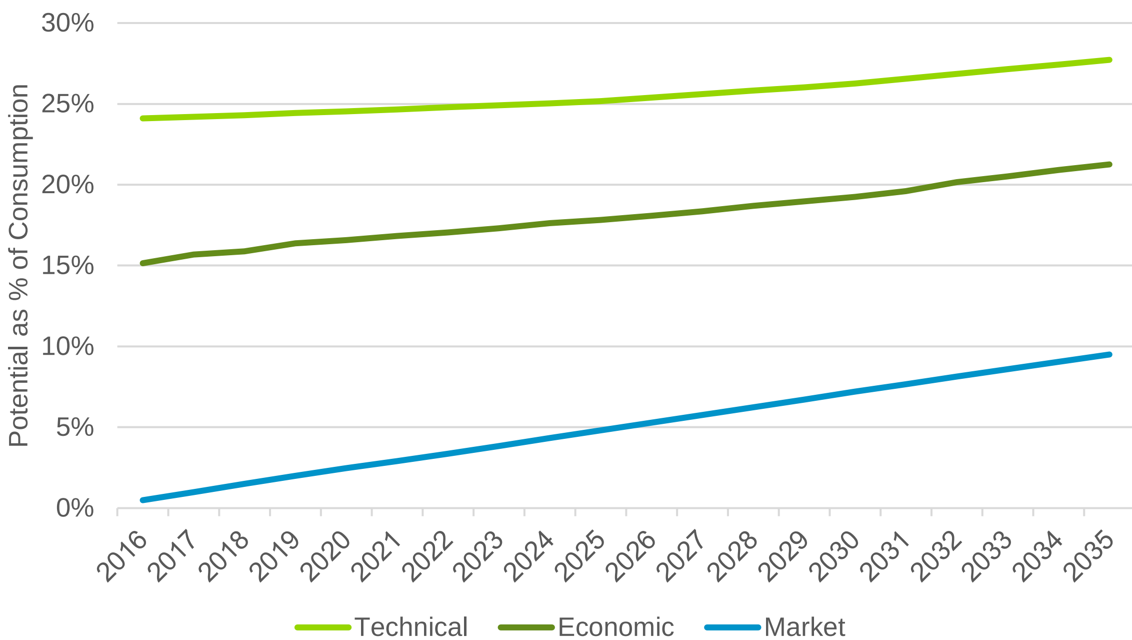


Source: Navigant

[20] The time horizon for the CPR is 2016-2035 (20 years).

Under the TRC screen, market potential grows from 0.5% in 2016 to 9.5% of forecast gas consumption by 2035, as shown in Figure 5-6 and in Appendix B. The annual incremental market potential is approximately 0.5% per year on average over the CPR time horizon.

Figure 5-6. Total Cumulative Gas Savings Potential as a Percentage of Consumption (%)

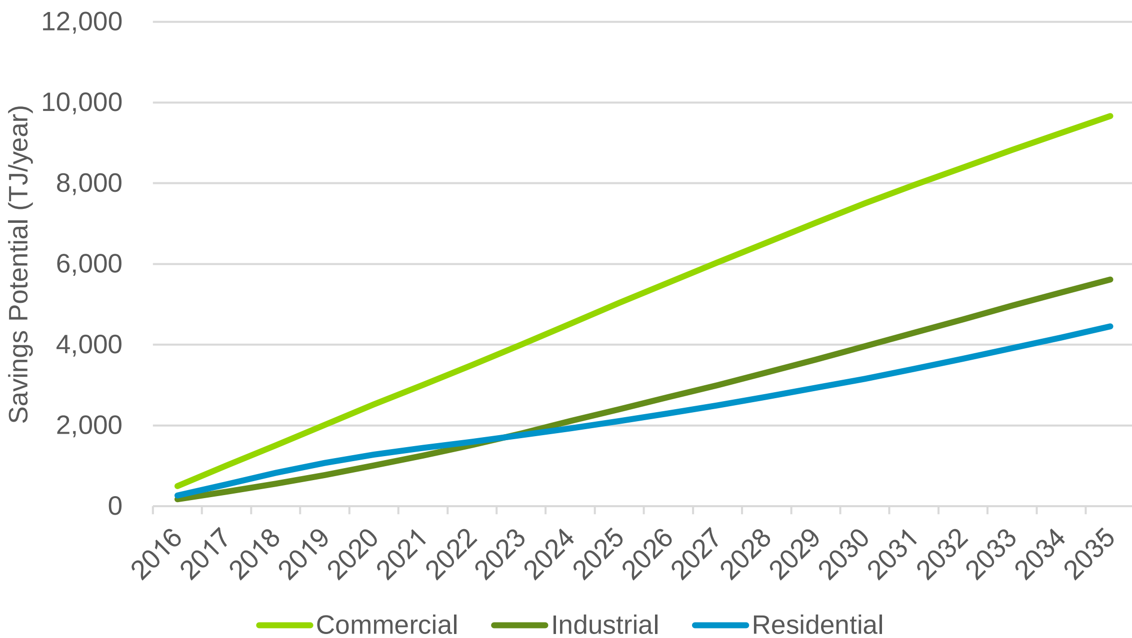


Source: Navigant

5.2.2 Results by Sector

Figure 5-7 and in Appendix B show the magnitude of gas market potential by sector. Navigant found the greatest potential exists in the commercial sector in terms of TJ/year and as a percentage of consumption. The commercial and industrial sectors captured just over 50% of economic potential by 2035, while the residential sector captured 28% of the economic potential.

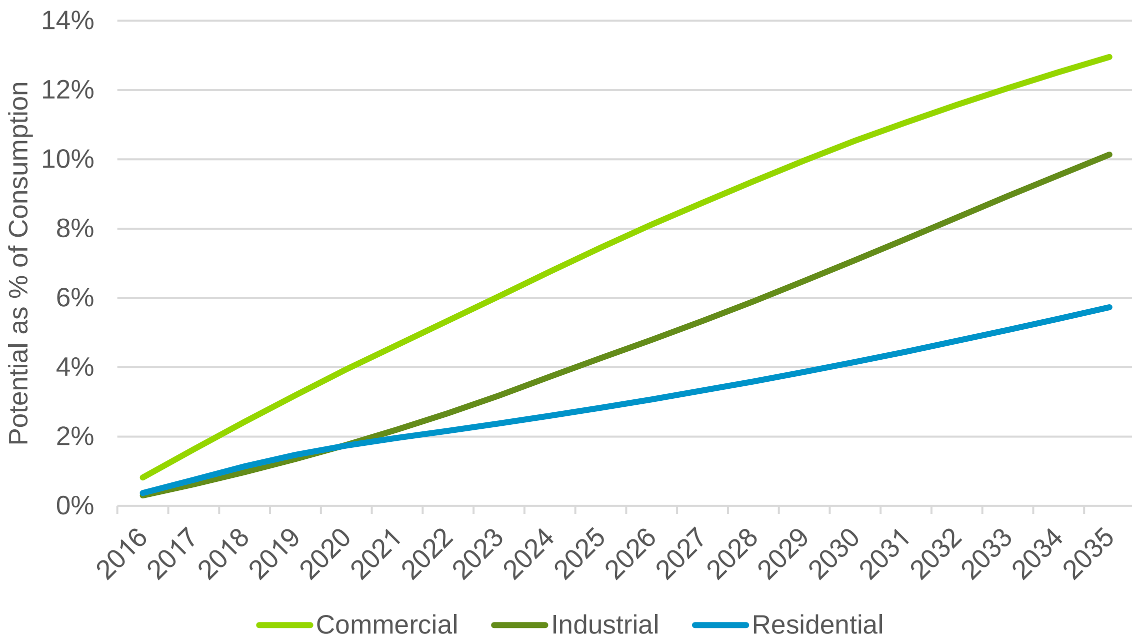
Figure 5-7. Cumulative Gas Savings Market Potential by Sector (TJ/year)



Source: Navigant

When viewed as a percentage of consumption, similar sector-level trends in the market potential are evident, as shown in Figure 5-8 and Table B-4. The commercial sector's market potential reaches 13% of commercial consumption by 2035, and the industrial sector achieves slightly over 10%. The residential sector increases to nearly 6% of consumption by the final study year, and this lower percentage reflects the lower cost-effectiveness and longer payback times of the residential sector on the whole.

Figure 5-8. Cumulative Gas Savings Market Potential as a Percentage of Consumption by Sector (%)

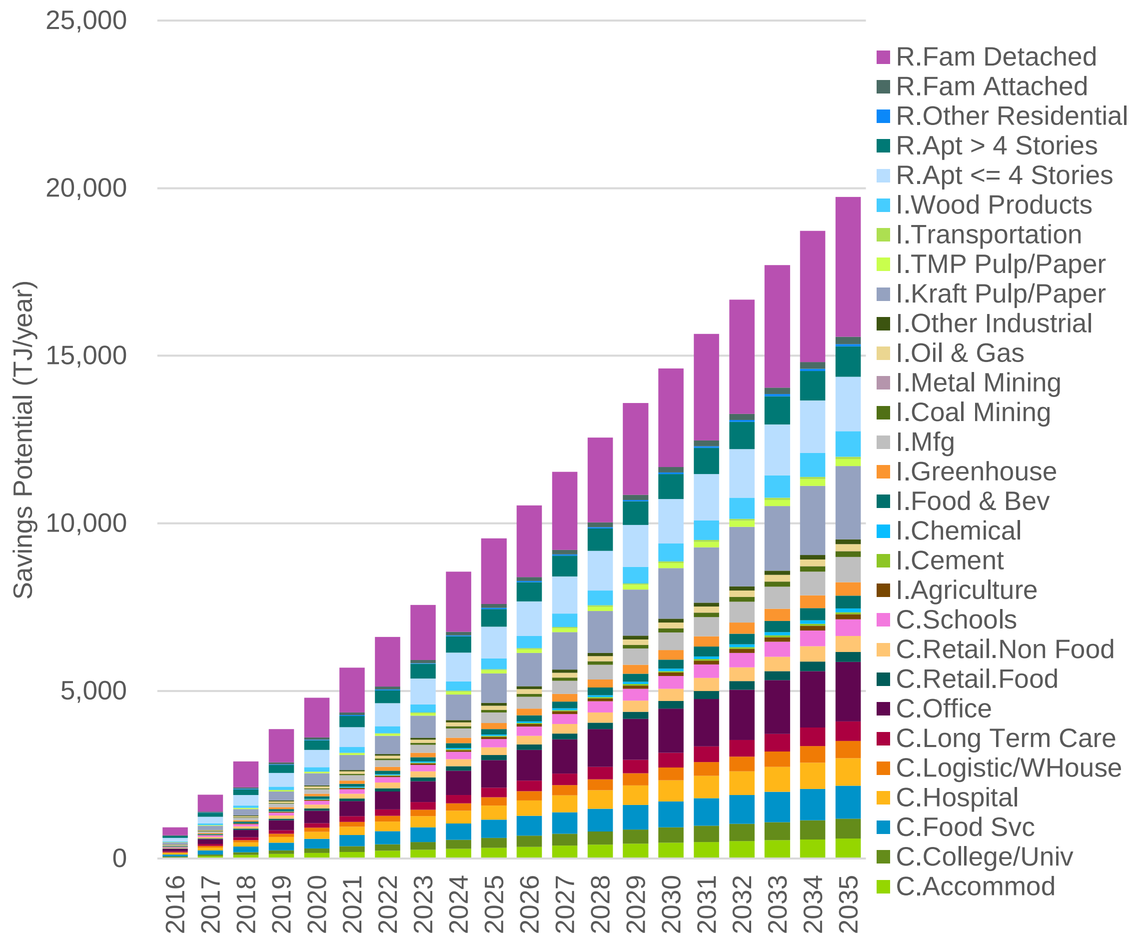


Source: Navigant

5.2.3 Results by Customer Segment

Figure 5-9 shows the gas energy market savings potential across all customer segments, and Table B-5 in Appendix B provides the associated data.[21] This figure highlights the large savings potential of the residential detached single-family home customer segment relative to other customer segments. Other segments with significant savings potential are kraft pulp and paper, apartments less than 4 stories, and offices. The segments with high savings are also segments with high consumption.

Figure 5-9. Cumulative Gas Savings Market Potential by Customer Segment (TJ/year)



Source: Navigant

[21] The LNG segment does not appear in this figure because FortisBC Gas does not supply natural gas to LNG facilities. Gas sales to LNG facilities are zero across the Reference Case forecast; hence, the savings potential is also zero.

Figure 5-10, Figure 5-11, and Figure 5-12 break out the gas energy market savings potential for each sector by customer segment. For the residential sector, detached single-family homes represents the largest savings potential of any customer segment by far, accounting for 93% of the total savings potential. Offices and apartments provide nearly half of the savings in the commercial sector. In general, the distribution of savings among customer segments aligns well with the distribution of gas consumption among segments. In the industrial sector, kraft pulp and paper accounts for the largest share of energy savings at 37%. Wood products and manufacturing also provide significant savings among industrial segments.

Figure 5-10. Residential Gas Savings Market Potential Customer Segment Breakdown in 2025

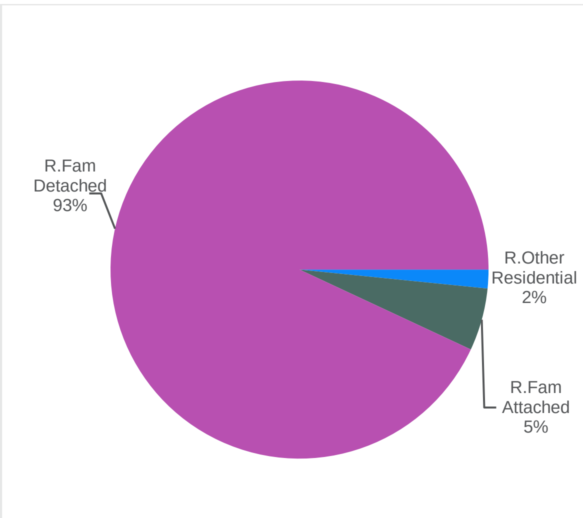


Figure 5-11. Commercial Gas Savings Market Potential Customer Segment Breakdown in 2025

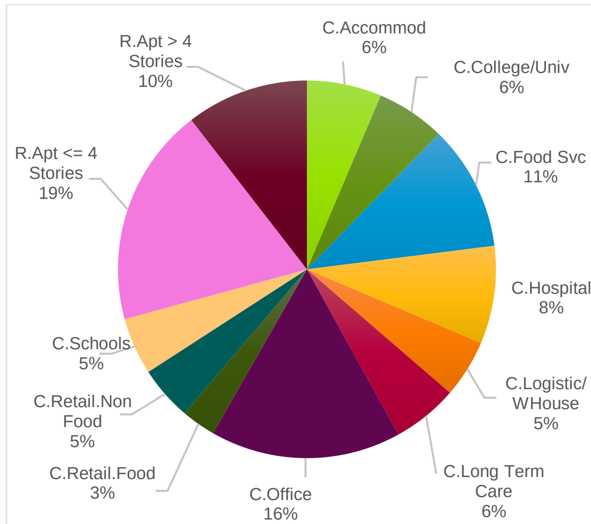
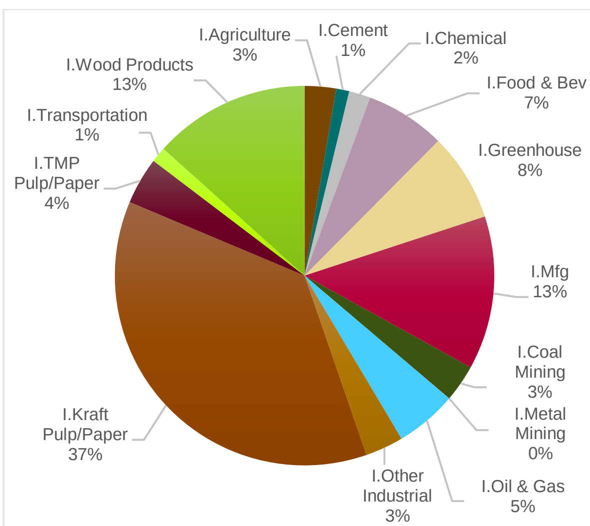


Figure 5-12. Industrial Gas Savings Market Potential Customer Segment Breakdown in 2025

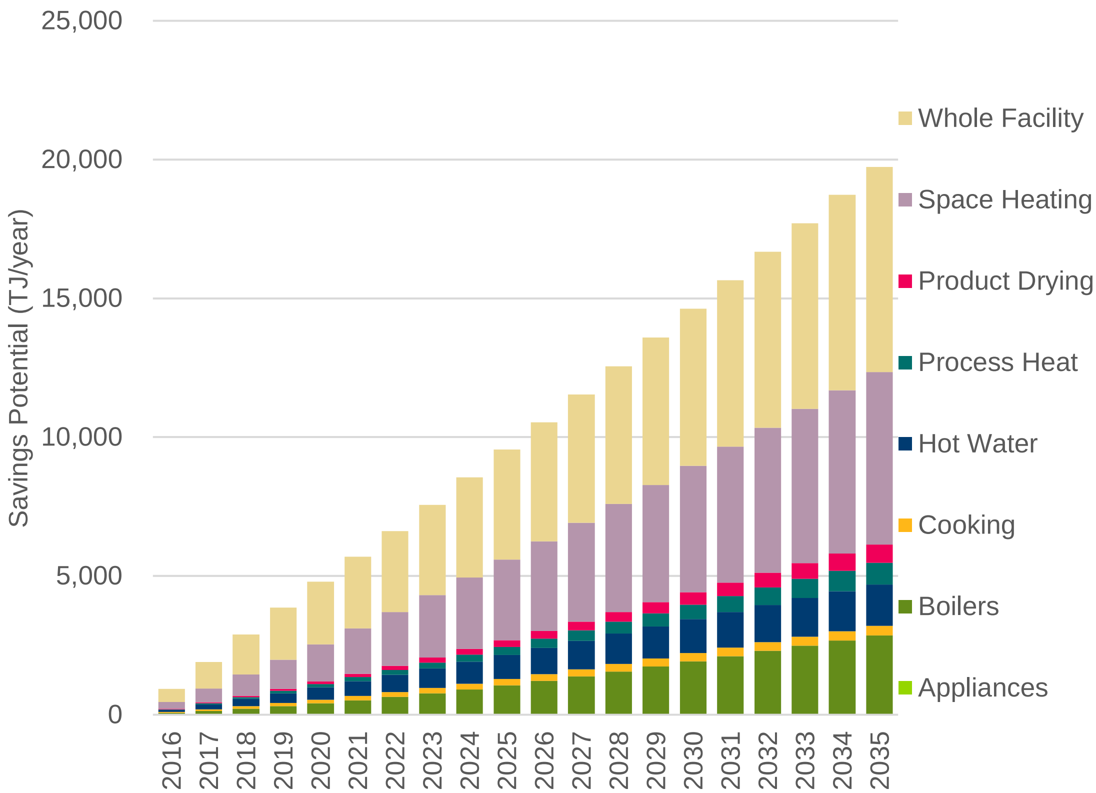


Source: Navigant

5.2.4 Results by End-use

Figure 5-13 shows the gas energy market savings potential across end-uses.[22] The data used to generate the figure are in Table B-6 in Appendix B. The dominant end-uses are space heating and whole facility. The bulk of savings potential in the space heating end-use comes from smart thermostats. The whole facility end-use primarily consists of savings from comprehensive whole-facility new construction practices, home energy reports, and energy management programs. As such, these whole-facility savings implicitly include savings from multiple end-uses.

Figure 5-13. Cumulative Gas Savings Market Potential by End-Use (TJ/year)



Source: Navigant

Figure 5-14, Figure 5-15, and Figure 5-16 break out the gas energy market savings potential for each sector. The whole facility end-use dominates the residential sector, accounting for 50% of the total savings potential. This is largely driven by home energy reports, which have by far the most market potential of all residential measures, and ENERGY STAR Homes, which is the third highest residential potential saver. In the commercial sector, the space heating and whole facility end-uses account for roughly 86% of the total market savings potential. Savings in commercial space heating come largely from HVAC control upgrades, condensing make-up air units and high efficiency furnaces. The whole-facility end-use's savings are driven by new building construction practices that are at least 45% above

[22] This study evaluated several gas appliances (convection ovens, gas ranges, and clothes washers and dryers) and found all to be non-cost-effective. As such, the appliances end use shows no market potential. For a list of measures associated with each end use, please refer to Appendix A.2 of the technical and economic potential report.

code. In the industrial sector, the boiler end-use plays the largest role, consisting of high savings measures like process boiler load control and heat recovery systems.

Figure 5-14. Residential Gas Savings Market Potential End-Use Breakdown in 2025

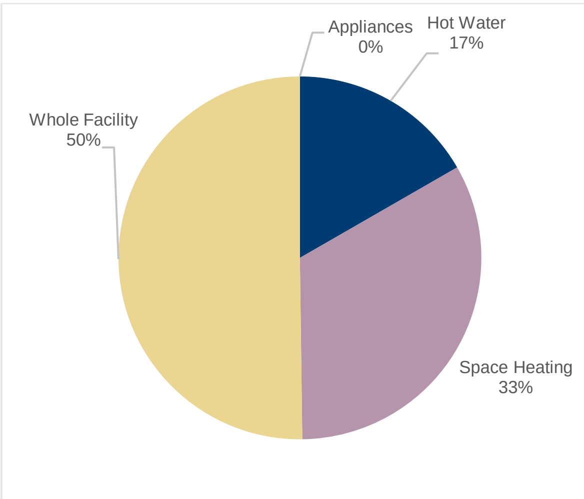


Figure 5-15. Commercial Gas Savings Market Potential End-Use Breakdown in 2025

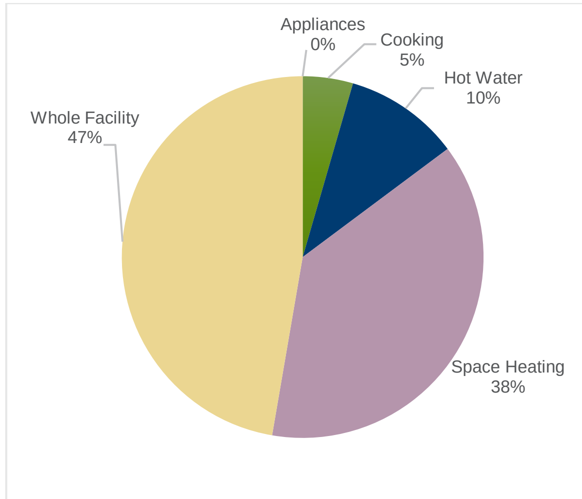
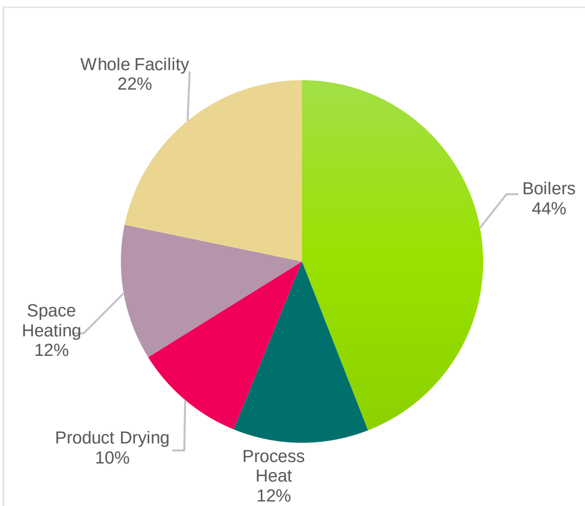


Figure 5-16. Industrial Gas Savings Market Potential End-Use Breakdown in 2025



Source: Navigant

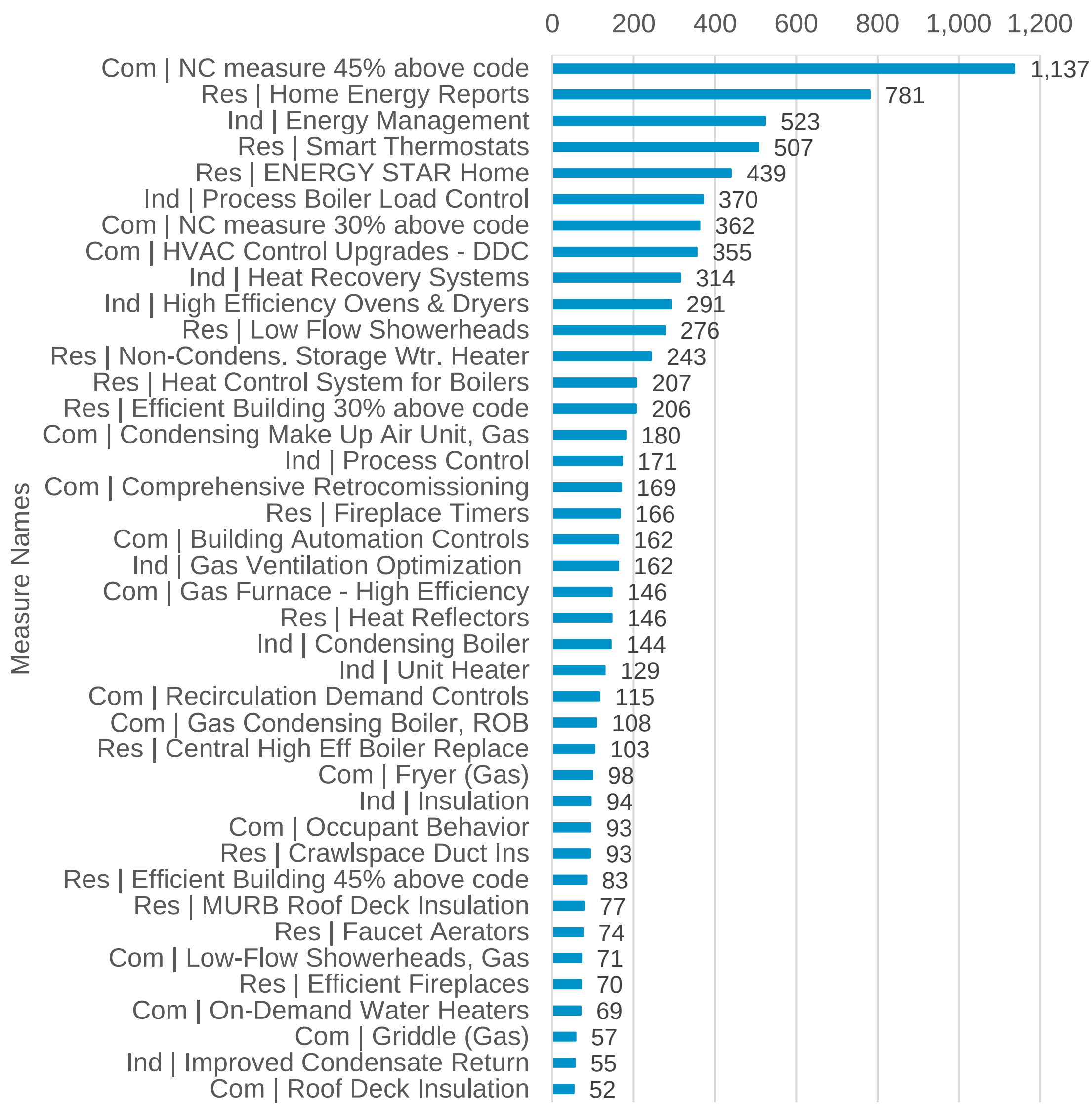
5.2.5 Results by Measure

Figure 5-17 and Table B-7 present the top 40 measures ranked by their gas energy market savings potential in 2025. Wherever a group of measures were similar in nature, Navigant consolidated their potential into a representative measure name to produce a more succinct view at the measure level. Unlike similar figures for economic and technical potential, these rankings already account for competition among measures providing the same service. Thus, one can add the potential shown without encountering issues of double counting.

When code-change measures become applicable, they “steal” savings potential from other related measures that may display significant savings in absence of the code. In this way, the sum of the total savings potential between the code and the related energy-efficient measure is the same before and after a code takes effect. This ensures there is no double counting of savings from codes and the energy efficient measures impacted by the code.

The top ten measures come from the whole-facility, space heating, boiler, and industrial process heating end-uses. Notably, five of the top ten measures are associated with the whole facility end-use. New construction practices 45% better than code ranks as the highest impact market potential measure. Smart thermostats, which has the highest economic savings potential, ranks fourth in terms of market potential. Home energy reports move from the 7th position in economic potential to the 2nd position in market potential.

Figure 5-17. Top 40 Measures for Gas Energy Market Savings Potential in 2025 (TJ/year)



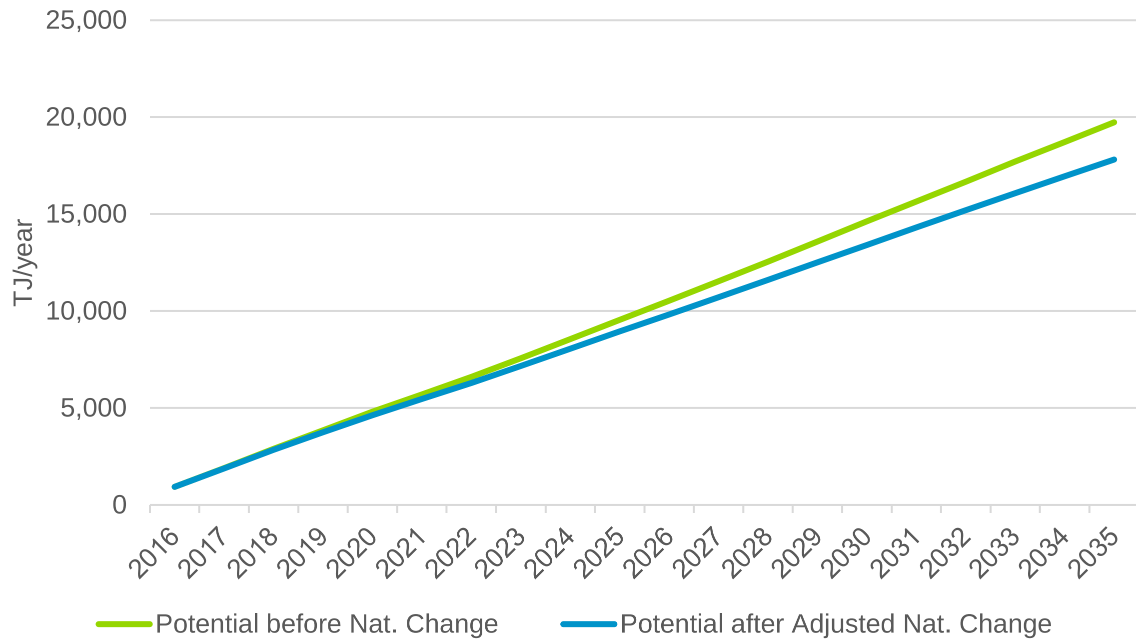
Source: Navigant

5.2.6 Adjustments for Natural Change

As discussed in Section 2.3.2, Navigant estimated natural change to account for differences in end-use consumption in the Reference Case compared to the frozen EUI case. Natural change accounts for changes in consumption that are naturally occurring and are not the result of utility-sponsored programs or incentives. Adding natural change to the frozen EUI case required adjusting the market potential forecasts accordingly.

Figure 5-18 and Table B-8 in Appendix B show the total market potential across all sectors before and after adjusting for natural change. The total natural change across all sectors is negative in all years, indicating an overall natural tendency toward increased energy conservation rather than growth. The adjusted natural change is computed by accounting for the percentage of the gross natural change that could reasonably be attributed to energy savings for each end-use. Market potential after adjustment for natural change is on average about 10% lower than potential before natural change by 2034.

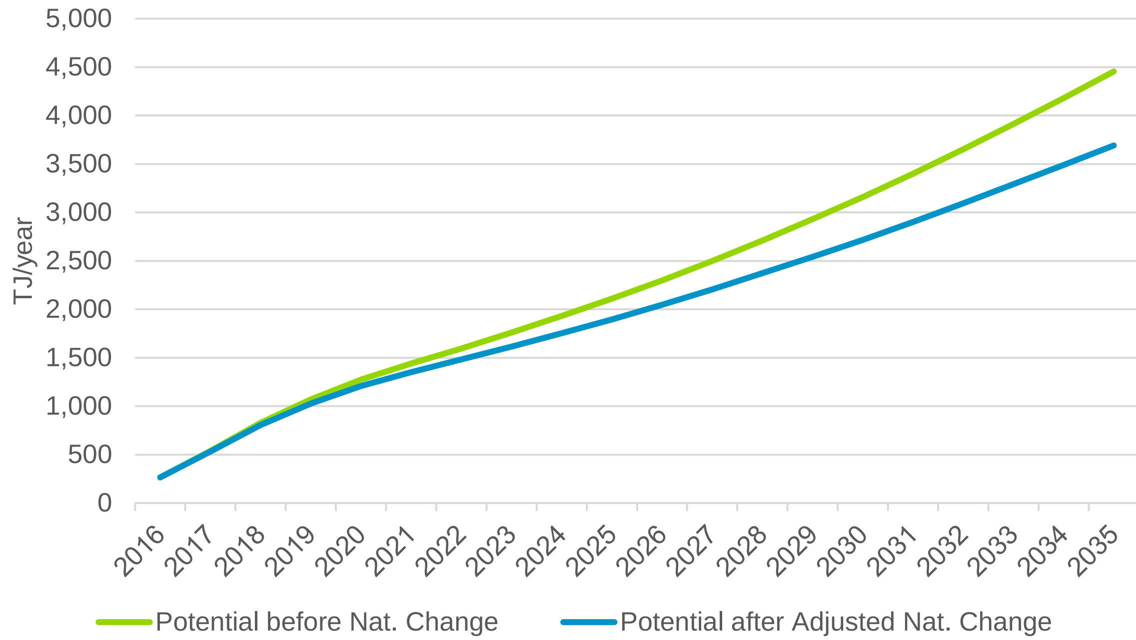
Figure 5-18. Gas Energy Market Savings Potential with Natural Change – All Sectors (TJ/year)



Source: Navigant

Figure 5-19 and Table B-9 show the effect of adjustments for natural change in the residential sector. Space heating and hot water end-uses account for significant natural conservation. In contrast, appliances account for a minor amount of natural growth. When aggregated to the sector level, natural conservation has a much larger effect than natural growth. On average across the study period, the residential technical potential after adjusted natural change is roughly 12% lower than the potential prior to natural change.

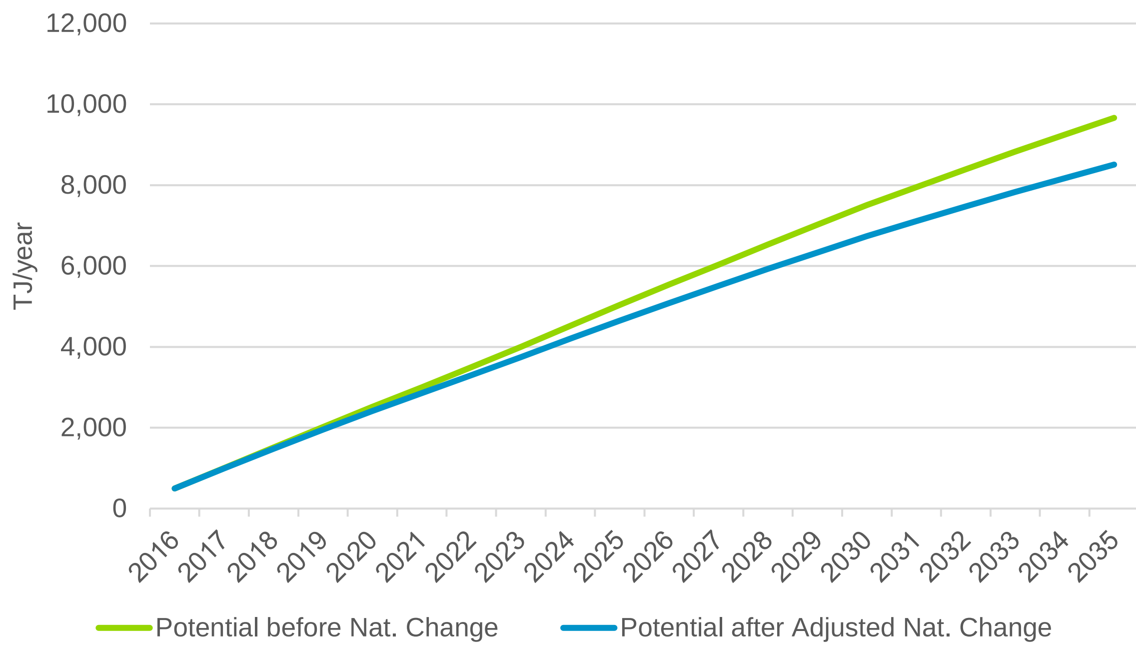
Figure 5-19. Residential Gas Energy Market Savings Potential with Natural Change (TJ/year)



Source: Navigant

The effect of adjustments for natural change on the commercial sector's market potential is slightly less than for the residential sector, as seen in Figure 5-20 and Table B-10. Space heating and hot water are the commercial end-uses contributing to natural change, and both exhibit natural conservation. On average across the study period, the commercial technical potential adjusted for natural change is roughly 9% lower than the potential prior to natural change.

Figure 5-20. Commercial Gas Energy Market Savings Potential with Natural Change (TJ/year)



Source: Navigant

For the industrial sector, there is no forecasted natural change, so adjustments to the market potential results presented in previous sections are not necessary.

5.3 Market Potential Budget Estimates

The following section describes the approach that Navigant used to develop the budget estimates for the market potential savings presented in this report, as well as the results of the market potential budget and cost effectiveness assessments when using the TRC test as an economic measure screen.

5.3.1 Approach to Budget Estimation

Navigant developed estimates of the portfolio-level DSM spending that FortisBC Gas would need to support the market potential savings forecast over the study period. Navigant calculated these estimates in the DSMSim™ model using incentive levels calibrated to align simulated 2016 incentive values with historic sector-level incentives as a percentage of total sector-level spending (as described in Section 5.1.7). The incentive budgets reflect the amount of spending that would result from the level of adoption for each measure that makes up the market potential estimates. Incentive budgets grow over time due to changes in the mix of DSM measures and cost inflation. The sector and total administration budgets result from the amount of savings potential in a given year multiplied by the historical per-unit-of-savings administrative expenditures ($/GJ) reported by FortisBC Gas, which the study escalates over time at the assumed inflation rate.[23]

5.3.2 Total Market Potential Budget

Table 5-2 presents the estimated spending levels for incentives, administrative costs (non-incentives), and the total portfolio. As can be seen from the table, the total simulated funding for market potential is roughly $21 million in 2016, and more than doubles to almost $54 million by 2035 as the portfolio mix changes and low-hanging fruit is harvested.

Table 5-2. Budgets by Sector – TRC Case (Million $)

Sector	Spending Type	2016	2020	2025	2030	2035	2016-2035 Total*
Commercial	Incentives	$9.52	$14.21	$18.58	$21.55	$23.05	$351.38
	Non-Incentives	$1.51	$1.62	$1.85	$1.90	$1.81	$34.83
	Total	$11.03	$15.83	$20.43	$23.45	$24.86	$386.22
Industrial	Incentives	$2.33	$3.94	$6.53	$8.93	$9.75	$131.07
	Non-Incentives	$1.14	$1.67	$2.35	$2.87	$3.08	$46.02
	Total	$3.47	$5.61	$8.89	$11.81	$12.83	$177.09
Residential	Incentives	$2.73	$4.28	$5.39	$7.83	$10.82	$123.04
	Non-Incentives	$3.55	$2.99	$2.85	$4.04	$5.36	$72.87
	Total	$6.27	$7.27	$8.24	$11.87	$16.18	$195.92
Portfolio	Incentives	$14.58	$22.43	$30.50	$38.31	$43.62	$605.50
	Non-Incentives	$6.19	$6.27	$7.06	$8.81	$10.25	$153.73
	Total	$20.77	$28.71	$37.56	$47.13	$53.87	$759.23

*The 2016-2035 Total column represents the sum of all forecasted years (2016-2035), not just those shown in the table.
Source: Navigant

The costs borne by the utility to acquire market savings—on a dollar-per-savings basis—increase 2 to 3 percent per year, on average and in real terms, for each sector. This contrasts with recent program experience, where per-unit-of-savings utility costs have shown declining trends. There are several factors creating this difference:

- Actual program implementation may be dynamically allocating incentive spending to measures providing lower cost savings than the incentive strategy employed in this analysis (refer to Section 5.1.5). Though the modeling approach captures customers' tendency to favor the adoption of economically attractive measures over less economically attractive measures, it does not preferentially incentivize the most economic measures.

[23] The study includes administrative costs directly tied to programs and measures providing energy savings. Outreach and enabling costs and portfolio-level administrative costs (i.e., not tied to a program) were not included in this study. This study's portfolio total administrative costs are a summation of sector-level administrative costs, so this analysis is likely to underrepresent total administrative budgets at the portfolio level. However, this underrepresentation may be partially offset by not accounting for efficiencies gained through program experience, which would reduce per-unit-of-savings administrative costs over time.

- Actual programs may not be experiencing significant saturation yet in the uptake of certain low cost measures. This study's upward trend in the percentage of spending directed to incentives indicates that low-cost savings are harvested early in the study horizon and the remaining savings opportunities become increasingly costlier.
- This study did not attempt to estimate the reduction in per-unit-of-savings administrative costs that could be realized as experience in program administration leads to greater efficiency in administrative spending.
- Compliancy to codes and efficiency standards enacted during the study horizon reduces the savings potential and cost-effectiveness of impacted measures, resulting in higher costs to the utility to capture those measures' savings potential.

5.3.3 TRC Cost Effectiveness

Table 5-3 shows the benefit-cost test ratios by sector and for the portfolio for each benefit-cost test. The benefit-cost test ratios are greater than 1.0 for all benefit-cost test types at the sector and portfolio level across all analysis years, with an exception for the RIM test, which very rarely has a benefit-cost test greater than 1.0 for DSM measures.

Table 5-3. Benefit-Cost Test Ratios for the Portfolio and by Sector

Sector	Year	Total Resource Cost Test	Utility Cost Test	Participant Cost Test	Rate Impact Measure Test
Commercial	2016	1.86	2.78	2.63	0.75
	2020	1.83	2.71	2.38	0.80
	2025	1.82	2.69	2.21	0.84
	2030	1.78	2.63	2.05	0.88
	2035	1.76	2.60	1.92	0.92
	2016-2035	1.84	2.71	2.27	0.83
Industrial	2016	2.07	2.23	3.50	0.75
	2020	2.47	2.67	3.60	0.85
	2025	2.81	3.05	3.60	0.95
	2030	2.99	3.25	3.48	1.02
	2035	3.22	3.50	3.47	1.10
	2016-2035	2.75	2.98	3.54	0.94
Residential	2016	1.16	1.59	3.14	0.51
	2020	1.70	2.43	3.45	0.61
	2025	1.93	2.75	3.41	0.67
	2030	1.98	2.78	3.28	0.70
	2035	2.02	2.81	3.16	0.74
	2016-2035	1.79	2.51	3.38	0.65
Portfolio	2016	1.68	2.33	2.84	0.69
	2020	1.89	2.63	2.77	0.75
	2025	2.03	2.79	2.68	0.82
	2030	2.07	2.82	2.59	0.86
	2035	2.12	2.88	2.53	0.90
	2016-2035	1.99	2.72	2.72	0.80

Source: Navigant

Table 5-4 presents the net benefits by sector and for the portfolio under each benefit-cost test. As with the benefit-cost test ratios, net benefits are positive in all cases, with the exception of the RIM test. The analysis estimates that the total net present value for the portfolio over the 2016-2035 analysis timeframe is more than $450 million from the TRC perspective.

Table 5-4. Cost Test Net Benefits for the Portfolio and by Sector (Million $)

Sector	Year	Total Resource Cost Test	Utility Cost Test	Participant Cost Test	Rate Impact Measure Test
Commercial	2016	$14.16	$19.58	$24.35	-$10.19
	2020	$19.47	$27.13	$30.87	-$10.97
	2025	$24.78	$34.46	$35.74	-$10.27
	2030	$26.94	$38.16	$35.94	-$8.37
	2035	$27.92	$39.81	$33.75	-$5.40
	2016-2035*	$218.08	$302.17	$319.53	-$96.98
Industrial	2016	$4.00	$4.27	$6.52	-$2.52
	2020	$8.89	$9.35	$11.43	-$2.54
	2025	$17.45	$18.19	$18.91	-$1.46
	2030	$25.53	$26.56	$24.69	$0.84
	2035	$31.01	$32.13	$26.79	$4.22
	2016-2035*	$143.16	$149.48	$156.42	-$13.26
Residential	2016	$1.39	$3.72	$10.82	-$9.43
	2020	$7.25	$10.40	$18.81	-$11.27
	2025	$10.96	$14.44	$23.02	-$11.18
	2030	$16.32	$21.09	$31.98	-$13.80
	2035	$22.94	$29.27	$42.01	-$15.94
	2016-2035*	$96.08	$130.83	$220.95	-$116.74
Portfolio	2016	$19.55	$27.57	$41.69	-$22.14
	2020	$35.61	$46.88	$61.11	-$24.77
	2025	$53.18	$67.09	$77.68	-$22.92
	2030	$68.78	$85.80	$92.61	-$21.34
	2035	$81.87	$101.22	$102.56	-$17.12
	2016-2035*	$457.31	$582.48	$696.90	-$226.97

**Total net benefits for 2016-2035 represent the total present values in 2016 dollars. Other yearly values represent non-discounted single-year net benefits.*
Source: Navigant

5.4 mTRC Results

This section describes the approach taken for estimating DSM potential using the mTRC benefit-cost test as a screen, rather than the TRC benefit-cost test. Given that the economic potential results will differ under the mTRC test from the results presented in Section 4, this section provides the results for both economic and market potential using the mTRC, as well as the sector and portfolio cost effectiveness.

5.4.1 Approach to Estimating mTRC Results

The primary change between the TRC benefit-cost test and mTRC benefit-cost test is the application of different values for avoided costs, with the mTRC avoided costs roughly six times higher than the TRC avoided costs.[24] The use of higher avoided costs increases the benefits calculated for each measure and results in more measures screening as cost-effective. Based on input from FortisBC Gas, Navigant also included the five high impact measures in the mTRC market potential, regardless of cost-effectiveness,[25] to capture additional market dynamics with these measures (as described in Section 5.1.7). All other calculations are the same between the TRC and mTRC tests.

5.4.2 mTRC Economic Potential Results

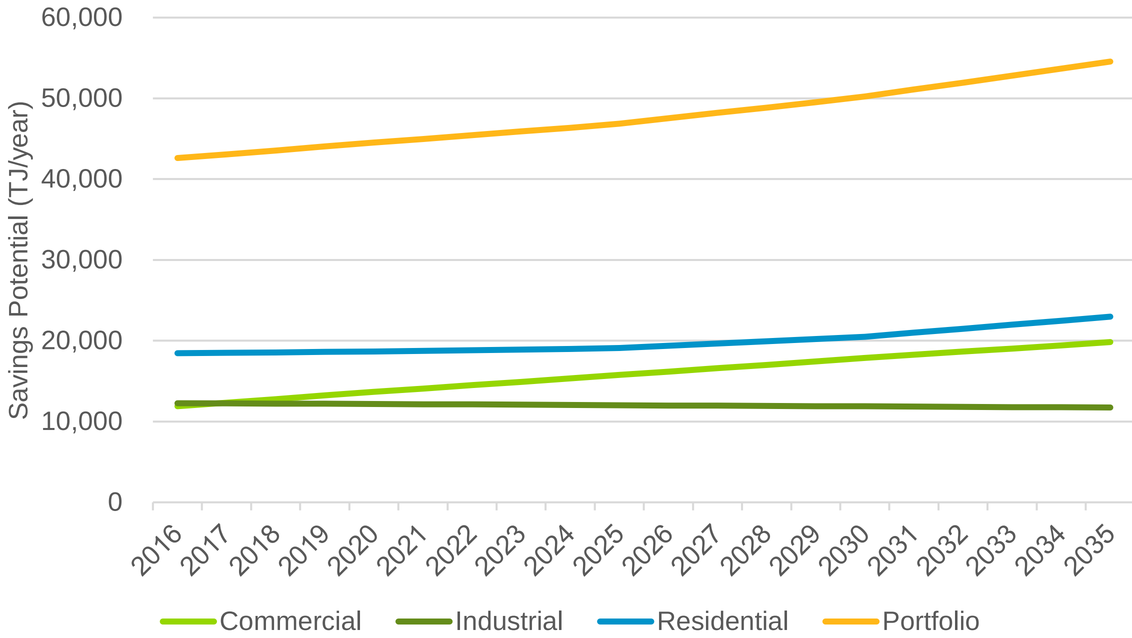
Figure 5-21 shows the cumulative gas economic potential by sector in TJ/year. The data used to generate the figure are in Table B-11 in Appendix B. The use of the mTRC screen instead of the TRC screen increases the proportion of technical savings potential that are economic. Economic potential increases from 71% of technical potential based on the TRC screen, to 94% based on the mTRC screen.

mTRC economic potential for the commercial and residential sectors increases significantly over the study period to 25% and 67%, respectively. This increase in economic potential over time is a result of whole-facility, high-impact measures such as new construction practices 45% more efficient than code and ENERGY STAR homes. Industrial sector economic potential stays roughly the same as the TRC case (see Section 4.2), decreasing by 4% over the study period, primarily because industrial gas consumption is not forecast to increase over time.

[24] The formulation of the mTRC benefit-cost test is the same as the TRC test, with the exception that the avoided costs stem from a zero emission energy supply alternative (ZEEA) cost and benefits are increased by a 15% non-energy benefits adder.

[25] As stated in Section 5.1.7, while these measures are cost effective overall, some measures are not cost effective for certain sub-sectors and regions within the analysis. Since actual programs focus on overall cost effectiveness across the sector, rather than within sub-sectors, Navigant forced the five high impact measures to pass across all sub-sectors to better reflect actual program implementation.

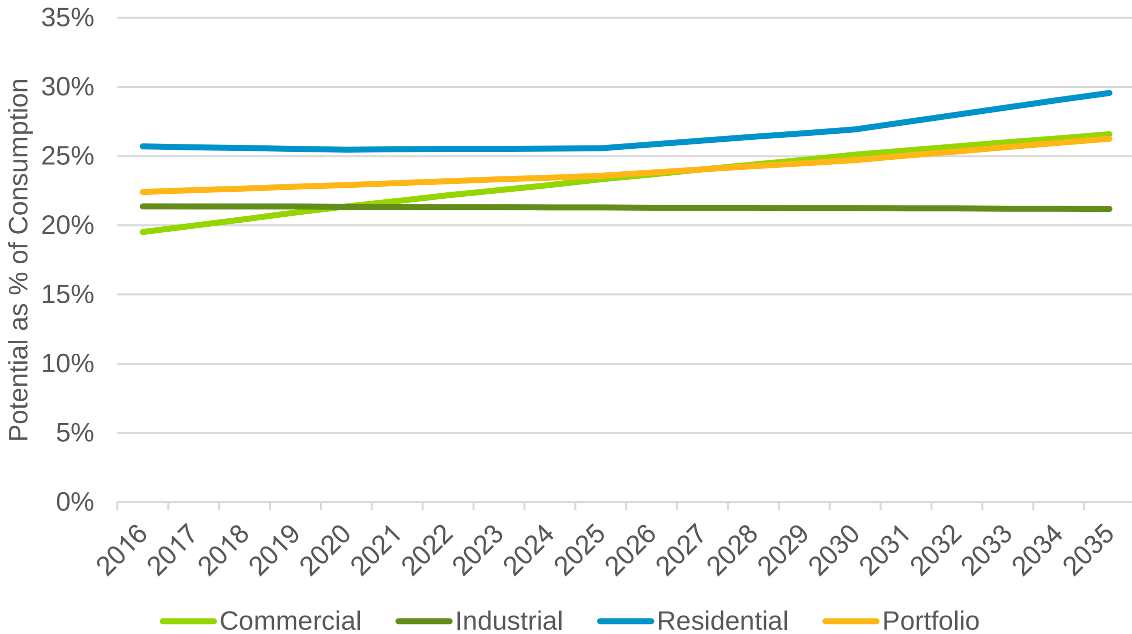
Figure 5-21. mTRC Cumulative Gas Savings Economic Potential by Sector (TJ/year)



Source: Navigant

Figure 5-22 shows the cumulative gas economic potential as a percent of sector consumption. The data used to generate the figure are in Table B-12 in Appendix B. Whole-facility, new construction measures in the residential and commercial sectors enable the increase in savings potential as a percent of sector consumption over time. Industrial savings as a percent of consumption do not increase because limited growth in the sector result in limited opportunities for high-impact measures. While the overall shape of the mTRC economic savings curves are similar to the TRC economic curves, the use of the mTRC screen increases the percentage of technical savings that are economic. Economic savings as a percent of consumption in 2016 increase from 15.1% (based on the TRC screen) to 22.4% (based on the mTRC screen). The 2035 economic savings increase from 21.3% to 26.3%.

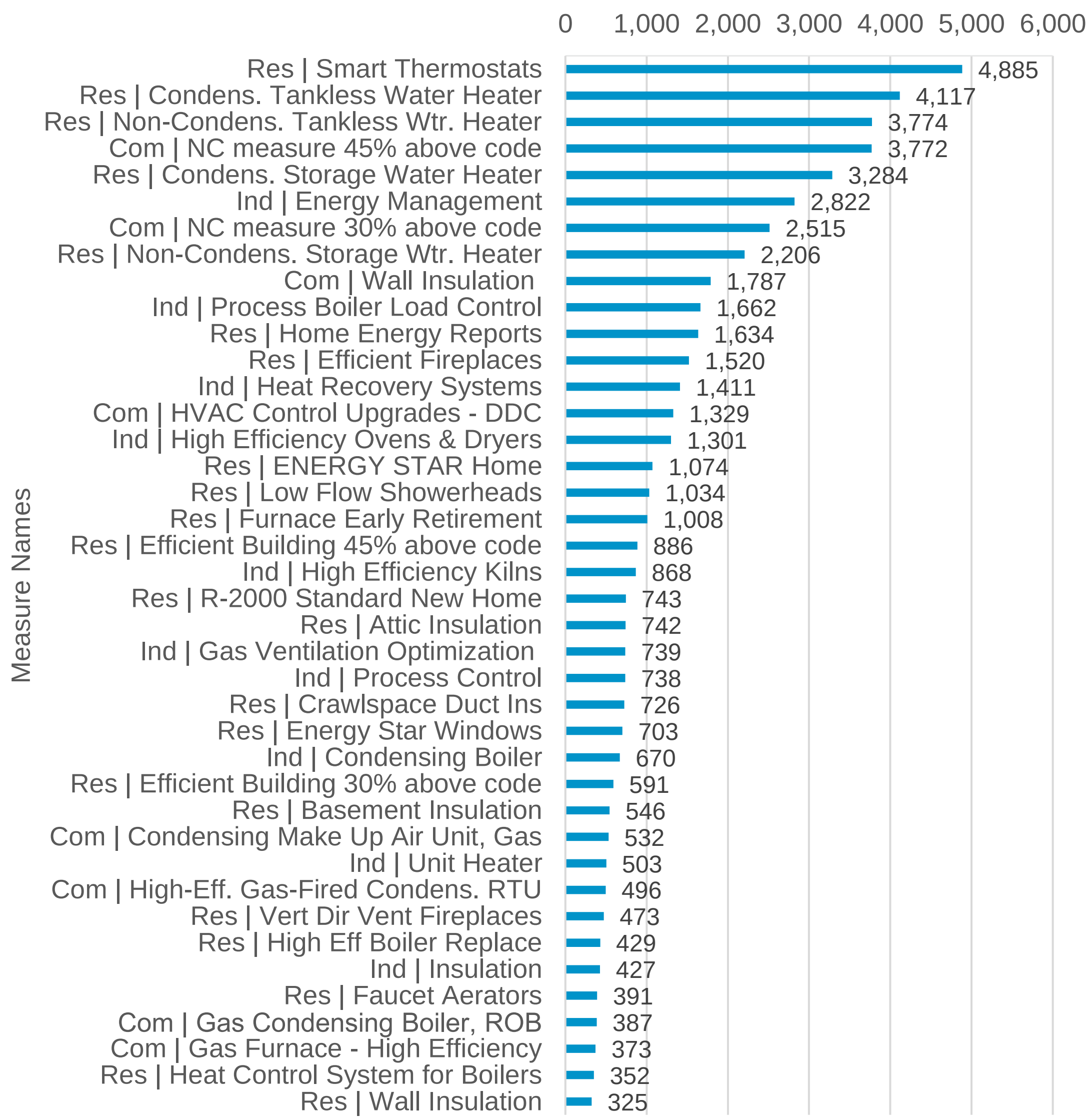
Figure 5-22. mTRC Cumulative Gas Savings Economic Potential as Percent of Sector Consumption (%)



Source: Navigant

Figure 5-23 and Table B-13 list the top 40 gas saving measures with the highest economic potential prior to adjustments made to competition groups. There are no changes in ranking or savings potential in results when compared with the top 10 technical potential measures. The four measures (residential condensing and non-condensing tankless water heaters, residential condensing storage water heaters, and commercial wall insulation) that were not economic using the TRC screen are economic using the mTRC screen.

Figure 5-23. mTRC Top 40 Measures for Gas Energy Economic Savings Potential in 2025 (TJ/year)

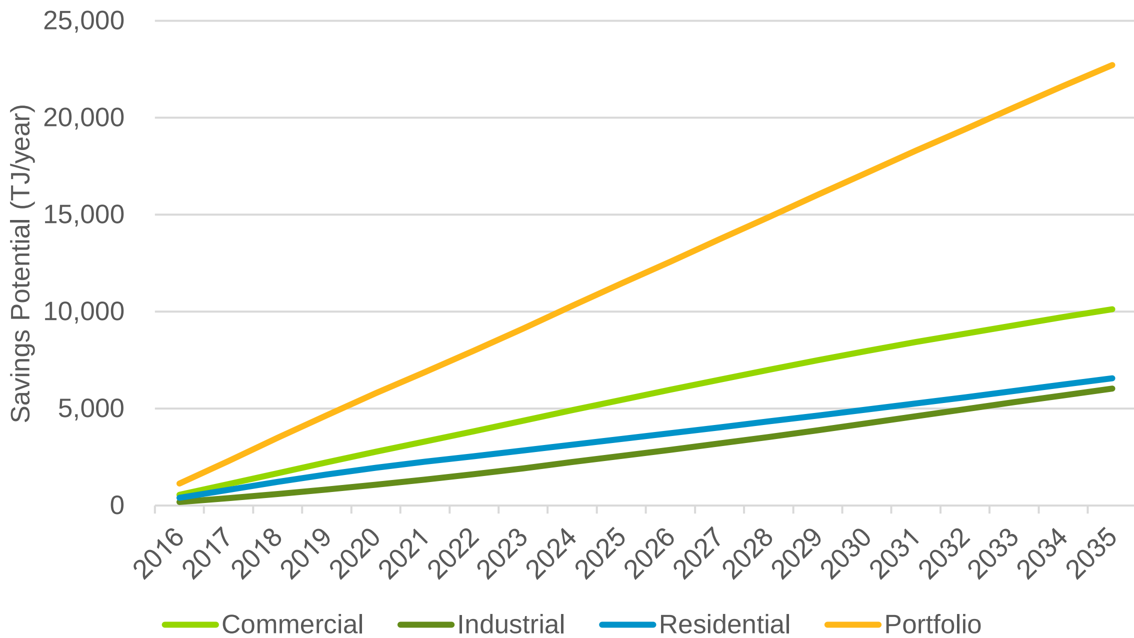


Source: Navigant

5.4.3 mTRC Market Potential Results

The following figures show the market potential results for the mTRC case. Figure 5-24 and Table B-14 show the cumulative gas market potential by sector in TJ/year. The commercial sector contributes approximately 46% of the cumulative gas savings market potential over the study period, down from approximately 50% using a TRC screen. The residential and industrial sectors contribute 30% and 24%, respectively. Relative to the TRC market potential savings, the residential sector's market potential increased 45%, while the commercial and industrial sectors only increased 5% and 7%, respectively.

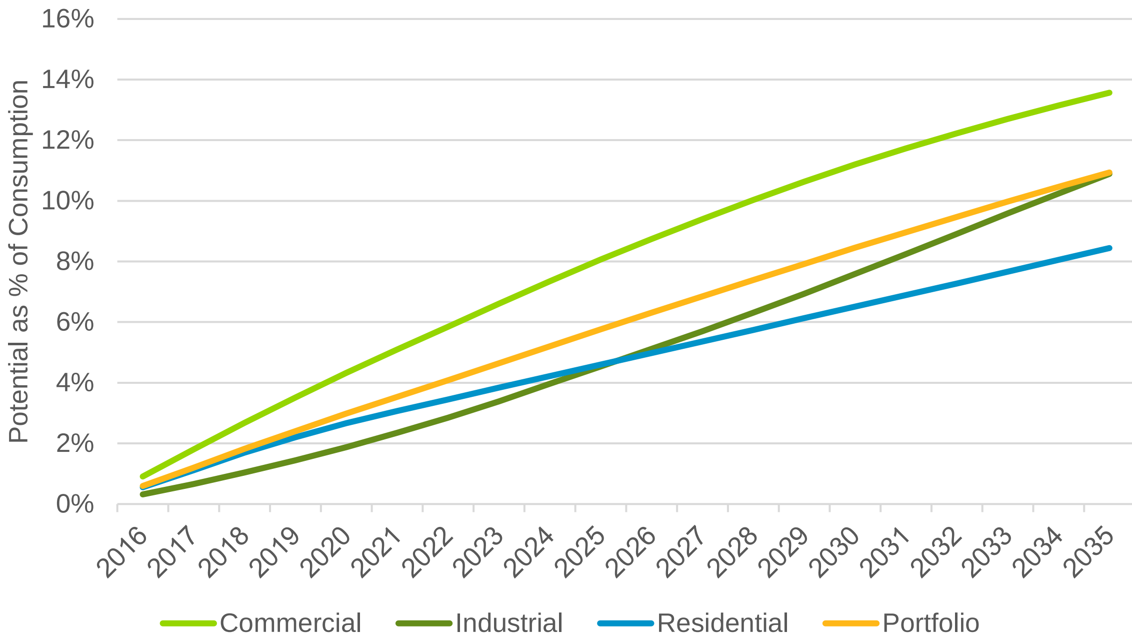
Figure 5-24. mTRC Cumulative Gas Savings Market Potential by Sector (TJ/year)



Source: Navigant

Figure 5-25 and Table B-15 show the cumulative gas market potential as a percent of sector consumption, with portfolio savings increasing from just under 0.6% to 10.9% of gas consumption over the timeframe of the analysis. Compared to the TRC market potential savings, the 2035 savings increased from 9.5% using the TRC screen to 10.9% using the mTRC screen. The residential sector saw the largest increase as a percent of consumption, rising from 5.8% using the TRC screen to 8.4% using the mTRC screen.

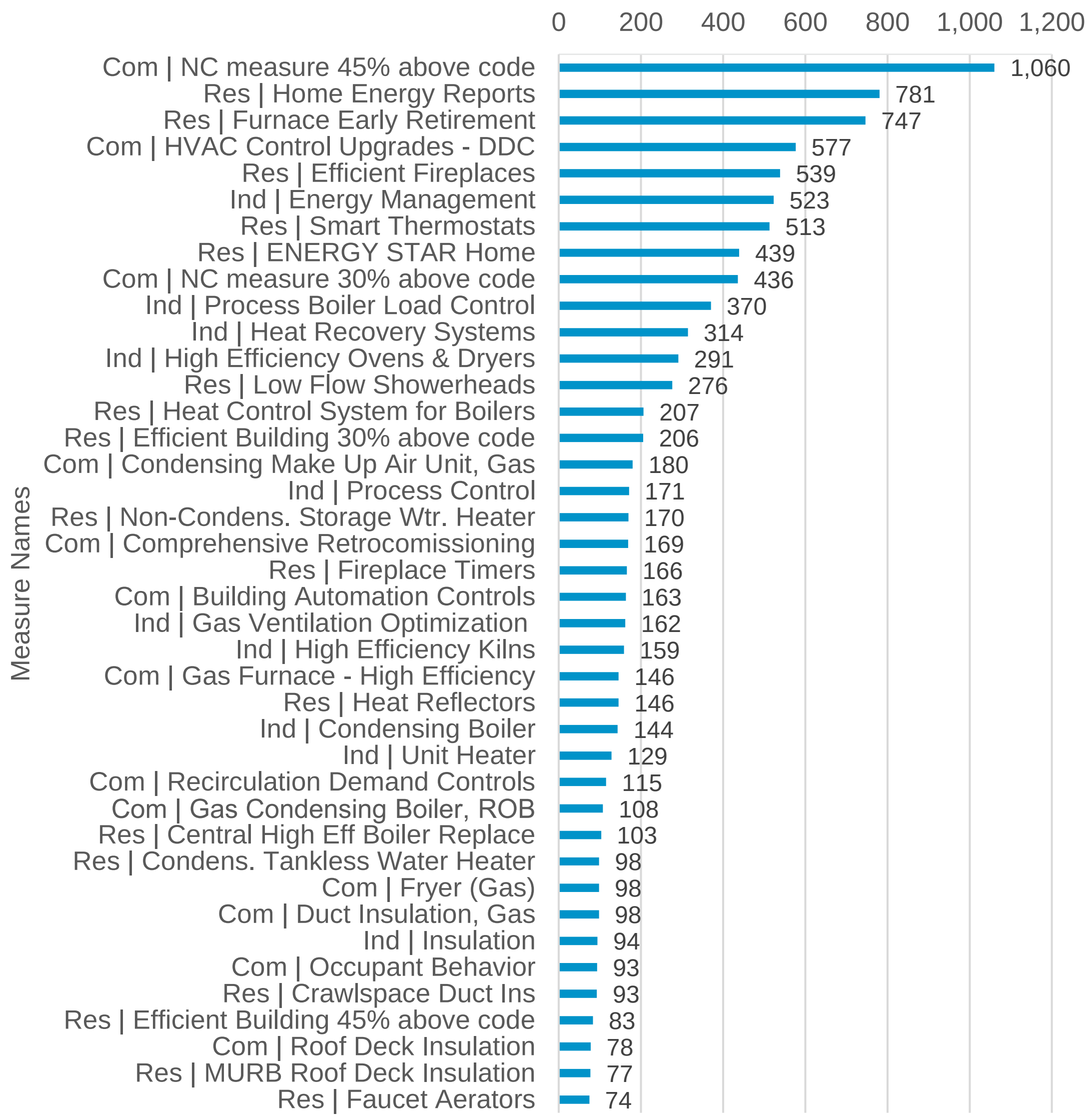
Figure 5-25. mTRC Cumulative Gas Savings Market Potential as Percent of Sector Consumption (%)



Source: Navigant

Figure 5-26 and Table B-16 list the top 40 gas saving measures with the highest market potential. Compared with the TRC market potential results, new construction practices 45% better than code and home energy reports remain as the top two measures. Residential furnace early replacement which is uneconomic using the TRC screen becomes economic and ranks third. Similarly, residential efficient fireplaces increase significantly in market savings using the mTRC and move into the top five measures.

Figure 5-26. mTRC Top 40 Measures for Gas Energy Market Savings Potential in 2025 (TJ/year)



Source: Navigant

5.4.4 mTRC Cost Effectiveness

The following tables present cost effectiveness results for the mTRC case, including the portfolio and sector-level budget estimates and benefit-cost test ratios. Table 5-5 shows the mTRC case's total portfolio budget is $1,388 million over the 2016-2035 timeframe, as compared to $760 million under the TRC case over the same timeframe. Although market potential savings increase by 15% using the mTRC screen instead of the TRC screen, the portfolio budget increased by approximately 85%. This is because the least costly savings are captured using the TRC screen (i.e., the "low hanging fruit"), whereas the measures captured using the mTRC screen are significantly more costly on a $/GJ basis.

The vast majority of the increased budget is from an increase in residential incentive costs. Residential incentives more than triple in magnitude, while commercial and industrial incentives increase by 14% and 34%, respectively.

Table 5-5. Budgets by Sector – mTRC Case (Million $/year)

Sector	Spending Type	2016	2020	2025	2030	2035	2016-2035 Total*
Commercial	Incentives	$13.77	$18.32	$21.65	$23.21	$23.16	$402.89
	Non-Incentives	$1.68	$1.76	$1.93	$1.93	$1.78	$36.33
	Total	$15.44	$20.08	$23.58	$25.14	$24.94	$439.22
Industrial	Incentives	$3.45	$5.70	$9.21	$12.67	$14.32	$187.59
	Non-Incentives	$1.21	$1.78	$2.52	$3.10	$3.36	$49.48
	Total	$4.66	$7.47	$11.73	$15.76	$17.67	$237.06
Residential	Incentives	$26.45	$32.93	$33.64	$31.43	$30.01	$606.37
	Non-Incentives	$5.32	$5.01	$4.71	$5.43	$6.43	$105.38
	Total	$31.78	$37.94	$38.35	$36.86	$36.44	$711.75
Portfolio	Incentives	$43.67	$56.94	$64.50	$67.31	$67.49	$1,196.85
	Non-Incentives	$8.21	$8.55	$9.17	$10.45	$11.57	$191.19
	Total	$51.88	$65.49	$73.67	$77.77	$79.05	$1,388.04

*The 2016-2035 Total column represents the sum of all forecasted years (2016-2035), not just those shown in the table.
Source: Navigant

Given that the change in avoided costs for the mTRC does not apply to the UCT, PCT, or RIM benefit-cost tests, these test ratios are only presented in Section 5.3.

Table 5-6 shows the mTRC benefit-cost test ratios by sector and for the portfolio. Compared with the TRC benefit-cost test ratio, the 2016-2035 portfolio benefit-cost ratio increases from 1.99 to 4.67. The mTRC benefit-cost ratios for the residential, commercial, and industrial sector also have increases of similar magnitude. The increase in benefit-cost ratios is a result of the higher avoided costs used for mTRC test.

Table 5-6. mTRC Benefit-Cost Test Ratios for the Portfolio and by Sector

Sector	Year	Benefit-Cost Ratio
Commercial	2016	6.86
	2020	6.54
	2025	6.32
	2030	5.98
	2035	5.65
	2016-2035	6.41
Industrial	2016	7.88
	2020	8.50
	2025	8.86
	2030	8.59
	2035	8.33
	2016-2035	8.55
Residential	2016	2.07
	2020	2.44
	2025	2.74
	2030	3.42
	2035	4.00
	2016-2035	2.66
Portfolio	2016	3.98
	2020	4.35
	2025	4.86
	2030	5.32
	2035	5.47
	2016-2035	4.67

Source: Navigant

Table 5-7 presents the mTRC net benefits by sector and for the portfolio. The net benefits increase from $460 million using the TRC screen to approximately $3,310 million using the mTRC screen. The residential, commercial, and industrial sectors increase in net benefits almost proportionally to the overall portfolio.

Table 5-7. mTRC Net Benefits for the Portfolio and by Sector (Million $/year)

Sector	Year	Net Benefits
Commercial	2016	$137.22
	2020	$165.37
	2025	$184.18
	2030	$183.98
	2035	$171.44
	2016-2035	$1,683.70
Industrial	2016	$34.95
	2020	$61.06
	2025	$100.57
	2030	$130.88
	2035	$141.95
	2016-2035	$832.10
Residential	2016	$48.88
	2020	$74.72
	2025	$82.88
	2030	$103.21
	2035	$126.07
	2016-2035	$801.37
Portfolio	2016	$221.05
	2020	$301.15
	2025	$367.63
	2030	$418.07
	2035	$439.47
	2016-2035	$3,317.18

*Total net benefits for 2016-2035 represent prevent values. Other yearly values represent non-discounted single year net benefits.

Source: Navigant

5.5 Hybrid mTRC/TRC Results

The “Hybrid” case uses results from the mTRC test for the residential sector and results from the TRC test for the commercial and industrial (C&I) sectors, which is most analogous to FortisBC Gas’s actual DSM program environment. Because sector-level results are identical to the mTRC case’s residential results and the TRC case’s C&I results, the reader can refer to Sections 5.2 and 5.4 for sector-level results. This section focuses exclusively on portfolio-level results, which are a weighted combination of TRC and mTRC results.

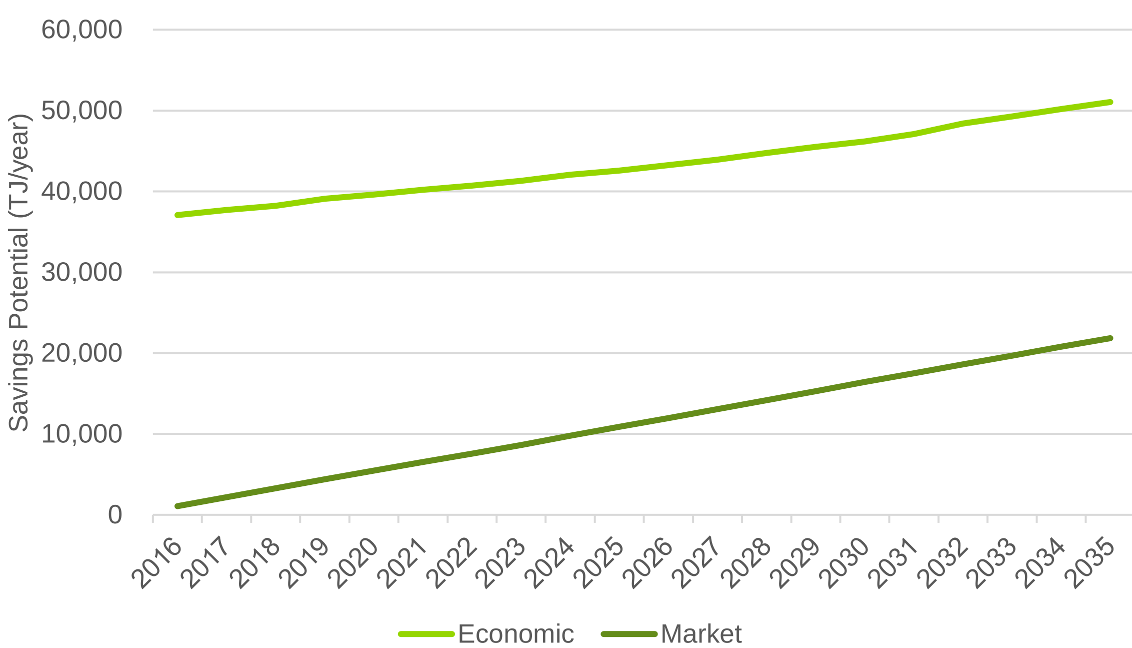
5.5.1 Approach to Estimating Hybrid mTRC/TRC Results

FortisBC Gas uses both the mTRC and TRC tests as cost effectiveness screens for measures within their existing DSM portfolio. As noted in Section 5.1, FortisBC Gas's regulatory environment at the time of this analysis allowed the utility to spend up to 33% of its entire DSM portfolio on measures or programs that require the mTRC to be cost effective. To date, FortisBC Gas's experience is that typically most programs in the residential sector require the mTRC. Since FortisBC Gas uses a combination of TRC and mTRC benefit-costs tests to screen measures and programs within their portfolio, Navigant estimated "Hybrid" market potential using the mTRC test for the residential sector and the TRC test for the C&I sectors to most closely simulate FortisBC Gas's actual DSM portfolio.

5.5.2 Hybrid mTRC/TRC Economic and Market Potential Results

Since the results from the Hybrid case are a weighted combination of the TRC and mTRC results, all results in this section will fall somewhere between the bounds set by those two cases. Figure 5-27 and Table B-17 in Appendix B show the economic and market gas savings potential for the Hybrid case. On average across the study period, the Hybrid case's economic potential is 20% larger than the TRC case and 9% smaller than the mTRC case, while the market potential is 12% larger than the TRC case and 5% smaller than the mTRC case. The Hybrid results more closely resemble the mTRC case because over two-thirds of the increase in market potential between the TRC and mTRC cases occurred in the residential sector, and those residential increases are captured in the Hybrid results.

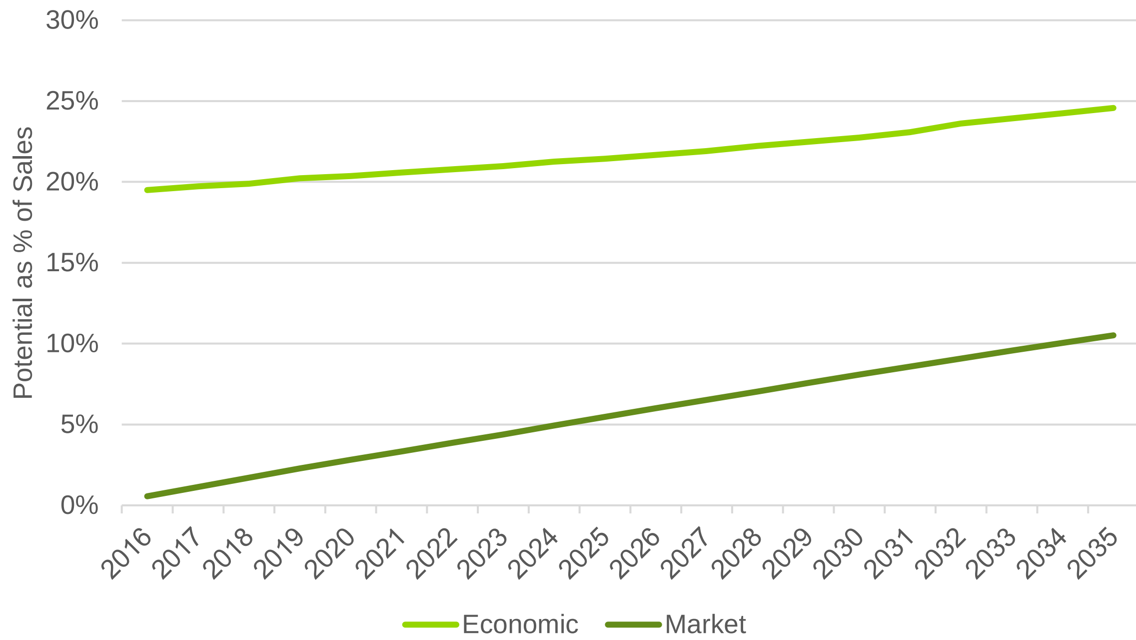
Figure 5-27. Hybrid Cumulative Gas Savings Economic and Market Potential by Sector (TJ/year)



Source: Navigant

Figure 5-28 and Table B-18 present the Hybrid case's economic and market potential as a percentage of total gas consumption. Market potential reaches just over 10% of total gas consumption by 2035, and it captures 43% of the economic potential.

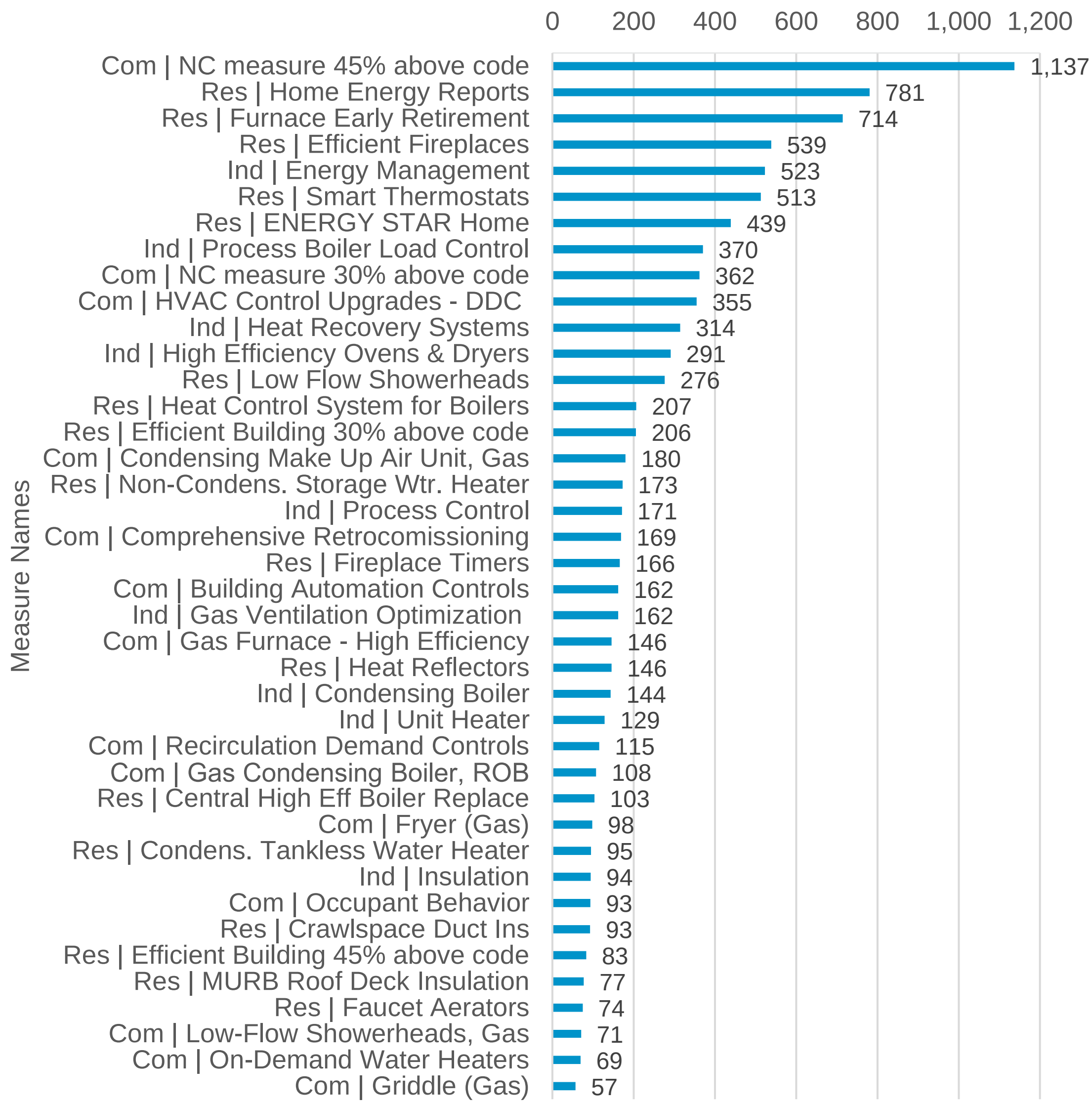
Figure 5-28. Hybrid Cumulative Gas Savings Economic and Market Potential as Percentage of Consumption (%)



Source: Navigant

Figure 5-29 and Table B-19 list the top 40 gas saving measures with the highest market potential for the Hybrid case. This table looks very similar to the TRC case except that residential measures have moved up the ranks. In particular, furnace early retirements and efficient fireplaces appear in the top ten, whereas they do not in the TRC case.

Figure 5-29. Hybrid Top 40 Measures for Gas Energy Market Savings Potential in 2025 (TJ/year)



Source: Navigant

5.5.3 Hybrid mTRC/TRC Cost Effectiveness

The following tables present cost-effectiveness results for the hybrid mTRC/TRC case. Table 5-8 shows that total spending for the Hybrid case begins at just over $46M/year and increases to $74M/year by 2035. The total 20-year spending in the Hybrid case is 71% larger than the TRC case and 8% smaller than the mTRC case. The costs borne by the utility to acquire market savings—on a dollar-per-savings basis—increase 0 to 3 percent per year, on average and in real terms, across the various sectors. This contrasts with recent program experience, where per-unit-of-savings utility costs have shown declining trends (see Section 5.3.2 for a discussion on this difference in cost trends).

Table 5-8. Budget for Portfolio – Hybrid Case (Million $/year)

Sector	Spending Type	2016	2020	2025	2030	2035	2016-2035 Total*
Portfolio	Incentives	$38.30	$51.08	$58.75	$61.91	$62.81	$1,114.66
	Non-Incentives	$7.97	$8.29	$8.92	$10.21	$11.33	$186.88
	Total	$46.27	$59.37	$67.67	$72.12	$74.13	$1,301.53

**The 2016-2035 Total column represents the sum of all forecasted years (2016-2035), not just those shown.*
Source: Navigant

The benefit-cost ratios and net benefits from the Hybrid case, which are presented in Table 5-9, are more similar to the TRC case than the mTRC case. Since the residential sector has lower benefit-cost ratios compared to the other sectors in both the TRC and mTRC cases, using the slightly higher residential results from the mTRC case does not significantly lift the benefit-cost ratios of the Hybrid portfolio. However, the additional net benefits that the residential mTRC case adds to the Hybrid portfolio is approximately $705 million in present value over the study period (expressed in 2016 dollars).

Table 5-9. Hybrid Portfolio Benefit-Cost Test Ratios and Net Benefits (Million $/year)

Sector	Year	Benefit-Cost Ratio	Net Benefits
Portfolio	2016	2.02	$67.04
	2020	2.26	$103.08
	2025	2.43	$125.10
	2030	2.73	$155.67
	2035	3.00	$185.00
	2016-2035*	2.41	$1,162.60

**Total net benefits for 2016-2035 represent present values in 2016 dollars. Other yearly values represent non-discounted, single-year net benefits.*
Source: Navigant

APPENDIX A. ADDITIONAL MODEL RESULTS

A.1 Detailed Model Results

For granular Base Case results from the model, see attachments

- “FortisGas_Appendix_A1_2017-02-10.xlsx”
- “FortisGas_Appendix_A1_mTRC_2017-02-10.xlsx”

APPENDIX B. SUPPORTING DATA FOR CHARTS

Table B-1. Total Cumulative Gas Savings Potential (TJ/year)

	Technical	Economic	Market
2016	45,828	28,797	934
2017	46,269	29,990	1,900
2018	46,717	30,522	2,895
2019	47,244	31,666	3,858
2020	47,699	32,214	4,799
2021	48,128	32,865	5,695
2022	48,619	33,430	6,611
2023	49,054	34,057	7,563
2024	49,496	34,844	8,556
2025	50,005	35,389	9,551
2026	50,645	36,087	10,537
2027	51,335	36,792	11,537
2028	51,985	37,645	12,554
2029	52,642	38,390	13,585
2030	53,348	39,111	14,625
2031	54,186	40,025	15,648
2032	55,030	41,321	16,678
2033	55,879	42,221	17,705
2034	56,732	43,248	18,726
2035	57,591	44,158	19,736

Source: Navigant

Table B-2. Total Cumulative Gas Savings Potential as a Percentage of Consumption (%)

	Technical	Economic	Market
2016	24.1%	15.1%	0.5%
2017	24.2%	15.7%	1.0%
2018	24.3%	15.9%	1.5%
2019	24.4%	16.4%	2.0%
2020	24.5%	16.6%	2.5%
2021	24.7%	16.8%	2.9%
2022	24.8%	17.1%	3.4%
2023	24.9%	17.3%	3.8%
2024	25.0%	17.6%	4.3%
2025	25.2%	17.8%	4.8%
2026	25.4%	18.1%	5.3%
2027	25.6%	18.4%	5.8%
2028	25.8%	18.7%	6.2%
2029	26.0%	19.0%	6.7%
2030	26.3%	19.2%	7.2%
2031	26.6%	19.6%	7.7%
2032	26.8%	20.2%	8.1%
2033	27.1%	20.5%	8.6%
2034	27.4%	20.9%	9.1%
2035	27.7%	21.3%	9.5%

Source: Navigant

Table B-3. Cumulative Gas Savings Market Potential by Sector (TJ/year)

	Commercial	Industrial	Residential
2016	498	172	265
2017	1,004	357	539
2018	1,511	557	828
2019	2,017	772	1,069
2020	2,519	1,005	1,276
2021	3,003	1,253	1,440
2022	3,496	1,519	1,596
2023	4,001	1,803	1,760
2024	4,520	2,106	1,930
2025	5,040	2,403	2,108
2026	5,541	2,699	2,297
2027	6,038	3,000	2,499
2028	6,533	3,311	2,710
2029	7,022	3,633	2,930
2030	7,505	3,962	3,159
2031	7,952	4,296	3,400
2032	8,394	4,632	3,652
2033	8,827	4,966	3,912
2034	9,251	5,295	4,180
2035	9,666	5,615	4,455

Source: Navigant

Table B-4. Cumulative Gas Savings Market Potential as a Percentage of Consumption by Sector (%)

	Commercial	Industrial	Residential
2016	0.8%	0.3%	0.4%
2017	1.6%	0.6%	0.7%
2018	2.4%	1.0%	1.1%
2019	3.2%	1.4%	1.5%
2020	3.9%	1.8%	1.7%
2021	4.6%	2.2%	2.0%
2022	5.3%	2.7%	2.2%
2023	6.0%	3.2%	2.4%
2024	6.8%	3.7%	2.6%
2025	7.5%	4.3%	2.8%
2026	8.1%	4.8%	3.1%
2027	8.7%	5.3%	3.3%
2028	9.4%	5.9%	3.6%
2029	10.0%	6.5%	3.9%
2030	10.5%	7.1%	4.2%
2031	11.1%	7.7%	4.4%
2032	11.6%	8.3%	4.8%
2033	12.1%	8.9%	5.1%
2034	12.5%	9.5%	5.4%
2035	13.0%	10.1%	5.7%

Source: Navigant

Table B-5. Cumulative Gas Savings Market Potential by Customer Segment (TJ/year)

	2016	2020	2025	2030	2035
C.Accommod	36	168	322	468	592
C.College/Univ	25	135	296	457	599
C.Food Svc	58	284	541	776	978
C.Hospital	44	212	422	631	822
C.Logistic/WHouse	22	118	250	386	518
C.Long Term Care	29	140	283	435	582
C.Office	71	370	823	1,323	1,776
C.Other Commercial	0	0	0	0	0
C.Retail.Food	11	66	147	228	298
C.Retail.Non Food	23	118	234	358	478
C.Schools	22	114	247	379	494
C.Streetlights/Signals	0	0	0	0	0
I.Agriculture	5	27	64	106	151
I.Cement	2	12	27	44	63
I.Chemical	3	19	44	73	108
I.Food & Bev	12	69	164	269	380
I.Greenhouse	13	77	181	289	407
I.LNG Facility	0	0	0	0	0
I.Mfg	23	135	314	525	753
I.Coal Mining	6	32	76	121	169
I.Metal Mining	0	0	0	0	1
I.Oil & Gas	11	59	126	171	216
I.Other Industrial	5	31	78	113	138
I.Kraft Pulp/Paper	59	355	880	1,512	2,185
I.TMP Pulp/Paper	7	41	96	152	213
I.Transportation	2	13	32	51	70
I.Wood Products	23	135	321	534	765
R.Apt <= 4 Stories	100	509	946	1,324	1,620
R.Apt > 4 Stories	56	286	528	740	909
R.Other Residential	4	21	34	49	67
R.Fam Attached	14	71	113	161	216
R.Fam Detached	246	1,184	1,962	2,949	4,172

Source: Navigant

Table B-6. Cumulative Gas Savings Market Potential by End-Use (TJ/year)

	2016	2020	2025	2030	2035
Appliances	0	0	0	0	0
Boilers	66	410	1,059	1,924	2,853
Cooking	30	133	226	295	347
Hot Water	82	445	871	1,222	1,490
Process Heat	19	117	291	527	787
Product Drying	15	94	240	441	658
Space Heating	248	1,340	2,899	4,560	6,208
Whole Facility	474	2,261	3,965	5,656	7,392

Source: Navigant

Table B-7. Top 40 Measures for Gas Energy Market Savings Potential in 2025 (TJ/year)

Rank	Measure	Market Potential
1	Com | NC measure 45 %>code	1,137
2	Res | Home Energy Reports	781
3	Ind | Energy Management	523
4	Res | Smart Thermostats	507
5	Res | ENERGY STAR Home	439
6	Ind | Process Boiler Load Control	370
7	Com | NC measure 30 %>code	362
8	Com | HVAC Control Upgrades - Direct Digital Data Control	355
9	Ind | Heat Recovery Systems	314
10	Ind | High Efficiency Ovens & Dryers	291
11	Res | Low Flow Showerheads	276
12	Res | Non-Condensing Gas Storage Water Heater	243
13	Res | Heat Control System for Boilers	207
14	Res | Energy Efficient Building 30% better than code	206
15	Com | Condensing Make Up Air Unit, Gas	180
16	Ind | Process Control	171
17	Com | Comprehensive Retrocomissioning	169
18	Res | Fireplace Timers	166
19	Com | Building Automation Controls	162
20	Ind | Gas Ventilation Optimization	162
21	Com | Gas Furnace - High Efficiency	146
22	Res | Heat Reflectors	146
23	Ind | Condensing Boiler	144
24	Ind | Unit Heater	129
25	Com | Recirculation Demand Controls for CDHW, Gas	115
26	Com | Gas Condensing Boiler, ROB	108
27	Res | Central High Eff Boiler Replace	103
28	Com | Fryer (Gas)	98
29	Ind | Insulation	94
30	Com | Occupant Behavior	93
31	Res | Crawlspace Duct Ins	93
32	Res | Energy Efficient Building 45% better than code	83
33	Res | MURB Roof Deck Insulation	77
34	Res | Faucet Aerators	74
35	Com | Low-Flow Showerheads, Gas	71
36	Res | Efficient Fireplaces	70
37	Com | Natural Gas On-Demand Water Heaters, ROB	69
38	Com | Griddle (Gas)	57
39	Ind | Improved Condensate Return	55
40	Com | Roof Deck Insulation	52

Source: Navigant

Table B-8. Gas Energy Market Savings Potential with Natural Change – All Sectors (TJ/year)

	Potential before Nat. Change	Potential after Adjusted Nat. Change
2016	934	934
2017	1,900	1,882
2018	2,895	2,842
2019	3,858	3,754
2020	4,799	4,629
2021	5,695	5,460
2022	6,611	6,300
2023	7,563	7,167
2024	8,556	8,061
2025	9,551	8,946
2026	10,537	9,828
2027	11,537	10,716
2028	12,554	11,611
2029	13,585	12,512
2030	14,625	13,412
2031	15,648	14,306
2032	16,678	15,201
2033	17,705	16,087
2034	18,726	16,960
2035	19,736	17,816

Source: Navigant

Table B-9. Residential Gas Energy Market Savings Potential with Natural Change (TJ/year)

	Potential before Nat. Change	Potential after Adjusted Nat. Change
2016	265	265
2017	539	532
2018	828	806
2019	1,069	1,027
2020	1,276	1,209
2021	1,440	1,350
2022	1,596	1,481
2023	1,760	1,616
2024	1,930	1,753
2025	2,108	1,894
2026	2,297	2,046
2027	2,499	2,207
2028	2,710	2,372
2029	2,930	2,542
2030	3,159	2,715
2031	3,400	2,901
2032	3,652	3,094
2033	3,912	3,290
2034	4,180	3,489
2035	4,455	3,691

Source: Navigant

Table B-10. Commercial Gas Energy Market Savings Potential with Natural Change (TJ/year)

	Potential before Nat. Change	Potential after Adjusted Nat. Change
2016	498	498
2017	1,004	994
2018	1,511	1,479
2019	2,017	1,954
2020	2,519	2,415
2021	3,003	2,857
2022	3,496	3,300
2023	4,001	3,748
2024	4,520	4,202
2025	5,040	4,648
2026	5,541	5,083
2027	6,038	5,509
2028	6,533	5,928
2029	7,022	6,337
2030	7,505	6,735
2031	7,952	7,109
2032	8,394	7,476
2033	8,827	7,831
2034	9,251	8,175
2035	9,666	8,510

Source: Navigant

Table B-11. mTRC Cumulative Gas Savings Economic Potential by Sector (TJ/year)

	Commercial	Industrial	Residential	Portfolio
2016	11,896	12,262	18,459	42,618
2017	12,325	12,240	18,512	43,077
2018	12,761	12,219	18,564	43,544
2019	13,235	12,198	18,617	44,051
2020	13,679	12,179	18,671	44,529
2021	14,081	12,145	18,753	44,979
2022	14,506	12,111	18,835	45,453
2023	14,916	12,079	18,918	45,913
2024	15,320	12,047	19,001	46,368
2025	15,774	12,016	19,084	46,873
2026	16,178	11,987	19,364	47,528
2027	16,598	11,958	19,644	48,200
2028	17,011	11,930	19,924	48,866
2029	17,429	11,903	20,205	49,537
2030	17,878	11,876	20,485	50,239
2031	18,262	11,847	20,984	51,093
2032	18,650	11,818	21,483	51,951
2033	19,042	11,790	21,982	52,815
2034	19,438	11,763	22,482	53,683
2035	19,838	11,736	22,982	54,556

Source: Navigant

Table B-12. mTRC Cumulative Gas Savings Economic Potential as Percent of Sector Consumption (%)

	Commercial	Industrial	Residential	Portfolio
2016	19.5%	21.4%	25.7%	22.4%
2017	20.0%	21.4%	25.6%	22.5%
2018	20.4%	21.4%	25.6%	22.7%
2019	20.9%	21.4%	25.5%	22.8%
2020	21.4%	21.4%	25.5%	22.9%
2021	21.8%	21.3%	25.5%	23.0%
2022	22.2%	21.3%	25.5%	23.2%
2023	22.6%	21.3%	25.5%	23.3%
2024	22.9%	21.3%	25.6%	23.4%
2025	23.3%	21.3%	25.6%	23.6%
2026	23.7%	21.3%	25.9%	23.8%
2027	24.0%	21.3%	26.1%	24.0%
2028	24.4%	21.3%	26.4%	24.3%
2029	24.7%	21.3%	26.7%	24.5%
2030	25.1%	21.2%	26.9%	24.7%
2031	25.4%	21.2%	27.5%	25.0%
2032	25.7%	21.2%	28.0%	25.3%
2033	26.0%	21.2%	28.5%	25.7%
2034	26.3%	21.2%	29.0%	26.0%
2035	26.6%	21.2%	29.6%	26.3%

Source: Navigant

Table B-13. mTRC Top 40 Measures for Gas Energy Economic Savings Potential in 2025 (TJ/year)

Rank	Measure	Economic Potential
1	Res | Smart Thermostats	4,885
2	Res | Condensing Gas Tankless Water Heater	4,117
3	Res | Non-Condensing Gas Tankless Water Heater	3,774
4	Com | NC measure 45 %>code	3,772
5	Res | Condensing Gas Storage Water Heater	3,284
6	Ind | Energy Management	2,822
7	Com | NC measure 30 %>code	2,515
8	Res | Non-Condensing Gas Storage Water Heater	2,206
9	Com | Wall Insulation	1,787
10	Ind | Process Boiler Load Control	1,662
11	Res | Home Energy Reports	1,634
12	Res | Efficient Fireplaces	1,520
13	Ind | Heat Recovery Systems	1,411
14	Com | HVAC Control Upgrades - Direct Digital Data Control	1,329
15	Ind | High Efficiency Ovens & Dryers	1,301
16	Res | ENERGY STAR Home	1,074
17	Res | Low Flow Showerheads	1,034
18	Res | Furnace Early Retirement	1,008
19	Res | Energy Efficient Building 45% better than code	886
20	Ind | High Efficiency Kilns	868
21	Res | R-2000 Standard New Home	743
22	Res | Attic Insulation	742
23	Ind | Gas Ventilation Optimization	739
24	Ind | Process Control	738
25	Res | Crawlspace Duct Ins	726
26	Res | Energy Star Windows	703
27	Ind | Condensing Boiler	670
28	Res | Energy Efficient Building 30% better than code	591
29	Res | Basement Insulation	546
30	Com | Condensing Make Up Air Unit, Gas	532
31	Ind | Unit Heater	503
32	Com | High Efficiency Gas-Fired Condensing Rooftop Unit (RTU)	496
33	Res | Vert Dir Vent Fireplaces	473
34	Res | High Eff Boiler Replace	429
35	Ind | Insulation	427
36	Res | Faucet Aerators	391
37	Com | Gas Condensing Boiler, ROB	387
38	Com | Gas Furnace - High Efficiency	373
39	Res | Heat Control System for Boilers	352
40	Res | Wall Insulation	325

Source: Navigant

Table B-14. mTRC Cumulative Gas Savings Market Potential (TJ/year)

	Commercial	Industrial	Residential	Portfolio
2016	554	183	397	1,134
2017	1,113	380	803	2,296
2018	1,673	593	1,229	3,494
2019	2,223	822	1,609	4,654
2020	2,769	1,070	1,955	5,794
2021	3,294	1,335	2,257	6,886
2022	3,827	1,618	2,549	7,994
2023	4,367	1,921	2,843	9,131
2024	4,911	2,244	3,137	10,292
2025	5,453	2,562	3,432	11,446
2026	5,974	2,880	3,729	12,583
2027	6,488	3,205	4,032	13,726
2028	6,995	3,539	4,337	14,871
2029	7,492	3,886	4,644	16,021
2030	7,980	4,240	4,951	17,171
2031	8,431	4,601	5,264	18,296
2032	8,870	4,964	5,583	19,418
2033	9,298	5,326	5,906	20,531
2034	9,716	5,684	6,233	21,632
2035	10,123	6,032	6,562	22,718

Source: Navigant

Table B-15. mTRC Cumulative Gas Savings Market Potential as Percent of Sector Consumption (%)

	Commercial	Industrial	Residential	Portfolio
2016	0.9%	0.3%	0.6%	0.6%
2017	1.8%	0.7%	1.1%	1.2%
2018	2.7%	1.0%	1.7%	1.8%
2019	3.5%	1.4%	2.2%	2.4%
2020	4.3%	1.9%	2.7%	3.0%
2021	5.1%	2.3%	3.1%	3.5%
2022	5.9%	2.8%	3.5%	4.1%
2023	6.6%	3.4%	3.8%	4.6%
2024	7.3%	4.0%	4.2%	5.2%
2025	8.1%	4.5%	4.6%	5.8%
2026	8.7%	5.1%	5.0%	6.3%
2027	9.4%	5.7%	5.4%	6.8%
2028	10.0%	6.3%	5.7%	7.4%
2029	10.6%	6.9%	6.1%	7.9%
2030	11.2%	7.6%	6.5%	8.5%
2031	11.7%	8.2%	6.9%	9.0%
2032	12.2%	8.9%	7.3%	9.5%
2033	12.7%	9.6%	7.7%	10.0%
2034	13.1%	10.2%	8.1%	10.5%
2035	13.6%	10.9%	8.4%	10.9%

Source: Navigant

Table B-16. mTRC Top 40 Measures for Gas Market Savings Potential in 2025 (TJ/year)

Rank	Measure	Market Potential
1	Com | NC measure 45 %>code	1,060
2	Res | Home Energy Reports	781
3	Res | Furnace Early Retirement	747
4	Com | HVAC Control Upgrades - Direct Digital Data Control	577
5	Res | Efficient Fireplaces	539
6	Ind | Energy Management	523
7	Res | Smart Thermostats	513
8	Res | ENERGY STAR Home	439
9	Com | NC measure 30 %>code	436
10	Ind | Process Boiler Load Control	370
11	Ind | Heat Recovery Systems	314
12	Ind | High Efficiency Ovens & Dryers	291
13	Res | Low Flow Showerheads	276
14	Res | Heat Control System for Boilers	207
15	Res | Energy Efficient Building 30% better than code	206
16	Com | Condensing Make Up Air Unit, Gas	180
17	Ind | Process Control	171
18	Res | Non-Condensing Gas Storage Water Heater	170
19	Com | Comprehensive Retrocomissioning	169
20	Res | Fireplace Timers	166
21	Com | Building Automation Controls	163
22	Ind | Gas Ventilation Optimization	162
23	Ind | High Efficiency Kilns	159
24	Com | Gas Furnace - High Efficiency	146
25	Res | Heat Reflectors	146
26	Ind | Condensing Boiler	144
27	Ind | Unit Heater	129
28	Com | Recirculation Demand Controls for CDHW, Gas	115
29	Com | Gas Condensing Boiler, ROB	108
30	Res | Central High Eff Boiler Replace	103
31	Res | Condensing Gas Tankless Water Heater	98
32	Com | Fryer (Gas)	98
33	Com | Duct Insulation, Gas	98
34	Ind | Insulation	94
35	Com | Occupant Behavior	93
36	Res | Crawlspace Duct Ins	93
37	Res | Energy Efficient Building 45% better than code	83
38	Com | Roof Deck Insulation	78
39	Res | MURB Roof Deck Insulation	77
40	Res | Faucet Aerators	74

Source: Navigant

Table B-17. Hybrid Cumulative Gas Savings Economic and Market Potential by Sector (TJ/year)

	Economic	Market
2016	37,075	1,067
2017	37,721	2,164
2018	38,213	3,296
2019	39,092	4,398
2020	39,598	5,479
2021	40,186	6,513
2022	40,718	7,564
2023	41,303	8,647
2024	42,057	9,763
2025	42,567	10,875
2026	43,246	11,969
2027	43,933	13,070
2028	44,768	14,181
2029	45,495	15,299
2030	46,198	16,418
2031	47,108	17,512
2032	48,399	18,609
2033	49,278	19,699
2034	50,162	20,779
2035	51,052	21,843

Source: Navigant

Table B-18. Hybrid Cumulative Gas Savings Economic and Market Potential as Percent of Sector Consumption (%)

	Economic	Market
2016	19.5%	0.6%
2017	19.7%	1.1%
2018	19.9%	1.7%
2019	20.2%	2.3%
2020	20.4%	2.8%
2021	20.6%	3.3%
2022	20.8%	3.9%
2023	21.0%	4.4%
2024	21.3%	4.9%
2025	21.4%	5.5%
2026	21.7%	6.0%
2027	21.9%	6.5%
2028	22.2%	7.0%
2029	22.5%	7.6%
2030	22.7%	8.1%
2031	23.1%	8.6%
2032	23.6%	9.1%
2033	23.9%	9.6%
2034	24.3%	10.0%
2035	24.6%	10.5%

Source: Navigant

Table B-19. Hybrid Top 40 Measures for Gas Energy Market Savings Potential in 2025 (TJ/year)

Rank	Measure	Market Potential
1	Com | NC measure 45 %>code	1,137
2	Res | Home Energy Reports	781
3	Res | Furnace Early Retirement	714
4	Res | Efficient Fireplaces	539
5	Ind | Energy Management	523
6	Res | Smart Thermostats	513
7	Res | ENERGY STAR Home	439
8	Ind | Process Boiler Load Control	370
9	Com | NC measure 30 %>code	362
10	Com | HVAC Control Upgrades - Direct Digital Data Control	355
11	Ind | Heat Recovery Systems	314
12	Ind | High Efficiency Ovens & Dryers	291
13	Res | Low Flow Showerheads	276
14	Res | Heat Control System for Boilers	207
15	Res | Energy Efficient Building 30% better than code	206
16	Com | Condensing Make Up Air Unit, Gas	180
17	Res | Non-Condensing Gas Storage Water Heater	173
18	Ind | Process Control	171
19	Com | Comprehensive Retrocomissioning	169
20	Res | Fireplace Timers	166
21	Com | Building Automation Controls	162
22	Ind | Gas Ventilation Optimization	162
23	Com | Gas Furnace - High Efficiency	146
24	Res | Heat Reflectors	146
25	Ind | Condensing Boiler	144
26	Ind | Unit Heater	129
27	Com | Recirculation Demand Controls for CDHW, Gas	115
28	Com | Gas Condensing Boiler, ROB	108
29	Res | Central High Eff Boiler Replace	103
30	Com | Fryer (Gas)	98
31	Res | Condensing Gas Tankless Water Heater	95
32	Ind | Insulation	94
33	Com | Occupant Behavior	93
34	Res | Crawlspace Duct Ins	93
35	Res | Energy Efficient Building 45% better than code	83
36	Res | MURB Roof Deck Insulation	77
37	Res | Faucet Aerators	74
38	Com | Low-Flow Showerheads, Gas	71
39	Com | Natural Gas On-Demand Water Heaters, ROB	69
40	Com | Griddle (Gas)	57

Source: Navigant

Appendix C-2

CONSERVATION AND ENERGY MANAGEMENT PROGRAM AREA COST EFFECTIVENESS TEST RESULTS

APPENDIX C-2: CONSERVATION AND ENERGY MANAGEMENT PROGRAM AREA COST EFFECTIVENESS TEST RESULTS

1.1 Background

The base year of the 2017 LTGRP forecast is 2015 but the C&EM analysis does not include data for 2015 and 2016 since these years are in the past already. FEI filed its actual program performance for these years with the Commission in its 2015 and 2016 C&EM Annual Reports.[1,2] FEI does not expect the LTGRP 2017 cost effectiveness test results to match its 2017 C&EM Annual Report because both filings are different in nature and methods and use different years of actuals data (2015 versus 2017, respectively). In particular, the 2017 LTGRP C&EM analysis excludes the items noted in Section 4.2.3.2 of the Application. The C&EM analysis, like the BC CPR, also includes numerous energy efficiency measures which are not included in FEI's current C&EM program portfolio.

All cost effectiveness test results reported below exclude data from behavioural and energy management measures. In alignment with the BC CPR, the 2017 LTGRP C&EM analysis assumes that these measures have negligible incremental costs which cause them to have uncharacteristically high cost effectiveness test results. Excluding data for these measures prevents their results from skewing the aggregate data reported below.

In general, Upper Bound cost effectiveness test ratios are lower than Lower Bound ratios because the low natural gas cost and carbon cost parameters in this scenario depress the avoided cost of gas which reduces the benefits from energy efficiency measures. The Modified Total Resource Cost Test (MTRC) represents an exception to this as this test relies on the Zero Emissions Energy Alternative (ZEEA) for its avoided cost of gas. In the 2017 LTGRP, the ZEEA is not impacted by the natural gas and carbon cost critical uncertainties. In general, cost effectiveness test ratios fall over time as the more easily realized energy savings opportunities (i.e. the low-hanging fruit) are depleted. The 2017 LTGRP C&EM cost effectiveness test results also display the Cost of Conserved Energy (CCE) in dollars per GJ. The CCE is an industry standard method for expressing the Total Resource Cost Test (TRC) results in dollars per GJ. Electric utilities use the CCE to express the net cost of saving one unit of utility-supplied energy. The CCE can be used to express UCT results in dollars per GJ by applying the UCT benefit and

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1 Appendix D-27: https://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/160330_FEI_2015_DSM_Annual_Report_FF.PDF.

2 Appendix D-28: https://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/170331_FEI_2016_DSM_Annual_Report_FF.PDF.

cost inputs.[3] While Section 4.2.3.3 of the Application outlines cost effectiveness test results for the aggregate C&EM portfolio, the remainder of this appendix provides the same results for each of the program areas within the 2017 LTGRP C&EM analysis.

1.2 Residential Program Area

Table C2-1 below summarizes the Reference Case cost effectiveness test results for the residential program area while Figures C2-1 to C2-4 illustrate how cost effectiveness test results vary across scenarios. The aggregate residential program area TRC ratio is lower and the aggregate Utility Cost Test (UCT) is higher than the corresponding portfolio level results. Aggregate residential CCE results are higher than the corresponding portfolio level results but the annual results drop over time.[4]

Table C2-1: Estimated Reference Case Cost Effectiveness Test Results – Residential Program Area

Year	TRC	MTRC	UCT	CCE ($/GJ)
Aggregate	**1.6**	**7.2**	**2.3**	**6.3**
2017	2.4	9.7	2.9	7.4
2018	2.2	9.0	2.8	7.2
2019	2.1	8.8	2.7	7.0
2020	2.1	8.6	2.7	7.0
2021	1.9	8.2	2.6	6.9
2022	1.9	7.9	2.5	6.8
2023	1.8	7.7	2.4	6.7
2024	1.7	7.3	2.3	6.8
2025	1.6	7.2	2.3	6.7
2026	1.6	7.1	2.3	6.6
2027	1.6	7.0	2.3	6.5
2028	1.5	6.9	2.2	6.4
2029	1.5	6.8	2.2	6.4
2030	1.5	6.7	2.2	6.3
2031	1.5	6.7	2.2	6.2
2032	1.5	6.9	2.2	6.1

[3] In this case, the CCE represents the annualized and, where applicable, discounted UCT costs divided by annual energy savings.

[4] This appears to be due to the relative trajectory of the ZEEA in relation to projected residential energy savings.

Year	TRC	MTRC	UCT	CCE ($/GJ)
2033	1.5	7.1	2.3	6.0
2034	1.6	7.2	2.3	5.9
2035	1.6	7.4	2.4	5.8
2036	1.6	7.6	2.4	5.7

Figure C2-1: Estimated TRC Results by Scenario – Residential Program Area

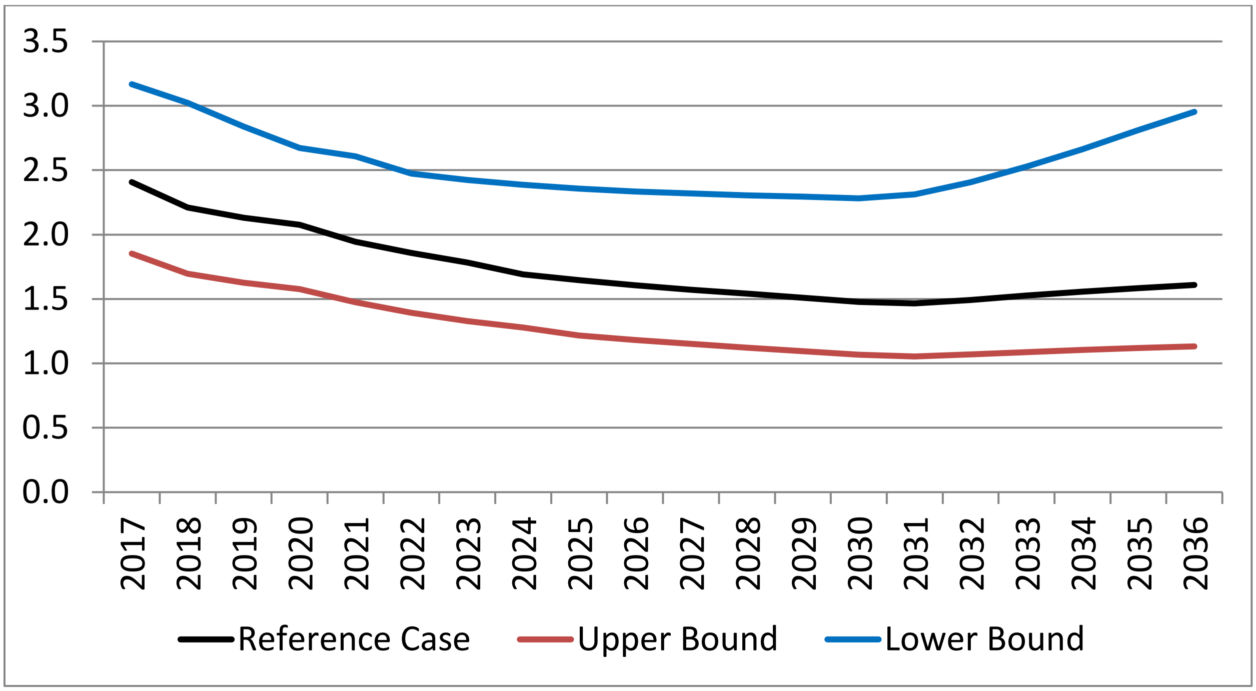


Figure C2-2: Estimated MTRC Results by Scenario – Residential Program Area

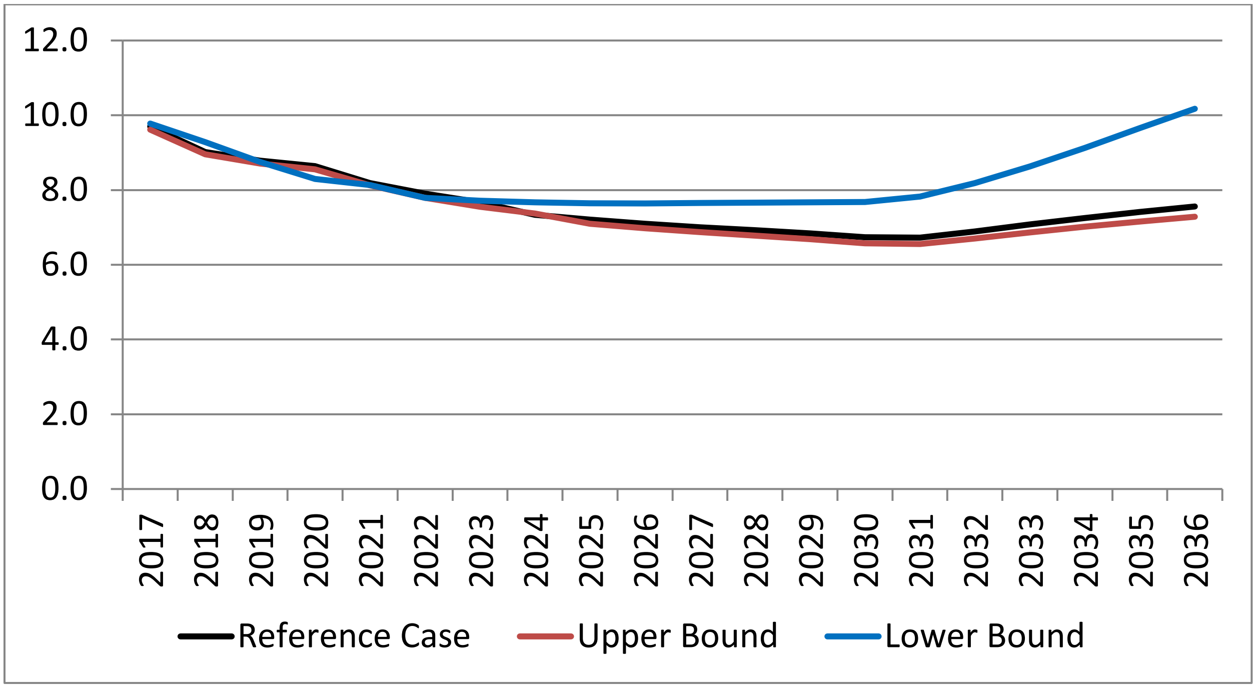


Figure C2-3: Estimated UCT Results by Scenario – Residential Program Area

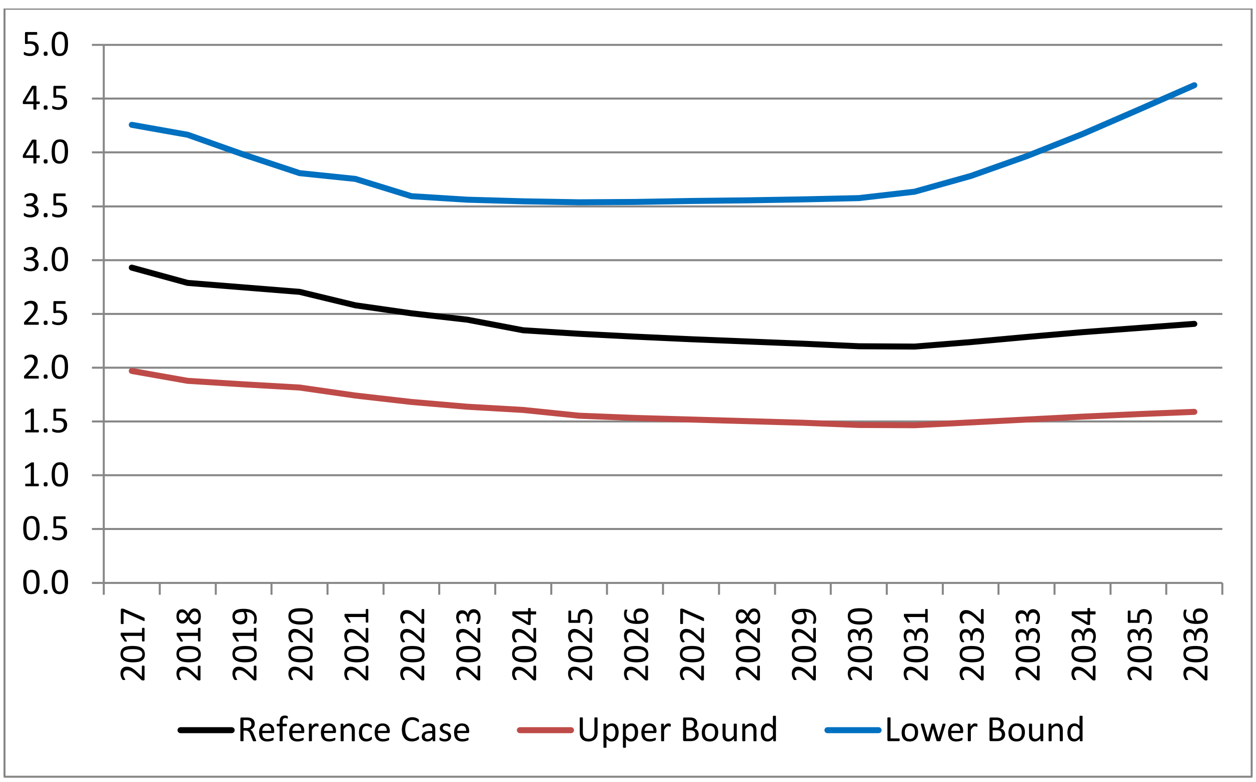
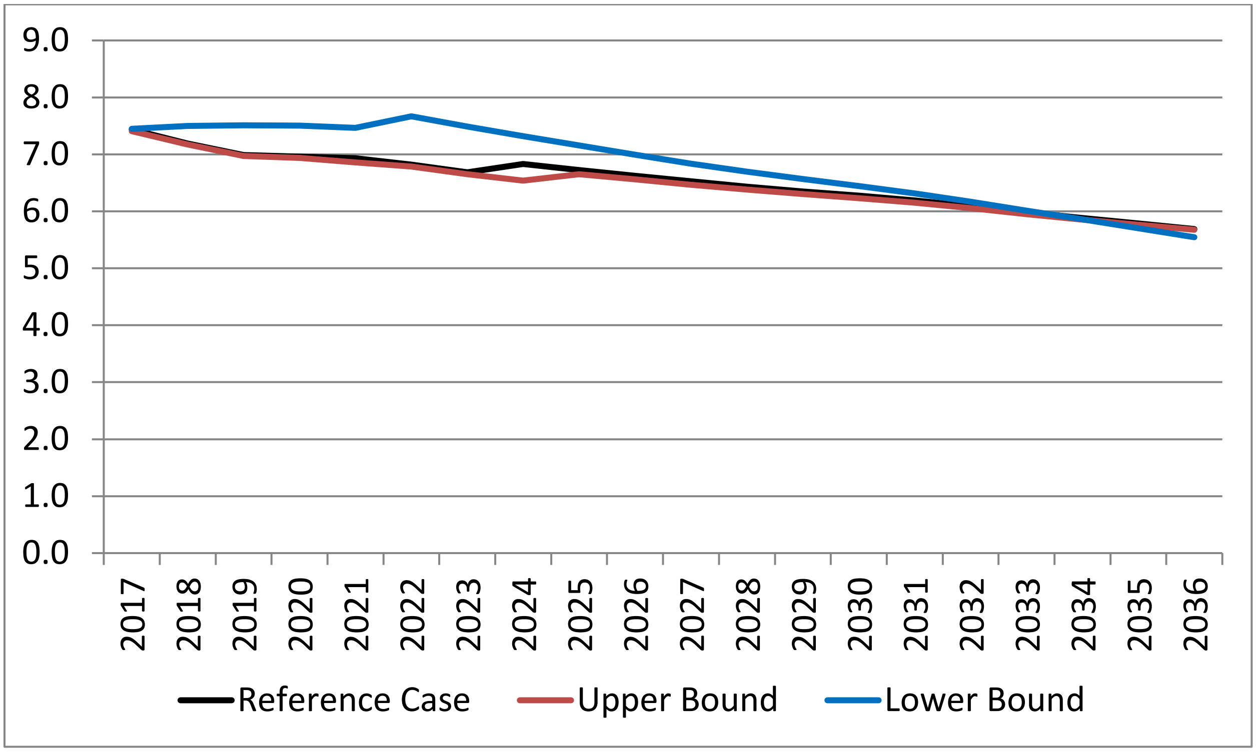


Figure C2-4: Estimated CCE Results by Scenario ($/GJ) – Residential Program Area



1.3 Commercial Program Area

Table C2-2 below summarizes the Reference Case cost effectiveness test results for the commercial program area while Figures C2-5 to C2-8 illustrate how cost effectiveness test results vary across scenarios. The aggregate commercial program area TRC ratio is higher than and the aggregate UCT is the same as the corresponding portfolio level results. Aggregate commercial CCE results are lower than the corresponding portfolio level results but annual results increase over time.

Table C2-2: Estimated Reference Case Cost Effectiveness Test Results – Commercial Program Area

Year	TRC	MTRC	UCT	CCE ($/GJ)
Aggregate	**2.8**	**14.9**	**2.2**	**4.0**
2017	5.8	31.8	5.0	1.3
2018	5.3	28.5	4.4	1.6
2019	4.5	24.4	3.7	2.2
2020	4.0	21.4	3.3	2.6
2021	3.5	19.1	2.9	3.0
2022	3.2	17.6	2.6	3.3

Year	TRC	MTRC	UCT	CCE ($/GJ)
2023	3.0	16.3	2.4	3.7
2024	2.9	15.7	2.3	3.8
2025	2.8	15.2	2.3	3.9
2026	2.7	14.8	2.2	4.0
2027	2.7	14.5	2.1	4.1
2028	2.6	14.2	2.1	4.1
2029	2.6	14.0	2.1	4.2
2030	2.6	13.8	2.0	4.2
2031	2.5	13.6	2.0	4.3
2032	2.5	13.4	2.0	4.3
2033	2.5	13.3	1.9	4.3
2034	2.4	13.1	1.9	4.3
2035	2.4	13.0	1.9	4.4
2036	2.4	12.9	1.9	4.4

Figure C2-5: Estimated TRC Results by Scenario – Commercial Program Area

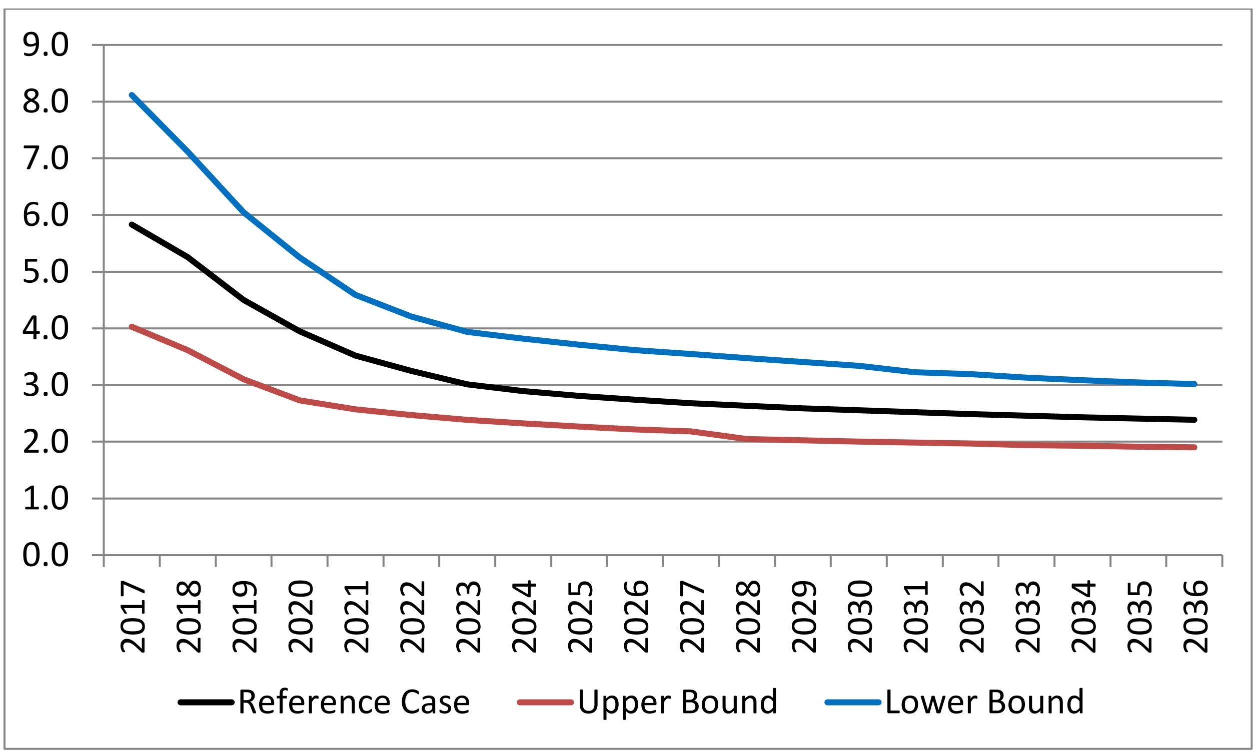


Figure C2-6: Estimated MTRC Results by Scenario – Commercial Program Area

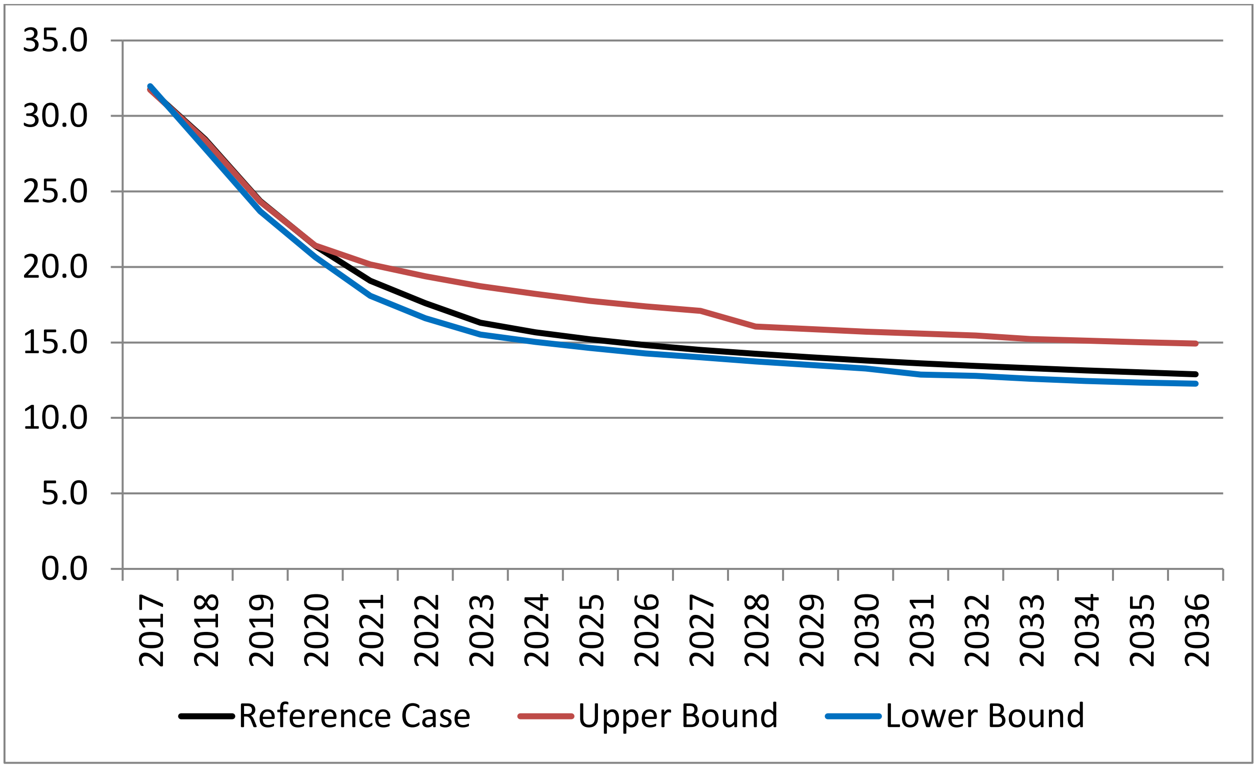


Figure C2-7: Estimated UCT Results by Scenario – Commercial Program Area

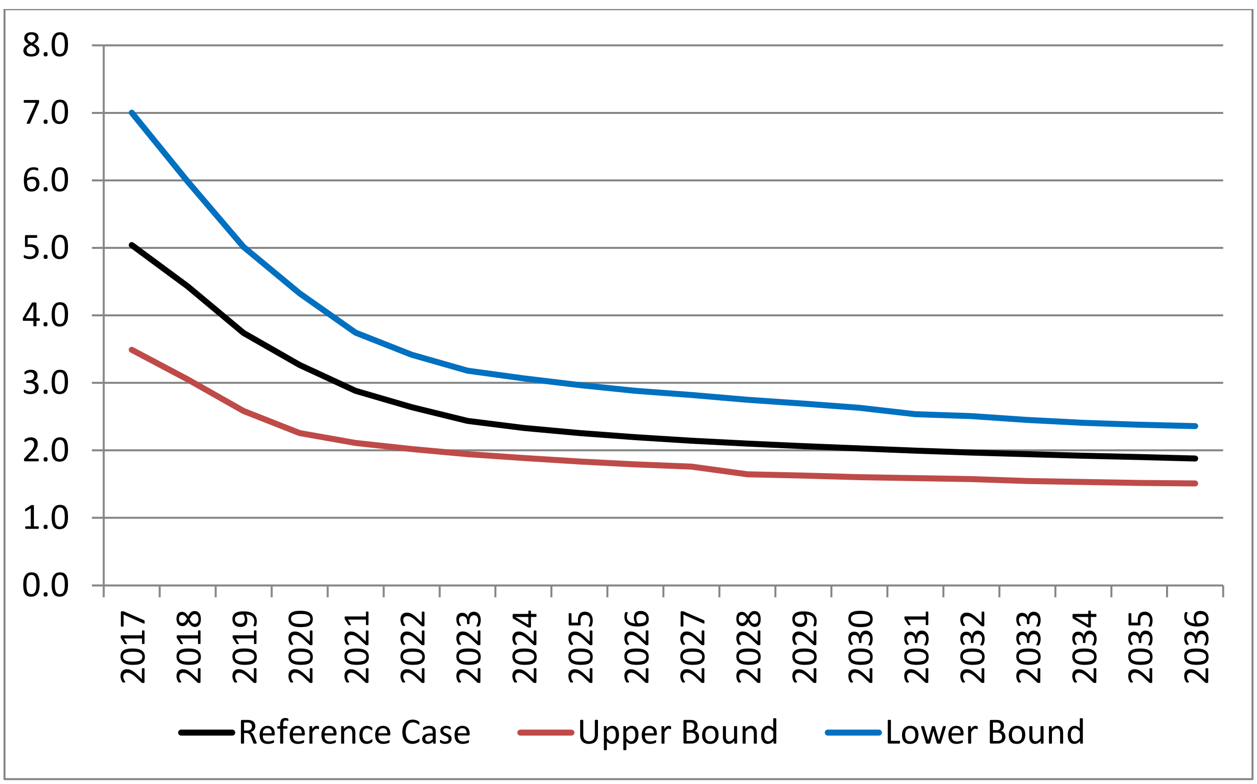
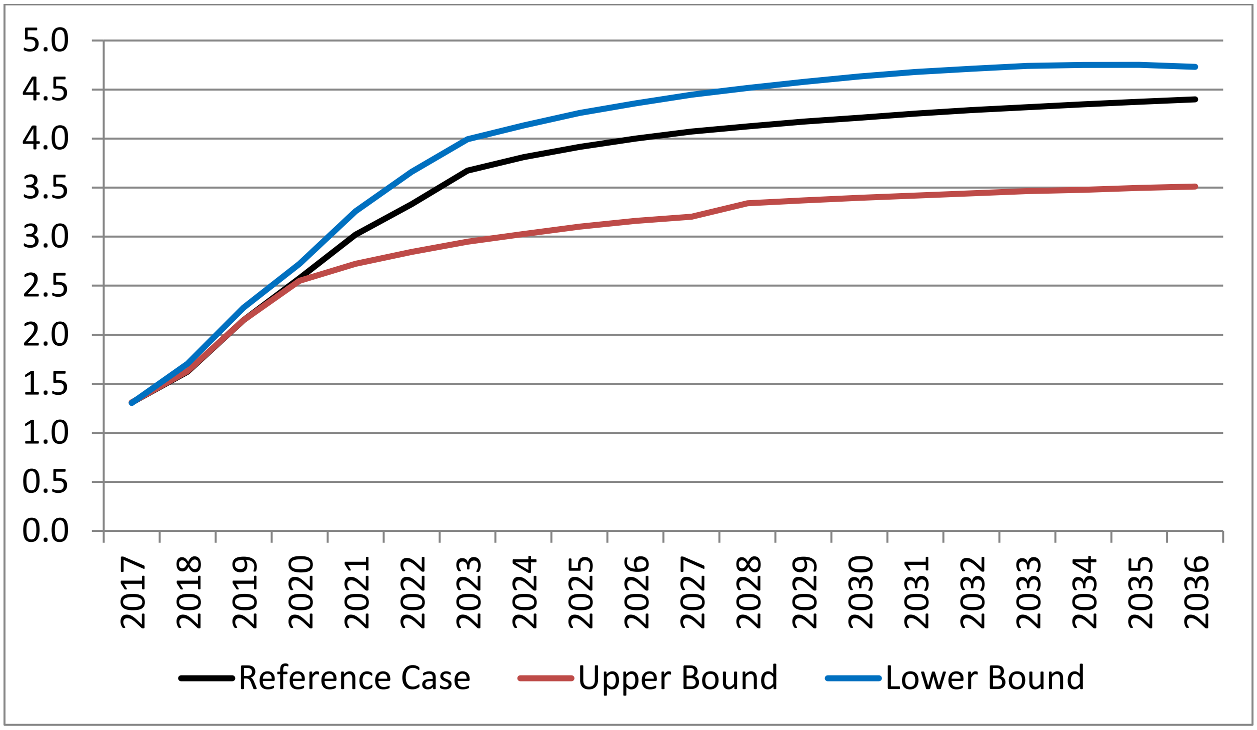


Figure C2-8: Estimated CCE Results by Scenario ($/GJ) – Commercial Program Area



1.4 Industrial Program Area

Table C2-3 below summarizes the Reference Case cost effectiveness test results for the industrial program area while Figures C2-9 to C2-12 illustrate how cost effectiveness test results vary across scenarios. The aggregate industrial program area TRC ratio is higher than and the aggregate UCT is lower than the corresponding portfolio level results. Aggregate industrial CCE results are lower than the corresponding portfolio level results and annual results remain flat over time.

Table C2-3: Estimated Reference Case Cost Effectiveness Test Results – Industrial Program Area

Year	TRC	MTRC	UCT	CCE ($/GJ)
Aggregate	**1.7**	**9.4**	**1.8**	**3.3**
2017	1.7	9.5	1.8	3.2
2018	1.7	9.5	1.8	3.3
2019	1.7	9.5	1.8	3.3
2020	1.7	9.4	1.8	3.3
2021	1.7	9.5	1.8	3.3
2022	1.7	9.5	1.8	3.3
2023	1.7	9.5	1.8	3.3

Year	TRC	MTRC	UCT	CCE ($/GJ)
2024	1.7	9.5	1.8	3.3
2025	1.7	9.5	1.8	3.3
2026	1.7	9.4	1.8	3.3
2027	1.7	9.4	1.8	3.3
2028	1.7	9.4	1.8	3.3
2029	1.7	9.4	1.8	3.3
2030	1.7	9.4	1.8	3.3
2031	1.7	9.4	1.8	3.3
2032	1.6	9.4	1.8	3.3
2033	1.6	9.4	1.8	3.3
2034	1.6	9.4	1.8	3.3
2035	1.6	9.4	1.8	3.3
2036	1.6	9.4	1.8	3.3

Figure C2-9: Estimated TRC Results by Scenario – Industrial Program Area

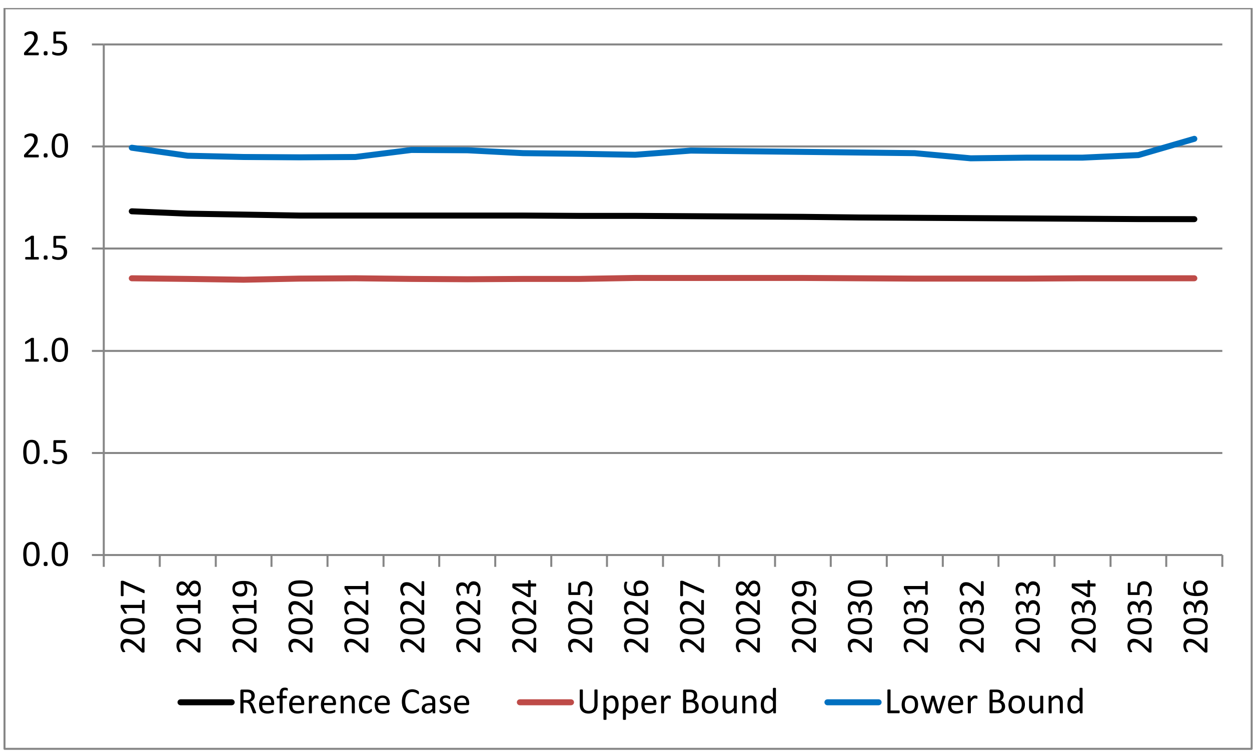


Figure C2-10: Estimated MTRC Results by Scenario – Industrial Program Area

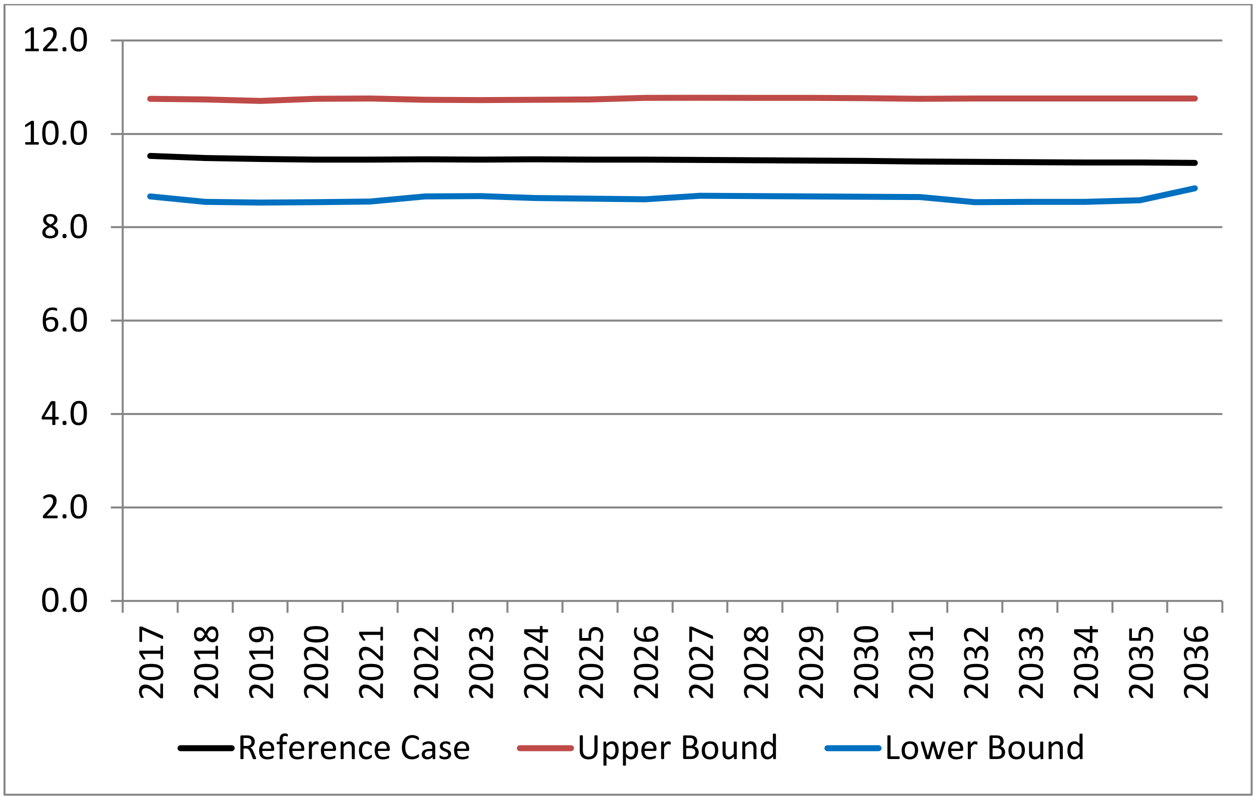
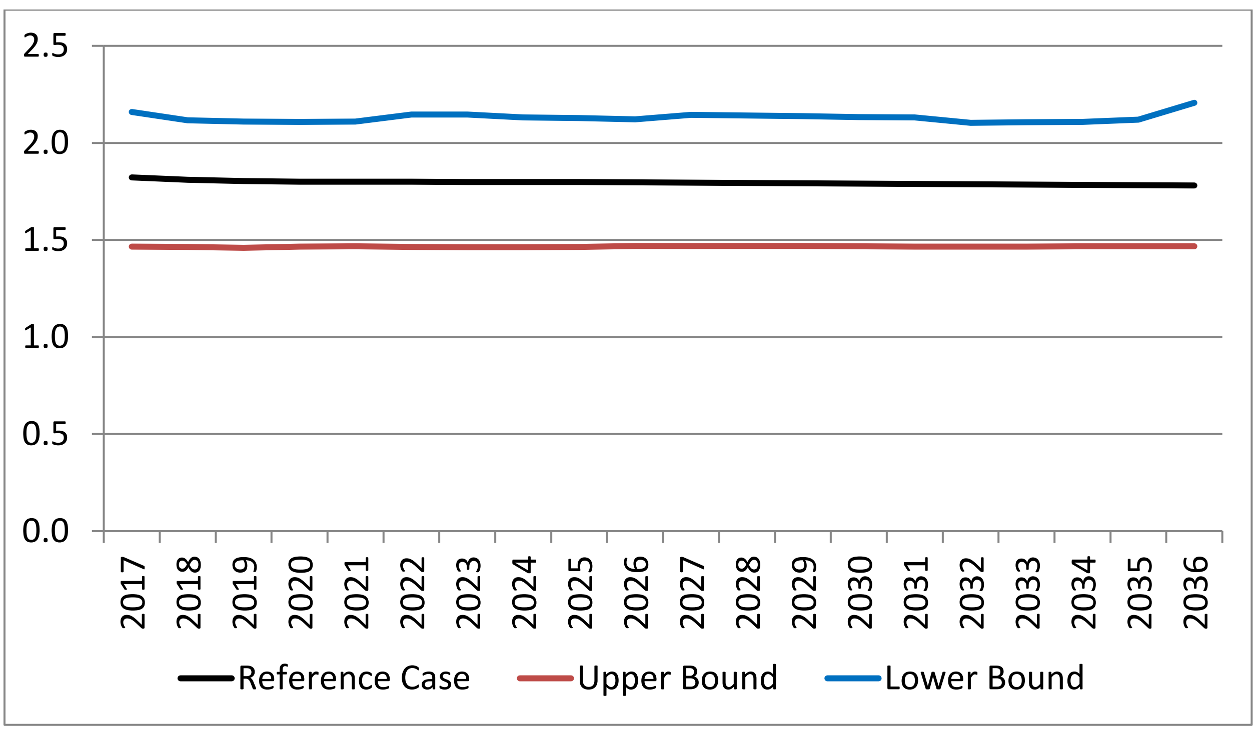
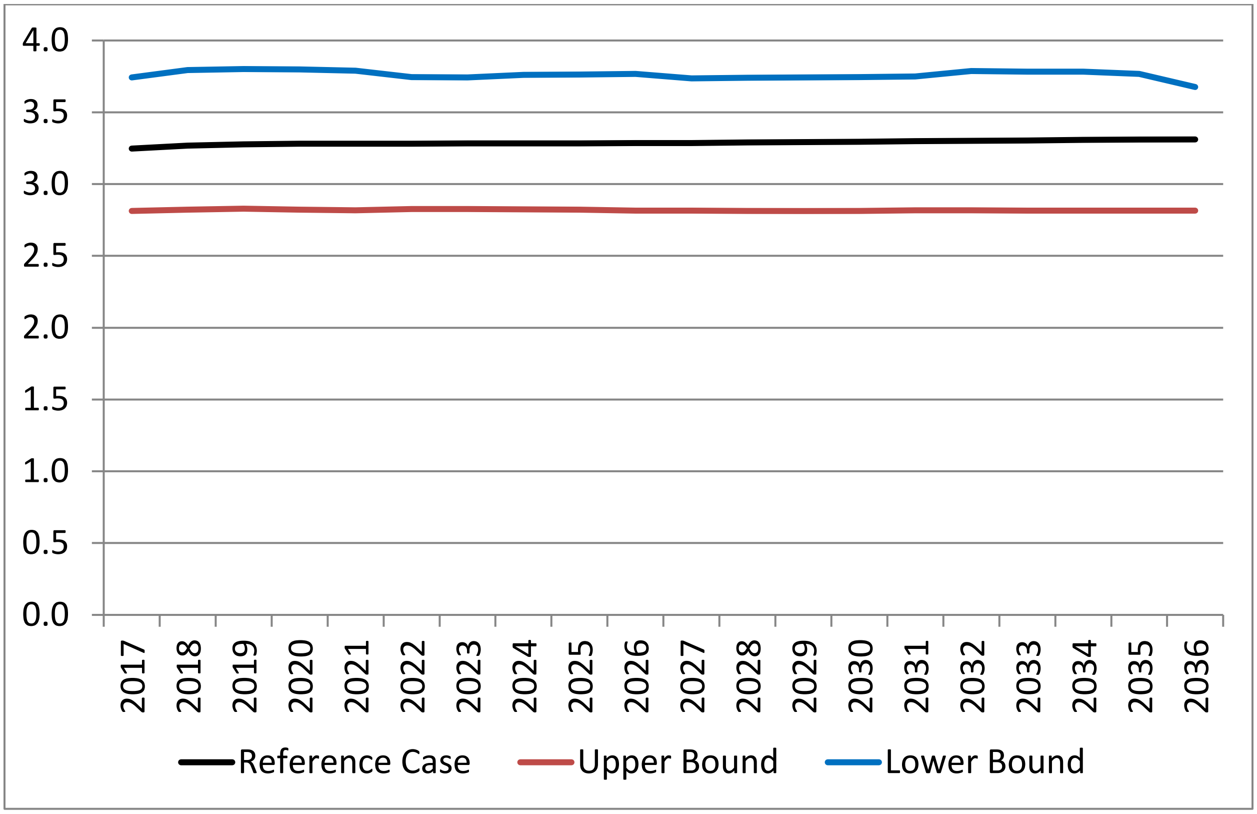


Figure C2-11: Estimated UCT Results by Scenario – Industrial Program Area



1 **Figure C2-12: Estimated CCE Results by Scenario ($/GJ) – Industrial Program Area**



2

Appendix D

REFERENCED DOCUMENTS

(Provided in electronic format only due to
document size and in order to conserve paper)

REFER TO LIVE SPREADSHEET MODELS

(accessible by opening the Attachments Tab in Adobe)

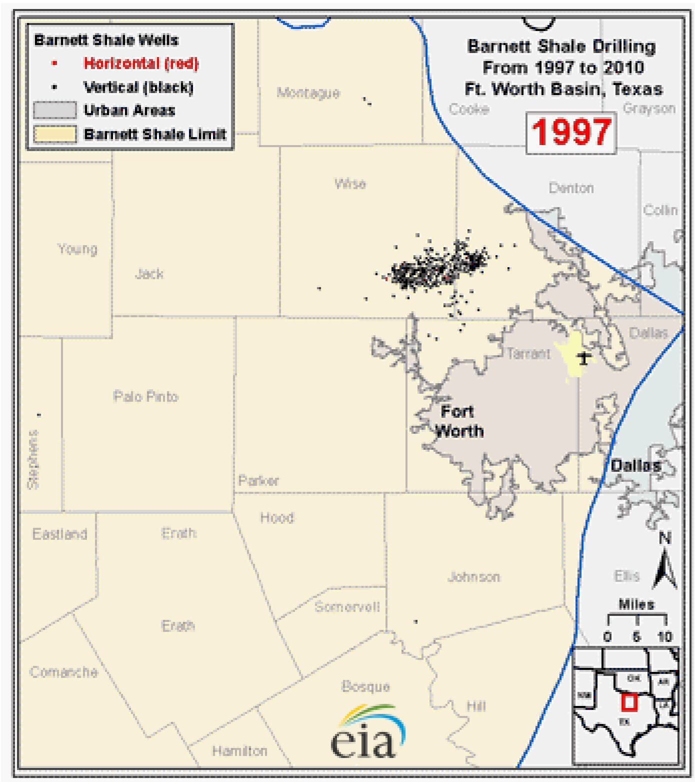
U.S. Energy Information Administration

Today in Energy

July 12, 2011

Technology drives natural gas production growth from shale gas formations

Watch Barnett Shale Drilling from 1997 to 2010



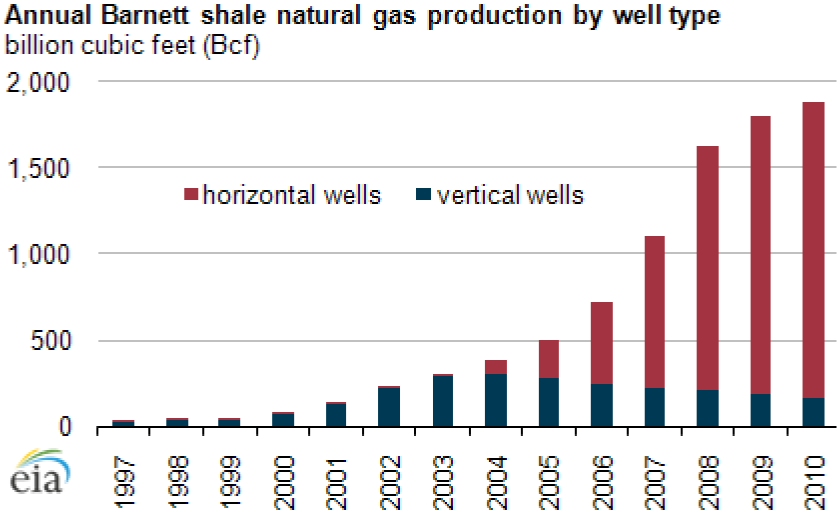
Source: U.S. Energy Information Administration based on HPDI, LLC

Rapid increases in natural gas production from shale gas formations resulted from widespread application of two key technologies, horizontal drilling and hydraulic fracturing. Horizontal drilling lets producers access far more natural gas from relatively thin shale deposits. In Texas' Barnett shale, the Nation's most developed shale play, the number of producing horizontal wells rose from fewer than 400 in 2004 to more than 10,000 during 2010.

Click on the map above to see how horizontal drilling has displaced traditional vertical drilling since 1997 in the Barnett shale.

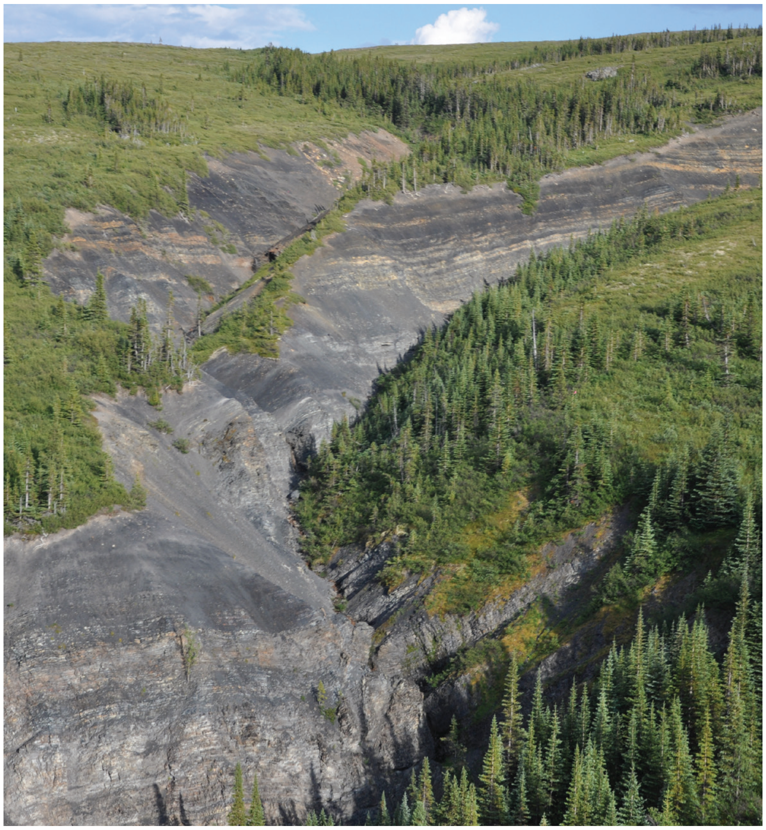
As the animation shows, producers have drilled some horizontal wells within the city of Fort Worth, and even on the property of the Dallas-Fort Worth airport, where wells began to appear in 2007 (near the end of the animation). The sharpened focus on horizontal drilling has generated steady and significant increases in natural gas production (see chart below). Annual production from horizontal wells exceeded that from vertical wells for the first time in 2006, and presently accounts for about 90% of total Barnett natural gas production.

Starting in the late 1990s, drilling in the Barnett grew rapidly, initially in the form of vertical wells. Since about 2003, however, the number of producing horizontal wells (red dots in the animation) has increased considerably, surpassing vertical wells (black dots) in 2007 and accounting for about 70% of producing wells in the Barnett during 2010.



Source: U.S. Energy Information Administration based on HPDI, LLC

Shale deposits are typically thin layers of rock that cover a wide area. Horizontal drilling lets producers drill through a much greater extent of gas-producing rock in such a formation. Horizontal wells can traverse 5,000 feet or more of a given shale deposit, while a vertical well would simply go through the deposit, tapping only a small vertical layer of shale. When combined with hydraulic fracturing to break apart the relatively impermeable shale, horizontal wells allow considerably greater gas production than vertical wells, more than enough to make up for their greater expense.



The Unconventional Gas Resources of Mississippian-Devonian Shales in the Liard Basin of British Columbia, the Northwest Territories, and Yukon

Energy Briefing Note • March 2016

Yukon Geological Survey

Northwest Territories Geological Survey

BC Oil & Gas Commission

British Columbia Ministry of Natural Gas Development

National Energy Board / Office national de l'énergie

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Table of Contents

Foreword

National Energy Board

The National Energy Board (NEB or Board) is an independent federal regulator established to promote safety and security, environmental protection and economic efficiency in the Canadian public interest within the mandate set by Parliament for the regulation of pipelines, energy development and trade. The Board's main responsibilities include regulating the construction, operation and abandonment of pipelines that cross international borders or provincial/territorial boundaries, as well as the associated pipeline tolls and tariffs, the construction and operation of international power lines and designated interprovincial power lines; and imports of natural gas and exports of crude oil, natural gas liquids (NGL), natural gas, refined petroleum products and electricity.

For oil and natural gas exports, the Board's role is to evaluate whether the oil and natural gas proposed to be exported is surplus to reasonably foreseeable Canadian requirements, having regard to the trends in the discovery of oil or gas in Canada.

If a party wishes to rely on material from this report in any regulatory proceeding before the Board, it may submit the material, just as it may submit any public document. Under these circumstances, the submitting party in effect adopts the material and could be required to answer questions pertaining to its content.

This report does not provide an indication about whether any application will be approved or not. The Board will decide on specific applications based on the material in evidence before it at that time.

The Northwest Territories Geological Survey

The Northwest Territories Geological Survey (NTGS) is a division of the Department of Industry, Tourism and Investment, Government of the Northwest Territories. The NTGS advances geoscience knowledge about the Northwest Territories for the benefit of northerners and all Canadians. The NTGS does this through the delivery of geoscience research, analysis of mineral and petroleum resources, and by offering excellence in digital data management. The NTGS regularly collaborates with its partners and other organizations in support of modern geoscience research, public awareness and education, and informed decision making.

The Yukon Geological Survey

The mandate of the Yukon Geological Survey (YGS) is to be the authority and provider of choice for the geoscience and related technical information required to enable stewardship and sustainable development of the Territory's energy, mineral, and land resources. The YGS generates and compiles information on Yukon's geology, mineral and petroleum resources; works in partnership with other branches of Yukon Government to distribute geoscience maps and publications to exploration companies, First Nations and the public; and through studies such as this assessment, contributes information required to make informed resource management decisions.

British Columbia Oil and Gas Commission

The BC Oil and Gas Commission (Commission) is the provincial regulatory agency with responsibilities for regulating oil and gas activities in British Columbia, including exploration, development, pipeline transportation and reclamation.

The Commission's core services include reviewing and assessing applications for industry activity, consulting with First Nations, cooperating with partner agencies, and ensuring industry complies with provincial legislation and all regulatory requirements. The public interest is protected by ensuring public safety, respecting those affected by oil and gas activities, conserving the environment, and ensuring equitable participation in production.

Responding to the complex and often competing economic, environmental and social priorities driving the oil and gas industry, the Commission maintains a modern regulatory framework and proactively looks for innovative solutions for continued safe and sustainable oil and gas development in the province. In accordance with its mandate, the Commission strives to deliver fair and timely decisions on proposed projects, balancing firm oversight of operational safety and First Nations' rights.

The Commission liaises with other provincial and federal government agencies in ensuring effective delivery of government policy, improved regulatory climate and cohesive application of existing regulations. It is of key importance for the Commission to stay fully apprised of the latest technological breakthroughs, and independent world-wide scientific research pertinent to the industry.

British Columbia Ministry of Natural Gas Development

The role of the British Columbia Ministry of Natural Gas Development is to guide the responsible development and ensure maximum economic benefits to British Columbians from the province's natural gas resources and the province's next new major industrial sector - that of liquefied natural gas (LNG).

Through teamwork and positive working relationships with its clients, the Ministry facilitates B.C.'s thriving, safe, environmentally responsible and competitive natural gas sector to create jobs and economic growth. In developing natural gas policies, legislation and guidelines, the Ministry consults with other ministries and levels of government, energy companies, First Nations, communities, environmental and industry organizations, and the public.

A key component of the Ministry's mandate is to develop tenure, royalty and regulatory policy for British Columbia's natural gas industry, thereby promoting the effective and environmentally responsible management of the province's natural gas resources.

The Ministry provides a range of natural gas related services, including the issuance of Crown subsurface resource rights, royalty programs, public geoscience and policies to address potential future resource opportunities, including unconventional natural gas resource development. The Ministry's LNG Secretariat reports to the new Cabinet Working Group on Liquefied Natural Gas, which will advise on budgets, structure, mandate and service plan goals.

Executive Summary

The marketable, unconventional gas potential of the Exshaw and Patry shales of the Liard Basin's Besa River Formation have been evaluated in a joint assessment by the National Energy Board, the British Columbia Oil and Gas Commission, the British Columbia Ministry of Natural Gas Development, the Northwest Territories Geological Survey, and the Yukon Geological Survey. The thick and geographically extensive Exshaw and Patry shales are expected to contain 6.20 trillion m³ (219 trillion cubic feet) of marketable natural gas.[1]

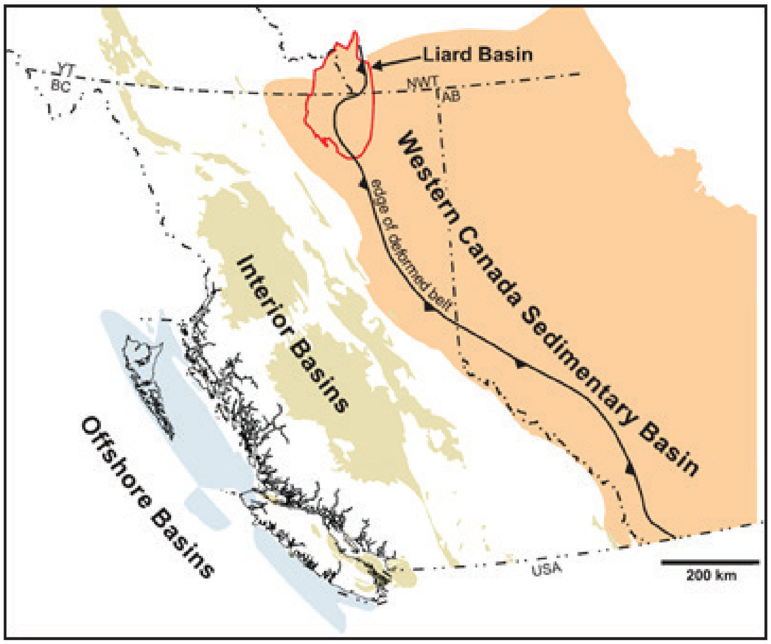

Figure 1. Location of the Liard Basin within the Western Canada Sedimentary Basin. The eastern boundary of the Liard Basin largely coincides with the Bovie Fault (see Figure 2). Modified from Ferri et al. (2015)

Introduction

The Liard Basin is a lightly drilled region at about 60 °N that straddles the boundaries of the Northwest Territories (NWT), Yukon, and the province of British Columbia (B.C.) (Figure 1). It is located at the far northwest corner of the Western Canada Sedimentary Basin (WCSB), Canada's major oil and gas producing area. The Liard Basin's unconventional[2] potential had not been assessed in detail before this study.

While **the Liard Basin's conventional potential was not assessed in this study**, conventional natural gas has been produced in the Liard Basin from the Beaver River Field of B.C. since the late 1960s, the Pointed Mountain Field and other gas fields of NWT since the early 1970s, and the Kotaneelee Field of Yukon since the late 1970s. Conventional gas has also been produced from B.C.'s Maxhamish Field since the late 1990s. Thus, there are already gas pipelines in the Liard Basin in all three jurisdictions.

[1] Marketable natural gas, as used in this report, indicates the volume of gas that is recoverable using existing technology, and is in a condition to be used by the market. While it implies a sense of economic recovery, no economic assessment was performed. The presence of gas pipelines did not affect this analysis.

[2] For this study, unconventional gas in the Liard Basin is considered natural gas that is developed using horizontal drilling and multi-stage hydraulic fracturing.

Geological Description

Sediments were deposited in the Liard Basin from the Cambrian period to the end of the Cretaceous period (from 540 million years (Ma) ago to 65 Ma ago). The central and eastern portions of the Liard Basin are relatively undeformed by faults where the Liard Basin's western and northwestern regions were faulted when the Rocky Mountains and Mackenzie Mountains were uplifted. The Liard Basin's eastern edge is defined by the Bovie Fault, separating it from the Horn River Basin. However, the two basins share many of the same shales, including the Exshaw and Horn River shales (Figure 2).[3] The Horn River Basin's shale gas potential was assessed in 2011.[4]

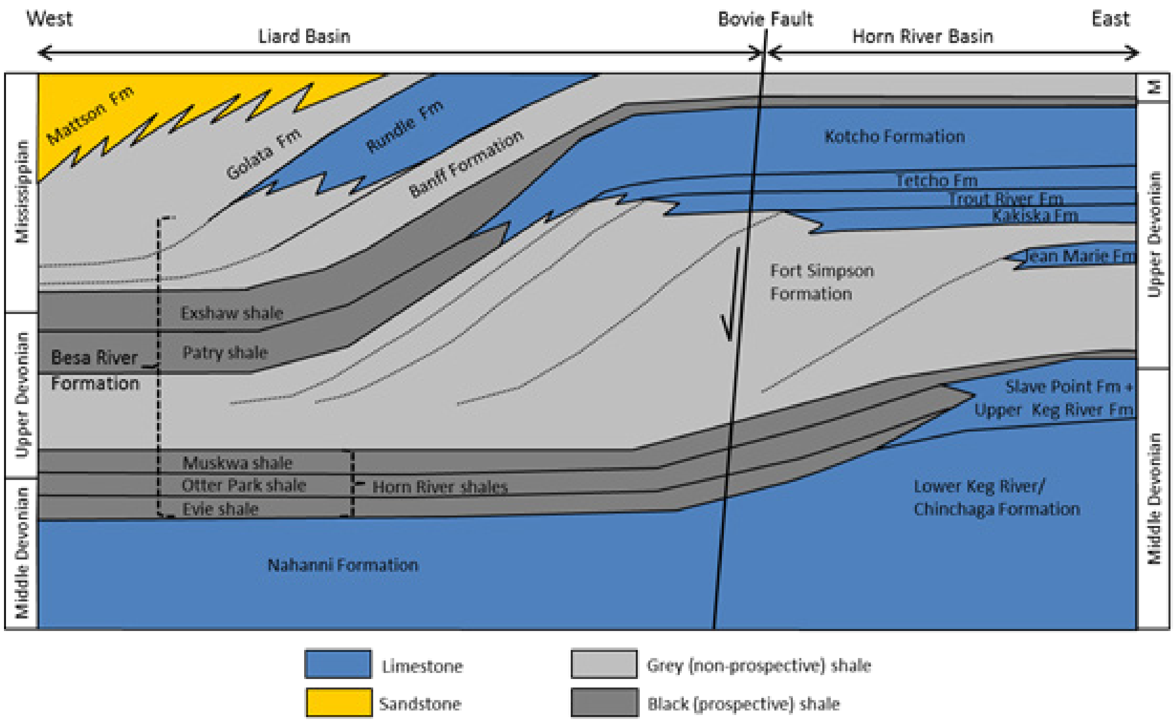

Figure 2. Stratigraphic architecture of the Besa River Formation and related units (not to scale). Vertical displacement on the Bovie Fault is not shown.

The Middle Devonian to Middle Mississippian Besa River Formation (deposited from 385 Ma to 335 Ma ago) is a succession of shales in the Liard Basin (Figure 2). The Besa River Formation ranges from 300 metres (m) thick to the west to over 2 000 m thick near the Bovie Fault to the east.

Straddling the Devonian-Mississippian boundary in the Besa River Formation is the Exshaw shale, which is prospective for shale gas. For most of the Liard Basin, the Patry shale underlies the Exshaw and is also prospective.[5] The Exshaw-Patry shale is in the early stages of exploration and, since 2009, has produced 356.6 million m^3 (12.6 billion cubic feet (Bcf)) of gas from two vertical wells and two horizontal wells in B.C.

The Exshaw-Patry shale's "net pay"[6] ranges from 20 m thick at the Liard Basin's eastern edge to over 200 m in the basin's centre. The Exhsaw-Patry shale is less than 1 kilometre (km) deep at the basin's northern edge to over 4 km deep in the centre of the basin. Total organic carbon (TOC) contents are typically 1.5 to 6 per cent. Silica contents are from 65 to 85 per cent. Porosity is between 4 and 9 per cent and is highest in organic-rich horizons.

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[3] The hierarchy of stratigraphic units in the Liard Basin has been simplified for this study, because it differs between the three jurisdictions and is being revised with new information.

[4] *Ultimate Potential for Unconventional Natural Gas in Northeastern British Columbia's Horn River Basin*, 2011.

[5] For more details on the characteristics and stratigraphy of the Exshaw-Patry succession in BC, please see Ferri, F, McMechan, M., and Creaser, R., 2015, *The Besa River Formation in Liard Basin, British Columbia,* pp. 1-27.

[6] Not all of a rock section may be prospective for hydrocarbons. "Net pay" is a measurement of a section's prospective thickness.

The Exshaw-Patry shale is also exceptional amongst North American shale gas plays because it is typically very deep, very rich in silica (the reservoir is very brittle and prone to cracking when hydraulic fracturing is applied), and it is 100 per cent over-pressured where tested.[7]

Deeper in the Besa River Formation are the Horn River shales (Figure 2), which extend into the Liard Basin from the Horn River Basin to the east, where they produce shale gas. Little information is available about these deeper shales in the Liard Basin of B.C., while more information is available in NWT and Yukon where the Horn River shales are shallower. In NWT and Yukon, these shales range from less than 1 km deep at the northern edge of the Liard Basin to more than 4 km deep at the territories' southern borders. The net pay ranges from 40 m at its northern edge to almost 300 m around the Pointed Mountain gas field of NWT.

Methods

The original gas-in-place (OGIP) in the Liard Basin was assessed using methods similar to those in a 2013 study that examined B.C.'s Montney Formation[8], where map grids of geological data were connected to free gas and adsorbed gas equations[9] to determine how gas volumes geographically vary. However, unlike the Montney study, this study's marketable gas was determined from the estimated ultimate recovery (EUR) from a hypothetical, index shale gas well as based on an analysis of Liard Basin production data. The EUR from an index tract[10] was then determined from the number of wells assumed to fully develop it. The EURs of other tracts in the Liard Basin were then determined by calibrating them to the index tract through their net pays, TOCs (a proxy for porosity, gas saturation, and adsorbed gas), pressures, and areas.

Statistical distributions were applied to some variables in assessment equations and then Monte Carlo simulations were used to estimate low, expected, and high values.[11] A surface loss to convert raw OGIP to dry OGIP through the removal of gas impurities[12], as well as to convert raw EURs to marketable EURs through the removal of impurities and some fuel gas for gas processing, was also applied.

In B.C. and Yukon, areas of the Liard Basin within the Rocky Mountains, Mackenzie Mountains, and Franklin Mountains were excluded from the assessment except for the outer fringes of the Rocky Mountain and Franklin Mountain foothills, which were considered a deformed play area. In NWT, the Franklin Mountains (including the Liard Range) were included in the assessment and formed NWT's deformed area. Elsewhere, the Liard Basin was considered undeformed.

To simulate reservoir risks in deformed areas where pressures can be naturally drained by faults, a reservoir risk factor was applied to OGIP. Meanwhile, technical risk factors were applied to EURs in deformed areas because of risks associated with drilling such that less gas was considered recoverable in the deformed areas of B.C. and Yukon, while no gas was considered recoverable in the deformed area of NWT except for the Pointed Mountain gas field. It was also assumed that development would not occur where net pay is less than 30 m and where depths are shallower than 1 500 m, because flow rates would be too low to justify drilling.

The Exshaw-Patry shale was assessed in B.C., NWT, and Yukon for both OGIP and marketable gas because prolonged production from the interval indicates that gas is present and recoverable. In contrast, the Horn River shales in the Liard Basin were assessed solely for OGIP and only in NWT and Yukon because the Horn River shales are considered to be too deep in B.C. to be developed. Although a preliminary well test in NWT indicates gas is present in the Horn River shales, there is not enough production data to indicate that gas is recoverable in any meaningful amount. No volumes of natural gas liquids were assessed because gas analyses indicate that the gas is dry.

More details of the assessment's methods are available in Appendix B.

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[7] Higher than normal gas pressures for that depth. Over-pressured formations can store more natural gas, because the gas is further compressed, and tend to have significant internal "push" to drive the gas out, improving recoveries and making economics better. "Normal" can be generally considered what the pressure would be under a column of water to that depth.

[8] *The Ultimate Potential for Unconventional Petroleum from the Montney Formation of British Columbia and Alberta – Energy Briefing Note.* 2013.

[9] Free gas is gas found in a rock's pore spaces; adsorbed gas is "stuck" to the side of organic matter or clay present in the rock.

[10] For this study, a tract in B.C. is considered to be four units arranged two-by-two (about 2.6 km^2) of the NTS geographic-grid system and one section (about 3.2 km^2) of the NTS-quad geographic-grid system in NWT and Yukon.

[11] A Monte Carlo simulation is a computerized process where random numbers (as determined from a statistical distribution) are picked hundreds to thousands of times to help determine a range of possibilities and uncertainty in an estimate.

[12] Natural gas in the Exshaw-Patry and Horn River shales is about 8 per cent and 15 per cent carbon dioxide, respectively. The carbon dioxide must be removed before it can be considered marketable.

Assessment Results and Observations

The ultimate potential for marketable, unconventional gas in the Liard Basin is estimated to be very large (Table 1), with expected volumes of 6 196 billion m³ (219 Tcf).[13] Uncertainty in the estimates is reflected by the spread between estimated low and high values in Table 1.[14] Most of the marketable gas is located in B.C., though NWT's and Yukon's potentials are still large.

For perspective, the Montney Formation's marketable potential has been estimated to be 12 719 billion m³ (449 Tcf) and the Horn River Basin's 2 198 billion m³ (78 Tcf). Further, total Canadian natural gas demand in 2014 was 89.4 billion m³ (3.2 Tcf)[15], making the Liard Basin gas resource equivalent to 68 years of Canada's 2014 consumption. However, it is too early to know whether the Liard Basin will significantly contribute to Canadian gas production in the near term because gas prices are expected to remain low for the next several years, deterring development. Although additional in-place gas potential is found in the Horn River shales of the Liard Basin (Table 2), it is uncertain whether any is technically recoverable.

By combining this marketable gas estimate with prior assessments, including assessments of conventional natural gas, the total ultimate potential in the WCSB is estimated to be 29 773 billion m³ (1 051 Tcf) (Table 3). Of this, 24 140 billion m³ (853 Tcf) remains after cumulative production to year-end 2014 is subtracted. This total is expected to evolve, likely growing over time as additional potential is estimated in unassessed shales, such as the Duvernay Formation of Alberta. Overall, Canada has a very large remaining natural gas resource base in the WCSB to serve its markets well into the future.

Table 1. Ultimate potential for Liard Basin unconventional gas in the Exshaw-Patry shale.

Shale	Play Area	Volume units	Gas in Place (dry)			Marketable Gas		
			Low	Expected	High	Low	Expected	High
Exshaw-Patry	Total	Billion m³	20 041	**34 365**	54 475	2 419	**6 196**	12 019
		Tcf	708	**1 213**	1 924	86	**219**	425
	British Columbia	Billion m³	14 070	**24 027**	37 863	1 839	**4 731**	9 139
		Tcf	497	**848**	1 337	65	**167**	323
	Northwest Territories	Billion m³	5 206	**9 017**	14 541	497	**1 250**	2 481
		Tcf	184	**318**	514	18	**44**	88
	Yukon	Billion m³	765	**1 321**	2 071	83	**215**	399
		Tcf	27	**47**	73	3	**8**	14

Table 2. Unconventional gas resources of the Liard Basin's Horn River shales

Shale	Play Area	Volume units	Gas in Place (dry)			Marketable Gas		
			Low	Expected	High	Low	Expected	High
Horn River	Northwest Territories	Billion m³	2 584	**5 293**	8 983	-	-	-
		Tcf	91	**187**	317	-	-	-
	Yukon	Billion m³	318	**593**	1 024	-	-	-
		Tcf	11	**21**	36	-	-	-

[13] "Tcf" is an abbreviation for trillion cubic feet.

[14] "Low" and "high", as used here, refer to a range where there is reasonably high confidence that the real in-place and eventual produced marketable volumes from the Exshaw-Patry shales will fall inside it. Thus, there is a small chance that real in-place and produced marketable volumes could be lower than the low values or higher than the high values.

[15] *Canada Energy Overview 2014*

Table 3. Estimate of ultimate potential for marketable natural gas in the WCSB

Estimate of Ultimate Potential for Marketable Natural Gas in the WCSB - Year-end 2014							
Area	Gas Type	10^9 m^3			Tcf		
		Ultimate Potential	Cumulative Production	Remaining	Ultimate Potential	Cumulative Production	Remaining
Alberta	Conventional	6 276	**4 622**	**6 798**	221.5	**163.2**	**240.1**
	Unconventional	5 143			181.6		
	CBM	*101*			*3.6*		
	Montney	*5 042*			*178.0*		
	Alberta Total	**11 419**			**403.1**		
British Columbia	Conventional	1 462	**769**	**15 547**	51.6	**27.2**	**549.0**
	Unconventional	14 854			524.6		
	Horn River	*2 198*			*77.6*		
	Montney	*7 677*			*271.0*		
	Cordova	*248*			*8.8*		
	Liard	*4 731*			*167.1*		
	British Columbia Total	**16 316**			**576.2**		
Saskatchewan	Conventional	297	**223**	**156**	10.5	**7.9**	**5.5**
	Unconventional	82			2.9		
	Bakken	*82*			*2.9*		
	Saskatchewan Total	**379**			**13.4**		
Southern NWT	Conventional	132	**14**	**1 368**	4.7	**0.5**	**48.3**
	Unconventional	1 250			44.1		
	Liard	*1 250*			*44.1*		
	Southern NWT Total	**1 382**			**48.8**		
Southern Yukon	Conventional	61	**6**	**271**	2.2	**0.2**	**9.6**
	Unconventional	215			7.6		
	Liard	*215*			*7.6*		
	Southern Yukon Total	**276**			**9.8**		
WCSB Total		**29 773**	**5 633**	**24 140**	**1 051**	**199**	**853**

Notes:

- Determined from reliable, published assessments by federal and provincial agencies.
- For this table, “unconventional” is defined as natural gas produced from coal (CBM) or by the application of multi-stage hydraulic fracturing to horizontal wells.
- The ultimate potential for natural gas should be considered an estimate that will evolve over time. Additional unconventional potential may be found in unassessed shales, such as the Duvernay Shale of Alberta.

Appendix A – List of Acronyms

B.C.	British Columbia
Bcf	Billion cubic feet
EUR	Estimated ultimate recovery
Ma	Million years
NTS	National topographic system
NWT	Northwest Territories
OGIP	Original gas in place
Tcf	Trillion cubic feet
TOC	Total organic carbon
WCSB	Western Canada Sedimentary Basin

Appendix B – Methods

Key Assumptions

1) The gas resource was considered to be a resource play in all three jurisdictions, where gas is pervasively distributed through the geologically defined area. Thus, the chance of success at discovering gas with a well is 100 per cent.
2) Well EURs are based on existing technology, current trends in development, and limited production. No detailed analyses of technological advancements have been performed for this study. Recoveries and levels of development could be different in the future as technology advances and the play matures.
3) No study has been undertaken to determine the economics for marketable resources and the determination of what can be developed is based on the view of the project agencies.

Stratigraphy and Study Area

Stratigraphic Intervals and Net Pay Determination

The Exshaw-Patry interval (Figure A.1) was treated as a single, radioactive shale whose net pay could be identified using a 10 ohm-m or higher reading on resistivity logs. Net pay in NWT's and Yukon's Horn River shales (Figure A.1) was identified with the same criteria.

Play Areas

The assessed area of the Liard Basin was defined on its eastern side by the Bovie Fault and on its western side by the western limit of Cretaceous outcrop. Thus, in B.C. and Yukon, the assessment area excludes the Rocky Mountains, Mackenzie Mountains, and Franklin Mountains except for the outer fringes of the Rocky Mountain and Franklin Mountain foothills, which form a deformed play area. Meanwhile, the Franklin Mountains (including the Liard Range) of NWT are included in the assessment and considered NWT's deformed area. Elsewhere, the Liard Basin is considered undeformed (Figure A.2). Areas north of 60º 40' N in the NWT were excluded because of proximity to Nahanni National Park.

Tracts

The Liard Basin map area was broken into a grid of small tracts to accommodate the way the reservoir locally changes. In B.C., a tract was considered a grid-spacing unit: four units arranged two-by-two in the National Topographic System (NTS) geographic-grid system, about 2.6 km^2 in size. In NWT and Yukon, a tract was considered a section in the NTS-quad geographic-grid system, about 3.2 km^2 in size.

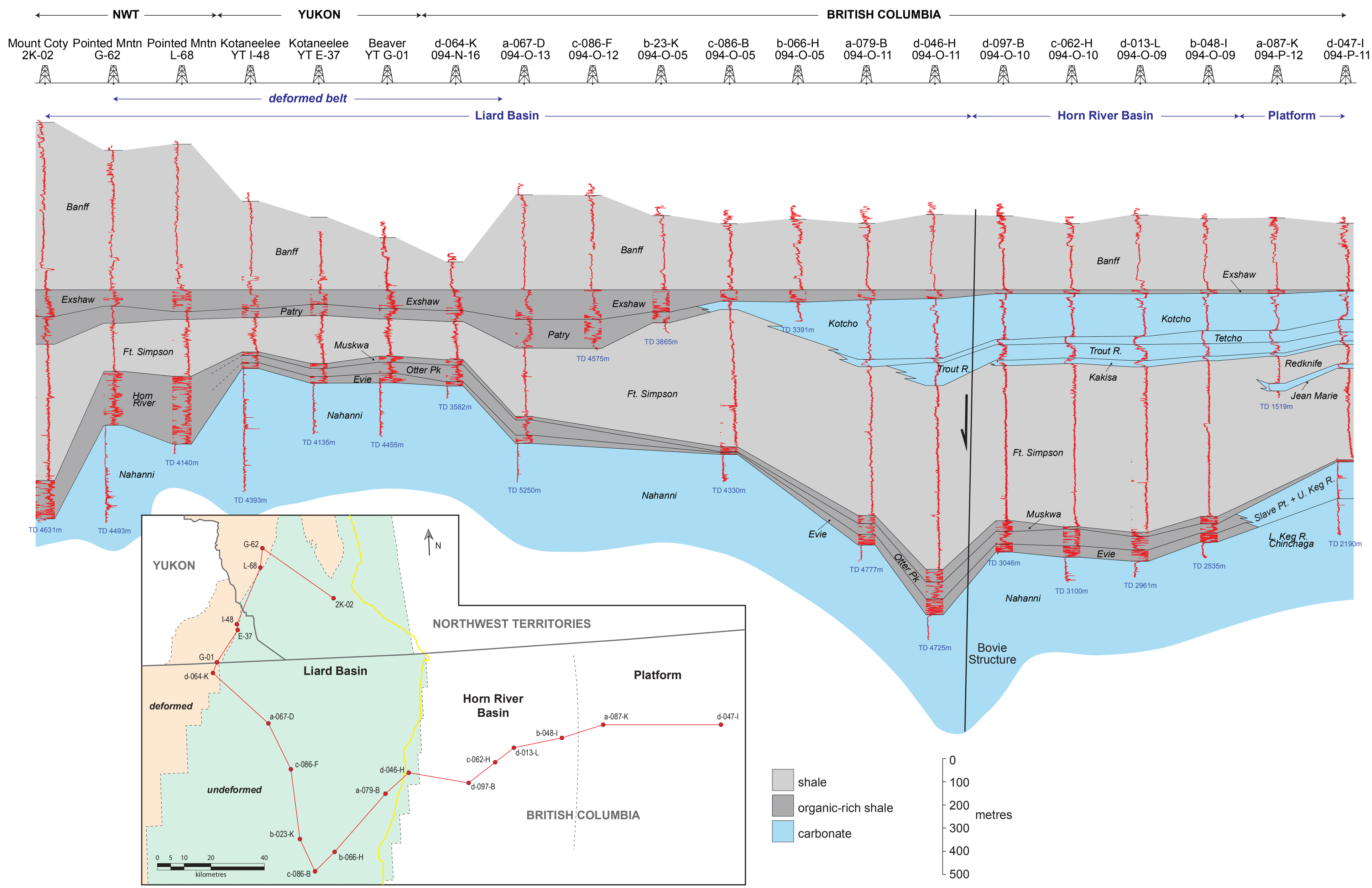

Figure A.1. Cross-section across study area with Exshaw top as datum

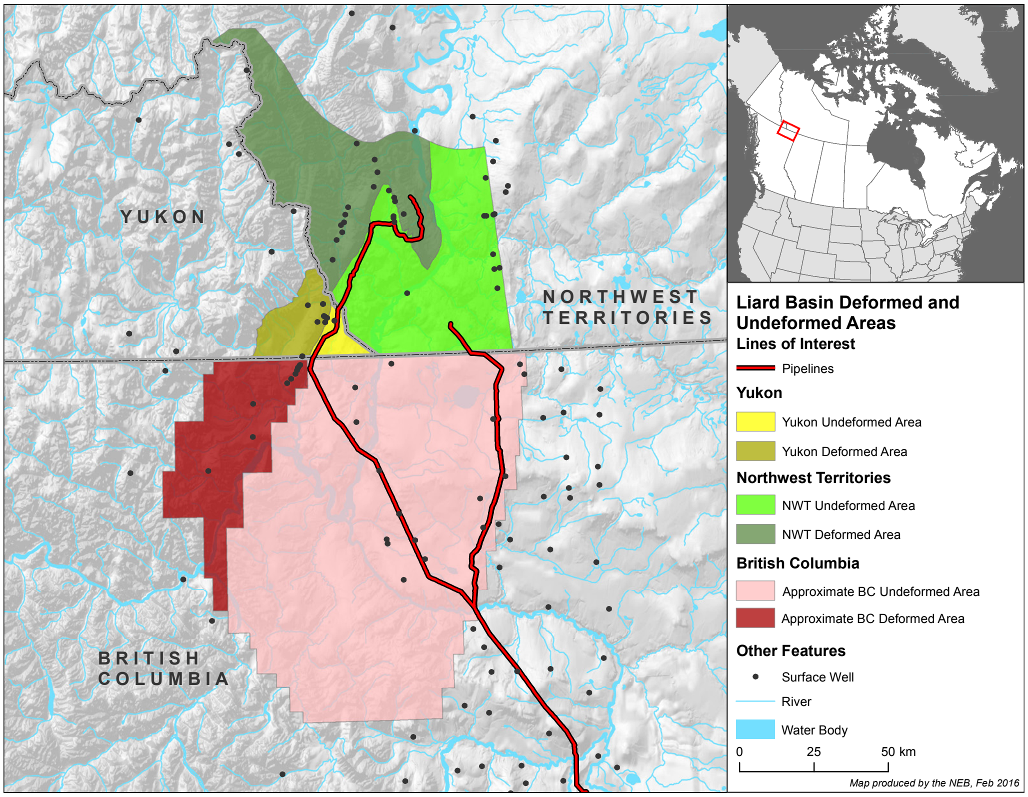

Figure A.2. Assessment play areas

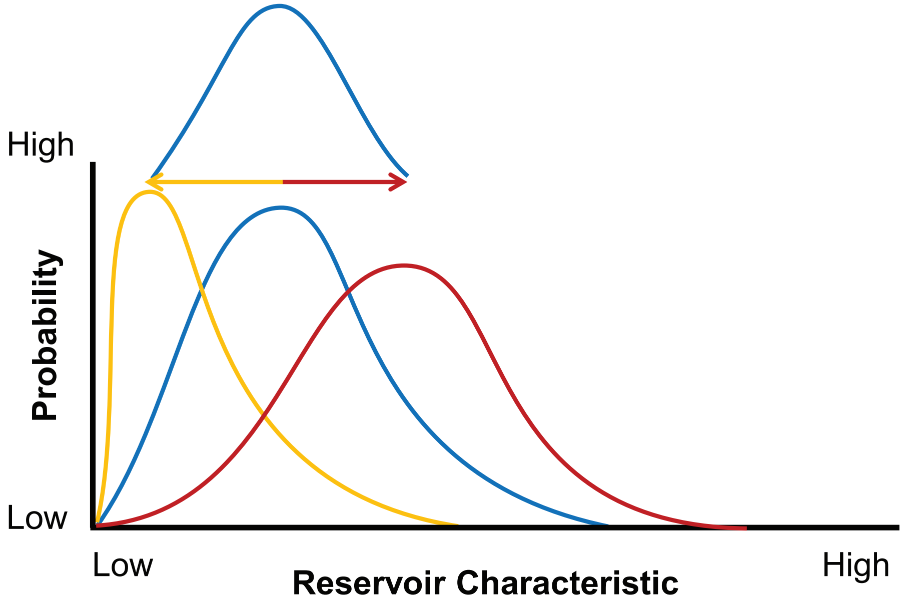

Figure A.3. One distribution applied upon another to create a "distribution of distributions"

Free and Adsorbed Gas Estimations for Estimation of in-place resources

The assessment was done on a map-grid basis where, for each tract, Monte Carlo simulations were run on a series of mathematical equations to determine volumes and the results summed to determine the total. The assessment was also integrated at two levels, i) a tract-by-tract scale, and ii) a basin scale (Figure A.3), to try to incorporate local changes with uncertainties inherent at the basin level.

See Table A.1 for the equation variables based on mapped data as well as the variables (both mapped and unmapped) that had distributions attached to them for the Monte Carlo simulations. Because the evaluated horizons were treated as single units, variables like porosity, water saturation, and TOC were applied as averages over the entire rock section.

To reduce potential skewing of distributions modeled on mapped data, “soft” maximums or minimums for distribution curves were used (i.e., the distribution’s low and high values wandered based on a percentage of the mapped “most likely” values) rather than “hard” maximum or minimums, as long as the soft values did not exceed or fall below impossible values, such as creating negative numbers. For distributions modeled on net pay, TOC, and depth, the uncertainties—the ranges between a tract’s low and high values—were reduced as determined by the number of data points in the surrounding NTS block in the case of B.C. and the surrounding grid area in NWT and Yukon.

In-place Resources Equations

Natural gas in the Liard Basin is present in two main forms: free and adsorbed. Therefore, the total raw natural gas stored in the Liard Basin prior to production can be determined by using the following basic equation at each grid point:

$$RGIP_{total} = RGIP_{free} + RGIP_{adsorbed}$$

Where $RGIP_{total}$ is the total raw gas in place, $RGIP_{free}$ is the free raw gas in place, and $RGIP_{adsorbed}$ is the raw adsorbed gas in place.

Free raw gas in place was estimated with a volumetric equation (all variables for all equations described in Table A.1):

$$RGIP_{free} = A \times H \times Ø \times S_g \times \frac{(D \times PG \times T_s)}{(P_s \times T_f \times Z)} \times RRF$$

Adsorbed raw gas in place was estimated with the equation:

$$RGIP_{adsorbed} = A \times H \times \rho_b \times (1 - Ø) \times \frac{(TOC \times LtO \times D \times PG)}{(P_L \times D \times PG)} \times RRF$$

Raw gas in place was converted to dry gas in place ($DGIP_{total}$) with the equation:

$$DGIP_{total} = RGIP_{total} \text{ X } (1 - SL_{GIP})$$

Reservoir Risk Factors

In B.C. and Yukon, a reservoir risk factor of 0.9 was applied to OGIP in deformed areas (i.e., OGIP would be reduced by 10 per cent) because, while there is some faulting that could drain gas pressures, these areas are largely in a relatively undeformed, broad syncline between the Franklin Mountains and the structurally controlled Beaver River and Kotaneelee gas fields. In NWT, a reservoir risk factor of 0.5 was applied to OGIP in deformed areas (except for the Pointed Mountain gas field, where 0.75 was used) because these are largely within the heavily faulted Franklin Mountains.

Table A.1. Variable descriptions and model inputs used for assessment – Exshaw-Patry succession

Variable	Symbol	Map (Y/N)	Prob. Dist. (Y/N)	Tract Model Inputs (low / most likely/ high)	Basin Model Inputs (low / most likely / high)	Correlations and notes	Data Source
Area (m^2)	*A*	Y	N	Map-grid spacing	-	-	-
Depth (m)	*D*	Y	Y	Based on map	-	-	Well logs
Net Pay (m)	*H*	Y	Y	0.9/1/1.1 tract multiplier	0.95/1/1.05 map multiplier	-	Well logs/ core
Porosity (%)	ϕ	N	Y	ϕ =0.6707*TOC%+ (2.0/4.272/6.5)	0.5/ 1/ 1.5 map multiplier	Correlated w/ TOC%	Core
Gas Saturation (%)	S_g	N	Y	S_g=3.7588*TOC%+ (37.0/56.659/76.0)	0.5/1/1.5 map multiplier	Correlated w/ TOC% map	Core
Pressure Gradient (kPa/m)	*PG*	N	Y	13/20/27	0.5/1/1.5 map multiplier	-	Production tests
Surface Pressure (kPa)	P_S	N	N	101.3	-	Standard conditions	-
Reservoir Temperature (°K)	T_F	N	N	Based on thermal gradients: map in NWT 40ºK/km YT 35-45ºK/km BC	-	Correlated w/ depth map	Well logs
Surface Temperature (°K)	T_S	N	N	273	-	Surface temperature	-
Gas Compressibility	*Z*	N	N	BC: 1.4 NWT & Yukon: 1.25	-	-	Gas analyses; best estimate
Surface Loss – GIP and EUR (fraction)	SL_{GIP} SL_{EUR}	N	N	SL_{GIP} = 0.08 SL_{EUR} = 0.12	-	-	Gas analyses; best estimate
Rock Matrix Density (ton/m^3)	ρ_b	N	N	2.6	-	-	Core
Total Organic Content — TOC (%)	*TOC*	Y (N in NWT)	Y	BC and Yukon: 0.5/1/1.5 tract multiplier NWT: 2.2/3.75/5.3	0.6/1/1.4 map multiplier	-	Core/well logs
Langmuir Volume to Organic Content Ratio (m^3/ton/TOC%)	*LtO*	N	Y	0.1667/0.5/1.5	0.5/1/1.5 map multiplier	-	Adsorbed gas tests on core samples
Langmuir Pressure (kPa)	P_L	N	Y	5 000/8 247/1 1500	0.5/1/1.5 map multiplier	-	Adsorbed gas tests on core samples
Reservoir Risk Factor (fraction)	*RRF*	N	N	Undeformed: 1 Deformed: BC/Yukon 0.9; NWT 0.5 (Pointed Mountain 0.75)	-	-	Best estimate

Table A.2. Variable descriptions and model inputs used for assessment – Horn River succession

Variable	Symbol	Map (Y/N)	Prob. Dist. (Y/N)	Tract Model Inputs (low / most likely/ high)	Basin Model Inputs (low / most likely / high)	Correlations and notes	Data Source
Area (m^2)	*A*	Y	N	Map-grid spacing	-	-	-
Depth (m)	*D*	Y	Y	Based on map	-	-	Well logs
Net Pay (m)	*H*	Y	Y	0.9/1/1.1 tract multiplier	0.95/1/1.05 map multiplier	-	Well logs/ core
Porosity (%)	ϕ	N	Y	ϕ =0.506*TOC%+ (0.75/3.55/6.25)	0.5/ 1/ 1.5 map multiplier	Correlated w/ TOC%	Horn River Basin core
Gas Saturation (%)	S_g	N	Y	S_g=2.8277*TOC%+ (43.94/68.47/93)	0.5/1/1.5 map multiplier	Correlated w/ TOC%	Horn River Basin core
Pressure Gradient (kPa/m)	*PG*	N	Y	10/16/22	0.5/1/1.5 map multiplier	-	Horn River Basin production
Surface Pressure (kPa)	P_S	N	N	101.3	-	Standard conditions	-
Reservoir Temperature (°K)	T_F	N	N	Based on thermal gradients: map in NWT 40ºK/km Yukon	-	Correlated w/ depth map	Well logs
Surface Temperature (°K)	T_S	N	N	273	-	Surface temperature	-
Gas Compressibility	*Z*	N	N	1.25	-	-	Gas analyses
Surface Loss – GIP (fraction)	SL_{GIP}	N	N	SL_{GIP} = 0.15	-	-	Gas analyses; best estimate
Rock Matrix Density (ton/m³)	ρ_b	N	N	2.6	-	-	Horn River Basin core
Total Organic Content — TOC (%)	*TOC*	Y (N in NWT)	Y	Yukon: 0.5/1/1.5 tract multiplier NWT: 0.5/2.5/5	0.6/1/1.4 map multiplier	-	Core/ cuttings/ well logs
Langmuir Volume to Organic Content Ratio (m³/ton/TOC%)	*LtO*	N	Y	0.1/0.335./0.5	0.5/1/1.5 multiplier	-	Horn River Basin core
Langmuir Pressure (kPa)	P_L	N	Y	2 000/5 650/8 650	0.5/1/1.5 multiplier	-	Horn River Basin core
Reservoir Risk Factor (fraction)	*RRF*	N	N	Undeformed: 1 Deformed: B.C./Yukon 0.9; NWT 0.5 (Pointed Mountain 0.75)	-	-	Best estimate

Estimated Exshaw-Patry EURs

B.C.'s c-45-K/94-O-5 horizontal well, which was completed in the Exshaw-Patry interval, was used to create an index well so that recoveries from an index tract could be determined. c-45-K's production was modeled using an early stage of transient flow for the first 84 months of post-peak production followed by a later stage of boundary-dominated flow, which is not yet observed in the historical data in any of the shale-gas wells in the Liard Basin (data up to 53 months). A cutoff of 50 years was applied to cumulative production to determine its EUR. Results were compared to nearby wells to determine whether the estimated EUR was reasonable. A well-quality factor was also applied, which caused the well's EUR to range higher or lower to simulate uncertainty in EUR results (zero as a minimum to twice as high as a maximum).

Transient flow

The modeled transient flow excluded the first month of post-peak data, which did not fit the main trend of historical data on a log-log plot of production vs. time. This early deviation was likely because the well was still flowing back hydraulic fracturing fluids or production was in early bilinear flow before transitioning to linear flow.

Transient flow was modeled by regressing the historical data using the Duong model[16], the Arps hyperbolic model[17] (where Excel's Solver is used to determine initial production, initial decline, and the Arps *b* exponent), and a Long Duration Linear Flow model (which, for this study, is a linear regression of the historical data on a log-log plot of production versus time) (Figure 4).

Boundary-dominated flow

Boundary-dominated flow at the end of transient flow for each of the three, above models was estimated using Arps hyperbolic flow. Because boundary-dominated flow is not yet observed in well data, initial production was assumed to be production at the end of each model's transient flow, the annual initial decline to be 0.1, and the Arps *b* exponent to be 0.5.

Indexing Tracts

The index well (Figure A.4 and Table A.3) was created by: 1) averaging the three estimated EURs; 2) calculating the EUR per 1 km of stimulated horizontal leg in c-45-K; and 3) creating a hypothetical well that would fit along the long axis of a tract while keeping "buffer" space at the well's toe and heel to avoid interfering with any wells that would be drilled in adjacent tracts.

The index tract (Table A.3) was created by estimating the amount of recoverable gas in a tract local to c-45-K as based on the number of index wells expected be drilled in it. Some reservoir characteristics at c-45-K—net pay, pressure, and TOC (which is assumed to be a proxy for porosity, gas saturation, and adsorbed gas concentrations)—were extracted from local tracts to create an index for how production in other tracts might behave where reservoir conditions differ. Because tract sizes change in the NTS grid based on how units and sections change sizes in north-south directions, the index tract was also indexed to tract size at c-45-K to reflect that well spacing or development plans could change where tracts are bigger or smaller.

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[16] Duong, A., 2011. Rate-decline analysis for fracture-dominated shale reservoirs. SPE 137748.

[17] Fekete. Traditional decline analysis theory.

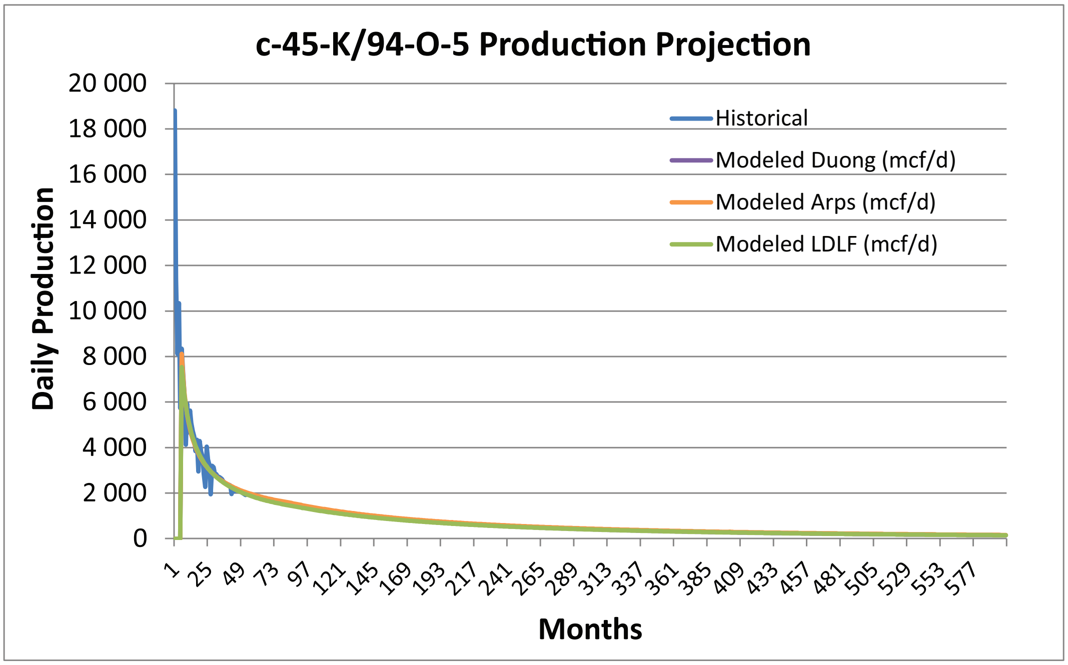


Figure A.4. Modeled production curves for c-45-K

Limits to Development

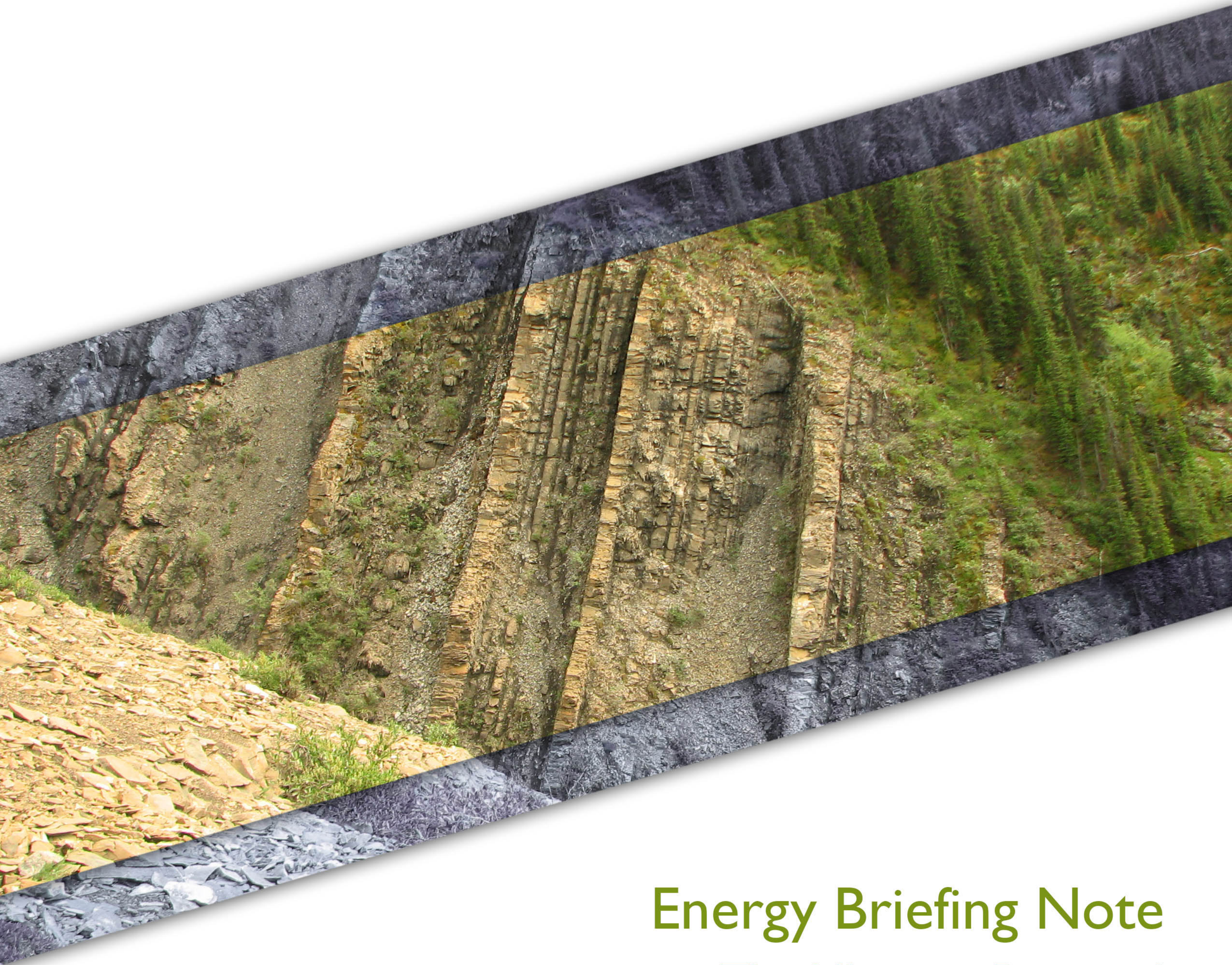
For the EUR analysis, it was assumed that no development would occur in areas shallower than 1 500 m or where the net pay was less than 30 m, because flow rates would likely be too low to justify drilling. In B.C. and Yukon, a technical risk factor of 0.75 was applied to tract EURs in deformed areas to simulate technical risks that recoveries may face. In NWT, the Franklin Mountains are heavily faulted and this technical risk factor was decreased to zero except in the Pointed Mountain gas field where it was decreased to 0.6 (i.e., outside the Pointed Mountain gas field, the NWT's deformed area was assumed to have gas in place in the Exshaw-Patry interval, but no recoveries).

Raw Gas to Marketable Gas Conversion

Similar to OGIP estimates, raw EUR was converted to marketable EUR by applying a surface loss based on expected impurity contents as well as fuel needed for gas processing.

Table A.3. Index well expected parameters

c-45-K			Index Well		Index DSU			
Raw EUR (Bcf)	Stim Hz length (km)	Raw EUR/ km	Stim Hz length (km)	Index well Raw EUR (Bcf)	Wells/ DSU	Raw EUR/ DSU (Bcf)	Surface Loss (fraction)	Sales EUR/ DSU (Bcf)
15.8	0.85	18.6	1.75	32.55	1.5	48.56	0.12	42.73



Energy Briefing Note

The Ultimate Potential for Unconventional Petroleum from the Montney Formation of British Columbia and Alberta

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Foreword

National Energy Board

The National Energy Board is an independent federal regulator established to promote safety and security, environmental protection and economic interest within the mandate set by Parliament for the regulation of pipelines, energy development and trade. The Board's main responsibilities include regulating the construction and operation of interprovincial and international oil and natural gas pipelines, international power lines, and designated interprovincial power lines.

For oil and natural gas exports, the Board’s role is to evaluate whether the oil and natural gas proposed to be exported is surplus to reasonably foreseeable Canadian requirements, having regard to the trends in the discovery of oil or gas in Canada.

If a party wishes to rely on material from this report in any regulatory proceeding before the Board, it may submit the material, just as it may submit any public document. Under these circumstances, the submitting party in effect adopts the material and could be required to answer questions pertaining to its content. This report does not provide an indication about whether any application will be approved or not. The Board will decide on specific applications based on the material in evidence before it at that time.

British Columbia Oil and Gas Commission

The BC Oil and Gas Commission is the provincial regulatory agency with responsibilities for regulating oil and gas activities in British Columbia, including exploration, development, pipeline transportation and reclamation.

The Commission’s core services include reviewing and assessing applications for industry activity, consulting with First Nations, cooperating with partner agencies, and ensuring industry complies with provincial legislation and all regulatory requirements. The public interest is protected by ensuring public safety, respecting those affected by oil and gas activities, conserving the environment, and ensuring equitable participation in production.

Responding to the complex and often competing economic, environmental and social priorities driving the oil and gas industry, the Commission maintains a modern regulatory framework and proactively looks for innovative solutions for continued safe and sustainable oil and gas development in the province. In accordance with its mandate, the Commission strives to deliver fair and timely decisions on proposed projects, balancing firm oversight of operational safety and First Nations’ rights.

The Commission liaises with other provincial and federal government agencies in ensuring effective delivery of government policy, improved regulatory climate and cohesive application of existing regulations. It is of key importance for the Commission to stay fully apprised of the latest technological breakthroughs, and independent world-wide scientific research pertinent to the industry.

For general information about the Commission, please visit www.bcogc.ca or phone 250-794-5200.

Alberta Energy Regulator

The Alberta Energy Regulator (AER) ensures the safe, efficient, orderly, and environmentally responsible development of hydrocarbon resources over their entire life cycle. This includes allocating and conserving water resources, managing public lands, and protecting the environment while providing economic benefits for all Albertans. The AER succeeds the Energy Resources Conservation Board and takes on regulatory functions from the Ministry of Environment and Sustainable Resource Development that relate to public lands, water, and the environment. In this way, the AER provides full-lifecycle regulatory oversight of energy resource development in Alberta - from application and construction to abandonment and reclamation, and everything in between. The AER is authorized to make decisions on applications for energy development, monitoring for compliance assurance, decommissioning of developments, and all other aspects of energy resource activities (activities that must have an approval under one of the six provincial energy statutes). This authority extends to approvals under the public lands and environment statutes that relate to energy resource activities.

The Energy Resource Appraisal Group (ERA) is part of the Geology, Environment and Reserves Branch of the AER. The ERA generates knowledge and information related to the oil and gas geology and resource endowment of Alberta. Data provided by the AER for this report was data compiled and created by ERA. Much of the data used in this report has been previously published by ERA in AGS Open File Reports.[1]

For general information about the Alberta Energy Regulator, please visit www.aer.ca or phone toll-free 1-855-297-8311.

British Columbia Ministry of Natural Gas Development

The role of the British Columbia Ministry of Natural Gas Development is to guide the responsible development and ensure maximum economic benefits to British Columbians from the province’s natural gas resources and the province’s next new major industrial sector—that of liquefied natural gas (LNG).

Through teamwork and positive working relationships with its clients, the Ministry facilitates B.C.’s thriving, safe, environmentally responsible and competitive natural gas sector to create jobs and economic growth. In developing natural gas policies, legislation and guidelines, the

[1] Available at: www.ags.gov.ab.ca/publications

Ministry consults with other ministries and levels of government, energy companies, First Nations, communities, environmental and industry organizations, and the public.

A key component of the Ministry’s mandate is to develop tenure, royalty and regulatory policy for British Columbia’s natural gas industry, thereby promoting the effective and environmentally responsible management of the province’s natural gas resources.

The Ministry provides a range of natural gas related services, including the issuance of Crown subsurface resource rights, royalty programs, public geoscience and policies to address potential future resource opportunities, such as unconventional natural gas resource development. The Ministry’s LNG Secretariat reports to the new Cabinet Working Group on Liquefied Natural Gas, which will advise on budgets, structure, mandate and service plan goals.

The Ministry is also responsible for the British Columbia Oil and Gas Commission.

Executive Summary

The Montney Formation's marketable, unconventional petroleum potential has been evaluated for the first time in a joint assessment by the National Energy Board, the British Columbia Oil and Gas Commission, the Alberta Energy Regulator, and the British Columbia Ministry of Natural Gas Development. The thick and geographically extensive siltstones of the Montney Formation are expected to contain 12,719 billion m^3 (449 Tcf) of marketable natural gas, 2,308 million m^3 (14,521 million barrels) of marketable NGLs, and 179 million m^3 (1,125 million barrels) of marketable oil.

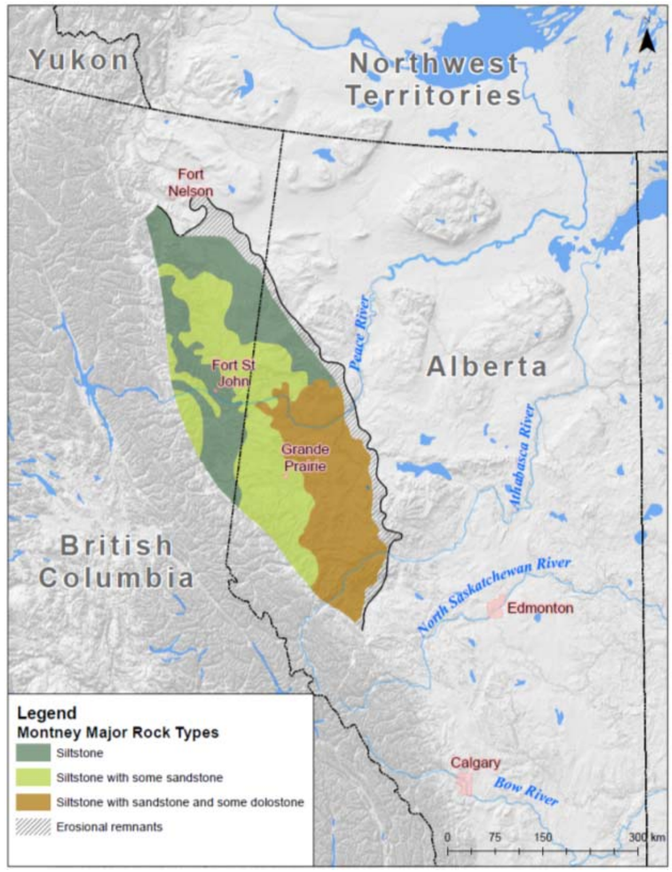

Figure 1. Generalized map showing the location of the Montney Formation in the subsurface of Alberta and British Columbia. Modified from the Geological Atlas of the Western Canada Sedimentary Basin.

Introduction

The Montney Formation of Alberta and British Columbia (Figure 1) has been the target of oil and gas exploration since the 1950s, with industry traditionally focusing on the Montney's conventional sandstone and dolostone reservoirs. These conventional reservoirs are encased in siltstone, which represents a far greater volume of rock within the formation and also contains oil and gas. However, Montney siltstones remained undeveloped until 2005, when advances in horizontal drilling and multi-stage hydraulic fracturing made it possible to economically develop this extensive, unconventional siltstone resource.

For this report, the National Energy Board (NEB), the British Columbia Oil and Gas Commission (BC OGC), the Alberta Energy Regulator (AER), and the British Columbia Ministry of Natural Gas Development (BC MNGD), collectively the Agencies, have jointly assessed the unconventional petroleum resources of the Montney Formation.[2] For British Columbia, both the in-place and marketable[3] petroleum volumes were estimated for the Montney siltstone, which included some thin sandstones that were unlikely to be developed conventionally. For Alberta, only marketable petroleum volumes were estimated because the in-place petroleum of Montney Formation siltstone was already determined in a prior study by the Energy Resources Conservation Board (now the AER). This is the first publicly released study to examine the marketable, unconventional petroleum potential of the Montney Formation in any detail.

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[2] For the purposes of this assessment, in Alberta, the Montney Formation will include the siltstone at the bottom of the overlying Doig Formation in Alberta. See Appendix A for more details.

[3] "In place" refers to the amount of petroleum originally in the reservoir. "Marketable resources", as used in this report, indicates the volume of in-place petroleum that is recoverable under foreseeable economic and technological conditions and in a condition ready to be used by the market. While it implies a sense of economic recovery, no economic assessment was performed.

Geological Description

The Lower Triassic Montney Formation is aerially extensive, covering approximately 130,000 km^2 (Figure 1). It is also thick, typically ranging from 100 m to 300 m, though thins to zero at its eastern and northeastern edges while increasing to over 300 m on its western side before it begins outcropping in the Rocky Mountains. Most of the formation consists of siltstone containing small amounts of sandstone that originally collected on the bottom of a deep sea, whereas more porous sandstones and shell beds were deposited in shallow water environments to the east. The depth of the formation also increases from northeast to southwest, generally along with increasing reservoir pressures and decreasing natural gas liquid[4] (NGL) and oil content. Thus, reservoir characteristics vary widely across the formation.

For a more detailed description of Montney geology in Alberta, please see *Summary of Alberta's Shale-and Siltstone-Hosted Hydrocarbon Resource Potential*[5] as well as the forthcoming assessment of the lowermost Doig siltstone's resource potential.[6] For more details on Montney geology in British Columbia, please see the *Montney Formation Play Atlas NEBC*.[7] Other details about the Montney Formation are available in Chapter 16 of the *Geological Atlas of the Western Canada Sedimentary Basin*.[8]

Methodology

For British Columbia, the Montney was assessed using a process similar to one used in a 2011 study of the shale gas resources in the Horn River Basin.[9] In the Horn River Basin assessment, the volumes of free gas and adsorbed gas[10] were determined by connecting map grids of geological data to free gas and adsorbed gas equations. This way, gas volumes could be estimated by location and capture how the geological nature of the shales changed from place to place. Statistical distributions were applied to some variables in the equations and then Monte Carlo simulations were used to estimate low, expected, and high values.[11] However, the Montney assessment was expanded to include NGLs and oil, which are not present in the Horn River Basin to any significant degree. Dissolved gas, which is gas that is dissolved in oil deep underground but is liberated at surface under lower pressures, was also estimated for the

[4] For this study, NGLs are defined as ethane, propane, butane, pentane, and heavier hydrocarbons that are produced in the gas stream out of a well.

[5] ERCB. *Summary of Alberta's Shale- and Siltstone-Hosted Hydrocarbon Resource Potential,* 2012. Available at: www.ags.gov.ab.ca.

[6] AER study, in preparation. Will be available at: www.ags.gov.ab.ca.

[7] Available at: www.bcogc.ca/montney-formation-play-atlas-nebc.

[8] Available at: www.ags.gov.ab.ca/publications/wcsb_atlas/atlas.html.

[9] BC MEM and NEB. *Ultimate Potential for Unconventional Natural Gas in Northeastern British Columbia's Horn River Basin,* 2011. Available at www.neb-one.gc.ca.

[10] Free gas is gas found in a rock's pore spaces; adsorbed gas is gas "stuck" to the side of any organic matter or clay present in the rock.

[11] A Monte Carlo simulation is a computerized process where random numbers (as determined from a statistical distribution) are picked hundreds to thousands of times to help determine a range of possibilities and uncertainty in an estimate.

Montney. Altogether, in-place and marketable petroleum resources were determined for dry natural gas[12], NGLs, and oil. Only over-pressured[13] areas were included in the British Columbia analysis, because unconventional development has so far been limited to over-pressured areas.

For the Alberta portion of the Montney, the in-place volumes of dry natural gas, NGLs, and oil have already been estimated as part of Alberta's two resource studies, their methodology described in the publication *Quantification of Uncertainty in Shale Gas Resources*.[14] For this joint study, a marketable resource volume was estimated by applying recovery factors to map grids of Alberta's in-place resource data. Because Montney development is occurring in both over-pressured and under-pressured areas in Alberta, the entire Montney unconventional play was assessed for marketable resources. Full development was assumed to occur in deeper areas (where the Montney mid-point depth was more than 1750 m) as these have a higher chance of being over-pressured according to pressure-depth data. Shallower areas are expected to have only partial development because they are typically under-pressured. Thus, a "development risk" factor was applied to shallower areas, as well as lower recovery factors.

Conventional reservoirs within the Montney section were excluded from this analysis as these have been assessed in prior studies.[15,16] Further, the methods for determining the in-place resources for each province, while similar, did have some significant differences. The geological mapping of the Montney Formation in British Columbia included some thin sandstones unlikely to be developed conventionally, while all sandstone was excluded from the Alberta analyses. No extra Monte Carlo simulations were run when adding British Columbia's and Alberta's low, expected, and high values together. Thus, while the addition between provinces is not statistically rigorous, the total results should still provide a reasonable estimate of total potential. More details on the methodology are available in Appendix A.

Assessment results and observations

The ultimate potential for unconventional petroleum in the Montney Formation is estimated to be very large (Table 1), with expected volumes of 12,719 billion m^3 (449 Tcf) of marketable natural gas, 2,308 million m^3 (14,521 million barrels) of marketable NGLs, and 179 million m^3 (1,125 million barrels) of marketable oil.[17] Uncertainty in the estimates is reflected by the spread between estimated low and high values in Table 1.[18]

[12] "Dry natural gas" is natural gas with the NGL contents and other impurities removed to make the gas ready to be shipped in gas distribution systems and sold to consumers.

[13] Higher than normal oil and gas pressures for that depth. Over-pressured formations can store more natural gas, because the gas is further compressed, and tend to have significant internal "push" to drive the petroleum out, improving recoveries and making economics better. "Normal" can be generally considered what the pressure would be under a column of water to that depth.

[14] AER. *Quantification of Uncertainty in Shale Gas Resources*, 2013 Available at: www.ags.gov.ab.ca.

[15] AEUB and NEB. *Alberta's Ultimate Potential for Conventional Natural Gas*, 2005. Available at: www.neb-one.gc.ca

[16] NEB and BC MEMPR. *Northeast British Columbia's Ultimate Potential for Conventional Natural Gas*, 2006. Available at: www.neb-one.gc.ca

[17] Common abbreviations used in this report are cubic metres (m^3), cubic metres per day (m^3/d), billion cubic feet per day (Bcf/d), trillion cubic feet (Tcf), and barrels per day (b/d).

[18] "Low" and "high", as used here, refer to a range where there is reasonably high confidence that the real in-place and eventual produced marketable volumes from the Montney will fall inside it. Thus, there is a small chance that real in-place and produced marketable volumes could be lower than the low values or higher than the high values.

The Montney's marketable unconventional gas resource is one of the largest in the world. While most of it is located in British Columbia (Table 2), Alberta's share is still large (Table 3). To further illustrate the size of the Montney, total Canadian natural gas demand in 2012 was 88 billion m^3 (3.1 Tcf)[19], making the Montney gas resource equivalent to 145 years of Canada's 2012 consumption. In addition, the Montney is already considered one of Canada's most economic gas plays.[20] Even though it is only in the early stages of development, its 2012 production rose to an average of 48.6 million m^3/d (1.7 Bcf/d) out of total Canadian marketable gas production of 392.7 million m^3/d (13.9 Bcf/d). [21] It is expected that Montney gas production will continue to increase and grow its share of Canadian production.[22]

By combining this marketable gas estimate with prior assessments, including the most recent estimates of western Canadian ultimate potential for <u>conventional</u> natural gas, the total ultimate potential in the Western Canada Sedimentary Basin (WCSB) has more than doubled to 23,249 billion m^3 (821 Tcf) (Table 4). Out of this total, 17,898 billion m^3 (632 Tcf) is remaining after cumulative production to year-end 2012 is subtracted. The ultimate potential for natural gas should be considered an estimate that will evolve, likely growing over time as additional unconventional potential can be found in unassessed shales, such as those in the Liard Basin of British Columbia and the Duvernay Formation of Alberta. Overall, Canada has a very large remaining natural gas resource base in the WCSB to serve its markets well into the future.

The marketable unconventional NGL and oil volumes in the Montney Formation are also very large. However, the volume of marketable oil, which is almost entirely found in Alberta, remains highly uncertain, as indicated by the wide spread between its low and high values. This is because the areas that are richest in Montney unconventional oil tend to be in shallower areas, where uncertainty about development is much greater. The Montney unconventional oil resource is only in the initial stages of development, with its 2012 production averaging only 4108 m^3/d (25,845 b/d), a small component of total Canadian 2012 oil production, which averaged 513,960 m^3/d (3.23 million b/d). Alberta's marketable NGL volumes are also highly uncertain, mostly because the in-place volumes are also largely found in shallower areas.

Table 1. Ultimate potential for Montney unconventional petroleum in British Columbia and Alberta.

Hydrocarbon Type	**In-Place**			**Marketable**		
	Low	**Expected**	High	Low	**Expected**	High
Natural Gas – billion m^3 (trillion cubic feet)	90,559 (3,197)	**121,080 (4,274)**	153,103 (5,405)	8,952 (316)	**12,719 (449)**	18,257 (645)
NGLs – million m^3 (million barrels)	13,884 (87,360)	**20,173 (126,931)**	28,096 (176,783)	1,540 (9,689)	**2,308 (14,521)**	3,344 (21,040)
Oil – million m^3 (million barrels)	12,865 (80,949)	**22,484 (141,469)**	36,113 (227,221)	72 (452)	**179 (1,125)**	386 (2,430)

[19] NEB. *Canada Energy Overview 2012,* 2013. Available at: www.neb-one.gc.ca.

[20] NEB. *Natural Gas Supply Costs in Western Canada in 2009*, 2010. Available at: www.neb-one.gc.ca.

[21] NEB. *Short-term Canadian Natural Gas Deliverability 2013-2015*, 2013. Available at: www.neb-one.gc.ca.

[22] NEB. *Canada's Energy Future: Energy Supply and Demand Projections to 2035*, 2011. Available at: www.neb-one.gc.ca.

Table 2. Ultimate potential for Montney unconventional petroleum in British Columbia.

Hydrocarbon Type	In-Place			Marketable		
	Low	**Expected**	High	Low	**Expected**	High
Natural Gas – billion m^3 (trillion cubic feet)	42,435 (1,498)	**55,664 (1,965)**	69,630 (2,458)	5,666 (200)	**7,677 (271)**	10,311 (364)
NGLs – million m^3 (million barrels)	11,974 (75,340)	**15,310 (96,332)**	19,172 (120,633)	1,418 (8,920)	**2,010 (12,647)**	2,760 (17,366)
Oil – million m^3 (million barrels)	211 (1,328)	**439 (2,763)**	739 (4,652)	1 (8)	**5 (29)**	11 (70)

Table 3. Ultimate potential for Montney, including lowermost Doig siltstone, unconventional petroleum in Alberta.

Hydrocarbon Type	In-Place (from ERCB/AER Reports)			Marketable (this report)		
	Low	**Expected**	High	Low	**Expected**	High
Natural Gas – billion m^3 (trillion cubic feet)	48,124 (1,699)	**65,415 (2,309)**	83,474 (2,947)	3,286 (116)	**5,042 (178)**	7,946 (281)
NGLs – million m^3 (million barrels)	1,910 (12,020)	**4,863 (30,599)**	8,924 (56,150)	122 (769)	**298 (1,874)**	584 (3,674)
Oil – million m^3 (million barrels)	12,654 (79,621)	**22,045 (138,706)**	35,373 (222,569)	71 (444)	**174 (1,096)**	375 (2,360)

Table 4. Ultimate potential for marketable natural gas in the WCSB

Estimate of Ultimate Potential for Marketable Natural Gas in the WCSB – Year End 2012							
Area		**Billion Cubic Metres**			**Trillion Cubic Feet**		
		Ultimate Potential	**Cumulative Production**	**Remaining**	**Ultimate Potential**	**Cumulative Production**	**Remaining**
Alberta	Conventional	6,276	**4,425**	**6,994**	222	**156**	**247**
	Unconventional						
	CBM	*101*			*4*		
	Montney	*5,042*			*178*		
	Unconventional Total	5,143			182		
	Total	**11,419**			**403**		
British Columbia	Conventional	1,462	**695**	**10,642**	52	**25**	**376**
	Unconventional						
	Horn River Basin	*2,198*			*78*		
	Montney	*7,677*			*271*		
	Unconventional Total	9,875			349		
	Total	**11,337**			**400**		
Saskatchewan	Conventional	**297**	**211**	**86**	**10**	**7**	**3**
Southern Territories	Conventional	**196**	**20**	**176**	**7**	**1**	**6**
WCSB Total		**23,249**	**5,351**	**17,898**	**821**	**189**	**632**

Notes for Table 4:
- Determined from previously published assessments by the National Energy Board and/or provincial agencies; coalbed methane (CBM) ultimate potential based on initial reserves in the AER ST-98 Report (available at: www.aer.ca).
- Cumulative production current to year-end 2012.
- Additional gas potential can be found in other regions of Canada. Please see Tables 2.6A and 2.6B of Saskatchewan's Ultimate Potential for Conventional Natural Gas, available at: www.neb-one.gc.ca
- Values may contain rounding errors when added.

Appendix A - Methodology

Introduction

The methodology for the analysis of the British Columbia portion of the Montney petroleum resource is largely based on a prior study that examined the shale-gas resources in the Horn River Basin[23], although it incorporates some new approaches to reflect geological differences in the reservoirs plus feedback received after the initial study. For the Alberta portion of the Montney petroleum resource, the in-place estimate had already been determined in two Alberta studies[24,25] from which a recoverable estimate was extracted for this study. Please see the two Alberta studies as well as *Quantification of Uncertainty in Shale Gas*[26] for more details on the AER's methodologies and assumptions.

Key Assumptions

1) In British Columbia, the petroleum resource was considered to be a resource play, pervasively distributed through the geologically defined area, though its constituents (oil, gas, and NGLs) could vary depending upon location. Thus, the chance of success at discovering petroleum with a well is 100 per cent. In Alberta's assessments of in-place petroleum potential, the range of water saturations included the possibility of having water-saturated wells, thus the chance of petroleum discovery was not necessarily 100 per cent.
2) In British Columbia, thin sandstones unlikely to be targeted by conventional development were included within the siltstone section. In Alberta, all sandstones were excluded from the in-place evaluations and were therefore excluded from this assessment.
3) No study has been undertaken to determine the economics for marketable resources and the determination of what is economic is based on the view of the Agencies. Prior studies have estimated the supply cost of the Montney gas resource to be one of the lowest cost in western Canada, however.[27]
4) Recovery factors are based on existing technology, current trends in development, and limited production. No detailed analyses of technological advancements have been performed for this study. The recovery factors and levels of development could be different in the future as technology advances and the play matures, in particular in the shallower areas of Alberta and under-pressured areas of British Columbia.

[23] BC MEM and NEB. *Ultimate Potential for Unconventional Natural Gas in Northeastern British Columbia's Horn River Basin*, 2011. Available at www.neb-one.gc.ca.

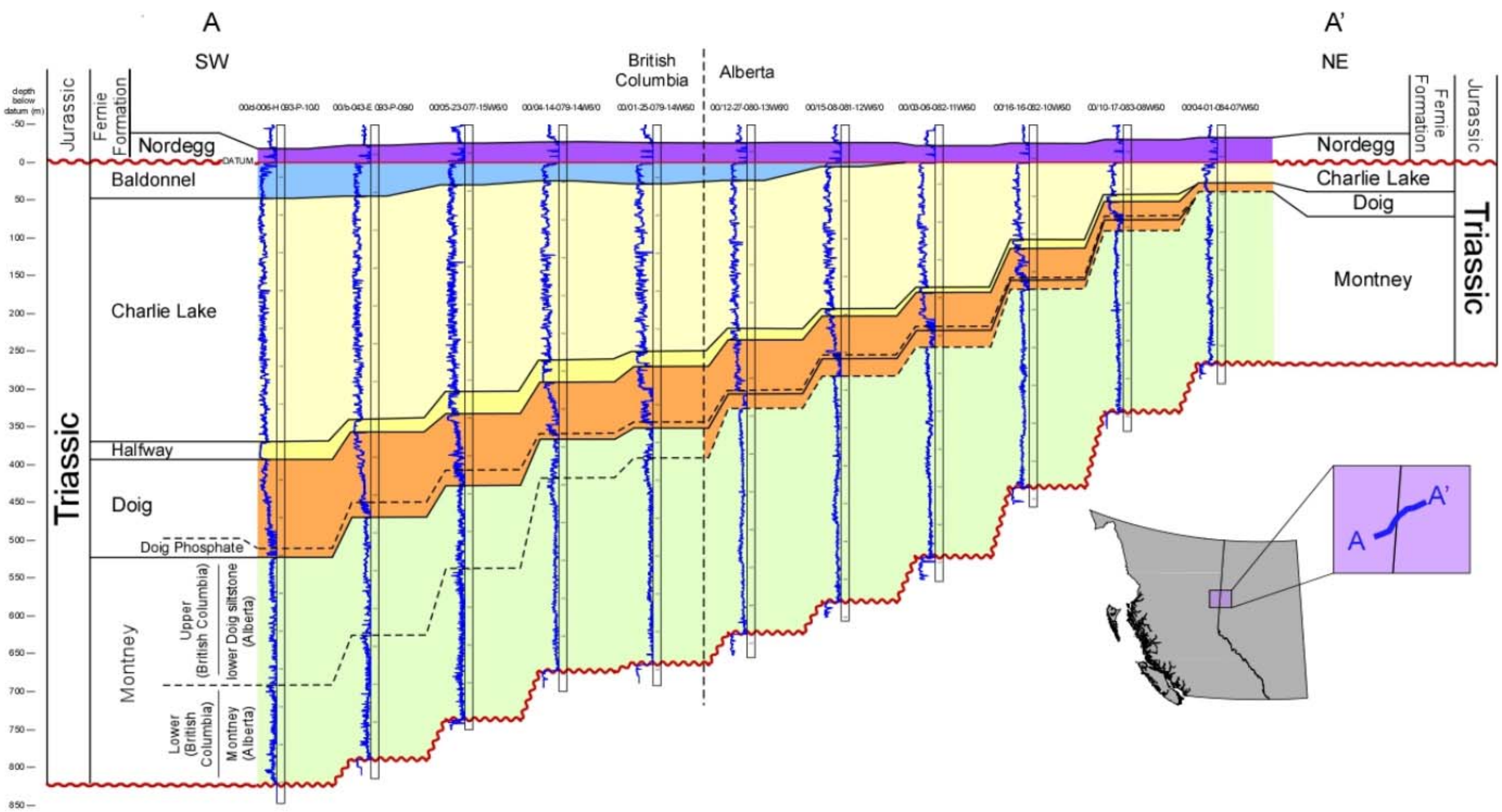
[24] ERCB. *Summary of Alberta's Shale- and Siltstone-Hosted Hydrocarbon Resource Potential*, 2012. Available at: www.ags.gov.ab.ca.

[25] AER study of lowermost Doig siltstone petroleum resources, in preparation.

[26] AER. *Quantification of Uncertainty in Shale Gas*, 2013. Available at: www.ags.gov.ab.ca.

[27] NEB. *Natural Gas Supply Costs in Western Canada in 2009*, 2010. Available at: www.neb-one.gc.ca.

Figure A.1. Cross section of the Montney Formation. Note the siltstone at the bottom of the Doig Formation in Alberta that is equivalent to the Upper Montney in British Columbia.



Stratigraphy and Study Area

Stratigraphic Intervals

In British Columbia, the Lower Triassic Montney Formation was treated as a single unit. In Alberta, a siltstone unit near the bottom of the overlying Doig Formation was included with the Montney because it is stratigraphically equivalent to the Upper Montney in British Columbia (Figure A.1). The two sections of rock in Alberta were then treated as a single unit for the assessment.

Play Area

For British Columbia, the assessment was limited to over-pressured areas due to a lack of unconventional development in under-pressured areas. However, the uncertainty model that was applied to the pressure-gradient map during Monte Carlo simulations could change typically under-pressured areas into over-pressured areas in the case of "high" scenarios, and could change typically over-pressured areas into under-pressured areas in "low" scenarios, thus the boundary between over-pressured areas and under-pressured areas varied by modeled iteration. Over-pressured areas were then assumed to be fully developed in order to determine marketable resources.

In Alberta, the play area was the geographical extent of mapped in-place, siltstone-hosted petroleum resources as determined during Alberta's previous studies. The entire area was assessed for marketable resources because development appears to be occurring in both over-pressured and under-pressured areas; however, the Montney was divided into two different development areas as based on depth. Areas deeper than 1750 m were considered to be more likely developed than shallower areas, as based on current exploration trends.

Tracts

Because of computational limitations, the British Columbia Montney data was aggregated on an NTS (National Topographic System) block basis instead of a smaller grid-spacing unit (GSU) basis, including over the Peace River Block, where values were converted from the DLS (domain land survey) grid to the NTS grid. In Alberta, the Montney data was aggregated on a township basis rather than by section. The equations to determine petroleum volumes were then applied to each NTS and township tract.

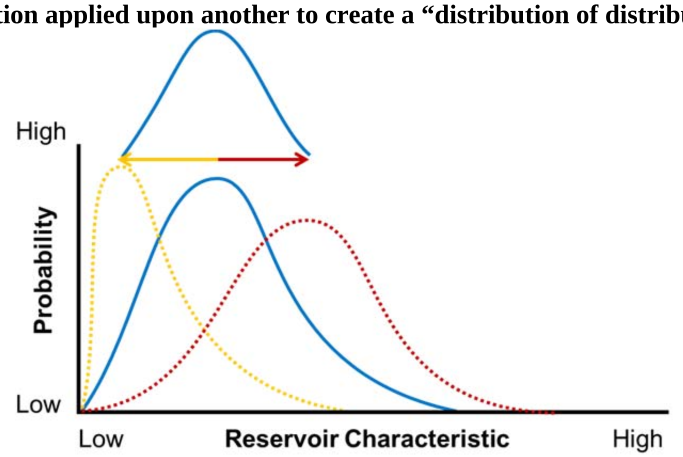
Free, Adsorbed, and Dissolved Hydrocarbon Estimations

British Columbia – Estimation of in-place and marketable resources

Like the Horn River Basin assessment, this assessment was done on a map-grid basis where, at each grid point, Monte Carlo simulations were run on a series of mathematical equations to determine volumes and the results summed to determine the total. Further, the assessment was integrated at two levels: i) a tract-by-tract scale; and ii) a basin scale (Figure A.2) in order to try to incorporate local changes with uncertainties inherent at the basin level. Please see the

“Resource Modeling” section of the 2011 Horn River Basin assessment for more details on this “distribution of distributions” methodology.

Figure A.2. One distribution applied upon another to create a “distribution of distributions”



Most of the maps for the Montney Formation already exist in the *Montney Formation Play Atlas NEBC*[28], such as depth, thickness, and pressure gradient maps. Other maps were constructed solely for this assessment, such as the gas compressibility and “propane plus” molar fraction maps. See Table A.1 for the variables in the assessment based on mapped data as well as the variables (both mapped and unmapped) that had distributions attached to them for the Monte Carlo simulations. Because the Montney Formation was treated as a single unit, variables like porosity, water saturation, and total organic content were applied as averages over the entire rock section.

Unlike the Horn River Basin assessment, no net pay cutoff was used for the Montney in British Columbia. Sandstones, where present within the siltstone within British Columbia, were included in the unconventional play if those sandstones were unlikely to be developed conventionally. Porosities in less prospective areas were assigned lower average porosities than in more prospective areas (i.e., porosities were reduced where depth was greater than 2800 m, or where thickness was greater than 300 m <u>and</u> the tract was on the western half of the British Columbia map). To reduce potential skewing of distributions modeled on mapped data, “soft” maximums or minimums for distribution curves were used (i.e., the distribution’s low and high values wandered based on a percentage of the mapped “most likely” values) rather than “hard” maximum or minimums as long as the soft values did not exceed or fall below impossible values, such as creating negative numbers. Further, when applying the basin-scale distribution to the tract-scale distribution, variables that could have zero as a minimum (such as porosity or water saturation) always had their minimums tied to zero. As a result, not only did the maximums and most likely values vary for those distributions at the tract level, but the shape of the curve could also change. For distributions modeled on the pressure gradient, the range between a tract’s low and high values was reduced as determined by the number of reservoir pressure measurements in it, which increased certainty in the mapped pressures.

Finally, typical solution gas ratios and formation volume factors from Montney and Doig oil pools in British Columbia, as well as gas-to-oil ratios obtained from production data, were

[28] Available at: www.bcogc.ca/montney-formation-play-atlas-nebc.

applied to an emerging oil play in British Columbia to back-calculate local free oil and free gas contents at reservoir conditions.

British Columbia – In-place Resources Equations

Natural gas and NGLs in the Montney Formation are present in three forms: free, adsorbed, and dissolved. Therefore, the total raw natural gas stored in the Montney Formation prior to production can be determined by using the following basic equation at each grid point:

$$RGIP_{total} = RGIP_{free} + RGIP_{adsorbed} + RGIP_{dissolved}$$

Where:

$RGIP_{total}$ = total raw gas in place
$RGIP_{free}$ = free raw in place
$RGIP_{adsorbed}$ = adsorbed raw in place
$RGIP_{dissolved}$ = dissolved raw gas

The assessment of Montney unconventional oil in British Columbia considers only free oil, which comprises a very small component of the total resource. Thus:

$$OIP_{total} = OIP_{free}$$

Where:

OIP_{total} = total oil in place
OIP_{free} = free oil in place

Free raw gas in place was estimated with the volumetric equation (all variables for all equations described in Table A.1):

$$RGIP_{free} = A \times H \times \Phi \times (1 - S_w) \times \left(\frac{D \times PG \times T_S}{P_S \times T_F \times Z} \right) \times (1 - OP_{fraction})$$

Adsorbed raw gas in place was estimated with the equation:

$$RGIP_{adsorbed} = A \times H \times \rho_b \times (1 - \Phi) \times \left(\frac{TOC \times LtO \times D \times PG}{P_L + D \times PG} \right)$$

Dissolved raw gas in place was estimated with the equation:

$$RGIP_{dissolved} = OIP \times GOR_{sol}$$

Raw gas was converted to dry gas with the equation:

$$DGIP_{total} = RGIP_{total} \times (1 - SL - NGL)$$

NGLs in place, in their gaseous form, was estimated with the equation:

$$NGLIP_{total\ gaseous} = RGIP_{total} \times NGL$$

Then converted to their volume in liquid form with the equation:

$$NGLIP_{total} = NGLIP_{tota\lg aeous} \times (C2_{frac} \times C2_{GtL} + C3_{frac} \times C3_{GtL} + ...)$$

Oil in place was estimated with the equation:

$$OIP_{free} = A \times H \times \Phi \times (1 - S_w) \times OP_{fraction} \ / \ FVF$$

But, since the free petroleum in the system is likely a mixture of oil and raw gas, an $OP_{fraction}$ (the fraction of oil in the petroleum in the reservoir) was required:

$$OP_{fraction} = \frac{OIP_{res}}{OIP_{res} + RGIP_{free(res)}}$$

$$= \frac{FVF}{\left[FVF + \dfrac{(GOR_{surface} - GOR_{sol}) \times P_S \times T_F \times Z}{T_S \times D \times PG}\right]}$$

British Columbia – Marketable Resources Equations

Marketable gas resources can be calculated with the following equation:

$$MG_{total} = MG_{free} + MG_{adsorbed} + MG_{dissolved}$$

Where:

MG_{total} = Total marketable dry gas
MG_{free} = Marketable free dry gas
$MG_{adsorbed}$ = Marketable adsorbed dry gas
$MG_{dissolved}$ = Marketable dissolved dry gas

Free marketable dry gas was estimated with the equation:

$$MG_{free} = DGIP_{free} \times RF_{gas}$$

Where RF_{gas} is the recovery factor, the most likely value assumed to be 15 per cent.

Marketable adsorbed dry gas, which is the amount of gas that can desorb from the organic and mineral matter in the formation at well-abandonment pressures and then be recovered by moving through the reservoir to any well, was estimated with the equation:

$$MG_{adsorbed} = RF_{gas} \times \left\{ DGIP_{adsorbed} - (1 - SL - NGL) \times A \times H \times \rho_b \times (1 - \Phi) \times \left(\frac{TOC \times LtO \times P_A}{P_L + P_A} \right) \right\}$$

Dissolved gas was assumed to be extracted with the free gas where present in the same reservoir, as subsurface de-pressurization during free-gas extraction would cause some dissolved gas to come out of solution from the oil. Therefore, the same recovery factor for free gas was applied to the dissolved gas. While this would likely lead to an overestimate of marketable dissolved gas, it forms a very small portion of the overall resource and its impact on the total results is minimal.

$$MG_{dissolved} = DGIP_{dissolved} \times RF_{gas}$$

Marketable NGLs can be estimated with the equation:

$$MNGL_{total} = MNGL_{free} + MNGL_{adsorbed} + MNGL_{dissolved}$$

Where:

$MNGL_{total}$ = Total marketable NGLs
$MNGL_{free}$ = Marketable Free NGLs
$MNGL_{adsorbed}$ = Marketable Adsorbed NGLs
$MNGL_{dissolved}$ = Marketable Dissolved NGLs

Free marketable and dissolved marketable NGLs (with the same potential overestimation of dissolved NGLs as for dissolved dry gas) were estimated with the equations:

$$MNGL_{free} = NGLIP_{free} \times RF_{gas}$$
$$MNGL_{dissolved} = NGLIP_{dissolved} \times RF_{gas}$$

Marketable adsorbed NGLs were estimated slightly differently than marketable dry gas. Since the heavier the hydrocarbon is the more prone it is to adsorption, it was assumed that only ethane and propane would desorb from organic matter during depressurization of the reservoir during production. Further, the amount of ethane desorbed was reduced by 50 per cent and propane by 75 per cent because of their stronger affinities relative to methane. Thus:

$$MNGL_{adsorbed\_gaseous} = NGL_{C2} \times RF_{gas} \times \left\{ RGIP_{adsorbed} - A \times H \times \rho_b \times (1 - \Phi) \times \left(\frac{TOC \times LtO \times P_A}{P_L + P_A} \right) \right\} \times 0.5 +$$
$$NGL_{C3} \times RF_{gas} \times \left\{ RGIP_{adsorbed} - A \times H \times \rho_b \times (1 - \Phi) \times \left(\frac{TOC \times LtO \times P_A}{P_L + P_A} \right) \right\} \times 0.25$$

The marketable adsorbed gas in gaseous form was then converted to liquid form via:

$$MNGL_{adsorbed} = NGLIP_{adsorbed\_gaseous} \times (C2_{frac} \times C2_{GtL} + C3_{frac} \times C3_{GtL})$$

Marketable oil was determined with the equation:

$$MO_{total} = OIP_{total} \times RF_{oil}$$

Where RF_{oil} is the recovery factor for oil, its most likely value assumed to be 1 per cent.

Alberta – Marketable Resources Equations

Because a range of in-place volumes of dry gas, NGLs, and oil for the Alberta Montney play had already been determined, including values for the lowermost Doig siltstone, only the recoverable quantities were estimated for this study. Rather than separately estimating recoverable quantities for each unit, the results of in-place Monte Carlo simulations for the Alberta Montney and lowermost Doig siltstone were added together on a township-by-township and iteration-by-iteration basis. The combined result was then re-simulated by using @Risk software's Resample function, during which recovery factors were applied.

Based on current trends in development, the Montney play in Alberta is largely being developed where the Montney depth is 1750 m or greater, though small developments are occurring in shallower areas. Thus, a development factor was applied to simulate the effects of partial development. The minimum development factor for a township was determined by how many sections in it contained either the surface hole or bottom hole location of existing or licensed horizontal Montney wells. A township where none of its sections had locations was assigned a minimum of 0. The maximum value for a township was then assumed to be 1 and the most likely 0.3 more than the minimum.

Higher recovery factors were applied to the Montney Formation where the formation mid-point was deeper than 1750 m, with the most likely value assumed to be 15 per cent for gas, as in British Columbia, though a 2 per cent most likely value was applied to the deep Montney oil resource given Alberta's more mature development. Lower recovery factors were applied where formation mid-point depths were shallower than 1750 m, the most likely value assumed to be 10 per cent for gas and 1 per cent for oil. Lower recovery factors in shallower areas are supported by available pressure data, which demonstrates that shallower areas in the Alberta Montney have a much greater tendency to be under-pressured. Dissolved gas was not considered to be recoverable, thus the amount of marketable gas in the Alberta Montney siltstone may be somewhat underestimated.

Therefore, marketable Alberta resources were estimated with the equations where *DF* is the development factor:

$$MG_{free} = GIP_{free} \times RF_{gas} \times DF$$
$$MG_{adsorbed} = GIP_{adsorbed} \times RF_{gas} \times DF \times DR$$

$$MG_{total} = MG_{free} + MG_{adsorbed}$$
$$MNGL_{total} = NGLIP_{free} \times RF_{gas} \times DF$$
$$MO_{total} = OIP_{free} \times RF_{oil} \times DF$$

DR is a desorption-reducing factor, because not all adsorbed gas would be able to be desorbed by the time a well was abandoned. This was assumed to be 0.33 as based on the results of the British Columbia analysis.

Table A.1. Variable descriptions and model inputs used for assessment.

Variable	Symbol	Map (Y/N)	Prob. Dist. (Y/N)	Tract Model Inputs (low/most likely/high)	Basin Model Inputs (low/most likely/high)	Correlations and notes	Data Source
Area (m^2)	A	N	N	Based on map-grid spacing	-	-	-
Depth (m)	D	Y	N	Based on map	-	-	Well logs
Thickness (m)	H	Y	N	Based on map	-	-	Well logs
Porosity (fraction)	Φ	N	Y	0.005/0.03/0.08 (normal) 0.001/0.025/0.06 (low)	0.01/0.03318/0.055	Positive correlation with recovery factor	Core and well logs
Water Saturation (fraction)	S_w	N	Y	0.01/0.25/0.5	0.05/0.25/0.45	Negative correlation with recovery factor	Best estimate
Pressure Gradient (kPa/m)	PG	Y	Y	-20/0/20 (% variance from mapped value)	-15/0/15 (% variance from mapped value)	Positive correlation with recovery factor;	Production tests
Surface Pressure (kPa)	P_S	N	N	101.3	-	Standard conditions	-
Abandonment Pressure (kPa)	P_A	N	N	3000	-	-	Gathering pipeline pressures; best estimate
Reservoir Temperature (^oK)	T_F	Y	N	Based on map	-	-	Well logs
Surface Temperature (^oK)	T_S	N	N	288	-	Standard conditions	-
Gas Compressibility	Z	Y	N	Based on map	-	-	Gas analyses
Non-hydrocarbon Gas Impurities and Fuel Gas (fraction)	SL	N	N	0.02	-	-	Gas analyses; best estimate
NGL fraction	NGL	Y	N	Based on map	-	Ethane-plus content estimated from correlation to propane-plus content	Gas analyses
Recovery Factor - gas and NGLs	RF_{gas}	N	Y	<u>Over-pressured gas</u> 0/0.15/0.3 (AB & BC) <u>Under-pressured gas</u> 0/0.1/0.2 (AB only)	<u>Over-pressured gas</u> 0.05/0.15/0.25 (AB & BC) <u>Under-pressured gas</u> 0.5/0.1/0.15 (AB only)	Positive correlation with pressure gradient and porosity; negative correlation with water saturation	Best estimate
Recovery Factor - oil	RF_{oil}	N	Y	<u>AB Over-pressured oil</u> 0/0.02/0.08	<u>AB Over-pressured oil</u> 0/0.02/0.05	Positive correlation with pressure gradient and porosity; negative	Best estimate

				BC Over-pressured oil 0/0.01/0.03 AB Under-pressured oil 0/0.01/0.05	BC Over-pressured oil 0/0.01/0.02 AB Under-pressured oil 0/0.01/0.04	correlation with water saturation	
Development Factor (fraction)	*DF*	N	N	0/0.3/1	0/0.3/0.9	-	Best estimate
Rock Matrix Density (ton/m^3)	ρ_b	N	N	2.725	-	-	Core
Total Organic Content (fraction)	*TOC*	N	Y	0.001/0.015/0.05	0.005/0.015/0.03	-	Core; best estimate
Langmuir Volume to Organic Content Ratio (m^3/ton/centile)	*LtO*	N	Y	27.5/44.65/74.7157	35/44.65/57	-	Adsorbed gas tests on core samples
Langmuir Pressure (kPa)	P_L	N	Y	4100/5800/9500	4500/5800/7000	-	Adsorbed gas tests on core samples
NGL Species Fraction	CN_{frac}	N	N	Based on NGL fraction map	-	Estimated from gas-analysis NGL fractions	Gas analyses
NGL Gas-to-Liquid Volume Converter	CN_{GtL}	N	N	-	-	-	Ideal gas laws
Formation Volume Factor	*FVF*	N	N	Based on depth and pressure gradient maps	-	Estimated from reservoir pressure	Conventional Montney and Doig reserves data
Oil Fraction of Petroleum at Reservoir Conditions	$OP_{fraction}$	N	N	-	-	-	calculated
Gas-to-Oil Ratio - solution	GOR_{sol}	N	N	Based on depth and pressure gradient maps	-	Estimated from reservoir pressure	Conventional Montney and Doig reserves data
Gas-to-Oil Ratio - surface	GOR_{surf}	N	N	Based on local map of B.C. oil trend	-	-	Production data; best estimate
Oil-in-Place at Reservoir Conditions	OIP_{res}	N	N	-	-	-	Calculated
Raw Free Gas in Place at Reservoir Conditions	$RGIP_{free(res)}$	N	N	-	-	-	Calculated

GOVERNMENT OF CANADA RESPONSE TO
THE STANDING COMMITTEE ON NATURAL RESOURCES' INTERIM REPORT:

"THE FUTURE OF CANADA'S OIL AND GAS SECTOR: INNOVATION, SUSTAINABLE SOLUTIONS AND ECONOMIC OPPORTUNITIES"

January 19, 2017

INTRODUCTION

The Government of Canada has reviewed the report of the Standing Committee and thanks its members for their efforts in developing this report. The Government also wishes to extend its thanks to the numerous witnesses who provided expert testimony to the Committee, providing the members with a diversity of perspectives on the oil and gas sector.

For Canadians, the oil and gas sector has long been a driver of economic growth, innovation, and prosperity. In 2015, Canada's the oil and gas sector employed more than 190,000 and accounted for 5.3 percent of Canada's total GDP. Capital investment in the oil and gas sector totalled $65 billion, representing 26 percent of total capital investment in Canada.

However, as the Standing Committee's report indicated, the Canadian oil and gas sector now faces considerable challenges. The Standing Committee's expert witnesses drew attention to a number of economic headwinds for the sector, including persistently low commodity prices; the emergence of low-cost competitors; potential constraints on export capacity; and significant declines in investment. Witnesses also called attention to social and environmental concerns affecting development in the sector. The Standing Committee cited a lack of confidence in regulatory approvals among Canadians which stemmed from among other things, insufficient recognition of Indigenous concerns and engagement; broad concerns around the environmental impacts of resource development, and doubts surrounding the need for oil and gas development as technology looks to reduce our reliance on fossil fuels.

Yet, according to the International Energy Agency (IEA), the world will depend on oil and gas as a significant source of energy for years to come. The 2015 IEA World Energy Outlook forecast that global demand for natural gas could increase by 47 percent from 2014 to 2040, while demand for oil could increase by 14 percent over the same period. In time, Canada has risen to become the world's third largest exporter of oil, and fourth largest exporter of gas. While Canadian energy powers the world, we can make investments in clean technology and renewable energy that will position Canada's energy sector for the future.

It is clear to our Government that in order for the energy sector to continue to be a driver of prosperity and play a part in meeting global demand for energy, resource development must go hand in hand with the environmental and social demands of Canadians.

The Government's Response to the specific recommendations made by the Committee follow. Given the linkages between the committee's recommendations, we have grouped the recommendations thematically in order to provide comprehensive responses. We outline our collaboration with governments at home and abroad to establish policies that will help us to meet our energy needs and address the challenges of climate change; the steps being taken to rebuild public trust through transparency, engagement, and improved environmental and regulatory review processes; our efforts to engage with Indigenous communities in a meaningful way; and investments in innovation and clean technologies that will position Canada for a more innovative and sustainable economy.

THEME 1: ESTABLISHING POLICY FRAMEWORKS THROUGH INTERGOVERNMENTAL COLLABORATION AND CO-OPERATION

RECOMMENDATION 5: ***The committee recommends that the Government of Canada continue to work on a National Energy Strategy in collaboration with Indigenous, provincial, territorial, and international partners to ensure that carbon accounting standards and credit transfer practices are considerate of neighbouring jurisdictions and that all carbon accounting standards are transparent and science-based.***

The Government recognizes the importance of collaborating with Indigenous peoples, provinces, territories, and international partners to ensure Canada's energy resources are developed sustainably as we transition to a lower-carbon future. To this end, the Government is actively working with provinces and territories to advance the Canadian Energy Strategy, which provinces and territories see as a critical tool to coordinate climate change-related actions across jurisdictions.

Our Government is building on momentum from the recent ratification of the Paris Agreement, and the commitments and actions already taken by provinces and territories. Through the Vancouver Declaration of 2016, Canada's First Ministers committed to work together under the Pan-Canadian Framework on Clean Growth and Climate Change to meet or exceed Canada's international emissions targets, and transition our country to a stronger, more resilient, low-carbon economy – while also improving our quality of life. We will transition to a low carbon economy by adopting a broad range of domestic measures, including carbon pricing mechanisms, adapted to each province's and territory's specific circumstances, in particular the realities of Canada's Indigenous peoples and Arctic and sub-Arctic regions.

Through collaboration, we are creating the conditions for collective prosperity, competitiveness, health, and security. The Government is committed to continuing to work with provinces and territories towards the development of a Pan-Canadian Framework, and will also continue to work and meet regularly with national Indigenous organizations. The Government has already committed to:

- support climate change mitigation and adaptation through investments in green infrastructure, public transit infrastructure and energy efficient social infrastructure;
- work together with the provinces and territories on how best to lever federal investments in the Low Carbon Economy Fund to realize incremental emission reductions;
- advance the electrification of vehicle transportation, in collaboration with provinces and territories;
- foster dialogue and the development of regional plans for clean electricity transmission to reduce emissions;
- advance efforts to eliminate the dependence on diesel in Indigenous, remote, and Northern communities – and use renewable, clean energy as a replacement; and

- as part of Canada's participation in “Mission Innovation”, double investments in clean energy, research and development over five years, and work with global partners to promote cleaner energy and better environmental outcomes.

With regards to the Government’s perspective on carbon accounting, standard methods of accounting for greenhouse gas emissions have already been established via the 2006 Intergovernmental Panel on Climate Change Guidelines for National Greenhouse Gas Inventories that were prepared in response to an invitation by the Parties to the United Nations Framework Convention on Climate Change (UNFCCC). As signatory to the 2015 Paris Agreement under the UNFCCC, in any potential participation in international credit transfers, Canada would comply with the robust accounting guidance for the use of international transferred mitigation outcomes that is prescribed by the Agreement.

RECOMMENDATION 9: The Committee recommends that the Government of Canada continue to strengthen our North American Energy Strategy and intergovernmental cooperation on energy policies by taking into account federal, provincial, territorial and Indigenous interests, and take measures to improve the quality and availability of national energy data.

The Government of Canada recognizes the importance of cooperation at various levels in relation to energy policies and energy data. Natural Resources Canada is engaged with the United States and Mexico in a variety of bilateral and trilateral collaborative projects which address a range of technology and policy issues pertaining to climate change and energy.

At the 2014 North American Leaders’ Summit, Leaders agreed to have their respective Energy Ministers meet annually to hold a North American Energy Ministerial (NAEM). The first NAEM was held in December, 2014, at which time a Memorandum of Understanding (MOU) Concerning Cooperation on Energy Information was signed.

Over the course of 2015, the three countries collaborated on energy information as well as a number of technical energy projects which included the launch of a web platform featuring new energy maps, which for the first time depict North American energy resources, production and infrastructure in a single place.

At the 2016 NAEM held in Winnipeg, a revised MOU Concerning Collaboration on Climate Change and Energy Collaboration was signed. This agreement will see Canada, Mexico and the United States collaborate and share information on key areas such as low-carbon electricity; clean energy technologies; energy efficiency; carbon capture, use and storage; climate change adaptation; and reducing emissions from the oil and gas sector, including from methane. The three countries will work together to increase alignment and ensure that the North American energy sector is developed responsibly, effectively and efficiently.

With respect to national energy data, Natural Resources Canada and Statistics Canada have worked to establish a framework for Canadian energy statistics, the Canadian Energy Statistics Framework (ESF), published in February 2016. The ESF is based on the United Nations’ International Recommendations on Energy Statistics. Initiatives are already underway to implement changes to improve the quality of energy data, ensuring it is reflective of Canada's modern energy system.

THEME 2: REBUILDING PUBLIC TRUST IN RESOURCE DEVELOPMENT THROUGH TRANSPARENCY, ENGAGEMENT, AND MODERNIZATION

RECOMMENDATIONS 2 and 4: ***The Committee recommends that the Government of Canada work in collaboration with industry and the Indigenous, provincial, territorial, and municipal governments to develop the supporting infrastructure needed to create a favourable environment for natural resource development and transportation, and to deliver oil and gas products to strategic domestic and international markets;***

And,

The Committee recommends that the Government of Canada address the broader issue of public trust in the energy sector, by fostering more transparency and public engagement in resource development decisions, and recognizing Canada's strong environmental regulations and the work of the national regulators.

The Government agrees with the recommendations. Resource industries have, and must continue to make vital contributions to the prosperity of Canadians. Today, Canada is among the world's largest oil and gas producers and exporters and we expect to continue to play a significant role in meeting global demand for energy. Accessing strategic markets ensures Canadians receive full value for our resources; resources which can fund the next generation of renewable energy.

The Government believes that resource development and environmental protections must go hand in hand, and that collaboration with stakeholders is essential to developing resources in a manner that maintains public trust.

Consultation will be at the core of the review of environmental and regulatory processes and is an essential part of ongoing project reviews. The Government is undertaking a review of environmental and regulatory processes so that Canadians may be certain that decisions on major projects will promote a clean environment and drive economic prosperity. The review focuses on: reviewing federal environmental assessment processes; modernizing the National Energy Board (NEB); and restoring lost protections and introducing modern safeguards to the *Fisheries Act* and the *Navigation Protection Act.*

The Government established a 5-member NEB Modernization expert panel to strengthen the organization to better respond to future needs. The panel will examine issues beyond environmental assessment, including the NEB's governance structure, role and mandate, with a focus on enhancing the participation of the public and Indigenous peoples in regulatory reviews. The expert panel has expertise in policy, energy, business, environment, scientific, regional and Indigenous knowledge, and will provide its recommendations on modernizing the

NEB by March 31, 2017.

The Government understands the crucial role the NEB plays. We will continue to rely on the NEB to support critical decisions on key projects while the modernization review is underway, and have put in place interim principles to guide our decisions on major resource project assessments that are already in-progress. These interim principles strengthen the consultation process and instill greater public confidence by ensuring that decisions are based on science, traditional knowledge of Indigenous peoples and other relevant evidence; views of the public and affected communities are considered; Indigenous peoples are meaningfully consulted, and greenhouse gas emissions are fully assessed.

Specific measures have been put in place to foster more transparency and public engagement in NEB reviews. This includes appointment of a Ministerial Panel that engaged people from potentially affected communities close to the proposed Trans Mountain Expansion pipeline and shipping corridors, as well as appointment of temporary members to the NEB, with the expectation that the NEB Chair would direct them to engage communities and Indigenous groups along the Energy East Pipeline route. Consultations with Indigenous people along proposed pipeline routes have been deepened and the views of Canadians on pipeline projects have been sought through online questionnaires.

The issue of broad public confidence was a key issue discussed at the 2016 Energy and Mines Ministers' Conference (EMMC), an annual gathering of federal, provincial and territorial (FPT) ministers responsible for energy and mining portfolios. The 2016 EMMC concluded with FPT ministers agreeing to endorse four common principles: to foster relationships, improve communications, balance community interests with environmental and health impacts, and support science and innovation. Work is underway to develop a joint action plan that proposes concrete actions to strengthen public confidence in each of these areas.

The review of environmental assessment processes builds on Canada's strong environmental regulations; regulations that are important for creating a culture of safety. For example, the *Pipeline Safety Act,* which came into force in June, 2016, enshrines the polluter-pays principle in legislation. Operators' liability will remain unlimited in cases of fault or negligence and increases to $1 billion regardless of fault. The Government is working to establish regulations on financial requirements, to ensure that federally-regulated pipeline companies are prepared to cover response, remediation costs, and liability claims.

The recently announced Oceans Protection Plan ensures that our coasts are maintained in a modern and efficient way that marries commercial use, environmental sustainability and security. It does so by creating a world-leading marine safety system, including new rescue stations; preserving and restoring the marine ecosystem using new environmental assessments and research, as well as taking measures to address abandoned boats and wrecks; enhancing partnerships with Indigenous communities, including emergency response training; and investing in both wildlife research and oil spill response technology to ensure that decisions taken in emergencies are evidence based.

In addition, in June 2016, Environment and Climate Change Canada (ECCC) introduced regulations which include performance standards for certain types of equipment that operate in oil and gas facilities. In early 2017, ECCC plans to propose federal methane regulations for the oil and gas sector, which will reduce emissions of methane – a potent greenhouse gas – by 40 to 45 percent from 2012 levels by 2025. These regulations are designed to deliver on commitments made at the North American Leaders Summit and through the Canada-United States Joint Statement on Climate, Energy and Arctic Leadership.

Taken together, these actions demonstrate that the federal government is actively working to strengthen public confidence.

THEME 3: EARLY AND EFFECTIVE ENGAGEMENT WITH INDIGENOUS PEOPLES IN RESOURCE DEVELOPMENT DECISIONS

RECOMMENDATION 3: ***The Committee recommends that the Government of Canada work to encourage the early engagement of Indigenous peoples in resource development decisions, in full compliance with existing treaty and Indigenous rights to land and resources. Furthermore, the Committee recommends that the government ensure that consultation processes consider the multidimensional impacts of resource development projects on Indigenous peoples, including issues concerning education, health, economic development, infrastructure and the environment.***

The Government agrees that meaningful Aboriginal consultation and Indigenous engagement in resource development decisions is essential for sustainable natural resource development in Canada. The Government also agrees that the multidimensional impacts of resource projects on Indigenous peoples are important considerations in resource development decisions. Accordingly, federal efforts to enhance both Indigenous engagement and Crown consultation have been increasing since the fall of 2015.

With respect to Canada's legal duty to consult, an approach to consultation and accommodation is in place under the *Consultation and Accommodation Guidelines for Federal Officials*, administered by Indigenous and Northern Affairs Canada (INAC). These Guidelines are built on case law and best practices, to enable federal officials to undertake their responsibilities in an effective and meaningful manner. These guidelines were last updated in 2011 and could be subject to further revision to reflect external reports, feedback from Indigenous peoples and other parties, and case law.

The government has advanced efforts to surpass legal requirements and deepen engagement with Indigenous peoples. Key elements of a whole-of-government approach to Indigenous consultation are in place under the Major Projects Management Office (MPMO) Initiative, which integrates consultation into the major project review process, to the extent possible, the provision of dedicated Indigenous participant funding for major project reviews, and consistency to consider and address Indigenous groups' multidimensional concerns.

Building on this initiative, the Major Projects Management Office-West (MPMO-West) was established at Natural Resources Canada to support early engagement on energy infrastructure development on the West Coast. Dedicated to developing trusting relationships with Indigenous communities and serving as a federal single window on energy infrastructure development, MPMO-West has sponsored and participated in multiple community-led events to discuss concerns.

Indigenous peoples are also being engaged regarding reviews of federal regulatory processes like the Environmental Assessment Review and NEB Modernization. Supporting NEB Modernization, officials from Natural Resources Canada are enhancing engagement with Indigenous peoples on other matters related to resource development. For example, officials from Natural Resources Canada are actively engaging on non-major pipeline projects to share information on provisions for pipeline safety and understand Indigenous groups' interests and concerns.

Interim principles that were introduced for major resource projects currently under review ensure that Indigenous peoples are meaningfully consulted, and that traditional knowledge of Indigenous peoples and other relevant evidence are considered. Consultations are being enhanced through the use of extended timelines as needed, more direct consultation on pipeline projects and additional participant funding. For example, the September 2016 decision on the Pacific NorthWest LNG Project involved meaningful consultation with Indigenous peoples, and where appropriate, impacts were accommodated. Consultations with Indigenous communities were extensive, and included funding to support participation. Indigenous groups near the project site will also participate with federal and provincial governments in environmental monitoring, a new approach that is consistent with the Government's reconciliation agenda and its commitment to enhance the capacity of Indigenous groups in reviewing and monitoring major resource development projects.

Each of the above noted activities and priorities are being advanced in a manner that seeks to build and strengthen relationships between Canada and Indigenous peoples. This is being done in a manner that is based on recognition of rights, respect, co-operation, and partnership. This relationship is vitally important – not just to the shared interests between Canada and Indigenous peoples, but to our respective identities as nations.

THEME 4: SUPPORTING INNOVATION AND GLOBAL LEADERSHIP IN CANADIAN OIL AND GAS

RECOMMENDATION 1: The Committee recommends that the Government of Canada continue to promote the benefits of investing in Canada's Natural Resources sectors, including oil and gas, which shall include the continued encouragement of innovation, research and development.

The Government believes that protecting the environment and growing the economy are not incompatible goals; in fact, our future success demands we do both. The Government is taking action on a number of fronts to reduce GHG emissions by advancing clean energy. For example, Budget 2016 provides $2 billion in funding for a Low Carbon Economy Fund which will support provincial and territorial initiatives aimed at reducing greenhouse gas emissions. Moreover, Budget 2016 provides $1 billion to support clean technology.

The Government, through its policy work and funding of research, development and demonstration (RD&D) of innovative technologies, has made significant investments to reduce greenhouse gas emission and other environmental impacts in Canada's natural resources sectors, including oil and gas. A "Strategy for Advancing Clean Technology in the Natural Resource Sectors" is being advanced; in addition, through "Mission Innovation", Canada has joined 20 other nations in pledging to double spending on clean energy R&D by 2021. This commitment to fund energy R&D will help improve Canada's oil and gas sector, making it more environmentally responsible and economically competitive.

The Government also recently launched initiatives under Budget 2016 targeting innovation in the natural resources sectors, including Natural Resources Canada's $50 million Oil & Gas Clean Tech Program to reduce greenhouse gas emissions in the oil and gas sector; along with the $25 million Clean Energy Innovation Program, which funds projects in areas including the reduction of methane and volatile organic compound emissions in the oil & gas sector.

RECOMMENDATIONS 6, 7 and 8: The Committee recommends that the Government of Canada, through Natural Resources Canada, enhance opportunities to connect inventors, researchers and entrepreneurs with the segments of the oil and gas industry that are most applicable to their areas of expertise;

the Committee recommends that the Government of Canada encourage collaboration through clusters and councils among governments, industry, academia, and international experts, with the aim of maximizing the innovative potential of Canada's oil and gas sector; and,

the Committee recommends that the Government of Canada encourage Canadian companies and entrepreneurs to become global leaders in their respective innovations and/or technologies.

The Government recognizes the importance of connecting innovators with industry, and encouraging Canadian companies to become global leaders. Natural Resources Canada is an associate member of the Canada's Oil Sands Innovation Alliance (COSIA), an alliance of leading oil sands companies focused on bringing together leading thinkers from industry, government, academia and the wider public to improve measurement, accountability and environmental performance in the oil sands.

The Government supports the aim of maximizing the innovative potential of Canada's oil and gas sector, and encourages collaboration through many of Natural Resources Canada's undertakings. Natural Resources Canada's Oil & Gas Clean Tech Program and the Clean Energy

Innovation Program both look to support collaborative projects between clean technology producers and industrial end users of technologies, including the oil and gas industry. In addition to its collaborative efforts through COSIA, Natural Resources Canada's CanmetENERGY lab engages with various levels of governments to maximize the innovative potential of Canada's oil and gas sector. Through collaborations such as the Alberta-Canada *"Collaboratory in Cleaner Oil Sands Development*", the Government is able to encourage strategic alignment between jurisdictions, and identify common projects for collaboration related to oil sands innovation areas.

The Government also actively pursues collaborations with the US Department of Energy, and over the years, has worked on harmonizing energy efficiency regulations, RD&D projects targeting the oil and gas sector, and carbon capture and storage.

Finally, the Government of Canada has actively supported Canada businesses in their efforts to access global markets. This has been achieved through various fora including international trade missions, most recently to India where 20 Canadian Companies met with Indian industry to explore opportunities for Canadian products and know-how. In addition, the Government continues to be an active contributor to international development partnerships, such as the Canada-US Clean Energy Dialogue, the Canada-Israel Industrial Research and Development Foundation, and "Mission Innovation".

PAN-CANADIAN FRAMEWORK

on Clean Growth and Climate Change

Canada's Plan to Address Climate Change and Grow the Economy

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PAN-CANADIAN FRAMEWORK on Clean Growth and Climate Change

Canada's Plan to Address Climate Change and Grow the Economy

FOREWORD

The Pan-Canadian Framework on Clean Growth and Climate Change presented here is our collective plan to grow our economy while reducing emissions and building resilience to adapt to a changing climate. It will help us transition to a strong, diverse and competitive economy; foster job creation, with new technologies and exports; and provide a healthy environment for our children and grandchildren.

The Pan-Canadian Framework is both a commitment to the world that Canada will do its part on climate change, and a plan to meet the needs of Canadians. We have built on the momentum of the Paris Agreement by developing a concrete plan which, when implemented, will allow us to achieve Canada's international commitments.

When First Ministers met last March in Vancouver, they agreed to take ambitious action in support of meeting or exceeding Canada's 2030 target of a 30 percent reduction below 2005 levels of greenhouse gas (GHG) emissions. First Ministers issued the Vancouver Declaration on Clean Growth and Climate Change and agreed that a collaborative approach between provincial, territorial, and federal governments is important to reduce GHG emissions and to enable sustainable economic growth.

The Pan-Canadian Framework builds on the leadership shown and actions taken individually and collectively by the provinces and territories, including through the Declaration of the Premiers adopted at the Quebec Summit on Climate Change in 2015. To note, the province of Saskatchewan has decided not to adopt the Pan-Canadian Framework at this time. The federal government has committed to ensuring that the provinces and territories have the flexibility to design their own policies and programs to meet emission-reductions targets, supported by federal investments in infrastructure, specific emission-reduction opportunities and clean technologies. This flexibility enables governments to move forward and to collaborate on shared priorities while respecting each jurisdiction's needs and plans, including the need to ensure the continued competitiveness and viability of businesses.

In the Paris Agreement, Parties agreed that they should, when taking action to address climate change, recognize and respect the rights of Indigenous Peoples. As we implement this Framework, we will move forward respecting the rights of Indigenous Peoples, with robust, meaningful engagement drawing on their Traditional Knowledge. We will take into account the unique circumstances and opportunities of Indigenous Peoples and northern, remote, and vulnerable communities. We acknowledge and thank Indigenous Peoples across Canada for their climate leadership long before the Paris Agreement and for being active drivers of positive change.

Pricing carbon pollution is central to this Framework. Carbon pricing will encourage innovation because businesses and households will seek out new ways to increase efficiencies and to pollute less. We will complement carbon pricing with actions to build the foundation of our low-carbon and resilient economy.

As Canada transitions to a low-carbon future, energy will play an integral role in meeting our collective commitment, given that energy production and use account for over 80 percent of Canada's GHG emissions. This means using clean energy to power our homes, workplaces, vehicles, and industries, and using energy more efficiently. It means convenient transportation systems that run on cleaner fuels, that move more people by public transit and zero-emission vehicles, and that have streamlined trade corridors. It means healthier and more comfortable homes that can generate as much power as they use. It means more resilient infrastructure and ecosystems that can better withstand climatic changes. It means land use and conservation measures that sequester carbon and foster adaptation to climate change. It means new jobs for Canadians across the country and opportunities for growth. It means leveraging technology and innovation to seize export and trade opportunities for Canada, which will allow us to become a leader in the global clean growth economy and will also help bring down the cost of low-emission technologies. It means healthier communities with cleaner air and healthy and diverse ecosystems across the country.

We will maintain a sustained focus on implementation of the Pan-Canadian Framework, consistent with the commitment under the Paris Agreement, to increase the level of ambition over time.

The Pan-Canadian Framework is a historic step in the transition to a clean growth and resilient economy. It is informed by what we have heard from Canadians. We will continue to grow our economy and create good jobs as we take ambitious action on climate change. We will work to ensure that the Pan-Canadian Framework opens new opportunities for Canadian businesses to not only maintain but also enhance their competitiveness. We will continue to engage Canadians to strengthen and deepen our action on clean growth and climate change. And we are committed to transparently assessing and reporting to Canadians on our progress.

Together, we have developed a Pan-Canadian Framework on Clean Growth and Climate Change. This is Canada's plan to address climate change and grow the clean economy.

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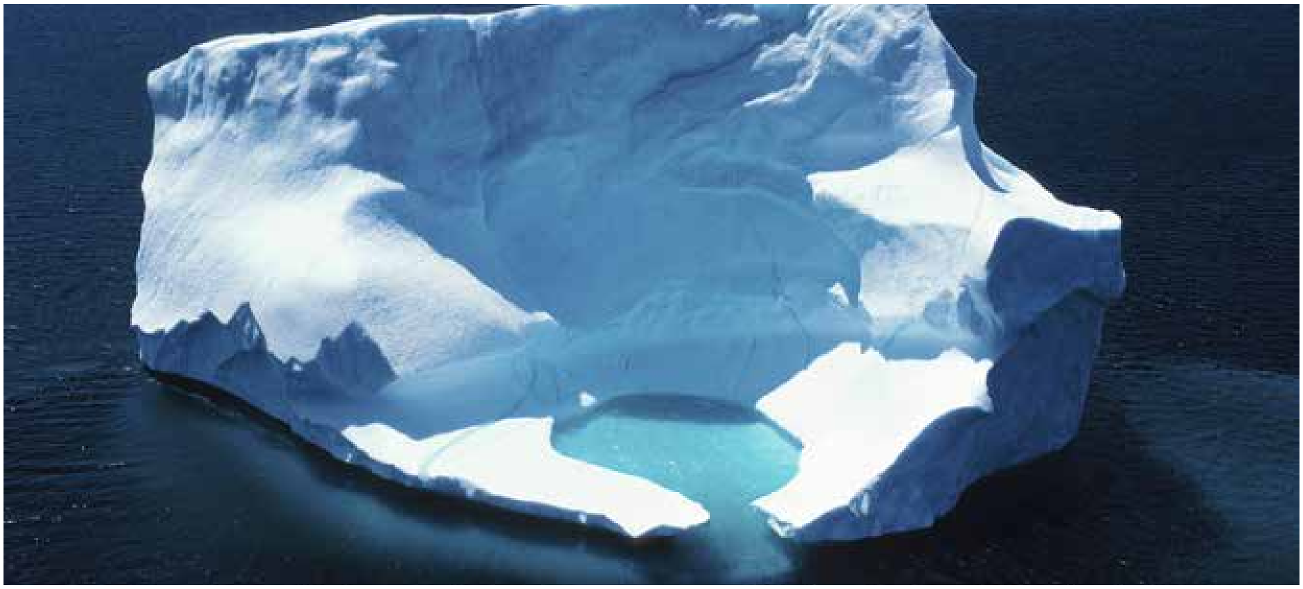


INTRODUCTION

In Canada and abroad, the impacts of climate change are becoming evident. Impacts such as coastal erosion; thawing permafrost; increases in heat waves, droughts and flooding; and risks to critical infrastructure and food security are already being felt in Canada. The science is clear that human activities are driving unprecedented changes in the Earth's climate, which pose significant risks to human health, security, and economic growth.

Taking strong action to address climate change is critical and urgent. The cost of inaction is greater than the cost of action: climate change could cost Canada $21-$43 billion per year by 2050, according to 2011 estimates from the National Round Table on the Environment and the Economy. Businesses and markets are increasingly considering climate risks. In recent years, severe weather events have cost Canadians billions of dollars, including in insured losses. Indigenous Peoples, northern and coastal regions and communities in Canada are particularly vulnerable and disproportionately affected. Geographic location, socio-economic challenges, and for Indigenous Peoples, the reliance on wild food sources, often converge with climate change to put pressure on these communities. Much has been done to begin addressing these challenges, including by Indigenous Peoples.

Acting on climate change will reduce risks and create new economic opportunities and good jobs for Canadians. There is already a global market for low-carbon goods and services worth over $5.8 trillion, which is projected to keep growing at a rate of 3 percent per year. Clean growth opportunities will benefit all sectors and regions. Canada will remain globally competitive through innovation, including through the development and promotion of innovative technologies with the potential to address climate change globally. This includes clean technology to enable the sustainable development of Canada's energy and resource sectors, including getting these resources to market, as Canada transitions to a low-carbon economy. Innovation can help further reduce emissions and the cost of taking action at home. Canadian technologies and solutions can also be exported abroad and deployed around the world, creating new markets and partners for Canadian businesses and supporting global action to reduce emissions.

The federal government will continue to work in close collaboration with other countries on climate solutions, including with partners across North America. A number of provinces and territories have already joined or are exploring entry into regional and international efforts to reduce GHG emissions.

Canadian municipalities will also continue to be important partners in developing and implementing climate solutions locally, as well as through international collaboration with other municipalities around the world.

The international community has agreed that tackling climate change is an urgent priority and also an historic opportunity to shift towards a global low-carbon economy. The adoption of the Paris Agreement in December 2015 was the culmination of years of negotiations under the United Nations Framework Convention on Climate Change. The Paris Agreement is a commitment to accelerate and intensify the actions and investments needed for a sustainable low-carbon future, to limit global average temperature rise to well below 2 °C above pre-industrial levels, and to pursue efforts to limit the increase to 1.5 °C. This will require taking action on long-lived GHGs such as carbon dioxide and short-lived climate pollutants such as methane, hydrofluorocarbons and black carbon.

As a first step towards implementing the commitments Canada made under the Paris Agreement, First Ministers released the Vancouver Declaration on Clean Growth and Climate Change on March 3, 2016.

1.1 How we developed the Framework

The development of the Pan-Canadian Framework was informed by input from Canadians across the country, who made it clear that they want to be part of the solution to climate change. Under the Vancouver Declaration, First Ministers asked four federal-provincial-territorial working groups to work with Indigenous Peoples; to consult with the public, businesses and civil society; and to present options to act on climate change and enable clean growth. The working groups heard solutions directly from Canadians, through an interactive website, in-person engagement sessions, and independent town halls.

Representatives of Indigenous Peoples contributed their knowledge and expectations for meaningful engagement in climate action and provided important considerations and recommendations either directly to working groups or to ministers, which helped shape this framework.

Ministers also reached out to Canadians, businesses, non-governmental organizations, and Indigenous Peoples to hear their priorities. In addition, ministerial tables were convened to provide their advice, including the Canadian Council of Ministers of the Environment, Ministers of Innovation, Ministers of Energy, and Ministers of Finance.

ENGAGING CANADIANS:
The Let's Talk Climate Action website was launched on April 22, 2016 to gather ideas and comments from Canadians about how Canada should address climate change. By the submission deadline of September 27, 2016, over 13,000 ideas and comments were received. In addition, consultations by governments and working groups on clean growth and climate change were held across Canada.

1.2 Pillars of the Framework

The Pan-Canadian Framework has four main pillars: pricing carbon pollution; complementary measures to further reduce emissions across the economy; measures to adapt to the impacts of climate change and build resilience; and actions to accelerate innovation, support clean technology, and create jobs. Together, these interrelated pillars form a comprehensive plan.

Pricing carbon pollution is an efficient way to reduce emissions, drive innovation, and encourage people and businesses to pollute less. However, relying on a carbon price alone to achieve Canada's international target would require a very high price.

Complementary climate actions can reduce emissions by addressing market barriers where pricing alone is insufficient or not timely enough to reduce emissions in the pre-2030 timeframe. For instance, tightening energy efficiency standards and codes for vehicles and buildings are common sense actions that reduce emissions, while also helping consumers save money by using less energy.

Canada is experiencing the impacts of climate change, so there is also a need to **adapt and build resilience**. This means making sure that our infrastructure and communities are adequately prepared for climate risks like floods, wildfires, droughts, and extreme weather events, including in particularly vulnerable regions like Indigenous, northern, coastal, and remote communities. This also means adapting to the impacts of changes in temperature, including thawing permafrost.

A low-carbon economy can and will be a strong and thriving economy. Taking action now, to position Canada as a global leader on clean technology innovation, will help ensure that Canada remains internationally competitive and will lead to the creation of new good jobs across the country. Investing in **clean technology, innovation, and jobs** will bring new and in-demand Canadian technologies to expanding global markets. These investments will help improve the efficiency and cost-effectiveness of mitigation and adaptation measures and will equip Canada's workforce with the knowledge and skills to succeed.

In implementing the Pan-Canadian Framework on Clean Growth and Climate Change, federal, provincial and territorial governments will review progress annually to assess the effectiveness of our collective actions and ensure continual improvement. First Ministers commit to **report regularly and transparently** to Canadians on progress towards GHG-reduction targets, on building climate resilience, and on growing a clean economy.

Our governments will continue to recognize, respect and safeguard the **rights of Indigenous Peoples** as we take actions under these pillars.

1.3 Elements of collaboration

The Pan-Canadian Framework reaffirms the principles outlined in the Vancouver Declaration, including

- recognizing the diversity of provincial and territorial economies and the need for fair and flexible approaches to ensure international competitiveness and a business environment that enables firms to capitalize on opportunities related to the transition to a low-carbon economy in each jurisdiction;
- recognizing that growing our economy and achieving our GHG-emissions targets will require an integrated, economy-wide approach that includes all sectors, creates jobs, and promotes innovation;
- recognizing that a collaborative approach between provincial, territorial, and federal governments is important to reduce GHG emissions and enable sustainable economic growth;
- recognizing that provinces and territories have been early leaders in the fight against climate change and have taken proactive steps, such as adopting carbon pricing mechanisms, placing caps on emissions, involvement in international partnerships with other states and regions, closing coal plants, carbon capture and storage projects, renewable energy production (including hydroelectric developments) and targets, and investments in energy efficiency;
- recognizing that the federal government has committed to ensuring that the provinces and territories have the flexibility to design their own policies to meet emission-reductions targets, including their own carbon pricing mechanisms, supported by federal investments in infrastructure, specific emission-reduction opportunities and clean technologies;
- recognizing the commitment of the federal government to work with provinces and territories to complement and support their actions without duplicating them, including by promoting innovation and enabling clean growth across all sectors;
- strengthening the collaboration between our governments and Indigenous Peoples on mitigation and adaptation actions, based on recognition of rights, respect, cooperation, and partnership;
- recognizing the importance of Traditional Knowledge in regard to understanding climate impacts and adaptation measures;

- recognizing that comprehensive adaptation efforts must complement ambitious mitigation measures to address unavoidable climate change impacts; and

- implementing a collaborative, science-based approach to inform Canada's future targets that will increase in stringency as required by the Paris Agreement.

Governments recognize the unique circumstances of the North, including disproportionate impacts from climate change and the associated challenges with food security, emerging economies and the high costs of living and of energy.

Federal, provincial, and territorial governments will work collaboratively to grow the economy, create good-paying and long-term jobs, and reduce GHG emissions in support of meeting or exceeding Canada's 2030 target. These actions will be supported by strong, complementary adaptation policies to build climate resilience. Indigenous Peoples will be important partners in developing real and meaningful outcomes that position them as drivers of climate action in the implementation of the Pan-Canadian Framework. All governments across Canada are committed to ambitious and sustained action on climate change, building on current actions and future opportunities.

THE FEDERAL GOVERNMENT'S RENEWED RELATIONSHIP WITH INDIGENOUS PEOPLES:

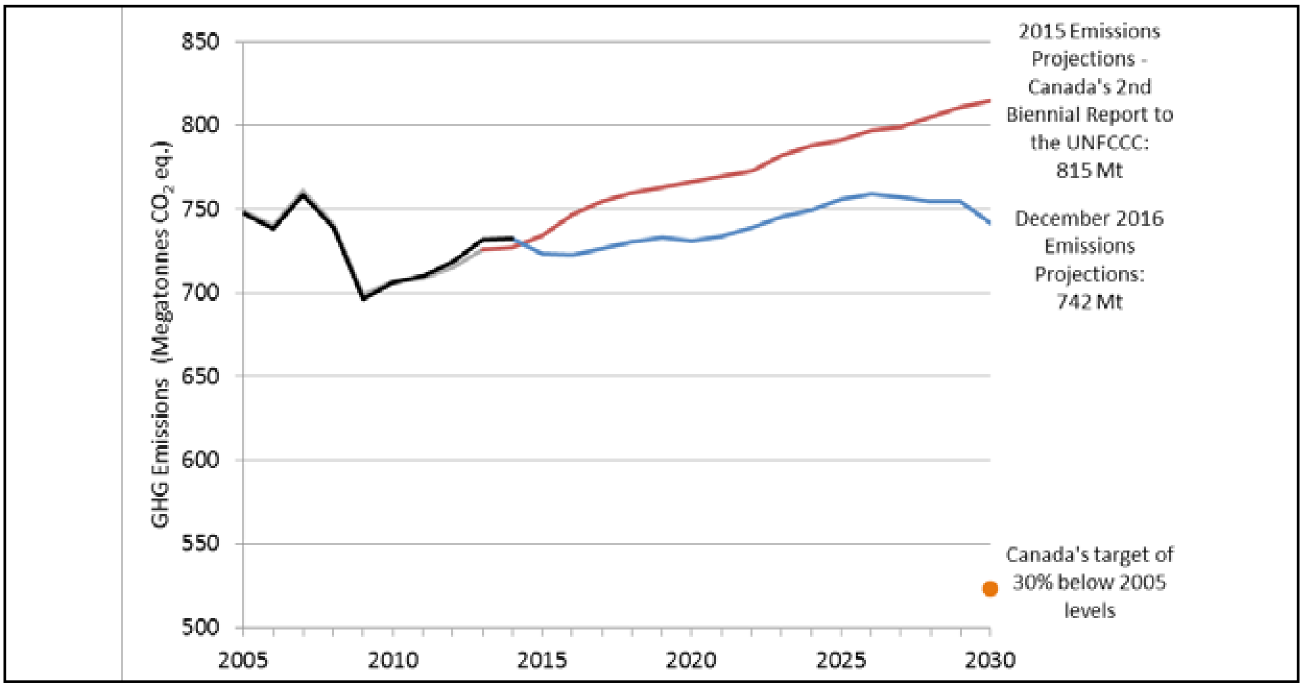
The federal government also reiterates its commitment to renewed nation-to-nation, government-to-government, and Inuit-to-Crown relationships with First Nations, the Métis Nation and Inuit, based on the recognition of rights, respect, cooperation, and partnership, consistent with the Government of Canada's support for the United Nations Declaration on the Rights of Indigenous Peoples, including free, prior and informed consent.

1.4 Emissions trajectory to 2030

The graph below highlights that total Canadian GHG emissions are projected to be 742 megatonnes (Mt) in 2030 under the December 2016 emissions projections (Environment and Climate Change Canada)[1]. Canada's target is 523 Mt.

Projections from the December 2016 emissions projections include revised forecasts for GDP and oil and gas prices and production[2]. Also incorporated are new federal, provincial, and territorial government measures that have legislative or funding certainty as of November 1st, 2016 and were not included in the 2015 emissions projections. These include: federal measures for increasing energy efficiency of equipment in buildings; Ontario's commitment to join the Western Climate Initiative cap-and-trade system; Alberta's coal phase-out, carbon levy, and oil sands emissions cap; Quebec's regulations for new high-rise buildings; and, British Columbia's low carbon fuel standard.

Figure 1: Emissions Projections to 2030



1 Canada's 2016 greenhouse gas emissions projections to 2030 will be released by Environment and Climate Change Canada in December 2016.

2

	Scenarios		
December 2016 Assumptions	**Low**	**Reference**	**High**
Average Annual GDP Growth (2014-2030)	1.0%	1.7%	2.3%
2030 WTI Oil Price (2014 US$/bbl)	42	81	111
2030 Henry Hub Natural Gas Price (2014 US$/GJ)	2.89	3.72	4.62
2030 GHG Emissions (Mt C02eq.)	**697**	**742**	**790**

PRICING CARBON POLLUTION

Overview

Carbon pricing is broadly recognized as one of the most effective, transparent, and efficient policy approaches to reduce GHG emissions. Many Canadian provinces are already leading the way on pricing carbon pollution. British Columbia has a carbon tax, Alberta has a hybrid system that combines a carbon levy with a performance-based system for large industrial emitters, and Quebec and Ontario have cap-and-trade systems. With existing and planned provincial action, broad-based carbon pricing will apply in provinces with nearly 85 per cent of Canada's economy and population by 2017, covering a large part of our emissions.

The federal government outlined a benchmark for pricing carbon pollution by 2018 (see Annex I). The goal of this benchmark is to ensure that carbon pricing applies to a broad set of emission sources throughout Canada and with increasing stringency over time either through a rising price or declining caps. The benchmark outlines that jurisdictions can implement (i) an explicit price-based system (a carbon tax or a carbon levy and performance-based emissions system) or (ii) a cap-and-trade system. Some existing provincial systems already exceeded the benchmark. As affirmed in the Vancouver Declaration, provinces and territories continue to have the flexibility to design their own policies to meet emissions-reduction targets, including carbon pricing, adapted to each province and territory's specific circumstances.

> **"THERE IS A GROWING CONSENSUS AMONG BOTH GOVERNMENTS AND BUSINESSES ON THE FUNDAMENTAL ROLE OF CARBON PRICING IN THE TRANSITION TO A DECARBONIZED ECONOMY."**
>
> World Bank, State and Trends of Carbon Pricing 2015

The following **principles** guide the pan-Canadian approach to pricing carbon pollution, and they are broadly based on those proposed by the Working Group on Carbon Pricing Mechanisms:

- Carbon pricing should be a central component of the Pan-Canadian Framework.

- The approach should be flexible and recognize carbon pricing policies already implemented or in development by provinces and territories.
- Carbon pricing should be applied to a broad set of emission sources across the economy.
- Carbon pricing policies should be introduced in a timely manner to minimize investment into assets that could become stranded and maximize cumulative emission reductions.
- Carbon price increases should occur in a predictable and gradual way to limit economic impacts.
- Reporting on carbon pricing policies should be consistent, regular, transparent, and verifiable.
- Carbon pricing policies should minimize competitiveness impacts and carbon leakage, particularly for emissions-intensive, trade-exposed sectors.
- Carbon pricing policies should include revenue recycling to avoid a disproportionate burden on vulnerable groups and Indigenous Peoples.

NEW ACTIONS

1) Provincial and territorial actions on pricing carbon pollution are described in Annex II.

2) The federal government will work with the territories to find solutions that address their unique circumstances, including high costs of living and of energy, challenges with food security, and emerging economies. The federal government will also engage Indigenous Peoples to find solutions that address their unique circumstances, including high costs of living and of energy, challenges with food security, and emerging economies.

3) The overall approach will be reviewed by 2022 to confirm the path forward.

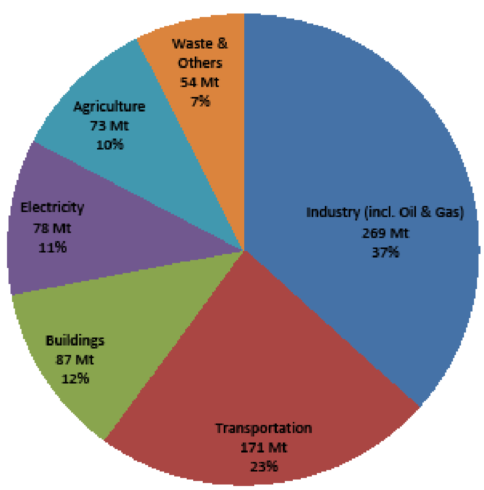
> **"CARBON PRICING IS THE MOST PRACTICAL AND COST-EFFECTIVE WAY TO LOWER GHG EMISSIONS WHILE ENCOURAGING LOW-CARBON INNOVATION."**
>
> Canada's Ecofiscal Commission

COMPLEMENTARY ACTIONS TO REDUCE EMISSIONS

Overview

To reduce emissions, meaningful action will need to be taken across all regions and sectors of the economy. Many of the things that Canadians do every day—like driving cars and heating homes—produce GHG emissions. Many activities that drive economic growth in the country, like extracting natural resources, industrial and manufacturing activities, and transporting goods to customers, also produce emissions. The policies that help drive down emissions can also help the economy to keep growing by cutting costs for Canadians, creating new markets for low-emission goods and services, and helping businesses use cleaner and more efficient technologies that give them a leg up on international competitors.

Emissions by sector in 2014
(megatonnes of CO_2 eq.)



Federal, provincial, and territorial governments will work together to make sure new actions build on and complement existing plans, policies, programs, and regulations and reflect lessons learned from past experience. New policies will be designed to focus on GHG-emission outcomes and will recognize flexibility for regional differences, including through outcomes-based regulatory equivalency agreements. Indigenous Peoples will be involved in defining and developing policies to support clean energy in their communities.

In developing policies, a number of factors will be considered, including:

- economic, environmental, and social impacts and benefits;
- how individual policies will work with carbon pricing;
- the need to consider and mitigate the impacts on emissions-intensive trade exposed sectors (e.g., resource sectors that are price takers on the global market), including the need to avoid carbon leakage;
- co-benefits such as improved health due to air pollutant reductions, and jobs and business growth;
- opportunities to realize near-term climate and health benefits through reducing emissions of short-lived climate pollutants; and,
- benefits for ecosystems and biodiversity.

FALLING COSTS OF RENEWABLE ENERGY:
Between 2010 and 2015, the costs for new utility-scale solar photovoltaic (PV) installations declined by two-thirds, while over the same period the cost of onshore wind fell by an estimated 30 percent on average (IEA, 2016)

Governments will be supporting the actions outlined in the Pan-Canadian Framework through policies and investments. Federal actions are described in Annex I, and provincial and territorial key actions and collaboration opportunities with the Government of Canada are described in Annex II.

3.1 Electricity

Canada already has one of the cleanest electricity systems in the world. About 80 percent of electricity production comes from non-emitting sources, more than any other G7 country. While electricity emissions are going down in large part due to the move away from coal-fired power toward cleaner sources, electricity generation is still Canada's fourth-largest source of GHG emissions.

Clean, non-emitting electricity systems will be the cornerstone of a modern, clean growth economy. Transformations to electricity systems will be supported by federal, provincial, and territorial governments, and, undertaken by utilities, private-sector players, and Indigenous Peoples.

The approach to electricity will include
(1) increasing the amount of electricity generated from renewable and low-emitting sources;
(2) connecting clean power with places that need it;
(3) modernizing electricity systems; and
(4) reducing reliance on diesel working with Indigenous Peoples and northern and remote communities.

Provinces and territories have already taken action on moving from traditional coal-fired generation to clean electricity. Ontario and Manitoba have already phased out their use of coal, Alberta has plans in place to phase out coal-fired electricity by 2030, Nova Scotia has created a regulatory framework to transition from coal to clean electricity generation, and Saskatchewan has a coal-fired generating unit with carbon capture technology, which captures 90 percent of emissions. New capacity will come from non-emitting sources—including hydro, wind, and solar—as well as natural gas. Energy efficiency and conservation will make added contributions to clean electricity systems.

ONTARIO'S COAL PHASE-OUT:
On April 15, 2014, **Ontario** became the first jurisdiction in North America to fully eliminate coal as a source of electricity generation. This action is the single largest GHG-reduction initiative in North America, eliminating more than 30 Mt of annual GHG emissions and equivalent to taking seven million vehicles off the road. On November 23, 2015, Ontario passed the *Ending Coal for Cleaner Air Act*, permanently banning coal-fired electricity generation in the province.

SASKATCHEWAN'S BOUNDARY DAM INTEGRATED CARBON CAPTURE AND STORAGE PROJECT:
is the world's first commercial-scale, coal-fired carbon capture and storage electricity project, and it is able to capture and sequester up to 90 percent of its GHG emissions.

WIND POWER:
Wind capacity in Canada grew 20 times between 2005 and 2015, and there is strong potential for further growth. For example, 4 wind farms in **Prince Edward Island** now generate almost 25 percent of the province's electricity requirements.

ALBERTA'S COAL PHASE-OUT:
Alberta's commitments to end emissions from coal-fired electricity and replace it with 30 percent renewable energy by 2030 are expected to achieve cumulative emission reductions of 67 Mt between now and 2030, and emissions in 2030 will be at least 14 Mt below what is forecast under the status quo. This reduction is the equivalent of taking 2.8 million cars off the road. This move will improve air quality and the health of Albertans and other Canadians. It will also ensure reliability, encourage private investment, and provide price stability for all Albertans.

Connecting clean power across Canada through stronger transmission-line interconnections will help reduce emissions and support the move away from coal. Many provinces already trade electricity across their borders, and there is potential to increase these flows, consistent with market rules and fair competition among electricity producers.

THE CANADIAN ENERGY STRATEGY:
Provinces and territories are already taking a cooperative approach toward sustainable energy development through the Canadian Energy Strategy, which was released by premiers in July 2015. As agreed under the Vancouver Declaration and building on the Quebec Summit on Climate Change in 2015, federal, provincial, and territorial energy ministers are collaborating on specific actions through the Canadian Energy Strategy, to contribute to the Pan-Canadian Framework on Clean Growth and Climate Change. Actions include energy conservation and efficiency, clean energy technology and innovation, and deployment of energy to people and global markets.

Modernizing electricity systems will involve expanding energy storage, updating infrastructure, and deploying smart-grid technologies to improve the reliability and stability of electric grids and to allow more renewable power to be added. As a leader in the development and deployment of innovative energy-storage solutions and smart-grid technology, Canadian clean technology producers stand to benefit from increased investments in our electricity systems.

Many Indigenous Peoples, as well as northern and remote communities in Canada rely on diesel fuel to produce electricity and heat. Opportunities exist for clean electricity infrastructure, distributed energy systems, renewable energy microgrids, as well as grid connections and hybrid systems, which will enhance wellbeing, create local economic opportunities, and contribute to better air quality and a cleaner environment overall. Investing in clean energy solutions will advance the priorities of Indigenous Peoples, as well as northern and remote communities to transition away from diesel.

COLVILLE LAKE SOLAR PROJECT – Colville Lake, Northwest Territories is located north of the Arctic Circle, and it is served with a winter road that is open just a couple of months each year. To reduce diesel use in this remote, off-grid community, a solar/diesel/battery hybrid electricity system has been installed. This system has allowed the diesel generators to be shut down for extended periods in the summer. This innovative energy solution has reduced diesel use and related emissions by 20-25 percent per year.

Taking these actions will have a number of benefits beyond reducing GHG emissions. Phasing out coal and reducing the use of diesel will reduce harmful air pollutants, which have significant implications for human health and associated health-care costs. Designing and building clean-power technologies and transmission lines represents major economic opportunities for Canada. Increasing the amount of clean and renewable electricity sold to the United States could also bring new revenue to utilities and provinces, respecting open-access rules under the authority of the U.S. Federal Energy Regulatory Commission.

THE CANADA INFRASTRUCTURE BANK:
The federal government is creating the Canada Infrastructure Bank, which will work with provinces, territories, and municipalities to further the reach of government funding directed to infrastructure, including clean electricity systems.

COMMUNITY-BASED ENERGY GENERATION:
In May 2015, **New Brunswick** introduced legislation to allow local entities to develop renewable-energy sourced electricity generation in their communities. This legislation will allow universities, non-profit organizations, cooperatives, First Nations, and municipalities to contribute to NB Power's renewable energy requirements.

NEW ACTIONS

1. Increasing renewable and non-emitting energy sources

Federal, provincial, and territorial governments will work together to accelerate the phase out of traditional coal units across Canada, by 2030, as recently announced by the federal government (see Annex I) and to build on provincial and territorial leadership.

The federal government has announced it will set performance standards for natural gas-fired electricity generation, in consultation with provinces, territories, and stakeholders (see Annex I).

Federal, provincial, and territorial governments will work together to facilitate, invest in, and increase the use of clean electricity across Canada, including through additional investments in research, development, and demonstration activities.

2. Connecting clean power with places that need it

Federal, provincial, and territorial governments will work together to help build new and enhanced transmission lines between and within provinces and territories.

3. Modernizing electricity systems

Federal, provincial, and territorial governments will work together to support the demonstration and deployment of smart-grid technologies that help electric systems make better use of renewable energy, facilitate the integration of energy storage for renewables, and help expand renewable power capacity.

4. Reducing reliance on diesel working with Indigenous Peoples and northern and remote communities

Governments are committed to accelerating and intensifying efforts to improve the energy efficiency of diesel generating units, demonstrate and install hybrid or renewable energy systems, and connect communities to electricity grids. This will be done in partnership with Indigenous Peoples and businesses. These actions will have significant benefits for communities, such as improving air quality and energy security, and creating the potential for locally owned and sourced power generation.

RAMEA WIND-HYDROGEN-DIESEL ENERGY PROJECT:
The off-grid community of Ramea in **Newfoundland and Labrador** hosts one of the first projects in the world to integrate generation from wind, hydrogen, and diesel in an isolated electricity system. Since 2010, the Ramea Wind-Hydrogen-Diesel Energy Project has successfully produced approximately 680 000 kilowatt hours of renewable energy.

3.2 Built environment

In Canada, using energy to heat and cool buildings accounted for about 12 percent of national GHG emissions in 2014 or 17 percent if emissions from generating the electricity used in buildings is also included. The emissions in this sector—created by burning fossil fuels and leaks in air conditioning systems—are projected to grow modestly by 2030 unless further action is taken.

In a low-carbon, clean growth economy, buildings and communities will be highly energy efficient, rely on clean electricity and renewable energy, and be smart and sustainable. Making the built environment more energy efficient reduces GHGs, helps make homes and buildings more comfortable and more affordable by lowering energy bills, and can promote innovation and clean job opportunities. Most building owners and architects estimate that retrofitting commercial and institutional buildings pays off in less than ten years, according to data from the Canada Green Building Council. Residential energy efficiency improvements helped Canadians save $12 billion in energy costs in 2013, an average savings of $869 per household.

The approach to the built environment will include (1) making new buildings more energy efficient; (2) retrofitting existing buildings, as well as fuel switching; (3) improving energy efficiency for appliances and equipment; and (4) supporting building codes and energy efficient housing in Indigenous communities.

Advances in clean technologies and building practices can make new buildings "net-zero energy", meaning they require so little energy they could potentially rely on their own renewable energy supplies for all of their energy needs. Through research and development, technology costs continue to fall, and government and industry efforts and investments will accelerate that trend. These advances, supported by a model "net-zero energy ready" building code, will enable all builders to adopt these practices and lower lifecycle costs for homeowners.

EFFICIENCY NOVA SCOTIA:
Canada's first energy efficiency utility—works with more than 100 local partners, and it has helped 225 000 program participants complete energy efficiency projects, saving Nova Scotians $110 million in 2016 alone. For example, the HomeWarming service is funded by the province of Nova Scotia as part of a long-term plan to upgrade all low-income homes in Nova Scotia, over the next 10 years.

At the same time, action is needed on existing buildings, since more than 75 percent of the building stock in 2030 will be composed of buildings already standing today. This can be supported by innovative policies like labelling a building's energy performance, establishing retrofit codes, and offering low-cost financing for retrofits.

Housing for Indigenous communities is particularly pressing. New housing will be built to high-efficiency standards and existing housing will be retrofitted. Indigenous Peoples have also identified the need to incorporate Traditional Knowledge and culture into building designs. Governments will partner with Indigenous Peoples in the design of relevant policies and programs.

Energy efficiency standards for equipment and appliances save consumers and businesses money on energy bills. An early market signal by the government, in the form of an intention to introduce standards by a specific year, can motivate the market to accelerate the uptake of the targeted technologies. Regulations can be supported by actions to educate consumers, to demonstrate benefits, and to overcome market barriers.

Construction in Canada is a $171 billion industry, and it employs well over a million people. New building codes will spur innovation and support Canadian businesses in developing more efficient building techniques and technologies. Investments in retrofits to improve energy efficiency have been shown to be strong job creators, providing direct local benefits, creating local jobs, and reducing energy bills.

NET-ZERO ENERGY BUILDINGS:
Construction costs for net-zero energy buildings have dropped 40 percent in the past decade, and they are continuing to fall. The benefits of net-zero energy buildings are significant. Estimated operating costs for a net-zero energy ready house is 30 percent to 55 percent less than for a typical house, depending on region, fuel type and occupant behaviour. For example, on a -32 °C day, the Riverdale NetZero Project (a semi-detached duplex in Edmonton, Alberta) only needs 6500 W of power for heat—the same amount of heat produced by four toasters.

NEW ACTIONS

1. Making new buildings more energy efficient

Federal, provincial, and territorial governments will work to develop and adopt increasingly stringent model building codes, starting in 2020, with the goal that provinces and territories adopt a "net-zero energy ready" model building code by 2030. These building codes will take regional differences into account. Continued federal investment in research, development, and demonstration, and cooperation with industry will help to reduce technology costs over time.

2. Retrofitting existing buildings

Federal, provincial, and territorial governments will work to develop a model code for existing buildings by 2022, with the goal that provinces and territories adopt the code. This code will help guide energy efficiency improvements that can be made when renovating buildings.

Federal, provincial, and territorial governments will work together with the aim of requiring labelling of building energy use by as early as 2019. Labelling will provide consumers and businesses with transparent information on energy performance.

Provincial and territorial governments will work to sustain and, where possible, expand efforts to retrofit existing buildings by supporting energy efficiency improvements as well as fuel switching, where appropriate, and by accelerating the adoption of high-efficiency equipment while tailoring their programs to regional circumstances. The federal government could support efforts of provinces and territories through the Low Carbon Economy Fund and infrastructure initiatives.

3. Improving energy efficiency for appliances and equipment

The federal government will set new standards for heating equipment and other key technologies to the highest level of efficiency that is economically and technically achievable.

4. Supporting building codes and energy efficient housing in Indigenous communities

Governments will collaborate with Indigenous Peoples as they move towards more efficient building standards and incorporate energy efficiency into their building-renovation programs.

SOCIAL HOUSING RETROFITS:
To help fight climate change, Ontario invested $92 million in 2016 to retrofit social housing buildings to reduce GHG emissions by installing energy efficient boilers, insulating outer walls and mechanical systems, and installing more energy efficient windows and lighting. Ontario's Climate Change Action Plan builds on this initial investment by committing up to $500 million more for social housing retrofits over the next five years.

Aki Energy in **Manitoba** is a non-profit Aboriginal social enterprise that works with First Nations to start green businesses in their communities and to create local jobs and strong local economies. Aki Energy is committed to helping First Nations lower the utility bills to heat buildings, and it has installed over $3 million in cost-effective renewable energy technologies in partnership with Manitoba First Nations.

3.3 Transportation

The transportation sector accounted for about 23 percent of Canada's emissions in 2014, mostly from passenger vehicles and freight trucks. Transportation emissions are projected to decline slightly by 2030 if no further action is taken. Governments are already working to make all modes of transportation more efficient and convenient, but more action is needed.

Low-carbon transportation systems will use cleaner fuels, will have more zero-emission vehicles on the road, will provide convenient and affordable public transit, and will transport people and goods more efficiently.

The approach to transportation will include (1) setting and updating vehicle emissions standards and improving the efficiency of vehicles and transportation systems; (2) expanding the number of zero-emission vehicles on Canadian roads; (3) supporting the shift from higher to lower-emitting types of transportation, including through investing in infrastructure; and (4) using cleaner fuels.

Emissions standards for cars and trucks ensure new engines are more fuel efficient. Retrofitting freight trucks to reduce wind resistance can also cut emissions. And streamlining how goods are transported can improve the overall efficiency of transportation systems.

Zero-emission vehicle technologies include plug-in hybrids, electric vehicles, and hydrogen fuel-cell vehicles. Many of these are becoming increasingly affordable and viable, and governments can help accelerate these trends, including by investing in charging and fueling infrastructure.

ELECTRIFICATION OF TRANSPORTATION:

Québec has committed to take significant action on the electrification of transportation by 2020, including by increasing the number of electric and plug-in hybrid vehicles registered in Québec to 100 000; adding 5000 electric-vehicle jobs and generating $500 million in investments; reducing the amount of fuel used each year in Québec by 66 million liters; and cutting annual GHG emissions from the transportation sector by 150 000 tonnes.

Shifting from higher- to lower-emitting modes of transportation includes things like riding public transit or cycling instead of driving a car, and transporting goods by rail instead of trucks. Improving public transit infrastructure and optimizing freight corridors can help drive these shifts.

Using cleaner fuels such as advanced biofuels can reduce the lifecycle carbon intensities of all fuels across transportation systems, as well as in other sectors like industry and buildings.

Taking these actions will have additional environmental and economic benefits beyond reducing GHG emissions. Efficiency improvements can help Canadians and businesses save money by spending less on fuel and reducing the costs of transporting goods. New, cleaner fuels can create opportunities for resource sectors. Businesses that develop new fuel and vehicle technologies will create jobs, help the economy grow, and give those businesses a competitive edge.

NEW ACTIONS

1. Setting emissions standards and improving efficiency

The federal government will continue its work to implement increasingly stringent standards for emissions from light-duty vehicles, including fuel-efficient tire standards, and to update emissions standards for heavy-duty vehicles.

The federal government will work with provinces, territories, and industry to develop new requirements for heavy-duty trucks to install fuel-saving devices like aerodynamic add-ons.

The federal government will take a number of actions to improve efficiency and support fuel switching in the rail, aviation, marine, and off-road sectors.

2. Putting more zero-emission vehicles on the road

Federal, provincial, and territorial governments will work with industry and other stakeholders to develop a Canada-wide strategy for zero-emission vehicles by 2018.

Federal, provincial, and territorial governments will work together, including with private-sector partners, to accelerate demonstration and deployment of infrastructure to support zero-emission vehicles, such as electric-charging stations.

3. Shifting from higher- to lower-emitting modes and investing in infrastructure

Federal, provincial, and territorial governments will work together to enhance investments in public-transit upgrades and expansions.

Federal, provincial, and territorial governments will invest in building more efficient trade and transportation corridors including investments in transportation hubs and ports.

Federal, provincial, and territorial governments will consider opportunities with the private sector to support refueling stations for alternative fuels for light- and heavy-duty vehicles, including natural gas, electricity, and hydrogen.

4. Using cleaner fuels

The federal government, working with provincial and territorial governments, industry, and other stakeholders, will develop a clean fuel standard to reduce emissions from fuels used in transportation, buildings and industry.

This will take into account the unique circumstances of Indigenous Peoples and northern and remote communities.

3.4 Industry

Canada's industries are the backbone of the economy, but they are also a major source of GHG emissions. In 2014, industrial sectors accounted for about 37 percent of Canada's emissions, the majority of which came from the oil and gas sector. Industrial emissions are projected to grow between now and 2030 as demand grows for Canadian-produced goods, at home and abroad.

A low-carbon industrial sector will rely heavily on clean electricity and lower-carbon fuels, will make more efficient use of energy, and will seize opportunities unlocked by innovative technologies. The province of Alberta has legislated an absolute cap of 100 Mt a year on emissions from the oil sands sector. There are a number of near-term opportunities to reduce industrial emissions while maintaining the competitive position of Canadian firms.

The approach to the industrial sector will include three main areas of action: (1) regulations to reduce methane and hydrofluorocarbon (HFC) emissions; (2) improving industrial energy efficiency; and (3) investing in new technologies to reduce emissions. Together, these actions will help set the path for long-term clean growth and the transition to a low-carbon economy.

Methane and HFCs are potent GHGs, dozens to thousands of times more powerful than carbon dioxide. The oil and gas sector is the largest contributor to methane emissions in Canada. Building on provincial actions and targets, the federal government has committed to reduce methane emissions by 40-45 percent by 2025. Canada joined almost 200 other countries in signing the Kigali Amendment to the Montreal Protocol, which will push the global phase out of HFC emissions. Taking action on HFCs can prevent up to 0.5 °C of global warming due to the potency of these gases, while continuing to protect the ozone layer.

There is significant potential to improve energy efficiency in Canada's industrial sectors. Energy management systems such as ISO 50001, the Superior Energy Performance program (SEP), and the ENERGY STAR for Industry program are useful tools that help businesses track, analyze, and improve their energy efficiency.

Using today's low-emission technologies and switching to clean electricity and lower-carbon fuels are near-term actions industry can take to reduce emissions. Over the longer-term, more dramatic emission reductions will be possible by using new technologies to transform how some industries operate. Investing in promising new technologies is an important area for action. Innovation will help Canadian businesses access global markets and attract foreign investment.

LOWER-CARBON INDUSTRIAL ACTIVITY IN CANADA:
Quebec's aluminum smelters have reduced their emissions by 30 percent since 1990. The modernized world-class aluminum smelter in Kitimat, BC will boost production and reduce emissions by nearly 50 percent. As a result of these investments, Canada's aluminum industry is now the most carbon-efficient producer of aluminum in the world.

OIL SANDS INNOVATION:
COSIA (Canada's Oil Sands Innovation Alliance) is an alliance of 13 oil sands producers, representing 90 percent of production from the Canadian oil sands, who are working together to develop technologies that help reduce the environmental impact of the oil sands, including reducing GHG emissions. Member companies have shared 936 distinct environmental technologies, costing $1.33 billion, since coming together in 2012.

Taking these actions will benefit businesses. Strengthening energy performance is one of the most cost-effective ways for industry to reduce energy use, it generally has quick payback periods, and it will continually generate financial savings. Measures that help cut costs or develop new technologies can improve competitiveness and create jobs and export opportunities for the clean technology sector.

NEW ACTIONS

1. Reducing methane and HFC emissions

The federal government will work with provinces and territories to achieve the objective of reducing methane emissions from the oil and gas sector, including offshore activities, by 40-45 percent by 2025, including through equivalency agreements.

The federal government has introduced proposed regulations to phase down use of HFCs to support Canada's commitment to the Montreal Protocol amendment.

2. Improving industrial energy efficiency

Federal, provincial, and territorial governments will work together to help industries save energy and money, including by supporting them in adopting energy management systems.

3. Investing in technology

Federal, provincial, and territorial governments working with industry will continue to invest in research and development and to promote deployment of new technologies that help reduce emissions.

Federal, provincial, and territorial governments will also work with industry to identify demonstration projects for promising pre-commercial clean energy technologies required to reduce emissions from energy production and use in the Canadian economy, including in the oil and gas sector.

3.5 Forestry, agriculture, and waste

Emissions from agriculture (livestock and crop production) and extraction of forestry resources accounted for about 10 percent of Canada's emissions in 2014, and they are not projected to significantly change by 2030. Municipal waste accounts for a small portion (about 3 percent) of Canada's total GHGs, and these emissions are projected to decline, largely due to increases in landfill gas capture.

Agricultural soils and forests also absorb and store carbon. The emissions or removals from carbon sinks can fluctuate with natural disturbances (e.g. forest fires), but there are still a number of actions that can increase carbon storage and reduce emissions.

Forests, wetlands, and agricultural lands across Canada will play an important natural role in a low-carbon economy by absorbing and storing atmospheric carbon. Actions taken by jurisdictions and woodlot owners to accelerate reforestation, to continuously improve sustainable management practices, and to plant new forests where they do not currently exist will enhance stored carbon. Clean technology, such as lower-carbon bioenergy, and bioproducts that use feedstock from agriculture and forestry waste and dedicated crops to replace higher-carbon fuels can also reduce emissions. Continued innovation and clean technology in agriculture will build on past GHG reduction successes of decreasing emissions per unit of production. The municipal waste sector will also be a key source of cleaner fuels such as renewable natural gas from landfills.

The approach to these sectors will include (1) enhancing carbon storage in forests and agricultural lands; (2) supporting the increased use of wood for construction; (3) generating fuel from bioenergy and bioproducts; and, (4) advancing innovation.

Forests, wetlands, and agricultural lands can be enhanced as “carbon sinks” through actions such as planting more trees, improving forest carbon management practices, minimizing losses from fires and invasive species, restoring forests that have been affected by natural disturbances, and increasing adoption of land management practices like increasing perennial and permanent cover crops and zero-till farming. Protecting and restoring natural areas, including wetlands, can also benefit biodiversity and maintain or enhance carbon storage.

Increasing the use of wood for construction can reduce emissions as the carbon stored in that wood gets locked in for a long period of time. Increasing domestic demand for Canadian wood products will also support the vibrant forest industries across Canada, which have a long history of innovating to develop new products and more efficient and sustainable forest practices.

The **Cheakamus Community Forest** carbon offset project is located adjacent to the Resort Municipality of Whistler, within the traditional territories of the Squamish and Lil'wat Nations. The project retains more carbon in the forest by using ecosystem-based management practices that include increasing protected areas and using lower-impact harvesting techniques.

The forestry, agriculture, and waste sectors also provide biomass for bioproducts that can be used in place of fossil fuels in other sectors. For example, waste products from forestry, agriculture, and landfills can be converted into energy sources such as renewable natural gas. Dedicated crops can be grown as feedstocks for products like bioplastics. Expanding renewable fuel industries represents an opportunity to create new jobs and economic growth across Canada.

BIOMASS-FIRED DISTRICT HEATING:

Prince Edward Island is home to Canada's longest running, biomass-fired district heating system. Operating since the 1980's, the system has expanded to serve over 125 buildings in the downtown core of Charlottetown, including the University of Prince Edward Island and the Queen Elizabeth Hospital, and cleanly burns 66 000 tons of waste materials annually.

Innovative solutions, including clean technologies, are required to reduce emissions from agriculture. Promising new technologies are being developed to reduce emissions from livestock and crop production, including from the use of precision farming and "smart" fertilizers, which time the release to match plant needs, and from feed innovations that reduce methane production in cattle. Actions pertaining to the agriculture sector will be developed collaboratively through Canada's Next Agriculture Policy Framework.

These actions in the forestry, agriculture, and waste sectors, and supporting clean technology businesses, can help to create jobs and build more sustainable communities.

NEW ACTIONS

1. Increasing stored carbon

Federal, provincial, and territorial governments will work together to protect and enhance carbon sinks, including in forests, wetlands, and agricultural lands (e.g. through land-use and conservation measures).

2. Increasing the use of wood for construction

Federal, provincial, and territorial governments will collaborate to encourage the increased use of wood products in construction, including through updated building codes.

3. Generating bioenergy and bioproducts

Federal, provincial, and territorial governments will work together to identify opportunities to produce renewable fuels and bioproducts, for example, generating renewable fuel from waste.

4. Advancing innovation

Federal, provincial, and territorial governments will work together to enhance innovation to advance GHG efficient management practices in forestry and agriculture.

3.6 Government leadership

Governments are directly responsible for a relatively small share of Canada's emissions (about 0.6 percent), but they have an opportunity to lead by example. A number of provinces are already demonstrating leadership, including through carbon neutral policies.

CARBON NEUTRAL GOVERNMENT:
British Columbia's public sector has successfully achieved carbon neutrality each year since 2010. Over the past 6 years, schools, post-secondary institutions, government offices, Crown corporations, and hospitals have reduced a total of 4.3 million tonnes of emissions through improvements to their operations and investments of $51.4 million in offset projects. British Columbia was the first—and continues to be the only—carbon neutral jurisdiction on the continent.

In a low-carbon, clean growth economy, federal, provincial, and territorial governments will be leaders in sustainable, low-emission practices that support the goals of clean growth and address climate change.

Municipalities are also essential partners. How cities develop and operate has an important impact on energy use and therefore GHG emissions.

LEADERSHIP BY CITIES:
The City of Whitehorse's Sustainability Plan outlines 12 community-wide goals in areas such as transportation, buildings, waste, GHG reductions, and resilient, accessible food systems, with associated targets for 2020, 2030, and 2050. For example, Whitehorse has set a target that new buildings will be 30 percent more efficient than the National Energy Code of Canada for Buildings, the National Building Codes, or achievable comparable EnerGuide ratings, while city-owned buildings will be 50 percent more efficient than the National Energy Code.

The public sector can play an important role by setting ambitious emissions reduction targets and by demonstrating the effectiveness of policies to reduce emissions (e.g. from vehicle fleets and buildings).

The approach to government leadership will include (1) setting ambitious targets; (2) cutting emissions from government buildings and fleets; and (3) scaling up clean procurement.

Governments control a significant share of assets like fleets and buildings. By setting targets and implementing policies to make buildings more efficient and to reduce emissions from vehicle fleets, the public sector can help to demonstrate the business case for ambitious action. Governments are also major purchasers and providers of goods and services, and they can help to build demand for low-carbon goods and services through procurement policies. They can also provide a testing ground for new and emerging technologies, creating new opportunities for Canadian firms developing clean technology products, services, and processes.

NEW ACTIONS

1. Setting ambitious targets

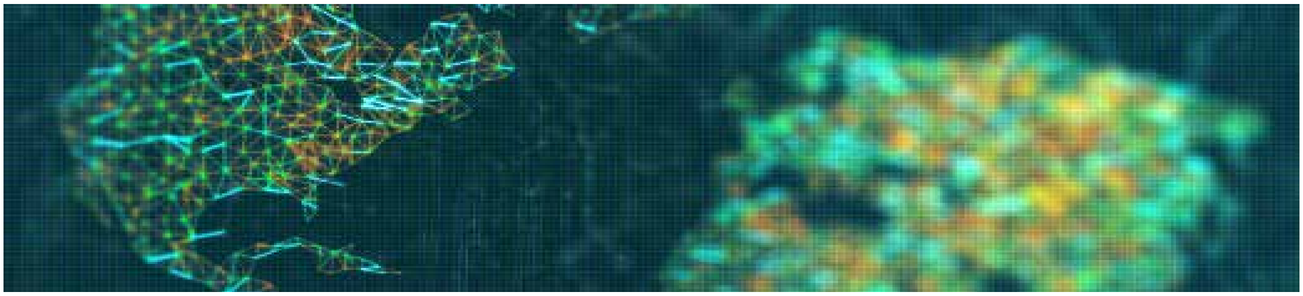
Federal, provincial, and territorial governments will demonstrate leadership through commitments to ambitious targets to reduce emissions from government operations. The federal government is committed to reduce its own GHG emissions to 40 percent below 2005 levels, by 2030 or sooner.

2. Cutting emissions from government buildings and fleets

Federal, provincial, and territorial government will scale up efforts to transition to highly efficient buildings and zero-emission vehicle fleets. The federal government has set a goal of using 100 percent clean power by 2025.

3. Scaling up clean procurement

Federal, provincial, and territorial governments will work together to modernize procurement practices, adopt clean energy and technologies, and prioritize opportunities to help Canadian businesses grow, demonstrate new technologies, and create jobs.



3.7 International leadership

Governments will work with their international partners, including developing countries, to help reduce emissions around the world. The federal government is investing $2.65 billion in climate finance to help developing countries transition to low-carbon economies and build climate resilience.

The priority is to first focus on reduction in emissions within Canada, but part of Canada's approach to climate change could also involve acquiring allowances for emissions reductions in other parts of the world, as a complement to domestic emissions reduction efforts. As recognized under the Paris Agreement (article 6), countries may choose to use emissions reductions that take place outside of their own borders, known as "internationally transferred mitigation outcomes", to meet their targets. Emissions reductions that take place outside of Canada may have lower costs and contribute to investment in sustainable development abroad. Quebec and California already participate in international emissions trading under their linked cap-and-trade system, which Ontario will soon join.

The approach to international leadership will include (1) delivering on Canada's international climate finance commitments; (2) acquiring internationally transferred mitigation outcomes; and (3) engaging in trade and climate policy.

Federal, provincial, and territorial governments will also explore mechanisms and opportunities for provinces and territories to collaborate in international fora, joint missions, and discussions on climate change and energy.

The federal government will continue to engage with and support Indigenous Peoples' action on international climate change issues, including through the United Nations Framework Convention on Climate Change, to formulate a platform for Indigenous Peoples, as agreed to in the Paris decision.

NEW ACTIONS

1. Delivering on Canada's international climate-finance commitments

The federal government will deliver on its historic commitment of $2.65 billion by 2020 to help the poorest and most vulnerable countries mitigate and adapt to the adverse effects of climate change.

2. Acquiring internationally transferred mitigation outcomes

The federal government, in cooperation with provincial and territorial governments and relevant partners, will continue to explore which types of tools related to the acquisition of internationally transferred mitigation outcomes may be beneficial to Canada and will advance a robust approach to the implementation of article 6 of the Paris Agreement. A first priority is ensuring any cross-border transfer of mitigation outcomes is based on rigorous accounting rules, informed by experts, which result in real reductions.

The federal government will work with Ontario, Quebec, and other interested provinces and territories, as well as with international partners, to ensure that allowances acquired through international-emissions trading are counted towards Canada's international target.

3. Engaging in trade and climate policy

The federal government, in cooperation with provincial and territorial governments, will work with its international partners to ensure that trade rules support climate policy.

ADAPTATION AND CLIMATE RESILIENCE

Overview

The impacts of climate change are already being felt across Canada. These changes are being magnified in Canada's Arctic, where average temperature has increased at a rate of nearly three times the global average. They pose significant risks to communities, health and well-being, the economy, and the natural environment, especially in Canada's northern and coastal regions and for Indigenous Peoples. Indigenous Peoples are among the most vulnerable to climate change due to their remote locations and reliance on wild foods. The changes already being experienced are both dramatic and permanent, with significant social, cultural, ecological, and economic implications.

Taking action to adapt to current and future climate impacts will help protect Canadians from climate change risks, build resilience, reduce costs, and ensure that society thrives in a changing climate.

INUIT AND CLIMATE IMPACTS:
Inuit and Inuit Nunangat, the homeland of Inuit in Canada, are experiencing significant climate change impacts, as highlighted in Inuit Tapiriit Kanatami's recent report on Inuit Priorities for Canada's Climate Strategy. More than 70 per cent of Canada's coastline is located in the Arctic and it is defined by ice. Average sea ice thickness is decreasing and sea ice cover is now dominated by younger, thinner ice. Some models are projecting that summer sea ice cover could be almost completely lost before 2050. These changes are already impacting access to wild foods and contributing to hazards and risks on ice.

Developing adaptation expertise and technology can further contribute to clean growth by creating jobs and spurring innovation. Adaptation is a long-term challenge, and it requires ongoing commitment to action, leadership across all governments, strong governance to assess and sustain progress, adequate funding, and meaningful engagement with, and continued leadership by, Indigenous Peoples. Federal investments (see Annex I) will support key adaptation measures.

Federal, provincial, and territorial governments have identified new actions to build resilience to climate change across Canada in the following areas:

1. Translating scientific information and Traditional Knowledge into action
2. Building climate resilience through infrastructure
3. Protecting and improving human health and well-being
4. Supporting particularly vulnerable regions
5. Reducing climate-related hazards and disaster risks

4.1 Translating scientific information and Traditional Knowledge into action

Canadians need authoritative science and information to understand current and expected changes. This includes changing conditions (e.g., rainfall, temperature, and sea ice) and the impacts of climate change across Canada. Long-term monitoring and local observations are also key. Data, tools, and information need to be widely accessible, equitable, and relevant to different types of decision-makers in different settings.

Translating knowledge into action takes leadership, skilled people, and resources. The Government of Canada's Adaptation Platform supports collaboration among governments, industry, and professional organizations on adaptation priorities. Building regional expertise and capacity for adaptation will improve risk management; support land-use planning; help safeguard investments; and strengthen emergency planning, response, and recovery. Decision-making by all governments will be guided by consideration of scientific and Traditional Knowledge.

INFORMATION AND TOOLS FOR ADAPTATION DECISIONS:
Decision-makers in five Quebec coastal municipalities collaborated with researchers, notably from the Université du Quebec à Rimouski and from Ouranos, a regional climate and adaptation consortium, to explore solutions to repeated damage of coastal infrastructure. Projections of future erosion, studies of sea ice and coastal vulnerability due to climate change, and cost-benefit analyses provided the foundation for the municipalities to make decisions on an adaptation solution.

The approach to information, knowledge, and capacity building will include (1) providing authoritative climate information and (2) building regional adaptation capacity and expertise.

Ensuring Canadians across all regions and sectors have the capacity to make informed decisions and to act on them provides the foundation for advancing adaptation in Canada. Indigenous-led community-based initiatives that combine science and Traditional Knowledge can help guide decision making. Including this information in regional and national impacts and adaptation assessments can further advance understanding of climate change across the country.

NEW ACTIONS

1. Providing authoritative climate information

The federal government will establish a Canadian centre for climate services, to improve access to authoritative, foundational climate science and information. This centre will work with provincial and territorial governments, Indigenous Peoples and other partners to support adaptation decision making across the country.

2. Building regional adaptation capacity and expertise

Governments will work with regional partners, including with Indigenous Peoples through community-based initiatives, to build regional capacity, develop adaptation expertise, respectfully incorporate Traditional Knowledge, and mobilize action. Canada's Adaptation Platform and regional consortia and centres support the sharing of expertise and information among governments, Indigenous Peoples and communities, businesses, and professional organizations and support action on joint priorities.

4.2 Building climate resilience through infrastructure

Climate change is already impacting infrastructure, particularly in vulnerable northern and coastal regions, as well as Indigenous Peoples. Climate-related infrastructure failures can threaten health and safety, interrupt essential services, disrupt economic activity, and incur high costs for recovery and replacement.

The approach to building climate resilience through infrastructure will include (1) investing in infrastructure that strengthens resilience and (2) developing climate-resilient codes and standards.

Traditional built infrastructure (e.g. roads, dykes, seawalls, bridges, and measures to address permafrost thaw) can address specific vulnerabilities. Additionally, living natural infrastructure (e.g. constructed/managed wetlands and urban forests) can build the resilience of communities and ecosystems and deliver additional benefits, such as carbon storage and health benefits.

Considering climate change in long-lived infrastructure investments, including retrofits and upgrades, and investing in traditional and natural adaptation solutions can build resilience, reduce disaster risks, and save costs over the long term.

ADAPTATION INFRASTRUCTURE:
The Red River Floodway was originally constructed in 1968 at a total cost of $63 million. It was recently expanded in 2014, at a cost of $627 million. Since 1968, the Floodway has prevented over $40 billion (in 2011 dollars) in flood-related damages for the City of Winnipeg.

NEW ACTIONS

1. Investing in infrastructure to build climate resilience

Federal, provincial, and territorial governments will partner to invest in infrastructure projects that strengthen climate resilience.

2. Developing climate-resilient codes and standards

Federal, provincial, and territorial governments will work collaboratively to integrate climate resilience into building design guides and codes. The development of revised national building codes for residential, institutional, commercial, and industrial facilities and guidance for the design and rehabilitation of climate-resilient public infrastructure by 2020 will be supported by federal investments.

4.3 Protecting and improving human health and well-being

Climate change is increasingly affecting the health and well-being of Canadians (e.g. extreme heat, air pollution, allergens, diseases carried by ticks and insects, and food security). Indigenous Peoples and northern and remote communities in particular are experiencing unique and growing risks to health and vitality.

The approach to protecting and improving human health and well-being will include (1) taking action to address climate change related health risks and (2) supporting healthy Indigenous communities.

Adaptation actions with an inclusive view of well-being (e.g. social and cultural determinants of health and mental health) will keep Canadians healthy and reduce pressures on the health system.

NEW ACTIONS

1. Addressing climate change-related health risks

Governments will collaborate to prevent illness resulting from extreme heat events and to reduce the risks associated with climate-driven infectious diseases, such as Lyme disease. Federal adaptation investments will support actions including surveillance and monitoring, risk assessments, modelling, laboratory diagnostics, as well as health-professional education and public awareness activities. Efforts will also continue to advance the science and understanding of health risks and best practices to adapt.

2. Supporting healthy Indigenous communities

The federal government will increase support for First Nations and Inuit communities to undertake climate-change and health adaptation projects that protect public health.

The federal government will also work with the Métis Nation on addressing the health effects of climate change.

FOOD SECURITY AND SUSTAINABILITY – PLANNING FOR CLIMATE CHANGE IMPACTS IN ARVIAT, NUNAVUT:
With the goal of promoting and providing access to healthy foods, a community-based project in Arviat, **Nunavut** involved researchers and community youth to monitor and collect data on optimal growing conditions in the community greenhouse and to build capacity for its ongoing operation.

4.4 Supporting particularly vulnerable regions

The Indigenous Peoples of Canada, along with coastal and northern regions are particularly vulnerable and disproportionately affected by the impacts of climate change. Unlike rebuilding after an extreme event like a flood or a fire, once permafrost has thawed, coastlines have eroded, or socio-cultural sites and assets have disappeared, they are lost forever.

The approach to supporting vulnerable regions will include (1) investing in resilient infrastructure to protect vulnerable regions; (2) building climate resilience in the North; (3) supporting community-based monitoring in Indigenous communities; and (4) supporting adaptation in coastal areas.

Action taken to support adaptation in vulnerable regions can help communities, traditional ways of life, and economic sectors endure and thrive in a changing climate. The knowledge, expertise, technologies, and lessons from adaptation actions in vulnerable northern and coastal regions can benefit other vulnerable regions and sectors.

COLLABORATING TO ADDRESS CLIMATE IMPACTS IN THE NORTH:
Nunavut, the Northwest Territories, and Yukon hosted the Pan-Territorial Permafrost Workshop in 2013, which brought together front-line decision makers and permafrost researchers from each territory to share knowledge, form connections, and look at possibilities for adaptation in the future.

NEW ACTIONS

1. Investing in resilient infrastructure to protect vulnerable regions

Federal, provincial, and territorial governments will work together to ensure infrastructure investments help build resilience with Indigenous Peoples as well as in vulnerable coastal and northern regions.

2. Building climate resilience in the North

Federal, territorial, and northern governments and Indigenous Peoples will continue working together to develop and implement a Northern Adaptation Strategy to strengthen northern capacity for climate change adaptation. Federal investments to build resilience in the North and northern Indigenous Peoples will support this work.

3. Supporting community-based monitoring by Indigenous Peoples

The federal government will provide support for Indigenous communities to monitor climate change in their communities and to connect Traditional

Knowledge and science to build a better understanding of impacts and inform adaptation actions.

4. Supporting adaptation in coastal regions

Federal, provincial, and territorial governments will support adaptation efforts in vulnerable coastal and marine areas and Arctic ecosystems. Activities will include science, research, and monitoring to identify climate change impacts and vulnerabilities; the development of adaptation tools for coastal regions; and the improvement of ocean forecasting. This knowledge will help inform adaptation decisions related to fisheries and oceans management and coastal infrastructure. Federal adaptation investments will help advance this work.

SUPPORTING VULNERABLE COASTAL COMMUNITIES:
Through the Atlantic Climate Adaptation Solutions Project, **Newfoundland and Labrador, Nova Scotia, Prince Edward Island,** and **New Brunswick** partner together and with Indigenous communities, regional non-profits, and industry to develop practical tools and resources to help vulnerable coastal communities consider climate change in planning, engineering practices, and water and resource management. Examples include land-use planning tools, best practices, and risk assessments.

4.5 Reducing climate-related hazards and disaster risks

Climate change is impacting the intensity and frequency of events such as floods, wildfires, drought, extreme heat, high winds, and winter road failures. Recognizing this reality, Federal-Provincial-Territorial Ministers Responsible for Emergency Management are updating emergency management in Canada including work to mitigate disasters, review the Disaster Financial Assistance Arrangements, develop build-back better strategies, and collaborate on public alerting. Additionally, the Canadian Council of Forest Ministers is working on the establishment of the Canadian Wildland Fire Strategy, with climate change highlighted as a key challenge.

The approach to reducing climate-related hazards and disaster risks will include (1) investing in infrastructure to reduce disaster risks; (2) advancing efforts to protect against floods; and (3) supporting adaptation for Indigenous Peoples.

Disaster risk-reduction efforts and adaptation measures can reduce the negative impacts of these events, some of which have a disproportionate impact on Indigenous Peoples.

NEW ACTIONS

1. Investing in infrastructure to reduce disaster risks

Federal, provincial, and territorial governments will partner to invest in traditional and natural infrastructure that reduces disaster risks and protects Canadian communities from climate-related hazards such as flooding and wildfires.

2. Advancing efforts to protect against floods

Federal, provincial, and territorial governments will work together through the National Disaster Mitigation Program to develop and modernize flood maps and assess and address flood risks.

3. Supporting adaptation in Indigenous Communities

Governments will work in partnership with Indigenous communities to address climate change impacts, including repeated and severe climate impacts related to flooding, forest fires, and failures of winter roads. The federal government will provide support to Indigenous communities for adaptation.

FLOOD AND DROUGHT PROTECTIONS THROUGH WETLANDS RESTORATION:
Alberta's Watershed Resiliency and Restoration Program provided a grant to Ducks Unlimited to restore approximately 558 hectares of wetlands in the South Saskatchewan River basin for the purposes of water storage for flood and drought protection. Using historical imagery and LiDAR data to identify drained wetlands, project leads then work with and compensate landowners to restore wetlands on private land.

CLEAN TECHNOLOGY, INNOVATION, AND JOBS

Overview

Global demand for clean technologies is significant and increasing. Fostering and encouraging investment in clean technology solutions can facilitate economic growth, long-term job creation, and environmental responsibility and sustainability. Taking action on climate change will help to capture new and emerging economic opportunities, including for Indigenous Peoples and northern and remote communities. The window of opportunity exists for Canada to create the conditions for new clean technology investment and exports and seize growing global markets for clean technology goods, services, and processes.

To effectively compete in the global marketplace and capitalize on current and future economic opportunities, Canada needs a step change in clean technology development, commercialization, and adoption across all industrial sectors. Clarity of purpose, investment, and strong coordination that leverages pan-Canadian regional and provincial/territorial strengths are essential to seizing the economic growth and job-creation opportunities of clean technology. International research, development, and demonstration collaboration is also essential. Governments, Indigenous Peoples, industry, and other stakeholders all have a role to play and must be engaged.

5.1 Building early-stage innovation

To become a leader in the development and deployment of clean technologies, Canada needs a strong flow of innovative ideas.

Government investments in clean technology research, development, and demonstration will create the largest benefit where coordinated and focused in areas that will most effectively help Canada to meet its climate change goals, create economic opportunities, and expand global-market opportunities. Efforts to coordinate and focus investment must go beyond governments and involve the collaboration of industry, stakeholders, academia, and Indigenous Peoples in the innovation process. Canada must leverage its domestic strengths, which vary by region. Developing international partnerships will create new economic opportunities, build areas of shared expertise, and foster stronger bilateral relations.

Sustainable Development Technology Canada (SDTC) provides funding support to companies across Canada to develop, demonstrate, and deploy innovative new clean technologies. SDTC has also launched joint funding opportunities in collaboration with Emissions Reduction Alberta and Alberta Innovates and partners with the Ontario Centres of Excellence to enhance Ontario's Greenhouse Gas Innovation Initiative. SDTC estimates its projects have reduced annual emissions by 6.3 Mt of CO_2e, generated $1.4 billion in annual revenue and, in 2015, supported more than 9200 direct and indirect jobs.

Through its participation in Mission Innovation, the federal government has committed to double its investments in clean energy research and technology development over five years, while encouraging greater levels of private sector investment in transformative clean energy technologies. On November 14, 2016, Canada and 21 other Mission Innovation partners launched seven Innovation Challenges aimed at catalyzing global research efforts in areas that could provide significant benefits in reducing GHG emissions, increasing energy security, and creating new opportunities for clean economic growth.

NEW ACTIONS

1. Supporting early-stage technology development

Governments will support new approaches to early-stage technology development, including breakthrough technologies, to advance research in areas that have the potential to substantially reduce GHG emissions and other pollutants. Innovative partnerships with the private sector will make an important contribution to this effort.

2. Mission-oriented research and development

Governments will encourage new "mission-oriented" research approaches to focus RD&D facilities, programs, and supports on clean technology and environmental performance issues.

5.2 Accelerating commercialization and growth

Given Canada's small domestic market, Canadian firms must look to highly competitive international markets to achieve scale. Succeeding in the globally competitive clean technology marketplace requires globally competitive talent, access to the capital and resources needed to demonstrate the commercial viability of products, and strong international networks that facilitate the cross-border flow of clean technology goods and services.

Canadian clean technology producers and researchers are currently confronted by a myriad of programs and services, at the federal, provincial, and territorial level. Streamlining and integrating access to support programs and services is a priority for businesses and essential to building commercial capacity in this area.

Compared with other technology areas, clean technologies face unique challenges and often take longer to get to market, making access to "patient capital" important to successful commercialization. While federal and provincial governments already have a range of supports in place, key needs exist in terms of accessing venture capital as well as working capital and support for first, large-scale commercial projects or deployments.

20/20 Catalysts Program is a mentorship program that matches Indigenous and non-Indigenous project mentors with Indigenous mentees to promote knowledge sharing that will enable Indigenous communities to drive change towards clean technology business and economic development.

Further development of clean technologies could create new opportunities in Canada's resource sectors, increase the productivity and competitiveness of Canadian businesses, and create new employment opportunities, while also improving environmental performance. Canada will need to be able to access the skills and expertise of talented workers from around the world to enable Canadian businesses to succeed in the global marketplace. It will also be important to ensure a commitment to skills and training to provide Canadian workers with a just and fair transition to opportunities in Canada's clean growth economy.

Indigenous Peoples are leaders of change in the transition to a low-carbon economy. Indigenous governments, organizations, and businesses can play a key role in developing pathways for the adoption and adaptation of clean technology solutions for Indigenous Peoples.

Building stronger businesses and commercial capacity in all of Canada's regions is essential to taking advantage of new market opportunities. Support for new technology start-ups, through incubators and accelerators, is important to this effort. A strong, focused Canadian clean technology export strategy is needed to position Canada in growing and emerging global markets.

MaRS Cleantech works closely with entrepreneurs and investors to create solutions in energy, water, agri-tech, advanced materials and manufacturing, and smart cities. Industry looks to MaRS Cleantech to assist with company growth and to remove complex technology-adoption barriers. MaRS supports high-impact businesses by connecting innovators with potential partners, customers, investors, talent, and capital. MaRS strives to build globally competitive companies and to drive clean technology innovation.

NEW ACTIONS

1. Access to government programs

Federal, provincial, and territorial governments will work together to create a coordinated "no-wrong door" approach to supporting Canadian clean technology businesses, ensuring full and effective access to the suite of government programs and services available to support their commercial success.

2. Increasing support to advance and commercialize innovative technologies

Governments will collaborate to enable access to capital for clean technology businesses to bring their products and services to market, including at the commercial-scale demonstration and deployment stages. This will include support for clean technology businesses in the natural resource sectors to improve both competitiveness and environmental performance.

3. Strengthening support for skills development and business leadership

Governments will work together to strengthen skills development and business-leadership capacity in support of the transition to a low-carbon economy.

VENTURE CAPITAL:
BDC Capital is launching a new $135 million venture capital fund to support Canadian energy and clean technology start-up businesses with global potential. The Industrial, Clean and Energy Technology (ICE) Venture Fund II will invest in 15 to 20 new high-impact Canadian start-up firms that demonstrate efficiency and strong scalability and will support the transition to a low-carbon economy. Fund II is a follow-on to BDC Capital's highly successful ICE Venture Fund I, which was launched in 2011 with investments of $287 million now under management.

4. Expedite immigration of highly qualified personnel

Governments will work together to enable expedited processing of visas and work permits for global talent, in particular for high-growth Canadian businesses such as those in the clean technology sector. This will attract top international talent and expand Canada's clean growth capacity.

5. Promoting exports of clean technology goods and services

Federal, provincial, and territorial governments will work collaboratively to strengthen clean technology export potential. This will include targeted export missions and the development of better market intelligence, addressing barriers to markets, support for export financing and marketing, and leveraging Canada's Trade Commissioner services.

6. Standards-setting

Governments will work together to exert a strong leadership role in international standards-setting processes for new clean technologies and to ensure that Canada's clean-technology capacity shapes future international standards.

5.3 Fostering adoption

The adoption of clean technology can create economic opportunities and improve environmental outcomes. Canada's performance on clean technology adoption by industry has significant room for improvement. Even amongst Canadian businesses that regularly adopt advanced technologies, clean technologies are the least likely to be adopted.

SmartICE (Sea-ice Monitoring And Real-Time Information for Coastal Environments) is a partnership with community, academic, government, and industry participation. It is developing an integrated system to provide near-real-time information about coastal sea-ice travel and shipping, improving safety and the ability to adapt to changing climate conditions. The pilot program is preparing to expand across the Arctic through a northern social enterprise.

Pricing carbon pollution will send a market signal that can drive innovation among Canadian businesses and, in return, will make them more competitive, including by opening up access to new markets and reducing costs of deploying clean technologies.

There is significant potential for Canadian governments to "lead by example" as early adopters of clean technology serving an essential role as a first or "reference customer" for Canadian clean technology goods, services, and processes. Having a "first sale" in Canada would boost businesses' chances of securing sales abroad. Beyond direct federal, provincial, and territorial government operations, other bodies, such as municipalities and publicly regulated utilities, could become significant markets for and adopters of clean technology.

Done effectively, the adoption of clean technology could be a mechanism for improving environmental circumstances and creating economic opportunity for Indigenous Peoples and northern and remote communities. Effective engagement and partnership with Indigenous Peoples is essential to this effort.

Encouraging dialogue between regulators and industry could improve certainty in clean technology development and allow for more effective and responsible regulation.

NEW ACTIONS

1. Leading by example

Federal, provincial, and territorial governments will develop action plans for greening government operations and encourage utilities and municipalities and other public sector entities to adopt clean technologies to lead by example.

2. Supporting Indigenous Peoples and northern and remote communities to adopt and adapt clean technologies

Federal, provincial, and territorial governments will support Indigenous Peoples and northern and remote communities in adopting and adapting clean technologies, and ensuring business models support community ownership and operation of clean technology solutions.

3. Consumer and industry adoption

Federal, provincial, and territorial governments will work together to promote and encourage effective working relationships between regulators and industry, providing for early dialogue and effective guidance, which can assist in bringing new clean technologies to market quickly and responsibly.

Governments will also support visible and effective certification programs to ensure consumer and business confidence and support green procurement.

5.4 Strengthening collaboration and metrics for success

An effective approach to clean technology development, commercialization, and adoption in Canada requires coherent, collaborative, and focused approaches. This is true within individual governments and between Canadian jurisdictions. A collaborative approach between governments should take into account regional strategies and jurisdictional responsibilities.

Regular and ongoing discussions between federal, provincial, and territorial governments regarding clean technology and clean growth would help eliminate duplication of efforts and identify gaps in support for clean technology development. Engaging Indigenous Peoples, industry, and stakeholders as a routine component of this process would be important.

There is inadequate data on Canada's clean technology capacity and potential. Building better data, and clear metrics for tracing the impact of government activities, would properly focus these activities and ensure that they achieve intended, meaningful results.

NEW ACTIONS

1. Enhance alignment between federal, provincial, and territorial actions

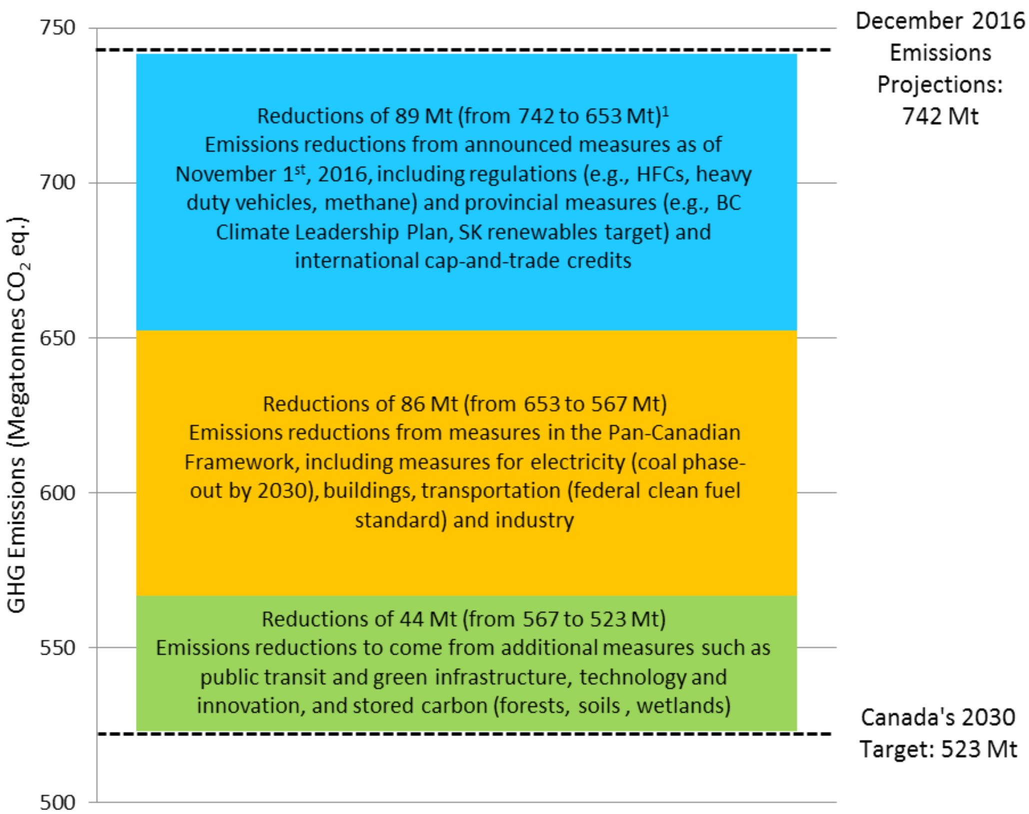
Governments will work together to improve policy and program coordination and sharing of data and best practices, which can sustain intergovernmental momentum and action on clean technology and clean growth. Continued partnership and engagement of Indigenous Peoples, industry, and stakeholders is essential to this effort.

Governments will work together to target and better align clean technology RD&D investments and activities in Canada, including opportunities for co-funding clean technology projects.

2. Establishing a clean technology data strategy

The federal government, working with the provinces and territories, will support the collection and regular publication of comprehensive data on clean technology in Canada to inform future government decision making, to improve knowledge in the private sector and stakeholder community, and to foster innovation.

PATHWAY TO MEETING CANADA'S 2030 TARGET



Note: Reductions from carbon pricing are built into the different elements depending on whether they are implemented, announced, or included in the Pan-Canadian Framework. The path forward on pricing will be determined by the review to be completed by early 2022.

[1] Estimates assume purchase of carbon credits from California by regulated entities under Quebec and Ontario's cap-and-trade system that are or will be linked through the Western Climate Initiative.

REPORTING AND OVERSIGHT

Overview

To help achieve the goals and actions laid out in this Pan-Canadian Framework, the programs and policies put in place will be monitored, results will be measured including impacts on GHG emissions, and actions and performance will be reported on publicly in a way that is transparent and accountable to Canadians. This public reporting will be complemented by ongoing public outreach, including with youth, inviting their contributions to Canada's action on clean growth and climate change. The effectiveness of actions will also be assessed with a view to ensuring continual improvement so as to increase ambition over time, in accordance with the Paris Agreement.

NEW ACTIONS

Measurement and reporting on emissions – Federal, provincial, and territorial governments will continue to collaborate on efforts to track and report GHG emissions in a consistent way across the country, to track progress on the Pan-Canadian Framework, and to support international reporting obligations. This will involve further technical work on measurement to improve emissions inventories and projections, and aligning these where possible. Federal, provincial, and territorial governments will work together through the Canadian Council of Ministers of the Environment (CCME) to examine options for the reporting of emissions and inventories to ensure consistency across provinces and territories, to support Canada's reporting to the UNFCCC, and for a pan-Canadian offset protocol framework and verified carbon credits that can be traded domestically and internationally.

Reporting on implementation – Federal, provincial, and territorial governments will work together to support the coordinated implementation of the Pan-Canadian Framework, engaging with relevant ministerial tables including ministers of environment, energy and mines, transportation, forestry, agriculture, innovation, infrastructure, emergency management, and finance, and with meaningful involvement of Indigenous Peoples. This will include a process to take regular stock of progress achieved, to report to Canadians and, to inform Canada's future national commitments in accordance with the Paris Agreement.

Analysis and advice – Federal, provincial, and territorial governments will engage with external experts to provide informed advice to First Ministers and decision makers; assess the effectiveness of measures, including through the use of modeling; and identify best practices. This will help ensure that actions identified in the Pan-Canadian Framework are open to external, independent review, and are transparent and informed by science and evidence.

Review - Federal, provincial, and territorial governments will work together to establish the approach to the review of carbon pricing, including expert assessment of stringency and effectiveness that compares carbon pricing systems across Canada, which will be completed by early 2022 to provide certainty on the path forward. An interim report will be completed in 2020 which will be reviewed and assessed by First Ministers. As an early deliverable, the review will assess approaches and best practices to address the competitiveness of emissions-intensive trade-exposed sectors.

Federal, provincial, and territorial governments will continue to engage and partner with Indigenous Peoples as actions are implemented and progress is tracked.

LOOKING AHEAD

This Plan provides a foundation for working together to grow the economy, reduce emissions, and strengthen resilience. Ongoing, collaborative action is needed to generate transformational change and to ensure that all Canadians benefit from the transition to a low-carbon economy. First Ministers are tasking their officials to develop an agenda for federal, provincial, and territorial Ministers to implement this Plan. Annual reports to First Ministers will enable governments to take stock of progress and give direction to sustain and enhance efforts.

ANNEX I: FEDERAL INVESTMENTS AND MEASURES TO SUPPORT THE TRANSITION TO A LOW-CARBON ECONOMY

FEDERAL INVESTMENTS

The federal government will help catalyze the transition to a clean growth economy through significant new investments to complement provincial and territorial actions and investments, including investments in infrastructure, the Low-Carbon Economy Fund, and clean technology funding.

- Budget 2016 outlined a number of new federal investments that will support a transition to a low-carbon economy. Some of these investments include
  - » $62.5 million to support the deployment of infrastructure for alternative transportation fuels, including charging infrastructure for electric vehicles and natural gas and hydrogen refueling stations as well as demonstration of next generation recharging technologies;
  - » $50 million over two years to invest in technologies that will reduce GHG emissions from the oil and gas sector;
  - » $82.5 million over two years to support research, development, and demonstration of clean energy technologies with the greatest potential to reduce GHG emissions;
  - » $100 million per year from the Regional Development Agencies to support clean technology, representing a doubling of thei existing annual aggregate support;
  - » $50 million over four years to Sustainable Development Technology Canada (SDTC) for the SD Tech Fund. These resources will enable SDTC to announce new clean technology projects in 2016 that support the development and demonstration of new technologies that address climate change, air quality, clean water, and clean soil;

THE FEDERAL GOVERNMENT HAS COLLABORATED WITH THE FEDERATION OF CANADIAN MUNICIPALITIES ON THE GREEN MUNICIPAL FUND (GMF) SINCE 2000.

- Budget 2016 provided an additional $125 million over two years including for projects that reduce GHG emissions.
- Recently announced projects under the GMF include a $31.5 million investment for 20 new sustainable municipal projects, such as Canada's first net-zero municipal library and Halifax's ground-breaking Solar City project.

» $40 million over five years to integrate climate resilience into building design guides and codes. The funding will support revised national building codes by 2020 for residential, institutional, commercial, and industrial facilities;

» $129.5 million to implement programming focused on building the science base to inform decision making, protecting the health and well-being of Canadians, building resilience in the North and Indigenous communities, and enhancing competitiveness in key economic sectors; and

» $10.7 million over two years to implement renewable energy projects in off-grid Indigenous and northern communities that rely on diesel and other fossil fuels to generate heat and power.

- Building on the infrastructure investments outlined in Budget 2016, the federal government has announced an additional $81 billion over 11 years for investments in public transit, social infrastructure, transportation that supports trade, Canada's rural and northern communities, smart cities, and green infrastructure.
- Green infrastructure funding will support projects that reduce GHG emissions, enable greater climate change adaptation and resilience, and ensure that more communities can provide clean air and safe drinking water for their citizens. Specific projects could include interprovincial transmission lines that reduce reliance on coal, the development of new low-carbon/renewable power projects, and the expansion of smart grids to make more efficient use of existing power supplies.
- The federal government is proposing the creation of the Canada Infrastructure Bank that will work with provinces, territories, and municipalities to further the reach of government funding directed to infrastructure. The Canada Infrastructure Bank will be responsible for investing at least $35 billion on a cash basis from the federal government into large infrastructure projects that contribute to economic growth through direct investments, loans, loan guarantees, and equity investments.
- Funding under the $2 billion Low Carbon Economy Fund will begin in 2017. This Fund will support new provincial and territorial actions to reduce emissions between now and 2030. Projects will focus on concrete measures that generate new, incremental reductions, while considering cost-effectiveness.
- The Government has also committed more than $1 billion, over four years, to support clean technology including in the forestry, fisheries, mining, energy and agriculture sectors.

FEDERAL CARBON PRICING BENCHMARK

The federal government outlined a benchmark for carbon pricing that reflects the principles proposed by the Working Group on Carbon Pricing Mechanisms and the Vancouver Declaration. Its goal is to ensure that carbon pricing applies to a broad set of emission sources throughout Canada with increasing stringency over time to reduce GHG emissions at lowest cost to business and consumers and to support innovation and clean growth.

The benchmark includes the following elements:

1. Timely introduction.

All jurisdictions will have carbon pricing by 2018.

2. Common scope.

Pricing will be based on GHG emissions and applied to a common and broad set of sources to ensure effectiveness and minimize interprovincial competitiveness impacts. At a minimum, carbon pricing should apply to substantively the same sources as British Columbia's carbon tax.

3. Two systems.

Jurisdictions can implement (i) an explicit price-based system (a carbon tax like British Columbia's or a carbon levy and performance-based emissions system like in Alberta) or (ii) a cap-and-trade system (e.g. Ontario and Quebec).

4. Legislated increases in stringency, based on modelling, to contribute to our national target and provide market certainty.

For jurisdictions with an explicit price-based system, the carbon price should start at a minimum of $10 per tonne in 2018 and rise by $10 per year to $50 per tonne in 2022.

Provinces with cap-and-trade need (i) a 2030 emissions-reduction target equal to or greater than Canada's 30 percent reduction target and (ii) declining (more stringent) annual caps to at least 2022 that correspond, at a minimum, to the projected emissions reductions resulting from the carbon price that year in price-based systems.

5. Revenues remain in the jurisdiction of origin.

Each jurisdiction can use carbon-pricing revenues according to their needs, including to address impacts on vulnerable populations and sectors and to support climate change and clean growth goals.

6. Federal backstop.

The federal government will introduce an explicit price-based carbon pricing system that will apply in jurisdictions that do not meet the benchmark. The federal system will be consistent with the principles and will return revenues to the jurisdiction of origin.

7. Five-year review.

The overall approach will be reviewed by early 2022 to confirm the path forward, including continued increases in stringency. The review will account for progress and for the actions of other countries in response to carbon pricing, as well as recognition of permits or credits imported from other countries.

8. Reporting.

Jurisdictions should provide regular, transparent, and verifiable reports on the outcomes and impacts of carbon pricing policies.

The federal government will work with the territories to address their unique circumstances, including high costs of living, challenges with food security, and emerging economies.

OTHER RECENT FEDERAL MEASURES

The federal government has also recently announced new federal measures, including

- During the North American Leaders Summit in June 2016, the federal government made joint commitments with the United States and Mexico to
  - phase out fossil fuel subsidies by 2025. The commitment was reaffirmed by G-20 countries in September 2016.
  - reduce methane emissions from the oil and gas sector by 40 to 45 percent below 2012 levels by 2025.
- On October 15, 2016, Canada signed onto the Kigali Amendment to the Montreal Protocol and committed to propose new regulations to significantly reduce HFC consumption and prohibit the manufacture and import into Canada of certain products containing HFCs. These proposed regulations were published on November 26, 2016. This is additional to measures already introduced to increase the recovery, recycling, and destruction of HFCs in refrigeration and air conditioning equipment and to established regulatory provisions for an HFC reporting system.
- On November 17, 2016, Canada released its Mid-Century Long-Term Low-Greenhouse Gas Development Strategy. The mid-century strategy describes various pathways for innovative and creative solutions. Canada's mid-century strategy is not a blueprint for action nor is it policy prescriptive. It is based on modelling of different scenarios and looks beyond 2030 to start a conversation on the ways we can reduce emissions for a cleaner, more sustainable future by 2050. As a result, it will be a living document.
- On November 21, 2016, the federal government announced that it would be amending its existing coal-fired electricity regulations to accelerate the phase out of traditional coal-fired electricity by 2030. The federal government also announced that, to support the transition away from coal towards cleaner sources of generation, performance standards for natural gas-fired electricity are also being developed.
- On November 25, 2016, the federal government announced that it will consult with provinces and territories, Indigenous Peoples, industries, and non-governmental organizations to develop a clean fuel standard. It is expected that once developed, a clean fuel standard would promote the use of clean technology and lower carbon fuels, and promote alternatives such as electricity, biogas, and hydrogen.

ANNEX II: PROVINCIAL AND TERRITORIAL KEY ACTIONS AND COLLABORATION OPPORTUNITIES WITH THE GOVERNMENT OF CANADA

INTRODUCTION

The Paris Agreement and the Vancouver Declaration have set an ambitious course for low carbon growth and climate action in Canada. The Pan-Canadian Framework on Clean Growth and Climate Change will build on the leadership shown and actions taken by the provinces and territories as well as new policies announced by the federal government.

This annex outlines provincial and territorial accomplishments in reducing greenhouse gas emissions and accelerating clean growth, and presents steps that each jurisdiction has taken or is taking to implement carbon pricing.

The annex also outlines areas where the federal government and each provincial and territorial government will work together to implement the Pan-Canadian Framework in order to spur growth and jobs for Canadians, reduce our emissions and adapt to climate change.

Each province and territory is unique and is responding to the urgency of climate change and the opportunity offered by clean growth in its own way. Effective action will require close collaboration between governments. Each provincial and territorial government has identified multiple areas for potential partnerships with the federal government, adapted to their own priorities, circumstances and strengths. Governments are committed to working together on these priorities to support the implementation of the Pan-Canadian Framework. Governments will also engage the contributions of Indigenous Peoples in advancing shared goals.

This work will be supported by significant new federal investments to drive the transition to a clean growth economy, as outlined in Budget 2016 and the 2016 Fall Economic Statement, including public transit and Green Infrastructure, the Canada Infrastructure Bank, the Low-Carbon Economy Fund, and funding for clean technology and innovation. Federal investments are intended to supplement and accelerate investments by provinces and territories, and will follow applicable program criteria.

BRITISH COLUMBIA

KEY ACTIONS TO DATE

Some of the key actions taken to date or under development in British Columbia include:

British Columbia's Climate Leadership Plan

B.C. has proven that it is possible to reduce emissions while growing the economy and creating jobs and it's important that this balance be maintained. With this in mind, B.C. released its Climate Leadership Plan in the summer of 2016.

Building on the comprehensive foundation established in 2008, the plan lays out a series of targeted, sector-specific actions that will reduce emissions by 25 million tonnes (Mt) of carbon dioxide equivalent (CO_2e) and create 66,000 jobs. The plan will be further strengthened in the months and years ahead, as B.C. continues to work with First Nations, the federal government, communities, industry and others. B.C. is committed to reducing GHG emissions by 80% below 2007 levels by 2050. To read B.C.'s Climate Leadership Plan, visit: http://climate.gov.bc.ca/

Revenue-Neutral Carbon Tax

B.C. has the highest broad-based carbon tax in North America. The carbon tax sets a transparent and predictable price on carbon while returning all revenue to B.C. individuals and businesses. The price signal creates a real incentive to reduce emissions across the economy and is the backbone of B.C.'s approach to climate action.

Forestry

B.C.'s forests offer potential for storing carbon, so the Province is taking further action to rehabilitate up to 300,000 hectares of Mountain Pine Beetle and wildfire impacted forests over the first five years of the program; recover more wood fibre; and avoid emissions from burning slash.

Clean LNG

B.C. has an abundance of natural gas, which is a lower carbon fuel that will play a critical role in transitioning the world economy off of high carbon fuels such as coal. B.C. is developing the resource responsibly, and provincial legislation will make the emerging LNG sector the cleanest in the world. B.C. is also electrifying upstream development of natural gas and will require a 45% reduction in methane emissions by 2025.

100% Clean Electricity

Thanks to significant historical investments, B.C.'s electricity is already 98% clean or renewable and British Columbians have the third-lowest residential rates in North America. Going forward under the Climate Leadership Plan, 100% of the supply of electricity acquired by BC Hydro for the integrated grid must be from clean or renewable sources. The $8.3 billion Site C Clean Energy Project is a major part of B.C.'s clean energy future and will create enough electricity to power 450,000 homes.

Clean Transportation

B.C. is taking real action to reduce emissions from the transportation sector and help British Columbians make greener choices—initiatives include Zero Emissions Vehicles rebates and funding for more charging stations (which have helped BC become the Canadian leader in clean energy vehicle sales per capita); a scrap-it program; low carbon and renewable fuel standards; and historic investments in transit. B.C.'s actions in the transportation sector have already reduced annual emissions by an estimated 2.5 Mt and combined with the new actions, will reduce annual emissions by up to a further 3.4 Mt by 2050.

Adaptation

In 2010, the Province created a comprehensive strategy to address the changes we will see as a result of climate change. It is based on three key strategies: build a strong foundation of knowledge and tools; make adaptation a part of government business; and assess risks and implement priority adaptation actions in key climate sensitive sectors. The Province is now working with the federal government and other Canadian jurisdictions to further improve the management of the risks associated with a changing climate.

These actions provide a strong contribution to a comprehensive pan-Canadian framework.

ACTION ON PRICING CARBON POLLUTION

B.C.'s revenue-neutral carbon tax has been in place since 2008. It is set at $30/tonne and covers approximately 75% of the province's economy. All revenues generated will be returned to tax payers. B.C. will assess the interim study in 2020 and determine a path forward to meet climate change objectives.

COLLABORATION PARTNERSHIP OPPORTUNITIES FOR CLEAN GROWTH AND CLIMATE CHANGE

British Columbia and the Government of Canada intend to collaborate in the following domains of priority to address climate change and advance clean growth:

Growing our forests; reducing our emissions

Forests present a unique opportunity to address climate change because trees absorb CO_2 when they grow. British Columbia, the Government of Canada and First Nations will work together to reduce GHG emissions through forestry activities, including reforestation, enhanced silviculture techniques, and the salvaging of unmerchantable trees for processing into dimensional lumber and bioenergy. The initiative is expected to reduce emissions by 12 Mt in 2050 and create 20,000 jobs.

Preparing for and adapting to climate change

British Columbia and the Government of Canada will support projects across the province to make infrastructure more resilient to a changing climate, and to help communities adapt to a changing climate. Flood mitigation will be an area of focus.

Reduce Emissions from Natural Gas Activities

British Columbia and the Government of Canada will work together to bring clean grid electricity to natural gas operations in northeast B.C. They will co-fund the construction of new transmission lines and other public electrification infrastructure that could serve up to 760 megawatts of upstream natural gas processing load and avoid up to 4 Mt of emissions per year.

Electricity Grid Interconnection

British Columbia and the Governments of Canada and Alberta will work together to restore the capability of the existing high-voltage electricity grid interconnection with Alberta. This project will improve access to clean electricity in Alberta and will result in lower GHG emissions and air pollution, and improved grid reliability in both provinces.

Clean Technology Innovation

British Columbia and the Government of Canada will work together to spur the development and commercialization of new technologies that will reduce emissions and create jobs for Canadians.

ALBERTA

KEY ACTIONS TO DATE

Some of the key actions taken to date or under development in Alberta include:

Climate Leadership Plan

The Climate Leadership Plan is a made-in-Alberta climate change strategy, specifically designed for Alberta's unique economy. While details of the final strategy are still being developed, the Alberta government has moved forward on a number of key areas.

Clean Electricity

Alberta will phase-out GHGs from coal-fired power plants and achieve 30% renewable energy by 2030.

Alberta will add 5,000 megawatts of renewable energy capacity by 2030 through the Renewable Electricity Program. To meet this target, investment in Alberta's electricity system will be solicited through a competitive and transparent bidding process, while ensuring projects come online in a way that does not impact grid reliability and is delivered at the lowest possible cost to consumers.

A new provincial agency, Energy Efficiency Alberta, has been created to promote and support energy efficiency and community energy systems for homes, businesses and communities.

Capping Oil Sands Emissions

A legislated maximum emissions limit of 100 Mt in any year, with provisions for cogeneration and new upgrading capacity, will help drive technological progress.

Reducing Methane Emissions

Alberta will reduce methane gas emissions from oil and gas operations by 45% by 2025.

Innovation and Technology

Alberta is investing in innovation and technology to reduce GHGs, encourage a more diversified economy and energy industry, and create new jobs, while improving opportunities to get the province's energy products to new markets. Alberta has created a task force that will make recommendations on a Climate Change Innovation and Technology Framework.

These actions provide a strong contribution to a comprehensive pan-Canadian framework.

ACTION ON PRICING CARBON POLLUTION

A carbon levy to be included in the price of all fuels that emit greenhouse gases when combusted, including transportation and heating fuels such as diesel, gasoline, natural gas and propane. The levy will be applied at a rate of $20/tonne on January 1, 2017 and will increase to $30/tonne one year later.

The Climate Leadership Plan is designed for Alberta's economy. The economic impact of carbon pricing is expected to be small, and every dollar will be reinvested back into the local economy. Reinvesting carbon revenue in our economy will diversify our energy industry by investing in large scale renewable energy, bioenergy initiatives, and transformative innovation and technology. Over the next 5 years:

$6.2 billion will help diversify our energy industry and create new jobs:

- $3.4 billion for large scale renewable energy, bioenergy and technology

- $2.2 billion for green infrastructure like transit
- $645 million for Energy Efficiency Alberta

$3.4 billion will help households, businesses and communities adjust to the carbon levy:

- $2.3 billion for carbon rebates to help low- and middle-income families
- $865 million to pay for a cut in the small business tax rate from 3% to 2%
- $195 million to assist coal communities, Indigenous communities and others with adjustment

COLLABORATION PARTNERSHIP OPPORTUNITIES FOR CLEAN GROWTH AND CLIMATE CHANGE

Alberta and the Government of Canada intend to collaborate in the following domains of priority to address climate change and advance clean growth:

Clean Electricity

Alberta and the federal government will to work together to advance renewable energy, coal to natural gas conversion, and potential hydroelectric projects, including pump storage projects. Alberta is committed to developing incentives for renewable generation in a manner that is compatible with Alberta's unique electricity market.

B.C. – Alberta Intertie

Alberta is working with British Columbia and the federal government to explore new and enhanced interties. The Alberta Electric System Operator is currently working with BC Hydro and industry on a key project, the restoration of the B.C.-Alberta 950 MW intertie to its full path rating (expected completion is in 2020). This restoration would allow imports of 1200 MW on the BC-AB intertie.

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Innovation and Technology

Alberta is focused on the opportunity to leverage environmental policies and programs into new manufacturing, innovation, and clean technology businesses. Current opportunities include superclusters, advanced sensor technology for environmental applications including methane monitoring and reductions, and municipal waste diversion. Innovative solutions will result in meaningful GHG reductions across Canada and the export of solutions to promote a lower carbon world.

Disaster Mitigation / Infrastructure

Alberta is undertaking targeted work to address the hazards to which Albertans are vulnerable, including flood, wildfire, heat, drought, landslides, and wind.

While hazards and disaster risks have always been a concern, climate change is driving the need to adapt to more intense and frequent events. Federal support for wildfire mitigation infrastructure will reduce the risk of wildland fires. In addition, flood risk requires immediate mitigation infrastructure such as dykes and dams. Federal partnership on these initiatives will support risk management.

ONTARIO

KEY ACTIONS TO DATE

Some of the key actions taken to date or under development in Ontario include:

Permanent Closure of Coal-fired Electricity Generating Stations

On April 15, 2014, Ontario became the first jurisdiction in North America to fully eliminate coal as a source of electricity generation. This action is the single largest GHG reduction initiative in North America. On November 23, 2015, Ontario passed the *Ending Coal for Cleaner Air Act*, permanently banning coal-fired electricity generation in the province.

Ontario's Climate Change Strategy and Action Plan

On November 24, 2015, Ontario released its Climate Change Strategy setting the framework for the province to meet its long-term 2050 GHG emissions reduction target. The Strategy highlights five key objectives for transformation:

1. A prosperous low-carbon economy with world-leading innovation, science and technology
2. Government collaboration and leadership
3. A resource-efficient, high-productivity society
4. Reducing GHG emissions across sectors
5. Adapting and thriving in a changing climate

On June 8, 2016, Ontario released its Climate Change Action Plan to implement the strategy over the next five years and put Ontario on the path to achieve its longer term objectives. Policies and programs identified in the Action Plan include:

- Transforming how ultra-low and carbon-free energy technologies are deployed in our homes and workplaces, and how we move people and goods
- Halting rising building-related emissions, with a focus on helping homeowners and small businesses move to low- and zero-carbon energy
- Making available funding for industries and manufacturers proposing to transform their operations and move off carbon-based fuels and peak electricity
- Aligning Ontario's R&D and innovation funding to place a greater emphasis on climate change science and technologies, with a view to making the discoveries that could lead to breakthroughs in zero-carbon technology

Ontario has made measurable progress in reducing GHGs. According to Environment and Climate Change Canada's 2016 National Inventory Report, from 2005 to 2014, Ontario's emissions decreased by 41 Mt (-19%), over the same period, Canada-wide emissions fell by 15 Mt (-2%).

These actions provide a strong contribution to a comprehensive pan-Canadian framework.

ACTION ON PRICING CARBON POLLUTION

On May 18, 2016, Ontario passed its landmark *Climate Change Mitigation and Low-carbon Economy Act,* which creates a long term framework for climate action. The Act creates a robust framework for cap and trade program, ensures transparency and accountability on how any proceeds collected under the program are used and enshrines emission reduction targets in legislation.

Ontario's approach, including its cap and trade program and associated emissions reduction targets, will exceed the standards of the federal carbon pricing benchmark. Ontario's targets are:

- 15% below 1990 levels by 2020;
- 37% below 1990 levels by 2030; and
- 80% below 1990 levels by 2050.

Ontario is a founding member of the Western Climate Initiative (WCI), a not-for-profit organization established in 2008 to help member states and provinces execute their cap and trade programs. In 2017, Ontario will link its cap and trade system with those of WCI members Quebec and California to create the largest cap and trade system in North America.

Ontario will set a cap on total emissions from the covered sectors in 2017 based on the forecast emissions for large final emitters, electricity generation and transportation and heating fuels. Allowances will then be created in an amount equal to the cap and either sold or provided free-of-charge to Ontario emitters.

COLLABORATION PARTNERSHIP OPPORTUNITIES FOR CLEAN GROWTH AND CLIMATE CHANGE

Ontario and the Government of Canada intend to collaborate in the following domains of priority to address climate change and advance clean growth:

Invest in Zero Emission Transportation and Infrastructure

Ontario is committed to increase uptake of zero emission passenger and commercial vehicles, both by providing purchasing incentives and by expanding the EV charging network across Ontario. In its 2016 budget, the federal government committed to support the deployment of alternative transportation fuel infrastructure, including electric charging stations. Ontario and the Government of Canada will work together to support the deployment of EV vehicles through enabling infrastructure.

Invest in Other Zero Emission Transportation

Ontario seeks a partnership with the Government of Canada to support enabling infrastructure that will increase the availability and use of lower carbon fuels, including LNG, increase the use of low carbon trucks and buses and increase the availability of LNG fueling infrastructure. Ontario is dedicating significant resources for these additional transportation initiatives. Expected emissions reductions in the transportation sector overall are 2.45 Mt in 2020.

Assist with Building Retrofits, Energy Audits and Technology Deployment

Ontario seeks a partnership with the Government of Canada as the province develops programs for fuel switching and energy efficiency, such as retrofits for existing residential buildings (including targeted initiatives for low-income households), and clean technologies for industries and small and medium enterprises. Partnership would increase investment in this area, allowing acceleration and scaling up of progress.

Ontario Climate Modelling Services Consortium

Ontario seeks a partnership with the Government of Canada to build regional capacity and support adaptation actions. Ontario plans to establish an Ontario Climate Modelling Services Consortium, which would act as a one window source of data to help the public and private sectors make evidence-based decisions.

The Consortium would operate at arm's length from government. Ontario would seek partnerships with other governments, non-governmental organizations and the private sector to ensure the organization's effectiveness and long term success. The Consortium would also be expected to develop service fee revenue streams to contribute to the organization's fiscal sustainability.

Electricity Transmission

Ontario, in collaboration with the Government of Canada, will work with its regional partners to advance opportunities to expand and upgrade electricity transmission infrastructure to support clean hydroelectric power to displace the production of electricity from fossil fuels.

Ontario will also collaborate with the Government of Canada to accelerate access to clean electricity in remote Indigenous communities. This will lessen dependence on expensive diesel fuel and reduce greenhouse gas emissions and air pollution.

QUÉBEC

KEY ACTIONS TO DATE

Some of the key measures taken to date by Québec, which has the lowest greenhouse gas emissions per capita between the provinces in Canada, include:

2013-2020 Action Plan on Climate Change (PACC 2013-2020)

PACC 2013-2020 will reduce GHG emissions by 20% below the 1990 level by 2020. Among its other measures, the action plan offers financial help to the different stakeholders of Québec society so they can reduce their energy consumption, improve their practices, innovate and adjust. The work surrounding the development of the actions of Québec after the 2020 period is underway, in particular to reduce GHG emissions of the province by 37.5 % below the 1990 level by 2030.

2016-2030 Energy Policy

The Energy Policy will favour a transition to a low carbon footprint economy, chiefly by improving energy efficiency by 15%, by reducing petroleum consumption by 40%, and by increasing the production of renewable energies by 25%. Québec is one of the world's main producers of renewable energy, which represents 99.8% of its total electricity production.

2013-2020 Governmental Climate Change Adjustment Strategy

The Strategy will mitigate the impact of climate change on the environment, the economy and the communities, and will strengthen the resiliency of Québec society. The government of Québec has, notably, invested in the Ouranos consortium in order to get a better understanding of the impact of climate change on its territory, and to better inform the decision-making process and the development of solutions.

2015-2020 Transport Electrification Plan

Québec targets 100,000 electric vehicles on the road in 2020 and one million in 2030. The zero-emission vehicle (ZEV) standard adopted in October 2016 will encourage automotive manufacturers to improve their offer of ZEV, and the investments in electrification will allow Québec to build up its available renewable energies, its expertise and its world-class know-how.

These measures represent a major contribution at the Pan-Canadian level.

ACTION ON PRICING CARBON POLLUTION

Pioneer in the use of cap-and-trade systems for greenhouse gas emissions allowances, Québec`s system has been linked to California's since 2014, and will soon be linked to that of Ontario. It represents the largest carbon market in North America, and is often referred to as an example of performance and rigour. Because it is based on hard caps to reduce GHG emissions, it is a robust and efficient tool to achieve the ambitious mitigation goals Québec has set for itself for 2020 and 2030.

Furthermore, auction revenues from its cap-and-trade system are entirely reinvested in measures that will spur the transition of Québec's economy to a more resilient and low-carbon one. This comprehensive approach, tailored to the needs and specificities of Québec, allows Québec to fulfill its leadership role in the fight against climate change in North America and internationally.

COLLABORATION PARTNERSHIP OPPORTUNITIES FOR CLEAN GROWTH AND CLIMATE CHANGE

The governments of Québec and Canada intend to collaborate in the following priority areas in order to fight climate change and allow clean economic growth:

Electric and Public Transport

Support the development of the offer and infrastructure of electric and public transport, by completing various projects such as the Metropolitan Electric Network (MEN), the implementation of bus rapid transit (BRT) systems between Montreal and Laval, the extension of the BRT in Gatineau, and the implementation of a BRT in Québec.

Energy Efficiency and Conversion

Speed up the reduction of GHG emissions in Northern communities, as well as on the Lower North Shore and Magdalen Islands, by replacing diesel with renewable energy sources for the electricity supply of their free-standing network.

Promote the implementation of energy performance and efficiency standards for new buildings, as well as for the renovation of existing buildings. Invest in the industrial sector to improve the energy performance of fixed production processes, by providing innovative technologies and reducing the use of gases with high warming potential such as hydrofluorocarbons, which Québec will continue to prioritize.

Recognition of the International Trade of Emission Rights

Contribute to the implementation of Articles 6 and 13 of the Paris Accord, to which the accounting and disclosure principles of the Western Climate Initiative (WCI) can contribute, as well as within a possible agreement between Canada and the United States regarding the accounting and attribution of "internationally transferred mitigation outcomes" as part of the contributions determined at national level (CDN).

Québec will also share with the government of Canada a detailed methodology, developed in collaboration with California and soon Ontario, in order to tabulate in its international reports the emission reductions achieved by Québec thanks to the carbon market.

Innovation and Adjustment to Climate Change

Promote innovation in green technology and GHG emission reduction, and collaborate on increasing the resiliency of the communities affected by climate change, by assessing the vulnerabilities and risks, adjusting land planning and use, and designing sustainable projects.

Québec will provide its expertise to the initiatives of the government of Canada, focusing in particular on joint financing of prevention and protection infrastructure against certain natural disasters linked to climate change.

NEW BRUNSWICK

KEY ACTIONS TO DATE

Some of the key actions taken to date or under development in New Brunswick include:

Transitioning to a Low-Carbon Economy: New Brunswick's Climate Change Action Plan

The Climate Change Action Plan outlines a bold vision for New Brunswick and sets renewed GHG reduction targets: 2030 target of 35% below 1990 levels; and 80% below 2001 levels by 2050. The plan also address other commitments, such as the Canadian Energy Strategy, released by the Council of the Federation in 2015, and contains a Climate Change Adaptation Strategy supported by actions to build resilience into New Brunswick communities, businesses, infrastructures and natural resources.

The Action Plan provides a clear path forward to reduce GHG emissions while promoting economic growth and enhancing current efforts to adapt to the effects of climate change.

Locally-owned Renewable Energy Projects that are Small Scale (LORESS)

In May 2015, the province introduced legislation to allow local entities to develop renewable energy sourced electricity generation in their communities. This will enable universities, non-profit organizations, co-operatives, First Nations and municipalities to contribute to NB Power's renewable energy requirements.

Shifting to renewables in electricity generation

Two fossil fuelled power plants were closed in recent years – one coal and one heavy oil. Also, 300 megawatts of wind energy was installed in the province and biomass fuel use in industry was expanded to displace oil. Solid waste landfills are capturing biogas and some are generating electricity.

These actions are allowing NB Power to achieve the regulated Renewable Portfolio Standard of 40% of in-province sales from renewable energy sources by 2020. This translates to approximately 75% non-emitting by 2020 including nuclear.

Adaptation

The province has developed a progressive Climate Change Adaptation Program including assembling future climate projections, and supporting climate impact vulnerability assessments in communities and for infrastructure. Adaptation projects also focus on solutions building and advanced planning to help reduce or avoid the costs of impacts such as more severe and frequent flooding, coastal erosion and storm events and disease and pest migration.

Several projects are carried out in collaboration with other Atlantic provinces, notably under the Regional Adaptation Collaborative (RAC), which involves federal support, as well as with the Gulf of Maine Council and US partners.

These actions provide a strong contribution to a comprehensive Pan-Canadian Framework.

ACTION ON PRICING CARBON POLLUTION

The province will implement a made-in-New Brunswick carbon pricing mechanism that addresses the requirements of the federal government for implementing a price on carbon emissions by 2018 and that at the same time recognizes New Brunswick's unique economic and social circumstances. The provincial government will take into consideration the impacts on low-income families, trade-exposed and energy-intensive industries, and consumers and businesses, when developing the specific mechanisms and implementation details, including how to reinvest proceeds.

Any carbon pricing policy will strive to maintain competitiveness and minimize carbon leakage (i.e., investments moving to other jurisdictions). Proceeds from carbon emissions pricing will be directed to a dedicated climate change fund.

COLLABORATION PARTNERSHIP OPPORTUNITIES FOR CLEAN GROWTH AND CLIMATE CHANGE

The Government of New Brunswick and the Government of Canada intend to collaborate in the following domains of priority to address climate change and advance clean growth:

Enhanced Electricity Generation and Transmission System

New Brunswick will work with the other Atlantic provinces and the Government of Canada to advance opportunities for clean electricity generation, transmission, storage and demand management linkages across the region. This will: improve access to non-emitting electricity; support the phase-out of coal-fired electricity generation; improve grid reliability and energy security; and, consistent with fair market principles, help provinces access export markets for clean, non-emitting electricity.

This will contribute to both the Atlantic Growth Strategy and Canadian Energy Strategy and will build on existing regional coordination efforts, leading to an integrated regional electricity strategy.

Energy Efficiency

The Government of New Brunswick, in partnership with the Government of Canada, will seek to enhance energy efficiency programs by targeting GHG emission reduction opportunities across sectors and fuels.

Examples of possible targeted interventions include programs that help: trucking fleets add aerodynamic and other efficiency measures to existing equipment; small- to medium-size industry improve their compressed air systems, boilers and lighting; commercial and institutional facilities invest in heating, lighting and other retrofits; and families retrofitting their homes to reduce energy costs, with special treatment for low- and fixed-income families.

Industrial Emissions Reductions

The Government of New Brunswick and the Government of Canada will work to support industrial emission reduction initiatives through technology and energy efficiency improvements while maintaining productivity. For example, there are significant opportunities to reduce emissions resulting from industrial production in the Belledune area of New Brunswick.

NOVA SCOTIA

KEY ACTIONS TO DATE

Some of the key actions taken to date or under development in Nova Scotia include:

The Environmental Goals and Sustainable Prosperity Act (2007)

In 2007, Nova Scotia passed legislation outlining principles for sustainable economic growth, including a requirement to reduce GHG emissions in the province to 10% below 1990 levels by 2020. The development and implementation of the Nova Scotia Climate Action Plan led to early action on the electricity sector, the largest source of emissions in the province. As a result, Nova Scotia has not only achieved its target six years early, it has also already met the Canadian 2030 target of 30% below 2005 levels, and is on a track to continue reducing emissions.

Nova Scotia's Greenhouse Gas Emissions Regulations

Nova Scotia was the first province in Canada to place a hard cap on GHG emissions from the electricity sector. These regulations, created in 2009 and enhanced in 2013, required the utility to reduce GHG emissions by 25% by 2020, and 55% by 2030. This is a measured and flexible approach which will enable a transition from coal to clean energy in the province.

Nova Scotia's Renewable Energy Regulations

In addition to the hard cap on GHG emissions, Nova Scotia also has a renewable energy standard for the electricity sector. This standard established requirements for 25% of electricity to be sourced from renewable energy by 2015, and 40% by 2020.

Energy Efficiency

Nova Scotia has Canada's first energy efficiency utility, Efficiency Nova Scotia. This independent organization has achieved an annual reduction in electricity demand of over 1% since its creation. It also administers comprehensive energy efficiency programs for low income and First Nations Nova Scotians. These efforts reduce GHG emissions while supporting the growth of the low carbon economy.

Tidal Energy

The Bay of Fundy and Minas Basin are home to the highest tides in the world- every day, more water flows into this bay than the output from all the rivers in the world combined. Nova Scotia has been supporting the development of these tides as a source of clean, predictable and reliable energy for Nova Scotians and as a clean technology export. The Fundy Ocean Research Centre for Energy (FORCE) now has a grid connected 2MW tidal turbine with plans to install more in the coming years.

Waste Management

Nova Scotia is also making efforts to reduce GHG emissions by diverting organic waste from landfills, recycling and creating a circular economy. Progress on waste diversion is reflected in a 30% reduction in greenhouse emissions from the waste sector since 2002.

These actions are just a snapshot of what Nova Scotians are doing to reduce GHG emissions and provide a strong contribution to a comprehensive pan-Canadian framework.

ACTION ON PRICING CARBON POLLUTION

As part of the pan-Canadian benchmark for carbon pricing, Nova Scotia has committed to implement a cap and trade program in the province that builds on our early action in the electricity sector.

COLLABORATION PARTNERSHIP OPPORTUNITIES FOR CLEAN GROWTH AND CLIMATE CHANGE

The Government of Nova Scotia and the Government of Canada intend to collaborate in the following priority domains to address climate change and advance clean growth:

Energy Efficiency

Nova Scotia and the Government of Canada are committed to partnering to enhance the existing provincial energy efficiency programs for homes and businesses with the objective of reducing energy use and saving energy costs. This could include expanded energy efficiency programs, efforts to accelerate the electrification of homes and businesses through heat pumps and smart meters, district energy systems, as well as electric vehicle infrastructure.

Renewable Energy Generation, Transmission and Storage

Nova Scotia, in partnership with the Government of Canada, will work together to advance opportunities for renewable energy generated from sources such as wind, tidal and solar, as well as the enabling transmission and storage infrastructure to ensure growth beyond current technical limits. Research and development capacity will continue to be strengthened.

Planning and Implementing Adaptation Infrastructure

Nova Scotia and the Government of Canada will work together and invest in projects to make infrastructure more resilient to a changing climate, and to help communities increase their capacity to adapt to a changing climate.

Regional Electricity Grid Connections

Nova Scotia will work with the other Atlantic provinces and the Government of Canada to advance opportunities for clean electricity generation, transmission, storage and demand management linkages across the region.

This will: improve access to non-emitting electricity; support the phase-out of coal-fired electricity generation; improve grid reliability and energy security; and, consistent with fair market principles, help provinces access export markets for clean, non-emitting electricity. This will contribute to both the Atlantic Growth Strategy and Canadian Energy Strategy and will build on existing regional coordination efforts, leading to an integrated regional electricity strategy.

PRINCE EDWARD ISLAND

KEY ACTIONS TO DATE

Some of the key actions taken to date or under development in Prince Edward Island include:

Climate Change Policy Framework

Prince Edward Island's primary areas of strategic focus for climate change fall into the themes of built environment, transportation, agriculture, conservation and adaptation. Prince Edward Island is in the process of developing new climate change strategies that will result in further actions and initiatives to reduce GHG emissions across the province, increase our resilience to a changing climate, and advance measures to strengthen and grow a prosperous green economy in the province.

Prince Edward Island does not have a legislated provincial emissions reduction target but does contribute to the regional target set by the Conference of the New England Governors and Eastern Canadian Premiers (NEG-ECP). The targets are 10% reductions from 1990 by 2020, 35% - 45% below 1990 levels by 2030, and 75-85% reduction from 2001 levels by 2050. PEI has realized a 9% reduction in GHG emissions since 2005.

PEI Wind Energy

Prince Edward Island is a world leader in producing clean electricity from wind. Prince Edward Island boasts the highest penetration of wind in Canada and 2nd highest in the world next to Denmark. The Government of Prince Edward Island has demonstrated a long-term commitment and investments of $119 million to wind energy.

The first commercial wind farm in Atlantic Canada was developed by the PEI Energy Corporation at North Cape in 2001. North Cape was expanded in 2003, doubling in size.

In January 2007, the PEI Energy Corporation commissioned its second wind farm at East Point. In 2014, the Island's newest wind farm was commissioned at Hermanville/ Clearspring. As a result, Prince Edward Island now has a total installed wind capacity of 78% of peak load, which supplies almost 25% of the province's total electricity requirements.

Biomass

Prince Edward Island is home to Canada's longest-running, biomass-fired district heating system. Operating since the 1980s, the system has expanded to serve over 125 buildings in the downtown core of Charlottetown, including the University of Prince Edward Island and the Queen Elizabeth Hospital. It has contributed to the establishment of a local waste-wood fuel-supply market. The system burns approximately 66,000 tons of waste materials annually.

Coastal Erosion

Prince Edward Island has partnered with the University of Prince Edward Island (UPEI) Climate Research Lab to study coastal vulnerability, including the award-winning Coastal Impacts Visualization Environment (CLIVE). CLIVE is an innovative 3D platform for visualizing the potential future impacts of coastal erosion and coastal flooding at local community scales, on PEI and elsewhere, using past data and Intergovernmental Panel on Climate Change models.

The province has also invested in UPEI in its development of an expansive, cutting-edge coastal erosion monitoring network. This research includes the use of drone and GIS technology to quantify and assess erosion volume of shoreline disappearance along Prince Edward Island's coastline.

Environmental Awareness in Agriculture

As a key industry for Prince Edward Island, agriculture is of particular consequence for climate change and green growth. In recent years, PEI farmers, watershed groups and the fertilizer industry have been implementing a 4R Nutrient Stewardship program to encourage the efficient use of fertilizer and help reduce related emissions.

Island farmers have been making advances in crop diversification, including testing potato varieties that require less fertilizer and adding nitrogen-fixing pulse crops which improve the environmental sustainability of annual cropping systems. The further use of robotics in dairy farming and food additives in livestock production is being employed to reduce methane emissions.

Prince Edward Island is also the first and only jurisdiction in Canada with a provincially-supported Alternative Land Use Services program. Currently, the program has converted almost 4,000 hectares of marginal land from annual crop production to perennial or permanent cover.

These actions provide a strong contribution to a comprehensive pan-Canadian framework and are helping facilitate the transition to a low-carbon economy.

ACTION ON PRICING CARBON POLLUTION

Prince Edward Island will introduce a made-in-PEI approach to carbon pricing which positively contributes to climate change action while benefitting Prince Edward Islanders and ensures optimal conditions for continued growth of the provincial economy. Prince Edward Island will focus on measures that will meaningfully decrease our GHG emissions and recognize the particular elements of our economy.

Our approach will ensure consistent and competitive alignment with efforts being made across the country, including mitigation and price initiatives in all provinces, especially those in our region. PEI is committed to an approach that will directly enhance provincial adaptation and mitigation efforts.

COLLABORATION PARTNERSHIP OPPORTUNITIES FOR CLEAN GROWTH AND CLIMATE CHANGE

Prince Edward Island and the Government of Canada intend to collaborate in the following domains of priority to address climate change and advance clean growth:

Energy Efficiency

Prince Edward Island, in partnership with the Government of Canada, will pursue improved energy efficiency for all sectors in the province as outlined in the 2016 PEI Energy Strategy. The Strategy and forthcoming Climate Change Action Plan are key policy tools in reducing GHGs, driving economic growth and creating jobs locally and in the region.

Prince Edward Island is committed to engaging in incremental actions through solutions for the built environment, including businesses and homes, as well as in new building construction. It has been clearly illustrated by research in the region that investing in efficiency is one of the most effective means of delivering jobs and economic growth widely – across sectors and regions – while reducing emissions and providing savings to consumers.

With a predominantly rural population and some of the highest electricity rates in the country, particular consideration will be given to low-income Island families, and sectors that may find the transition to a lower-carbon environment challenging.

Clean Energy

Energy resilience and security and a move to greater electrification are key priorities for the province. Prince Edward Island, in partnership with the Government of Canada, will work to expand its world-class wind resource, invest in solar, and enable greater integration of renewable energy through storage. Prince Edward Island will work with the other Atlantic Provinces and the Government of Canada to advance opportunities for clean electricity generation, transmission, storage and demand management linkages across the region.

This will: improve access to non-emitting electricity; support the phase-out of coal-fired electricity generation; improve grid reliability and energy security; and, consistent with fair market principles, help provinces access export markets for clean, non-emitting electricity. This will contribute to both the Atlantic Growth Strategy and Canadian Energy Strategy and will build on existing regional coordination efforts leading to an integrated regional electricity strategy.

Adaptation

With its 1100 km of coastline, Prince Edward Island is uniquely vulnerable to climate impacts and is positioned to advance innovative solutions to make infrastructure more resilient to a changing climate.

Prince Edward Island and the Government of Canada will work together to act on findings from disaster risk reduction planning and coastal infrastructure assessment, and to improve decision-making capacity to adapt to climate change through planning, training and monitoring.

Research and Development

Prince Edward Island and the Government of Canada will work together to support research and development on promising practices and innovation in the areas of agriculture, marine industries, and smart grid and micro-grid/ storage. Prince Edward Island provides an ideal demonstration site for development in these areas.

This research will advance better understanding of influences on emissions and opportunities for clean growth in key sectors of the Prince Edward Island economy.

Transportation

Prince Edward Island relies on exports for continued economic growth. The Prince Edward Island economy is heavily reliant on ground transportation for the movement of goods to markets across Canada and around the world, and the movement of people across the province. The province has no rail system, large container ports, or robust public transit. As the most rural province in Canada, mitigation in transportation is a difficult challenge.

Prince Edward Island and the Government of Canada will work together on methods to support an eventual move to greater electrification in transportation, including corresponding work with other jurisdictions in Canada. Proposed specific areas of work include installation of public charging infrastructure across the province and in collaboration regionally where possible.

NEWFOUNDLAND & LABRADOR

KEY ACTIONS TO DATE

Newfoundland and Labrador is making significant investments to increase the use of clean and renewable hydroelectric power in the province. The Muskrat Falls hydroelectric development, with capital costs of over $9 billion, will result in 98% of electricity consumed in the province coming from renewable sources by 2020.

Muskrat Falls will facilitate advancing by more than a decade the decommissioning of the largest thermal oil-fired electricity generation facility in the province, reducing greenhouse gas (GHG) emissions by about 1.2 Mt annually (equivalent to more than 10% of the province's total emissions in 2015), and assisting other jurisdictions to meet their GHG reduction targets.

To focus the province's efforts to tackle climate change, Newfoundland and Labrador has adopted GHG emission reduction targets of 10% below 1990 levels by 2020 and 75-85% below 2001 levels by 2050, and has endorsed, on a regional basis, the Conference of New England Governors and Eastern Canadian Premiers' reduction marker range of at least 35-45% below 1990 levels by 2030.

To make progress towards these targets Newfoundland and Labrador released a Climate Change Action Plan in 2011 identifying 75 actions to reduce GHG emissions and adapt to the adverse impacts of climate change. Building on this work, Newfoundland and Labrador passed the *Management of Greenhouse Gas Act* in June 2016, creating a legislative framework for reducing GHGs from large industry, and has completed public consultations to inform new provincial actions on climate change.

These actions provide a strong contribution to a comprehensive Pan-Canadian Framework.

ACTION ON PRICING CARBON POLLUTION

The Government of Newfoundland and Labrador and the Government of Canada continue to collaborate to ensure that Newfoundland and Labrador's climate change plan, including carbon pricing, is consistent with the goals in the Pan-Canadian Framework to reduce GHG emissions, improves resilience to climate impacts, and accelerates innovation and job creation.

This made-in-Newfoundland and Labrador plan will address the province's particular social, economic, and fiscal realities. This includes sensitivity to the particular circumstances facing Labrador communities, and the need to consider impacts on all remote and isolated communities, vulnerable populations, consumers and trade-exposed industries, as well as the need to take account of the province's reliance on marine transportation and the absence of lower carbon alternatives.

COLLABORATION PARTNERSHIP OPPORTUNITIES FOR CLEAN GROWTH AND CLIMATE CHANGE

Newfoundland and Labrador and the Government of Canada intend to explore collaboration in the following priority domains to address climate change and advance clean growth:

Renewable Energy

Newfoundland and Labrador and the Government of Canada intend to jointly explore opportunities to develop renewable energy, including such actions as enhancing hydroelectric capacity, increasing transmission infrastructure, and offsetting diesel use in small-scale off-grid electricity systems.

These efforts will also seek to maximize collaboration with other Atlantic provinces in the electricity sector, contributing to both the Atlantic Growth Strategy and Canadian Energy Strategy, and will build on existing regional coordination efforts, leading to an integrated regional electricity strategy.

Transportation

Newfoundland and Labrador and the Government of Canada intend to jointly explore opportunities to reduce GHG emissions in all parts of the transportation sector, including electric vehicles and associated infrastructure, on- and off-road freight and industrial transportation, marine vessels, and public transit.

Energy Efficiency

Newfoundland and Labrador and the Government of Canada intend to jointly explore opportunities to develop energy efficiency programming, improve energy codes, and support fuel switching in all sectors reliant on fossil fuels.

Adaptation

Newfoundland and Labrador and the Government of Canada intend to jointly explore opportunities to expand climate monitoring and adaptation product and information development, as well as best management practices.

Green Innovation

Newfoundland and Labrador and the Government of Canada intend to jointly explore opportunities in research and development in green technology, including fostering innovation networks and initiation of pilot projects.

YUKON

KEY ACTIONS TO DATE

Some of the key actions taken to date or under development in Yukon include:

Yukon Government Climate Change Action Plan

The Yukon government *Climate Change Action Plan* has four goals: reducing GHG emissions; addressing the impacts of climate change; leading Yukon action on climate change; and enhancing our knowledge and understanding of climate change.

KEY ACTIONS

Work to date in achieving *Climate Change Action Plan* goals includes:

Reducing GHG emissions (mitigation)

- Setting nine sector-specific targets in the areas of transportation, heating buildings, electricity, and industrial operations.
- Completing a study of Yukon's transportation sector, and launching a Ride Share program in partnership with the City of Whitehorse.
- Supporting Yukon homeowners with the Good Energy Residential Incentives Program, which provides incentives to purchase high efficiency wood stoves, boilers and pellet stoves.
- Carrying out detailed energy audits of seven high-consumption Yukon government buildings.
- A Yukon Biomass Strategy to guide the development of a biomass energy sector in the territory.

Addressing the impacts of climate change (adaptation)

- Completing ten adaptation projects in the areas of permafrost impacts to highways, buildings, hydrological responses, and agricultural capacity; flood risk mapping; forestry implications including the encroachment of mountain pine beetle in lodgepole pine forests; and bioclimate shifts.
- With the Pan-Territorial Adaptation Strategy, territorial governments are collaborating on practical adaptation measures for the north. Permafrost thaw has been a key focus.

Leading Yukon action on climate change

- Participating in international and national climate change efforts that impact Yukon, such as the United Nations Framework Convention on Climate Change Conference of the Parties (COP) meetings, including a developmental opportunity for a Yukon youth ambassador.
- Currently supporting the Yukon College to develop a climate change policy course to be offered by Yukon College.

Enhance our knowledge and understanding of climate change

- Supporting development of the Climate Change Indicators and Key Findings report, an important source of independent information that will guide action and research on climate change in Yukon.
- Provide ongoing funding for the Northern Climate Exchange at Yukon College.

These actions provide a strong contribution to a comprehensive pan-Canadian framework.

ACTION ON PRICING CARBON POLLUTION

The Government of Yukon recognizes the role of carbon pricing in the pan-Canadian Framework for Clean Growth and Climate Change.

Given Yukon's particular circumstances, the Government of Canada and the Government of Yukon will work together to assess the implications of carbon pricing in the territory for its economy, communities and people including energy costs, and to develop solutions together.

The Government of Yukon and the Government of Canada will also work together to assess the implications of carbon pricing in Canada on the cost of living in Yukon. This will be an important consideration for future policy development.

As outlined in the federal government's benchmark, 100% of the revenues from carbon pricing will be retained by Yukon. Yukon government will distribute these revenues back to individual Yukoners and businesses through a rebate.

COLLABORATION PARTNERSHIP OPPORTUNITIES FOR CLEAN GROWTH AND CLIMATE CHANGE

Yukon and the Government of Canada intend to collaborate in the following domains of priority to address climate change and advance clean growth:

Advancing Renewable Energy

Yukon government and the Government of Canada will partner in advancing renewable energy projects in Yukon. This will improve the energy infrastructure in Yukon, including developing new renewable energy sources to provide clean energy for current and future electricity needs.

It will also support remote communities in diminishing their reliance on diesel for electricity and will support the expanded use of biomass as a cleaner option for heating in Yukon.

Energy Efficiency

Yukon government, in partnership with the Government of Canada, will support energy efficiency through the retrofitting of existing buildings. Sound investments in retrofits and new energy efficiency projects will be supported by expanding the capacity for collecting, analyzing, and reporting emissions data that will help identify the areas of greatest opportunity for reducing emissions.

Adaptation: Building Resilient Yukon Communities

Canada's Northern jurisdictions and the Government of Canada are working together to develop the Northern Adaptation Strategy. The Government of Canada will partner with Yukon to help build climate-resilient Yukon communities.

Research collaboration will build the knowledge necessary for evidence-based decision-making in community planning. Investments in infrastructure will address known risks such as infrastructure built on thawing permafrost.

Green Innovation and Technology

Yukon government and the Government of Canada will partner on new research and pilot projects that will explore promising areas for climate action in the north, such as seasonal energy storage, cleaner transportation options, and community-level renewable energy generation.

NORTHWEST TERRITORIES

KEY ACTIONS TO DATE

NWT Climate Change Strategic Framework

The Government of the Northwest Territories (GNWT) has committed to develop a climate change strategy that takes northern energy demands and the cost of living into account. It will reflect commitments to reduce greenhouse gas emissions, explore carbon pricing systems and how to develop local alternatives such as hydro, biomass, wind and solar.

NWT Energy Strategy

The GNWT is currently working on a new 10 year Energy Strategy. The Energy Strategy will focus on the affordability, reliability and environmental impacts of energy in the NWT and will promote energy efficiency, renewable and alternative energy in the electricity, heating and transportation sectors.

The GNWT continues to take the following territorial adaptation actions:

- Support adaptation decision-making with knowledge, information collection and sharing
- Build capacity to translate adaptation knowledge into action
- Build climate-resilience through investments in infrastructure
- Invest in land use planning, management plans and building adaptation capacity and expertise
- Support most vulnerable regions, conducting risk assessments and completing hazard mapping
- Reduce climate-related hazards and disaster by developing disaster risk management plans
- Adapt renewable energy options and solutions for cold regions

The GNWT continues to take the following territorial emissions mitigation actions:

- Work with our federal, provincial indigenous partners and others to find solutions to address diesel use in remote off-grid communities including to develop the NWT's hydroelectricity potential to reduce GHG emissions in the electricity sector.
- Implement policies to support the adoption of lower carbon and energy efficient technologies.
- Implement policies to support industry and large emitters in the adoption of lower carbon and energy efficient technologies.
- Continue biomass initiatives and work towards the development of a local forest and wood product industry and develop local wood pellet manufacturing as an alternate local fuel source.
- Addressing energy use and GHG emissions in government buildings and operations.

These actions provide a strong contribution to a comprehensive pan-Canadian framework.

ACTION ON PRICING CARBON POLLUTION

Through the Climate Change Strategic Framework, the GNWT is exploring potential impacts and opportunities that may arise from pursuing different carbon pricing systems in the territory.

The GNWT recognizes the role of carbon pricing in the pan-Canadian Framework for Clean Growth and Climate Change. Given the NWT's particular circumstances, the Government of Canada and the GNWT will work together to assess the implications of carbon pricing in the territory for its economy, communities and people including energy costs, and to develop solutions together.

The GNWT and the Government of Canada will also work together to assess the implications of carbon pricing in Canada on the cost of living in the NWT. This will be an important consideration for future policy development.

As outlined in the federal government's benchmark, 100% of the revenues from carbon pricing will be retained by the NWT.

COLLABORATION PARTNERSHIP OPPORTUNITIES FOR CLEAN GROWTH AND CLIMATE CHANGE

The NWT will work with the Government of Canada, in collaboration with regional partners, to advance opportunities for clean electricity generation, transmission, storage and demand management linkages across the region.

This will: improve access to non-emitting electricity; support the phase-out of coal-fired electricity generation; improve grid reliability and energy security; and, subject to fair market principles, help the region access export markets for clean, non-emitting electricity.

The NWT and the Government of Canada intend to collaborate in the following priority areas to address climate change and advance clean growth:

Taltson Hydro Expansion and Transmission Links

The proposed Taltson hydro expansion is a small scale run of river hydro project that could be developed with little environmental impact next to the existing power plant, on an already developed river, and combined with a transmission link to provide a green energy corridor to our southern neighbours.

The expansion of the Taltson hydro facility would help reduce Canada's GHG emissions by 360,000 tonnes annually for 50-plus years.

The 60 MW expansion of the Taltson hydro facility could be built in partnership with NWT Indigenous governments, creating economic opportunities for Indigenous-owned businesses across the North. The NWT and Government of Canada will undertake technical and feasibility studies as a first step, including the NWT launching the environment assessment process.

Renewable Solutions for Off-Grid Diesel Communities

The Government of Canada and the GNWT will explore opportunities for reducing reliance on diesel in off-grid communities. For example, the Inuvik Wind Project could produce between 2 and 4 megawatts of wind energy for the Town of Inuvik. The project would reduce GHG emissions by 4,300 tonnes per year and eliminate the need for 1.3 million litres of diesel annually in the largest diesel community in the NWT, and help reduce the cost of living for residents.

For other off-grid diesel powered communities of the NWT, a suite of renewable solutions such as solar and wind in combination with energy storage systems and variable generators could reduce diesel use and emissions by 25 percent, an annual GHG elimination of nearly 3000 tonnes.

All-Weather Road Infrastructure for Adapting to Climate Impacts

The safety and reliability of winter roads is being impacted by climate change. Construction of the Mackenzie Valley Highway from Wrigley to Norman Wells would provide safe, secure, and reliable access into the Sahtu region, helping decrease the high cost of living in communities and support the development of resources in the region.

The Great Bear River is a priority as the seasonal ice crossing is increasingly vulnerable to impacts of climate change. Climate change is also limiting access to existing diamond mining operations in the Slave Geological Province.

Construction of an all-weather Slave Geological Province Access Corridor would reduce costs for industry exploration and development in a region that holds world-class deposits of natural resources and continues to be a major contributor to the Canadian and NWT economy.

NUNAVUT

KEY ACTIONS TO DATE

Some of the key actions taken to date or under development in Nunavut include:

Energy efficiency upgrades

The Nunavut Energy Retrofit Program was piloted in Iqaluit in 2007, and addressed all of the government of Nunavut's Iqaluit Government of Nunavut-owned buildings. The one-time project investment of $12.8 million has led to annual savings in excess of $1.6 million and 1,594 tonnes of GHG reductions.

In combination with the conversion of three of our facilities to residual heat, our GHG reduction is approximately 4,100 tonnes, which is roughly 20% of those buildings' total emissions.

Development of a Climate Change and Adaptation strategy

Upagiaqtavut was developed in 2011 and serves as a guiding document for the impacts of climate change in Nunavut (http://climatechangenunavut.ca/sites/default/files/3154-315_climate_english_reduced_size_1_0.pdf).

Climate change databank

The Government of Nunavut is developing and uses information technology to centralize and increase the access to climate change information, such as permafrost data and landscape hazards maps. The information is used to improve infrastructure planning and help mitigate the effects of climate change across Nunavut.

Climate Change Secretariat

The Government of Nunavut is establishing a Climate Change Secretariat (CCS), which will be the central point within the government to address both climate change adaptation and mitigation issues.

ACTION ON PRICING CARBON POLLUTION

The Government of Nunavut recognizes the role of carbon pricing in the pan-Canadian Framework for Clean Growth and Climate Change. Given Nunavut's particular circumstances, the Government of Canada and the Government of Nunavut will work together to assess the implications of carbon pricing in the territory for its economy, communities and people including energy costs, and to develop solutions together.

The Government of Nunavut and the Government of Canada will also work together to assess the implications of carbon pricing in Canada on the cost of living in Nunavut. This will be an important consideration for future policy development.

As outlined in the federal government's benchmark, 100% of the revenues from carbon pricing will be retained by Nunavut.

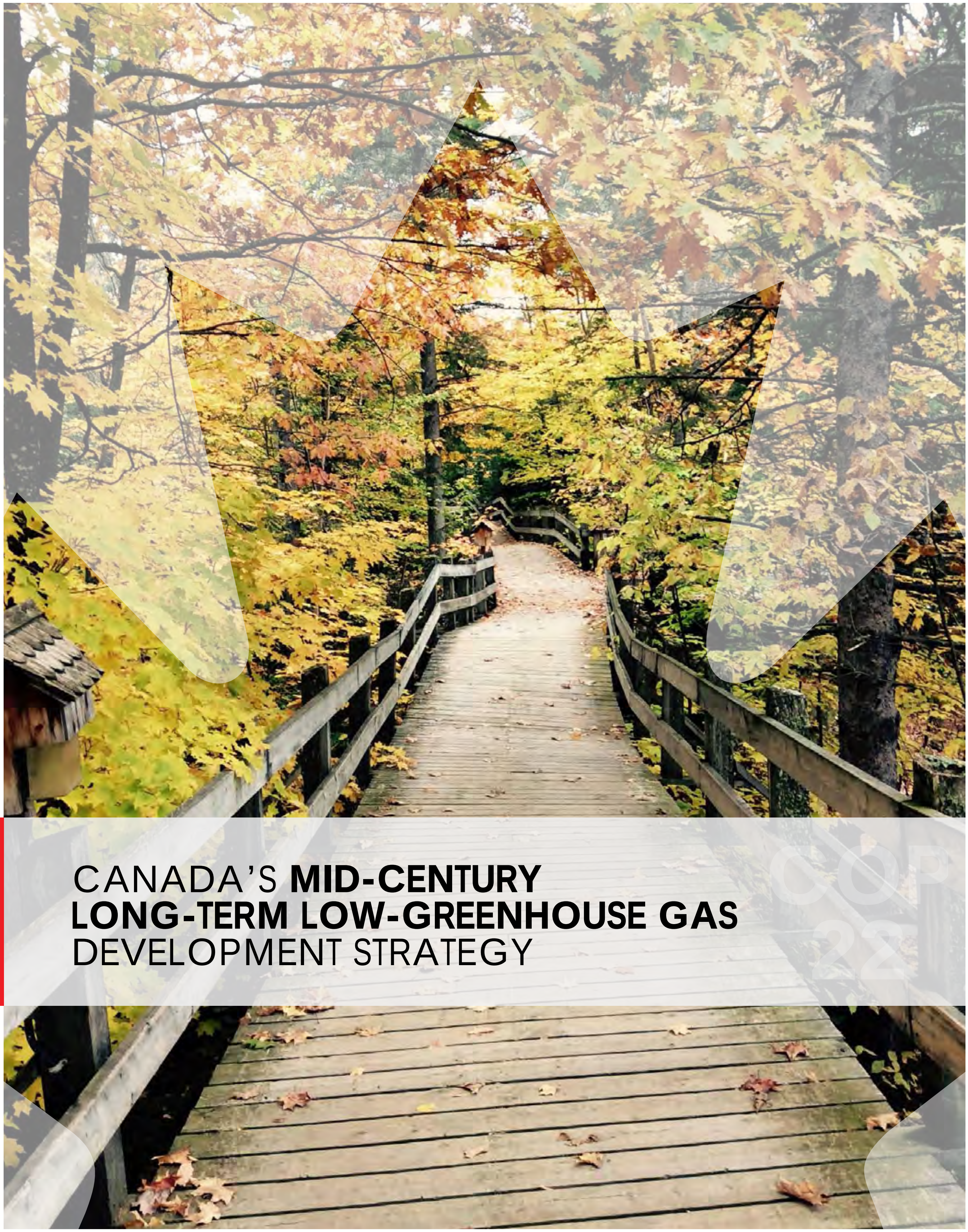
COLLABORATION PARTNERSHIP OPPORTUNITIES FOR CLEAN GROWTH AND CLIMATE CHANGE

Nunavut and the Government of Canada intend to collaborate in the following domains of priority to address climate change and advance clean growth:

Nunavut and the Government of Canada will assess the economic and technical feasibility of electrification through hybrid power generation in Nunavut's communities. Hybrid power generation would significantly reduce emissions while at the same time ensure that Nunavut's isolated communities have reliable power.

Nunavut and the Government of Canada will work together to develop a retrofit program to increase the energy efficiency of public and private housing. Investment in safe and energy efficient housing is a key component of building strong resilient communities in the Arctic.

Government of Canada | Gouvernement du Canada



CANADA'S **MID-CENTURY LONG-TERM LOW-GREENHOUSE GAS** DEVELOPMENT STRATEGY

Canada

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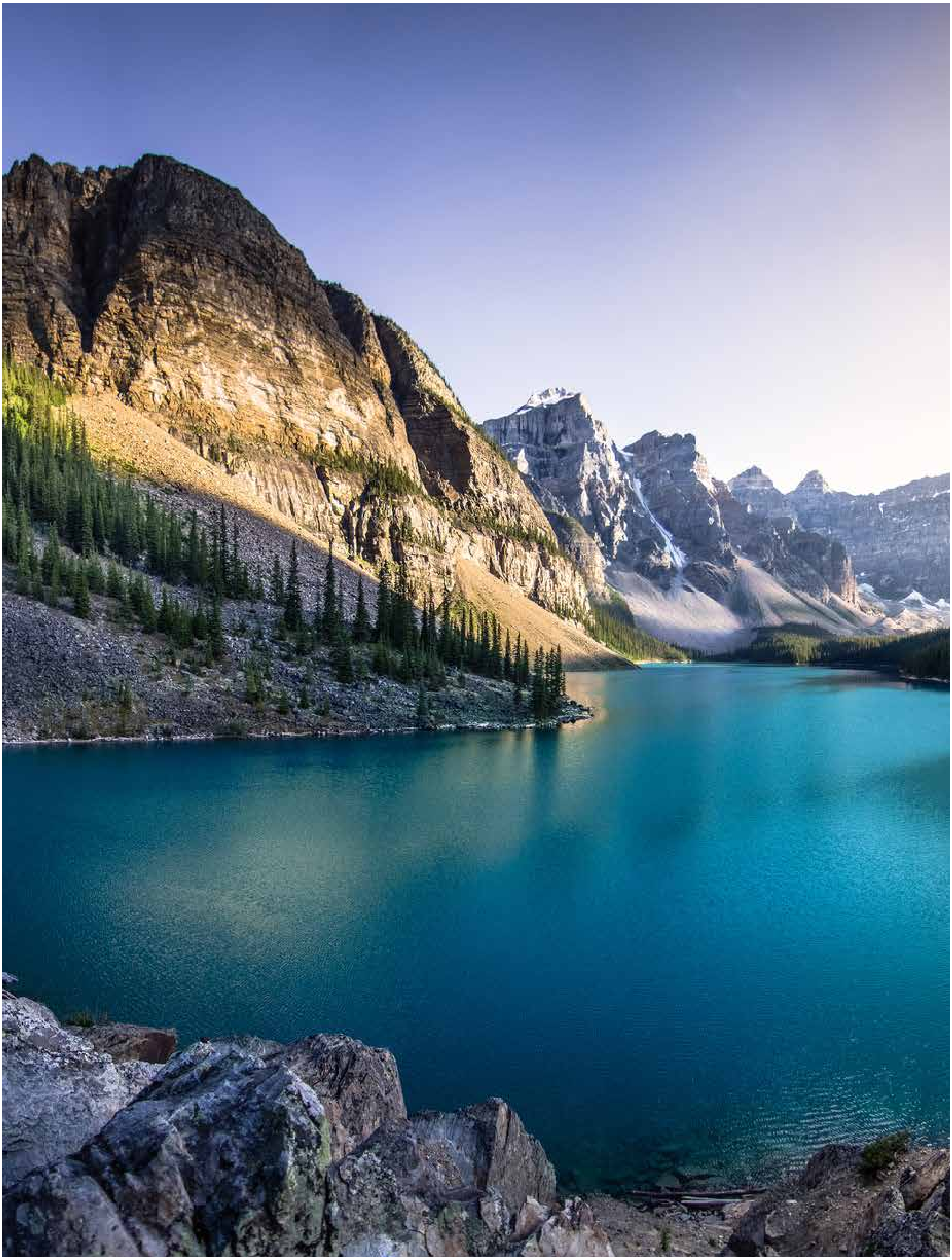
Foreword

Canada views this initial Mid-Century Strategy report as an opportunity to begin the conversation about what a long-term low-greenhouse gas emission society would entail. The report provides a basic framework regarding what challenges and opportunities have currently been identified in academic literature and expert based analyses regarding deep emissions reductions in the mid to long-term.

Canada submits this strategy to the *United Nations Framework Convention on Climate Change* (UNFCCC) under the premise that the content of the report will continue to be updated and adjusted as Canada advances on the implementation of its low-carbon development pathway. As such, Canada's position is that the Mid-Century Strategies should be submitted in an iterative or cyclical process, where Parties provide regular updates as low-GHG technologies and national circumstances continue to evolve.

This iterative process will allow the Canadian public, experts, and stakeholder communities, to provide substance to this framework as Canada moves towards a common global objective of reducing greenhouse gas emissions.



Executive Summary

Canada is committed to creating a cleaner, more innovative economy that reduces emissions and protects the environment, while creating well-paying jobs and promoting robust economic growth.

A low-greenhouse gas future represents an opportunity to increase prosperity and the well-being of Canadians, to improve the livability of the built environment, modernise transportation, and enhance the natural environment.

Canada's actions on climate change will help communities in Canada in tangible and meaningful ways, since clean growth is not just good for the planet — it's also good for the economy. The benefits include: reducing air pollution and congestion, modernising infrastructure to provide more inclusive and sustainable cities, creating cleaner and more modern communities, growing Canada's clean technology sector, increasing economic productivity and efficiency, saving energy and reducing energy costs, and enhancing resilience to the impacts of climate change.

Addressing climate change paves the way towards innovation and jobs in the clean energy and technology sectors. This represents an opportunity to adopt innovations that can enhance quality of life. Canada is investing in a cleaner future for our children and grandchildren, and creating the right conditions for communities everywhere to create good jobs in a modern, clean global economy.

For the purpose of the Mid-Century Strategy, Canada examines an emissions abatement pathway consistent with net emissions falling by 80% in 2050 from 2005 levels. This is consistent with the Paris Agreement's 2°C to 1.5°C temperature goal.

The Paris Agreement, adopted at the 21st Conference of the Parties (COP21) to the *United Nations Framework Convention on Climate Change (UNFCCC)*, represents the first time in history that virtually all of the world's nations agreed to pursue their highest possible ambition to combat climate change under a common framework. Through the Paris Agreement over 195 countries representing 97% of global GHG emissions agreed to strengthen the global response to the threat of climate change, including by holding the increase in the global average temperature to well below 2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels.

Building on analyses from the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report, the United Nations Environment Programme (UNEP) states that GHG emission reductions in the order of 70 to 95% below 2010 levels would be required by 2050 to remain on a pathway consistent with a >50% likelihood of limiting average global temperature rise to 1.5°C. Achieving this temperature goal is only possible through actions on carbon dioxide and short-lived climate pollutants (SLCPs) together. For the purpose of the *Mid-Century Strategy*, Canada examines an emissions abatement pathway consistent with net emissions falling by 80% from 2005 levels.

Reducing greenhouse gas emissions to levels consistent with the reasonable probability of maintaining this temperature goal will not be easy. It will require substantial effort on the part of all Canadians, with a fundamental restructuring of multiple sectors of the economy. Cost-effective abatement opportunities will need to be realised from virtually every greenhouse gas emissions source and activity. In the energy sector, this will include enhanced energy efficiency and conservation, finding cleaner ways to produce and store electricity, and switching towards non-emitting electricity or other low-GHG alternatives.

Although this will require thoughtful and significant effort on the part of all Canadians (including robust government policy such as carbon pricing, regulatory measures, and support for technology development), the cost of inaction poses a dire risk that cannot be ignored. This risk is threefold:

- Ongoing emissions of anthropogenic GHGs will cause atmospheric concentrations to continue to rise, leading to higher global average temperatures and a cascade of related impacts, including increases in severe weather, and rising sea level.
- Failure to act now means that costs will likely rise in the future as the required pace of decarbonisation increases. This raises the probability of misallocation of investment and infrastructure, as well as stranded assets.
- As the world moves to address climate change, Canada should not be left behind in the emerging global markets for clean energy and related goods and services.

A global clean growth economy offers considerable economic opportunities and co-benefits such as growing Canada's clean technology sector, using more efficient technology globally, mitigating other types of pollutants, improving health and air quality, and increasing productivity through more efficient life cycle production.

Responding to climate change presents an opportunity for Canada to discover and adopt new and innovative ways to enhance our quality of life, while ensuring that this prosperity is sustainable given finite natural resources and environmental concerns. For example, designing low-carbon buildings can save on energy requirements and heating, cooling, and electricity costs, while increasing natural light and airflow. As another example, reducing traffic congestion through more sustainable movement of people and goods would reduce GHG emissions as well as air and noise pollution, save travel time, and lead to healthier and more productive cities. Often through analysing supply chains, or life-cycle assessments of final products, solutions can be found that are environmentally, socially, as well as economically preferable.

Finding low-GHG solutions will also provide Canada with opportunities to help other countries that are also pursuing low-GHG objectives. Canada's clean technology sector has grown substantially over the last few years, and there continues to be considerable prospects for continued growth in the sector. Further investments in research, development and deployment (RD&D) of clean technology, will support Canada's competitiveness in the short and long term, both in emerging and traditional market, creating higher paying jobs, and stimulating exports.

Through "Mission Innovation", Canada along with 20 governments and the European Union, have agreed to double their respective investments in transformative, clean energy research and development over five years, encourage private sector investment in clean energy technology, and increase collaboration among participating countries. Canada is making key investments in clean energy and emissions-reducing technology to accelerate domestic adoption and to deploy our energy know-how and technology to markets around the world. Adopting innovative technologies in the natural resources sectors (energy, mining, forestry, agriculture, and fisheries) will promote Canada's international leadership in sustainable resource development, providing prosperity to Canadians.

While today's technologies and knowledge can significantly reduce emissions, the transition to a low-carbon economy can be eased through innovation, a scale up of RD&D investment, and private sector investment.

Most international and Canadian greenhouse gas mid-century abatement analyses note that deep cuts in emissions are possible with today's technology, although mitigation costs remain high in certain areas. For example, an assessment from the Council of Canadian Academies published in 2015, suggests that Canada can significantly reduce GHG emissions by using commercially available technologies in key sectors of the economy. Studies consistently point to currently deployed technologies as being essential components to the climate change solution, such as expanding the use of non-emitting electricity across end-use sectors, increasing the use of alternative fuels, and improving energy conservation and efficiency.

Many studies also note that new and emerging technologies can help to smooth our transition to a low GHG economy. For example, the International Energy Agency (IEA) demonstrates that a sustainable energy transition is possible with currently deployed or near-commercial technologies, but that the long-term transition will be eased (in terms of investment requirements and timing) with the near-term acceleration of deployment of clean energy options, or the development of more innovative technologies. The IEA highlights that current global RD&D investments are well below what is required to achieve our international climate goals.

Likewise, substantial financial investments are needed from the private sector to move towards a low-GHG future, and related risks and opportunities associated with these investments should be identified early. Carbon pricing can provide the market signal required for private sector investment and innovation. Technology developers and users are best positioned to bring forward new technologies that will ultimately succeed. Innovation in clean technologies, whether it is a breakthrough technology or one that improves the efficiency of an existing process, can lead to significant GHG abatement internationally as the new technology becomes utilised globally.

Canada's mid-century and long-term objectives will be ultimately realized though short-term concrete action.

Canada's Mid-Century Strategy is not a blueprint for action, and it is not policy prescriptive. Rather, the report is meant to inform the conversation about how Canada can achieve a low-carbon economy. This includes describing modelling analyses that illustrate various scenarios towards deep emissions reductions. Canada's Mid-Century Strategy outlines potential GHG abatement opportunities, emerging key technologies, and identifies areas where emissions reductions will be more challenging and require policy focus in the context of a low carbon economy by 2050.

To deliver on Canada's short term action, the Government of Canada is working closely with provinces and territories, and with National Indigenous Organizations to finalize a pan-Canadian framework for clean growth and climate change, which will include actions to reduce emissions, build resilience, and spur innovation and create jobs.

This will develop Canada's plan for meeting the 2030 target of reducing GHG emissions to 30% below 2005 levels, and also includes a carbon pricing framework. The pan-Canadian framework will pave the way towards innovation and jobs in the clean energy sector, and help Canadians manage the effects of climate change, by building capacity for adaptation and strengthening resilience.

On March 3, 2016, Canada's First Ministers and Indigenous Leaders met in Vancouver and committed to developing a concrete plan to achieve Canada's international greenhouse gas reduction commitments through a pan-Canadian framework for clean growth and climate change. Canada's First Ministers released the Vancouver Declaration in which they agreed to build on commitments and actions already taken by provinces and territories in order to meet or exceed Canada's GHG emissions targets. They highlighted the need to foster investment to promote clean economic growth and create jobs that support the transition to a low-carbon economy, while benefitting individual Canadians and addressing competitiveness impacts on businesses. They committed to deliver mitigation actions by adopting a broad range of domestic measures, including carbon pricing mechanisms, adapted to each jurisdiction's specific circumstances. Commitments were also made to develop and implement strong, complementary adaptation policies and action on climate resilience to address climate risks facing our populations, infrastructure, economies and ecosystems, and Canada's northern regions in particular.

The Mid-Century Strategy will help inform the pan-Canadian framework, while long term planning is essential to infrastructure and energy investments, setting the course for a low-carbon future.

The development of a Mid-Century Strategy is an essential step to set the course towards a low-carbon economy as it will inform longer term planning and investment. Long-term planning is fundamental for creating and managing robust energy systems, and careful and far-sighted policy making is essential to combat climate change in an economically efficient, socially acceptable, and effective manner. Because of the long-lived nature of some energy supply and demand equipment, investments and policy decisions made today will affect the level of greenhouse gases in 2050. For example, many of the buildings and electricity generating facilities built today will continue to be operational in 2050. Once these assets are locked-in, replacing them with cleaner alternatives will impose additional costs and complexity. Likewise, government policies should be designed with both a shorter term as well as longer-term focus, ensuring that greenhouse gas emissions will continue to decline towards a low-GHG future.

By aligning its goals to the UNFCCC temperature goals, Canada now has an opportunity to integrate climate change objectives into its long term planning processes. Although this report does not propose specific policies, it identifies key options for Canada's low-GHG development. For example, the anticipation of significant growth in Canadian electricity demand should underpin mid-century investment and planning. Planners should keep in mind that this increased demand will stem from both Canadian applications as they switch away from more carbon intensive energy sources, as well as potentially supplying clean electricity to our continental neighbours. As another example, planners should note that regional differences will be a key consideration due to the variation in electricity generating portfolios, and technical capacities from one jurisdiction to another.

All regions and sectors must act to reduce emissions, but specific abatement pathways could differ from one jurisdiction to another. Regional cooperation will be key to our success.

The Strategy that we present constitutes a growing consensus over possible avenues for low-carbon development informed by independent expert analysis.

This Strategy identifies key objectives and building blocks that could underlie our transition to a low-GHG economy. These building blocks frame the foundation of Canada's long term climate change mitigation strategy:

- Electrification has been identified as an essential step in all deep GHG mitigation analyses. The electrification of end use applications that are currently using fossil fuels is fundamental, for example, using electricity to power certain cars, trucks, building appliances and heating systems, and energy requirements for some industries.
- Concurrent trends towards decarbonisation of the electricity generating sector are needed. Electricity generation in Canada is already more than 80% non-emitting, with a trend towards non-emitting generation expected to continue, including through increased government action.
- The significant increase in electricity demand resulting from electrification policies (e.g., doubling or more by 2050), and electricity exports, should be satisfied through low-carbon sources.
- Canada, and North America's, electricity future will be shaped by interprovincial and intercontinental cooperation. Enhanced interjurisdictional electricity transmission interties could allow areas with hydropower, or other forms of non-emitting generation, to sell electricity to other provinces or U.S. States that rely on fossil fuels.
- Energy efficiency and demand side management are key to achieving deep GHG reductions. For example, the International Energy Agency (IEA) estimates that 38% of the required global emissions reductions associated with a 2°C pathway could be met through energy efficiency improvements. Efficiency gains are also key enablers of electrification technologies and consumer savings.

- Some sectors such as heavy industries, marine transportation, some heavy freight transportation, and aviation could move to lower or low-carbon fuels such as second generation biofuels or hydrogen. Alternatively, new and emerging technologies in synthetic hydrocarbons or energy storage would be needed.
- Abatement of non-carbon dioxide greenhouse gases, such as methane and hydrofluorocarbons, is a priority given their high global warming potentials. Reductions of these pollutants can often help slow the rate of near-term warming and contribute to achievement of the global temperature goal. Although black carbon is not classified as a greenhouse gas, it has strong global warming effects that must also be addressed.
- Behavioural changes will also contribute to a low-GHG economy. For example, innovative approaches to moving people and freight are likely to become more widely adopted over the next 35 years, as well as changes in the way people live, work, and consume.
- Cities are home to 70% of the world's energy-related carbon dioxide emissions. Canadian cities host 80% of the national population, compared to 62% sixty years ago. With a continuing trend in urbanization for the upcoming decades, cities across Canada cannot afford to wait to increase climate change mitigation and adaptation efforts.
- Canada's forests and lands will continue to play an important role in sequestering substantial amounts of carbon dioxide from the atmosphere. This sequestration can be augmented through policies and measures that better manage our forests and forest products. Without consideration of the global land sector, the 1.5 to 2°C temperature goal will be very hard to achieve.
- Innovation will also be crucial. A sustainable energy transition is possible with currently deployed or near-commercial technologies, but the long-term transition will be eased with the near-term accelerated deployment of clean energy options, or the development of more innovative technologies. The private sector has an important role to play in this respect including spurring investment and innovation towards low GHG alternatives. Carbon pricing will be an important element to achieving this objective.
- Collaboration with provinces and territories, Indigenous peoples, municipalities, business and other stakeholders will be essential to Canada's long-term success in enabling clean growth, reducing emissions and seizing the opportunities of the low-carbon global economy.

1 Context

KEY MESSAGES:

- Most Canadians recognise the need to mitigate climate change and limit the increase in the global average temperature, but the magnitude of the challenge is less well understood, with a requirement for very deep emissions cuts from every sector by mid-century.
- Mitigating greenhouse gas emissions is necessary to avoid the increasing threat presented by climate change. Benefits of action to reduce climate risk will outweigh costs and the international community is moving towards low-greenhouse gas economies. A particular focus on short-lived climate pollutants is also required if we are to stay below the 1.5°C - 2°C temperature goal.
- Canada has worked closely with the United States and Mexico in the development of this report. Our continental partners have also described ambitious mitigation action by 2050 in their respective strategies.
- Encouraging international efforts, including reducing emissions in other countries will be key to the global response.
- Working collaboratively with Indigenous peoples by supporting their on-going implementation of climate change initiatives will be key. Consultations with Indigenous communities must respect the constitutional, legal, and international obligations that Canada has for its Indigenous peoples.
- The Mid-Century Strategy will help inform the pan-Canadian framework (PCF) for clean growth and climate change.

1.1 Most Canadians recognise the need to mitigate climate change and limit the increase in the global average temperature, but the magnitude of the challenge is less well understood, with a requirement for very deep emissions cuts from every sector by mid-century.

Canada played a leadership role in advancing the adoption of the Paris Agreement and supporting the global temperature goal of holding the increase in the global average temperature to well below 2°C and pursue efforts to limit the temperature increase to 1.5°C above pre-industrial levels. Ensuring that the global temperature remains well below 2°C will require global greenhouse gas emissions to peak as soon as possible with a rapid decline in emissions thereafter. It will also require fast concurrent actions on short-lived climate pollutants (SLCPs) (see chapter 5).

The latest assessment report from the Intergovernmental Panel on Climate Change (IPCC) relied on a range of models to examine feasible scenarios for global emissions trajectories consistent with limiting global warming to less than 2°C. Building from this analysis, a recent study from the United Nations Environment Programme (2015)[1] found that scenarios consistent with limiting warming to 2°C, with a >66% chance, reach net zero global anthropogenic carbon dioxide emissions by about 2070, while those consistent with limiting warming to 1.5°C with a > 50% chance reach net zero carbon dioxide emissions by about 2050.

1 United Nations Environment Programme, *Emissions Gap Report 2015.*

Net "*negative*" carbon dioxide emissions (i.e., more emissions are sequestered through anthropogenic means than released to the atmosphere) would then be required later in the century to meet the temperature goal. Negative carbon dioxide emissions may be achieved, for example, with large-scale afforestation or bioenergy with carbon capture and storage. Negative CO_2 emissions are required in these scenarios to offset hard-to-mitigate non-CO_2 emissions (e.g., methane and nitrous oxide emissions associated with food production), in order to achieve net zero global anthropogenic GHG emissions.

In terms of total greenhouse gas emissions, according to the IPCC's Fifth Assessment Report, a limited number of studies provide scenarios that are more likely than not to limit warming to 1.5°C by 2100; these scenarios are characterized by GHG concentrations below 430 ppm CO_2-eq by 2100 and 2050 emission reduction between 70% and 95% below 2010.[2]

In this context, the United States noted that its Intended Nationally Determined Contribution target is consistent with a straight line emission reduction pathway from 2020 to deep, economy-wide emission reductions of 80% or more by 2050. Other jurisdictions such as Japan and the EU have adopted similar goals. For the purpose of the *Mid-Century Strategy*, Canada examines an emissions abatement pathway consistent with net emissions falling by 80% from 2005 levels.

1.2 Mitigating greenhouse gas emissions is necessary to avoid the increasing threat presented by climate change. Benefits of action to reduce climate risk will outweigh costs and the international community is moving towards low-greenhouse gas economies. A particular focus on short-lived climate pollutants is also required if we are to stay below the 1.5°C - 2°C temperature goal.

The consequences of inaction to reach the temperature goals are severe, and will have an impact on the global environment, health, and quality of life. The global average temperature is projected to continue to increase well beyond 2°C over the 21st century if no further action is taken. With some regions of the world experiencing severe effects earlier than others, including in some of the most vulnerable areas.

The IPCC concluded that global climate change risks are high to very high with global mean temperature increases of 4°C or more above preindustrial levels, consistent with expected levels by 2100 under a business-as-usual scenario. These risks include substantial species extinction, large risks to global and regional food security, and compromised normal human activities such as growing food or working outdoors due to the combination of high temperature and humidity. These risks are reduced substantially under scenarios which limit global warming to 2°C or lower.[3]

Several studies have shown that the cost to address climate change decreases if early action is taken. For example, in 2014, the White House's Council of Economic Advisers published a report stating that for the same level of temperature stabilisation, each decade of delayed mitigation effort leads to a 40% increase in net mitigation costs.[4] A 2012 Navius Research report, which considered the implications of policy delay in the context of an aggressive 2050 target, suggested that a delay in domestic GHG policy action from 2012 to 2020 could cost Canada an additional $87 billion over the 2020 to 2050 period, which represents an increase of about 27% in the cost of abatement.[5]

In addition, several studies suggest that the benefits of mitigation action can often outweigh the cost over the long run in terms of energy and fuel savings though resource efficiency gains. For example, a recent New Climate Economy Report shows that cities globally could save $16.6 trillion over the 2015-2050 period through investments in projects such as mass transit and energy efficient buildings.[6] Although there is inherent uncertainty around predicting far into the future, the agreement in the literature reinforces the point that early action on climate change is crucial to reducing the overall cost of climate change over time.

1.3 Canada has worked closely with the United States and Mexico in the development of this report. Our continental partners have also described ambitious mitigation action by 2050 in their respective strategies.

As described in the *Leaders' Statement on a North American Climate, Clean Energy, and Environment*

2 IPCC, Climate Change 2014: Synthesis Report. *Summary for Policymaker*

3 Intergovernmental Panel on Climate Change, *Climate Change 2014; Impacts Adaptation and Vulnerability.*

4 Executive Office of the President of the United States, *The Cost of Delaying Action to Stem Climate Change.*

5 Navius Research Inc., *Investment and Lock-In Analysis for Canada: Low Carbon Scenarios to 2050.*

6 Global Commission on the Economy and Climate, *The Sustainable Infrastructure Imperative: Financing for Better Growth and Development.*

Partnership, North America has the capacity, resources, and the moral imperative to show strong leadership building on the Paris Agreement, which entered into force on November 4, 2016. We recognize that our highly integrated economies and energy systems afford a tremendous opportunity to harness growth in our continuing transition to a clean energy economy. Our actions to align climate and energy policies will protect human health and help level the playing field for our businesses, households, and workers.

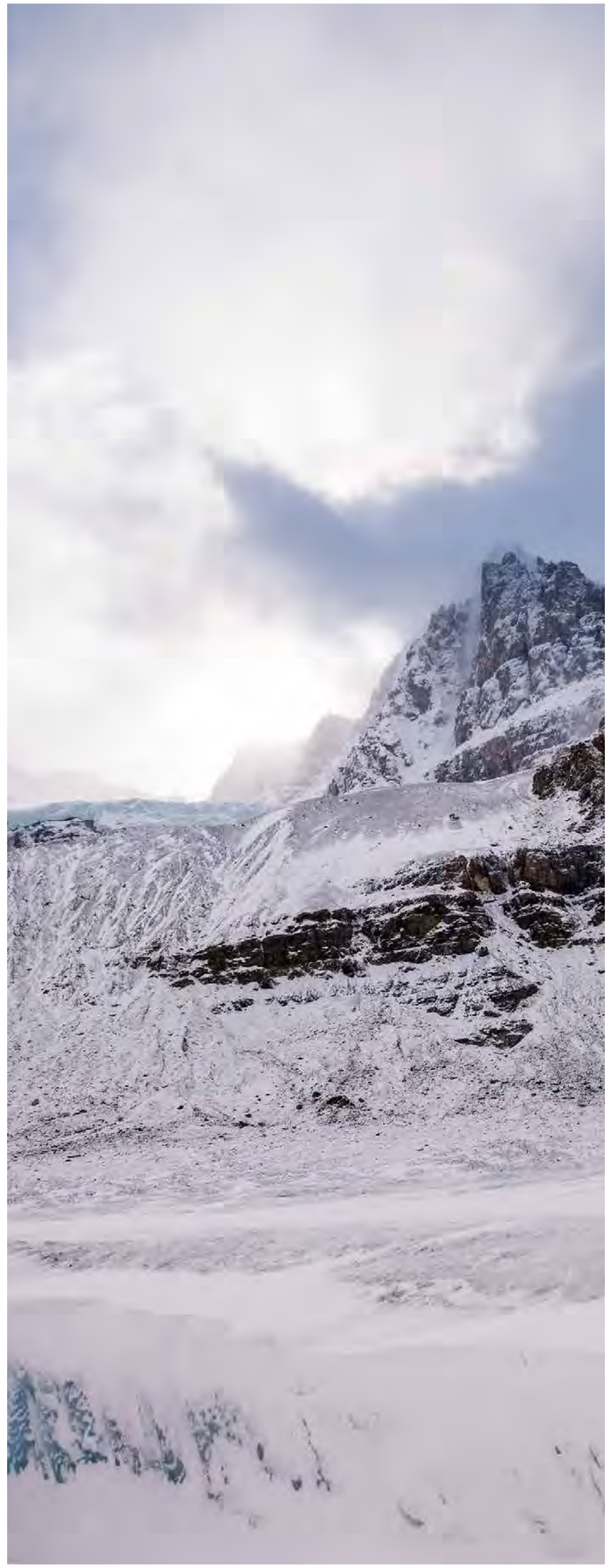
In recognition of our close ties and shared vision, Canada has worked closely with the U.S. and Mexico in the development of this report, including sharing analyses and key insights. Our partners' respective *Mid-Century Low-GHG Emissions Development Strategies* outline ambitious mitigation action by 2050.

1.4 Encouraging international efforts, including reducing emissions in other countries will be key to the global response.

The Paris Agreement recognises that addressing climate change through adaptation, technology, and capacity building will require significant international cooperation and finance, especially in the context of sustainable development. International collaboration is also fundamental to building an innovation and knowledge based economy.

Collaboration on technology innovation will underpin successful global efforts. The Carbon Trust, a global leading think tank on GHG emissions and energy technologies, was commissioned by the United Kingdom to analyse the benefits of energy technology innovation. Their paper *United Innovations* concludes that through collaborative energy technology innovation, "the world could save US$550 billion on the cost of deploying clean energy technologies over the next decade".

International cooperation to mitigate greenhouse gas emissions will be fundamental to limiting temperature rise. This is because GHG abatement costs differ substantially from sector to sector and jurisdiction to jurisdiction, but the environmental benefits of reducing a given amount of emissions are always the same. Cooperating to mitigate emissions in the most cost effective areas will ensure that financial resources are used in the most efficient way, resulting in larger reductions in emissions per unit of capital investment.



Article 6 of the *Paris Agreement* recognises that countries may choose to use internationally transferred mitigation outcomes, including emissions trading, to help access more cost effective abatement opportunities, as well as to help other countries mitigate emissions and promote sustainable development. International market-based approaches to reduce emissions (e.g., linked cap-and-trade programs; bilateral cooperative approaches; etc.) can stimulate cost effective and economically efficient greenhouse gas mitigation. Some regions of the world, including subnational governments, are already working cooperatively, or link carbon markets. These "bottom-up" type approaches could continue to develop and grow moving forward. For example, the province of Quebec has linked its emission trading system to California's through the *Western Climate Initiative*, with other subnational regions planning or considering doing the same. By 2050, it is hoped that there will be an international emissions trading system in place that would ensure robust environmental integrity and transparency at a global level.

In Canada, there are challenges to reducing greenhouse gas emissions from emissions-intensive heavy industry, primary extraction, and certain applications in the transportation sector. In the short-to-medium term, there may be more cost effective GHG reduction opportunities in other sectors or regions, where abatement technologies are more effective or lower-GHG alternatives exist. Emissions trading, or accessing internationally transferred mitigation outcomes, can provide a lower cost method of reducing GHG emissions, allowing more time for GHG intensive capital stock to turn over and allow low-carbon alternatives to be introduced without stranding assets. Canada recognises that sustainable development is a key principle pertinent to this type of cooperation. Canada will consider internationally transferred mitigation outcomes as a short-to-medium term complement to reducing emissions at home. Likewise, Canada intends to take into account internationally transferred mitigation outcomes arising from cross-border subnational emission trading as part of its international contribution to addressing climate change.

1.5 Working collaboratively with Indigenous peoples by supporting their on-going implementation of climate change initiatives will be key. Consultations with Indigenous communities must respect the constitutional, legal, and international obligations that Canada has for its Indigenous peoples.

There are a number of statements and agreements[7] that highlight Canada's commitment to consult, collaborate, and engage Indigenous peoples. Work to address climate change and related interactions with Indigenous peoples, must be consistent with Canada's approach to implementing the United Nations Declaration on the Rights of Indigenous peoples, in accordance with Canada's constitution.

This is especially relevant given the disproportionate challenges that First Nations, Inuit, and Métis communities face because of climate change. Despite the changes that are facing both traditional resources and the land, indigenous citizens and communities alike are taking tangible steps to become active drivers of change. For them, building resilience in the face of climate change is fundamentally about food, water, and energy independence, where Indigenous communities are self-sufficient.

Indigenous peoples, communities, and organisations across Canada are implementing a range of climate change initiatives.[8] Above and beyond renewable energy projects, Indigenous peoples are implementing ground-breaking initiatives on sustainable land use management, food security, and education informed by traditional values. Advancing cross-cultural learning on climate change mitigation and adaptation is one step in the journey towards reconciliation in Canada.

In order to move forward, Canada will encourage the development of green infrastructure in northern and remote Indigenous communities. It is also important for municipalities, provinces and territories to promote energy security for Indigenous peoples. For example, through its Feed-in Tariff program, Ontario has been able to set aside 10% for community and Indigenous engagement in renewable energy projects, with many Indigenous communities as partners or owners in renewable energy systems as a result.[9]

7 For example: the United Nations Framework Convention on Climate Change's Paris Agreement; the Vancouver Declaration; the Leader's Statement on a North American Climate, Clean Energy, and Environment Partnership.

8 Scurr, C., and Beaudry, J., *Gap Analysis First Nations Climate Change Adaptation South of 60 Degrees Latitude.*

9 Indigenous Economic Development Indigenous Affairs Working Group, *Ontario Aboriginal Energy Partnerships Program.*

1.6 The Mid-Century Strategy will help inform the pan-Canadian framework (PCF) for clean growth and climate change.

On March 3, 2016, Canada's First Ministers and Indigenous Leaders met in Vancouver and committed to developing a concrete plan to achieve Canada's international greenhouse gas reduction commitments through a pan-Canadian framework for clean growth and climate change. Canada's First Ministers released the Vancouver Declaration in which they agreed to build on commitments and actions already taken by provinces and territories in order to meet or exceed Canada's GHG emissions target for 2030. They highlighted the need to foster investment to promote clean economic growth and create jobs that support the transition to a low-carbon economy, while benefitting individual Canadians and addressing competitiveness impacts on businesses. They committed to deliver mitigation actions by adopting a broad range of domestic measures, including carbon pricing mechanisms, adapted to each jurisdiction's specific circumstances. Commitments were also made to develop and implement strong, complementary adaptation policies and action on climate resilience to address climate risks facing our populations, infrastructure, economies and ecosystems, and Canada's northern regions in particular.

Canada's *Mid-Century Strategy* will help inform the pan-Canadian framework for Clean Growth and Climate Change, but does not outline any further specific policies. Instead, Canada's Mid-Century Strategy outlines potential GHG abatement opportunities, emerging key technologies, and identifies areas where emissions reductions will be more challenging and require policy focus – in the context of achieving very low greenhouse gas objectives by 2050. The strategy also outlines the importance of addressing other pollutants, such as black carbon, that are significant climate warmers.

2 Existing Analyses on Decarbonisation

The study and analysis of what low-carbon futures might look like and the pathways for how we might achieve them is relatively recent. There is, however, a rapidly growing body of international research on low-carbon futures, including a few analyses that have focused on Canada. From this work, a number of common themes and conclusions have emerged that inform the development of this report. This work involves examining various pathways that Canada can take to achieve a low-carbon economy in 2050 and identifying associated opportunities and challenges. The studies also highlight Canada's achievements in decreasing GHG emissions to-date, provide wide-ranging insights on potential transformational low-emitting GHG technologies, and point to policies and measures that could be implemented to achieve deep reductions in GHG emissions and the necessary innovation required to ease this transition.

This literature review aims to highlight the principle themes and key messages from relevant research in order to inform the development of Canada's Mid-Century Low GHG Strategy. The review focuses on Canada-wide approaches and does not consider provincial-level pathway assessments.

KEY MESSAGES:

- Substantial decarbonisation by mid-century is possible with current technologies.
- Decarbonisation presents opportunities to improve social welfare and economic productivity.
- Challenging areas for abatement require increased policy focus, research and development, and investment.
- Decarbonisation objectives should underlie long-term, coordinated planning in key areas such as investments towards new infrastructure and clean technologies.

2.1 Substantial decarbonisation by mid-century is possible with current technologies.

Canada has already started to decarbonise and can do even more with currently available technologies. In its *Canada 2015 review*, the International Energy Agency (IEA) mentions that Canada has achieved important reductions to date through federal and provincial/territorial initiatives. The report underlines that in 2013, more than 75% of Canada's current electricity generation mix is non-emitting due to significant production from hydro and nuclear and that, over the past decade, Canada has decreased its energy intensity by 20%. It also mentions the progress made in the industrial sector with four carbon and capture storage projects, including the Boundary Dam CCS project, which is the world's first commercial application of CCS to a coal-fired power plant.[10]

An assessment from the *Council of Canadian Academies* published in 2015 suggests that Canada can significantly reduce GHG emissions by using commercially available technologies in key sectors of the economy.[11] The assessment identifies many existing

10 International Energy Agency, *Energy Policies of IEA Countries: Canada 2015 Review, p. 10.*
11 Council of Canadian Academies, *Technology and Policy Options for a Low-Emission Energy System in Canada.*

technologies that are able to achieve further energy efficiency improvements and increase production of non-emitting electricity. These technologies are commercially available, can deepen current energy efficiency improvements, and further decarbonise the electricity generation sector. The report also highlights the opportunity to stimulate the low carbon transition at the time of infrastructure renewal.

The *Deep Decarbonization Pathways Project*[12] is a global initiative of 16 countries covering 74% of energy emissions that aims at providing country specific pathways to meet a mitigation goal consistent with limiting global temperatures to 2°C above pre-industrial levels. The project suggests that current and developing technologies can achieve decarbonisation if sufficiently broad, wide, and nationally appropriate climate policy is imposed. The Canadian study published in 2015 provides six decarbonisation pathways, several of which rely on pushing deployment of currently available technologies. The results suggest that Canada can make significant progress through the decarbonisation of the electricity grid using mainly renewable energy sources (e.g., hydro, wind, solar), some fossil fuels with CCS, and replacement of combustion-based energy sources with electricity in many sectors (including the transportation, buildings, manufacturing, and heavy industry sectors). The study employed a highly detailed, behaviourally realistic technology stock turnover model (CIMS) to capture changes in energy, process an fugitive emissions, linked to regionally and sectorally disaggregated macroeconomic model (RGEEM) to capture changes in GDP, economic structure, employment and trade. Emissions reductions in both models were driven by a policy package of performance based technology regulations and hybrid (i.e., general tax and cap and trade) carbon pricing.

The *Trottier Energy Futures Project* looks at 11 different scenarios for Canada to achieve different levels of GHG reductions by 2050 using one optimisation model and one simulation model that integrate energy and economic systems with different sets of strategies to achieve reductions at a minimum cost. The projections presented in the report provide detailed information on Canada's sectoral energy consumption and production for each scenario and take into account specific regional circumstances. The report states that "for most scenarios, the approach was based on currently deployed technologies with plausible extrapolations for future improvements and cost reductions".[13] These include expanding the use of non-emitting electricity across end-use sectors, increasing the use of biofuels in the transportation sector, and improving energy conservation and efficiency. The report also noted that further research is needed on ways to achieve net-negative GHG emissions, including through bioenergy with carbon capture and storage (BECCS), increased use of wood products for carbon retention in buildings, and carbon sequestration through afforestation and reforestation.

The Canadian study *Acting on Climate Change: Solutions from Canadian Scholars* also provides an insight into how current technologies and appropriate policy options are sufficient to decarbonise the Canadian economy. A concerted effort of sixty Canadian scholars, the report suggests that Canada can rely 100% on low-carbon electricity production by 2035, due to the availability of renewable energy sources in the country, making it possible to achieve an 80% reduction in GHG emissions by 2050. In addition, an evolving smart urban design, drastic changes in the transportation sector and a broader sustainability agenda are all fundamental factors that will help change energy consumption in Canada. To this end the authors suggest numerous policies, such as east-west interprovincial electricity trade, and emphasise the benefit of a carbon pricing policy.

2.2 Decarbonisation presents opportunities to improve social welfare and economic productivity.

The Smart Prosperity roadmap, *New thinking*, provides a vision of Canada's potential low-carbon future with healthy, vibrant, and green communities. The Canadian think tank proposes a future Canadian society in which smart cities and towns provide sustainable means of living in communities with hyper-efficient insulated buildings with roof tiles made of solar panels, plenty of public parks and community gardens, and streets and sidewalks filled with electric plug-in stations for next-generation electric cars. In this green economy, clean innovation would provide many job opportunities using human ingenuity to efficiently produce goods and services while continuously seeking new ways to reduce greenhouse gas emissions. Smart grid systems endowed with advanced technologies would allow home appliances, such as water heaters, to act as electric batteries and transportation modes

12 Bataille, C. et al., *Pathways to Deep Decarbonization in Canada.*

13 Trottier Energy Futures Project, *Canada's Challenge & Opportunity, p. 6.*

to recharge and start their duties at inexpensive, low-peak load times. Under this vision, connected communities could become more efficient by sharing resources and knowledge. The roadmap states that Canada's future prosperity depends on the investment choices we make today and that the development of clean infrastructures will "offer substantial economic opportunities for Canadian companies, many of which are already among the leaders in energy technology, water infrastructure, and transportation innovation".[14]

A transition to a low-carbon economy could present significant benefits beyond GHG abatement that could improve Canadian's well-being by producing jobs in the clean technology industry and improving productivity in other sectors. The International Energy Agency (IEA) report *Energy Technology Perspectives (ETP) 2016* underscores Canadian success stories.[15] For example, in Alberta, the Drake Landing Solar Community (DLSC) integrates solar thermal energy to its district system to store significant amount energy underground during the summer so it can be used in the winter for space heating. According to the DLSC, each of the single family homes reduces about 5 tonnes of GHG per year and is 30% more efficient than conventionally built homes.[16] Another success story relates to the use of applications for traffic signals (e.g., communications systems, adaptive control systems, traffic-responsible, real-time data collection and analysis, maintenance management systems) in British Columbia to allow motorists to turn off their engines while they wait at the Peace Arch Border Crossing. The system reduces GHG emissions by 45% while decreasing levels of air pollution which result in improvements in human health. Vehicle users also incur fuel savings.[17]

Data analysed in the *2016 Canadian Clean Technology Industry Report*, published by Analytica Advisors, suggests that the Canadian clean technology sector has grown considerably over the last decade and that a pathway toward decarbonisation would further stimulate the sector by increasing domestic demand for clean technologies, thereby developing domestic knowledge and innovation. The report mentions that the Canadian clean technology sector delivers "high-skill, high-wage, knowledge-based jobs"[18] and that it continues to out-perform other industries on that aspect. Clean technologies can also increase the productivity and efficiency of other sectors of the economy, including traditional industries, and make them more competitive. Nevertheless, the report also highlights that these same Canadian companies are losing market share world-wide, and that moving swiftly towards decarbonisation could provide significant opportunities to the sector.

The *Trottier Energy Futures Project* also points to other kind of economic opportunities, such as taking advantage of potential mutual benefits from a greater integration of the electricity network and trade between the U.S. and Canada. More specifically, Quebec could increase exports of zero-emitting electricity to the U.S. North East region, and Manitoba could do the same with the U.S. Mid-West region. The benefits include higher electricity sale revenues for Quebec and Manitoba and lower cost electricity supply for American States, opportunities for optimal integrated system dispatch

14 Smart Prosperity, *New Thinking-Canada's Roadmap to Smart Prosperity*, p. 50.
15 International Energy Agency, *Energy Technology Perspectives*, p. 199, p. 231 & p. 326.
16 Drake Landing Solar Community, *Welcome to Drake Landing Solar Community.*
17 Government of British Colombia, *Greening the Border.*
18 International Energy Agency, *Energy Technology Perspectives 2016*, p. XXII.

which could generate revenue through trading of energy, minimised overall cost of system supply (complementing Canadian hydro production with U.S. low cost nuclear and thermal baseload), the sharing of emergency reserve, and a more stable system. The report also mentions that there may be further opportunities for reducing overall electricity costs since the peak demands in Canada and the U.S. occur at different periods of the year (most of Canadian provinces' peak periods are in the winter, while U.S. peak period is in the summer), and for complementing the baseload with more intermittent renewables.[19]

2.3 Challenging areas for abatement require increased policy focus, research and development, and investment.

Decarbonisation pathways also present challenges which require effective and flexible policies that encourage innovation. The academic literature stresses the need for Canada to capitalise on its vast knowledge and expertise to spur innovation and develop clean technologies to cost-effectively reduce emissions in some areas, particularly industrial process emissions and freight transportation. In order to succeed in making major scientific breakthroughs and ensuring clean reliable energy systems, the literature emphasises the need for private and public actors to strengthen research, development and deployment (RD&D) in all sectors of the economy, and continuously engage with the international community. In their 2015 report, the *Council of Canadian Academies* provides an overview of the key challenges faced by industries. These are mainly associated with the lack of cost-effective, low emission-intensive ways to produce high levels of heat, and that energy-related emissions are scattered across many different processes and applications. The report points to R&D, technological development, and flexible policies as key solutions to reduce the costs and encourage commercialisation of low-emitting technologies.

The *National Round Table on the Environment and the Economy* (NRTEE) provided their recommendations in a report titled *Getting to 2050: Canada's Transition to a Low-emission Future*. The report established many "enabling conditions" which would guide Canada in formulating a long-term strategy to achieve its long-term GHG emission and air pollution targets. The report pointed out that long term policy certainty is central to provide predictability to attract new durable investments in clean technology and innovation. The report proposed to establish an economy wide price signal, through a market-based policy. The NRTEE also highlights the need to create a level playing field for energy investments with the goal of enhancing Canadian firms' access to fast-growing low-carbon markets and mobilising investments in low-carbon infrastructure and technology.

Mark Jacobson from Stanford University and other researchers have also looked at energy roadmaps to convert 139 countries to 100% clean and renewable energy use. The roadmaps represent pathways for converting the energy systems of these countries to ones powered by wind, water, and sunlight (WWS). The roadmaps are based on IEA energy consumption data projected to a 2050 BAU scenario. They rely on existing WWS electricity generation technologies and exclude nuclear, CCS, biofuels or natural gas, and do not include the construction of new hydropower dams.

In the wake of the COP21 Conference, the Royal Dutch Shell company published the report *A Healthy Planet: Pathways to Net-Zero Emissions: A New Lens Scenarios Supplement*. The report highlights current societal challenges in achieving a net zero GHG world. The report recognises the important role of renewable energy in decarbonising the energy system but points out other challenges that many industrial sectors are facing (e.g., iron and steel, cement manufacturing, heavy freight and air transportation, chemical and fertilizers). To make progress on reducing these emission sources, the report suggests mass deployment of carbon capture and storage technologies combined with sustainable biomass use. The report also recommends policies to accelerate the world's transition to a low-carbon economy including economy-wide carbon pricing and financial investment for research and development in low-carbon technologies.

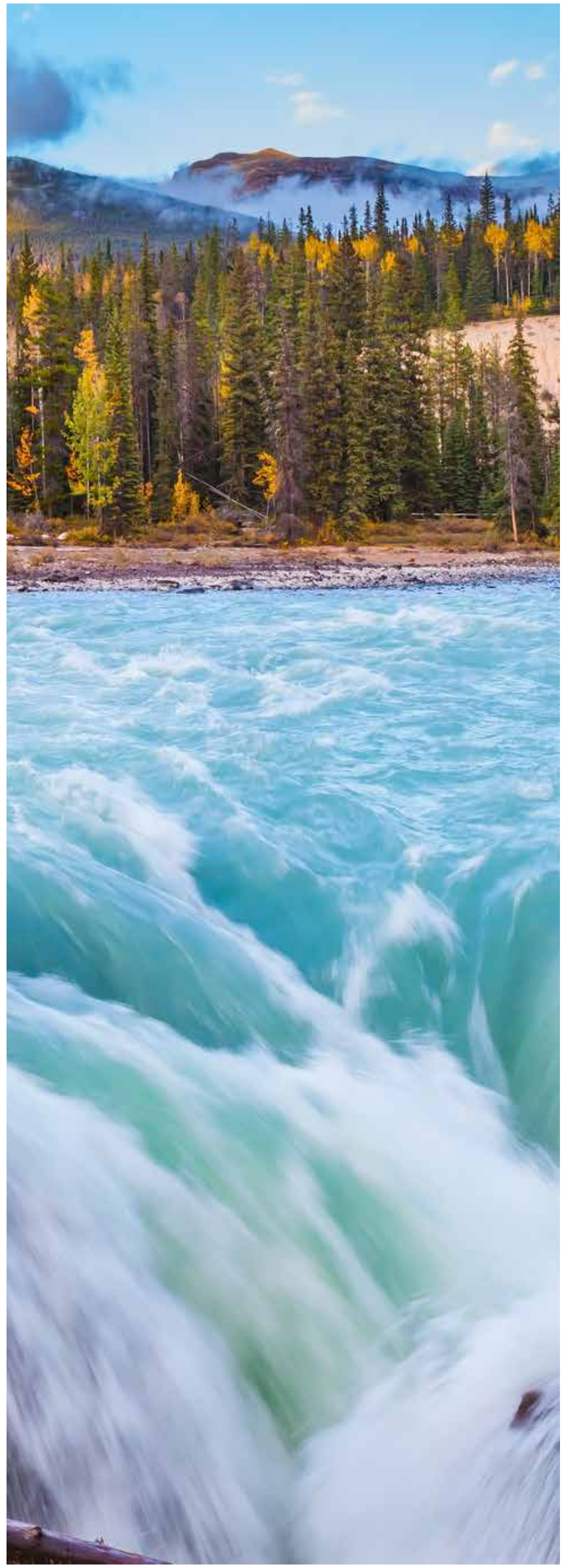
19 Trottier Energy Futures Project, *Canada's Challenge & Opportunity*, pp. 217-224.

2.4 Decarbonisation objectives should underlie long-term, coordinated planning in key areas such as investments towards new infrastructure and clean technologies.

Smart Prosperity's roadmap stresses the importance of building smart infrastructure to facilitate the penetration of clean transportation modes and non-emitting energy. The roadmap also points to municipal governments having a key role in planning zoning and permitting in order to favour clean development of cities. This vision will require strong coordination from federal and provincial governments, National Indigenous Organisations across the country, municipalities, and the public.

As cities are becoming the heart of economic development and strategic centres for innovation in clean technologies, they offer significant opportunities to contribute to reducing GHG emissions. IEA's *Energy Technology Perspectives (ETP) 2016* presents an extensive modelling exercise including projections of three pathways using four interlinked models of the energy supply, and the buildings, industry, and transport sectors. The results present the structural changes required to shift the world toward clean energy and transform cities into innovation powerhouses. The report also highlights the role cities play in driving energy demand and the solutions they may offer to lower the carbon content of the world's energy systems. According to the report, increasing energy demand from urban economic and population growth will need to go hand in hand with innovation and massive deployment of clean technologies and significant behavioral changes. It also emphasises the role of cities in supporting higher efficiency transport and buildings, with dense urban development being a structural prerequisite. Increased demands in space heating and cooling could be decoupled by connecting households to district energy networks. Sustainable land-use planning, the implementation and electrification of transportation modes, and the installation of rooftop solar photovoltaics present attractive solutions to propel cities toward a low-carbon pathway. All of these solutions will require careful planning of today's investments in infrastructure by all levels of government.

The report from the *Council of Canadian Academies* also mentions that many investment decisions such as transmission and distribution systems and strategic planning of urban, land-use and infrastructure developments will allow for a better integration of low-emitting electricity use.



3 Decarbonisation and Expansion of Canada's Electricity System

KEY MESSAGES:

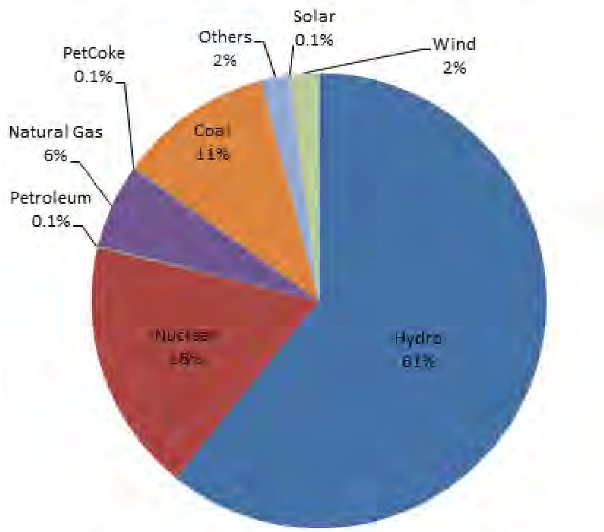
- Canada's electricity generating portfolio is already more than 80% non-GHG emitting, with the trend towards cleaner generation expected to continue. This provides Canada with an international comparative advantage relative to countries seeking to decarbonise their fossil fuel dominated portfolios.
- A low carbon electricity system will allow for GHG emissions reductions in other sectors (e.g., transportation, buildings, industrial processes) through electrification. The anticipation of significant growth in electricity demand should underpin long term investment and planning.
- Further decarbonisation of the electricity sector will facilitate the transition to a low-GHG future. Non-emitting sources will need to be considered for all new and existing needs, but generating portfolios will differ from one jurisdiction to another. Regional differences will need to be a key consideration for electricity climate change policies.
- Interprovincial, interjurisidictional, and intercontinental cooperation will enhance integration of clean electricity generation to satisfy growing demand. Canada's contribution towards global GHG abatement could include providing clean power to our continental neighbours, as well as clean power services to the international community.
- Energy conservation and energy efficiency measures should increase and be implemented alongside efforts to reduce emissions from electricity generation. Electricity savings should underlie decarbonisation pathways: demand side management and reducing equipment and transmission losses makes electrification far more effective and feasible

3.1 Canada's electricity generating portfolio is already more than 80% non-GHG emitting, with the trend towards cleaner generation expected to continue. This provides Canada with an international comparative advantage relative to countries seeking to decarbonise their fossil fuel based portfolios

Canada already has one of the cleanest electricity systems in the world, with more than 80% of electricity generated from sources that do not produce greenhouse gas emissions such as hydro, wind, solar, and nuclear power. Canadian rivers provide immense hydroelectric generating capability, and Canada is second largest producer of hydroelectricity globally. In 2014, Canada produced 379 terawatt hours (TWh) of hydroelectricity, representing 9.8% of global production[20] with further capacity remaining untapped. There is also significant potential for the development of other renewable energy sources across Canada.

20 National Energy Board, *Canada's Energy Future 2016: Energy Supply and Demand Projections to 2040.*

Figure 1: Canadian Utility by Source (2014)



Source: CANSIM Tables 127-0006 for fossil fuel sources and 127-0007 for other sources. Total generation data is extracted from CANSIM 127-0007.

In 2014, nuclear power provided 18% of Canada's electricity generation from electric utilities (63% of Ontario's generation and 34% of New Brunswick's generation). Canada is the world's second-largest producer and exporter of uranium—representing over 20% of world production—and ranks fourth globally in identified resources of uranium. There are 4 operating nuclear power stations in Canada—3 in Ontario and 1 in New Brunswick, with a combined total of 19 reactors. In Ontario, planned investments of $25 billion over the next 15 years will extend the life of 10 nuclear reactors for another 25 to 30 years.

Electricity-related emissions have been declining in Canada due to a return to service of a number of nuclear units, fuel switching from coal to natural gas, and government policies to phase out coal-fired electricity. This trend is expected to continue as hydropower generation and electricity generation from renewables, such as wind and solar, are expected to increase throughout Canada.

Although electricity generation is already moving in a positive direction with respect to a low-GHG future, government policy and long-term planning can help accelerate this trend. For example, as Canadian provinces continue to move away from coal-fired electricity, they will face decisions regarding what type of fuel should replace and augment generating capacity. Natural gas might provide a lower-GHG option than coal in the short run, but its place in a decarbonised system is less clear over a longer-term horizon.

As the global community moves to reduce greenhouse gas emissions, many countries will face challenges with regard to the decarbonisation of their electricity generating sectors. In this respect, Canada is already ahead of many of its peers. Currently, Canada is the second largest producer of hydropower after China, fourth globally for generation from a combination of hydro, wind, solar and biomass,[21] and sixth for generation from nuclear energy.[22] Given this comparative advantage, Canada has the opportunity to increase its clean electricity exports, as well as leverage its expertise in current and emerging technologies (e.g., electrification technologies; smart grids for intermittent sources) that could help other countries reduce their emissions.

3.2 A low-carbon electricity system will allow for GHG emissions reductions in other sectors (e.g., transportation, buildings, and industrial processes) through electrification. The anticipation of significant growth in electricity demand should underpin long term investment and planning

Although electricity generation only accounted for 11% of Canada's emissions in 2014, continuing to move towards a non-emitting electricity generating sector would help decarbonise other sectors, such as, transportation and buildings. Increasing the share of non-emitting electricity generation is fundamental to Canada's low-carbon future.

A near decarbonisation of the electricity sector is underscored in most of the deep-decarbonisation literature, both nationally and internationally. For example, in the IEA Energy Technology Perspective 2016, the global electricity power sector is almost completely decarbonised by 2050 under a scenario consistent with the global 2°C temperature goal. Domestically, virtually all of the academic and expert analysis on deep decarbonisation in Canada point to non-emitting electricity and the electrification of buildings and passenger vehicles as fundamental aspects to a low-carbon future given current technologies. For example, the *Trottier Energy Futures Project* shows that one of the lowest cost options to decarbonise Canada is to move the electricity generation sector toward a zero-emitting transition by expanding renewables, especially hydro, and other non-emitting sources.

21 International Energy Association, *IEA's Electricity Information Report.*

22 Nuclear Energy Institute, *Top 10 Nuclear Generating Countries.*

The near term focus on mitigation in this sector also reflects the technological availability of abatement options including the ability to tackle large point sources of emissions over a shorter time period. From an investment perspective, Canada is at a point in time where its traditional coal-fired generating sources are facing closures or refurbishments with carbon capture and storage, primarily due to government policies; therefore, there is an opportunity to transition to a decarbonised system at more limited incremental cost.

Meanwhile, the price of renewable electricity such as wind and solar continues to decline dramatically, making these options increasingly economically attractive. Recent *Bloomberg New Energy Finance* analysis projects the levelised cost of electricity for onshore wind and photovoltaics solar to decrease by 41% and 59%, respectively, from 2016 to 2040.[23] The levelised cost of electricity (LCOE) is an economic assessment of the average total cost to build and operate a power-generating asset over its lifetime divided by the total energy output of the asset over that lifetime. It can also be regarded as the minimum cost at which electricity must be sold in order to break-even over the lifetime of the project.

The U.S. Energy Information Agency (EIA) describes the average levelised costs for plants entering service in 2022 and 2040 in the U.S. (see Table 1). The EIA notes that some renewables such as wind power are expected to be cheaper than fossil-fuel based forms of generation within the U.S by 2022. These costs take into account building and operating a plant over its lifetime, fuel costs (where appropriate) and the federal tax burden, but do not include regional factors or utilisation rates. Government subsidies are not included in the estimates but would decrease the costs even further.[24] It should be emphasized that these are future costs in the United States and cannot be directly compared to Canada.

In Canada, the Canadian Council on Renewable Electricity (CanCORE)[25] states that hydropower and wind are already cost-competitive. Solar energy is quickly catching up and is on track to be the least-cost generation technology in most countries around the world by 2030.

Table 1: Average Levelised Costs of Electricity (2015 $/MWh) for Plants Entering Service in 2022 & 2040; United States[26]

Energy Source	2022	2040
Wind	64.5	58.8
Wind Offshore	158.1	133.7
Natural Gas-fired Conventional Combined Cycle	58.1	57.6
Hydroelectric	67.8	65.3
Advanced Nuclear	102.8	93
Biomass	96.1	78.7
Geothermal	45.0	57.0
Solar Photovoltaics	84.7	71.2
Coal with CCS	139.5	125.8

3.3 Further decarbonisation of the electricity sector will facilitate the transition to a low GHG future. Non-emitting sources will need to be considered for all new and existing needs, but generating portfolios will differ from one jurisdiction to another. Regional differences will need to be a key consideration for electricity climate change policies.

Modeling analyses that examine deep aggregate cuts to GHG emissions in Canada by mid-century indicate that Canada's future non-emitting electricity portfolio could take various forms, and different non-emitting options exist for each Canadian jurisdiction. The following section outlines the various scenarios developed around non-emitting electricity generation scenarios for Canada and explains the modelling results of each scenario.

23 Bloomberg New Energy Finance, *Coal and Gas to Stay Cheap, but Renewables Still Win Race on Costs.*
24 U.S. Energy Information Administration, *Levelized Cost and Levelized Avoided Cost of New Generation Ressources in the Annual Energy Outlook 2016.*
25 Canadian Council on Renewable Electricity, *Powering Prosperity Climate Report.*

26 U.S. Energy Information Administration, *Levelized Cost and Levelized Avoided Cost of New Generation Ressources in the Annual Energy Outlook 2016.*

MODEL AND SCENARIO DESCRIPTION

Deep Decarbonisation Pathways Project – High Ambition (DDPP):

Ambition:

The DDPP modelled its scenarios in line with achieving 89% GHG emission reductions from overall emission levels projected for 2050, excluding agriculture, which corresponds to an emissions reduction of 88% from 2015 levels by 2050 (78Mt CO_2e).

Model Description:

The DDPP uses an energy and economic model to forecast demand for GHG-intensive goods and services, energy balances, technology and ultimately emissions (CIMS model). CIMS is a bottom-up technology-focused model that competes and selects technology market shares based on firm and household responses to the DDPP policy package, including carbon pricing and technology regulations. To forecast GDP, employment, economic structure and trade, a macroeconomic regionally and sectorally disaggregated Computable General Equilibrium (CGE) model called GEEM, is used.

Scenario Description:

- This modelling work assumes GDP growth ranging from 2% to 2.2% per year from 2015 to 2050.
- The scenario discussed here is based on oil prices of $80 ($US2014) per barrel in 2050.

Trottier Energy Futures Project:

Ambition:

The Trottier Energy Futures Project modelled its scenarios based on achieving a 60% GHG emission reduction target from the 1990 levels in combustion emissions. This corresponds to a 65% reduction from 2015 combustion emission levels. This analysis excludes process emissions. Scenarios 3 (Current Tech Trottier) and 8 (New Tech Trottier) of the report are shown in this section.

Model Description:

The Trottier Energy Futures Project uses two models to develop its scenarios, the North American TIMES Energy Model (NATEM) and CanESS models. Both models include separate representations of the sectors in Canada's economy, split for all provinces and territories.

Scenario Description:

- Scenarios 3 (Current Tech Trottier) and 8 (New Tech Trottier) of the report are shown, both of which aim to achieve a 60% GHG emission reduction target from the 1990 levels in the energy sector.
- This work relies on the National Energy Board's GDP per capita growth rate from 2010 to 2035, which is 1.9%, with somewhat slower growth after 2035.
- This modelling exercise assumes an oil price of about $135 ($2011) per barrel in 2050.

Environment and Climate Change Canada: Global Change Assessment Model (GCAM) – High Non-Emitting:

Ambition:

This modelling work was based on a net 80% GHG emission reduction from 2005 levels. This is modelled as a combination of full reductions achieved in the combustion and non-combustion sectors, as well as the addition of scenarios representing a 65% reduction in Canadian economy emissions, with a 15% achievement through Internationally Transferable Mitigation Outcomes and Land sector credits.

Model Description:

GCAM is a dynamic-recursive model with technology-rich representations of the economy, energy sector, land use and water linked to a climate model. GCAM is a Representative Concentration Pathway class model that can be used to simulate scenarios, policies, and emission targets from various sources.

Scenario Description:

The first scenario (High Nuclear) is heavily dependent on nuclear electricity production, while the second scenario (High Hydro) relies on a mix of hydro and wind to produce a majority of its electricity generation.

- This modelling work was based on a 65% and net 80% GHG emission reduction from 2005 levels.

<u>Environment and Climate Change Canada: Computable General Equilibrium Model (CGE) – High Demand Response:</u>

Ambition:

- This modelling work was based on a net 80% GHG emission reduction from 2005 levels. This is modelled as a combination of full reductions achieved in the combustion and non-combustion sectors, as well as the addition of scenarios representing a 65% reduction in Canadian economy emissions, with a 15% achievement through with the addition of scenarios including Internationally Transferable Mitigation Outcomes and Land sector credits.

Model Description:

- This is a multi-sector, multi-regional open-economy recursive-dynamic computable general equilibrium model of the global economy. The model captures characteristics of country-specific or regional production and consumption patterns through a detailed input-output table and links countries/regions via bilateral trade. The model incorporates rich detail in energy use and greenhouse gas emissions related to the combustion of fossil fuels and tracks non-energy related greenhouse gas emissions. Economic activities in regions involve 28 industrial sectors, final consumption by the household, the governments and investment.

In the figure below, results from these scenarios are presented with respect to electricity generation. Comparing results across models, or across modelled scenarios, provides us with overarching high-level messages and key takeaways for Canada's decarbonised electricity sector. The graph depicts various electricity generating portfolios in the year 2050 from the four different models, and compares these to the current generating mix (2014), labelled as "Historical" in the graph.

In all of the scenarios, Canadian electricity generation will increase substantially to fulfill end-use electrification requirements. Essentially, additional electricity is required to power cars, light trucks, buildings, and industrial production processes that are switching away from fossil fuel generation to electricity to power their needs. In the ECCC analyses, total electricity generation increases by 113 to 189% between 2013 and 2050, whereas it increases by 184 to 295% in the Trottier analyses and by 160% in the DDPP analyses.

Depending on the modelling scenario, there is a huge variation in potential electricity demand growth. This is dependent on the level of energy efficiency/consumption changes emerging from the modelling results. However, in all of the low GHG economy modelling analyses, non-emitting sources such as hydro, nuclear, wind, and solar replace fossil fuel generation well before mid-century.

All scenarios demonstrate growth in hydropower electricity generation between 2013 and 2050. The ECCC High Hydro scenario illustrates a 172% increase in hydropower generation. In the DDPP analyses, hydro increases by 120%, whereas in the Trottier analyses it increases by 134% in both scenarios.

Figure 2: Scenarios of Canada's Non-Emitting Electricity Generating Supply

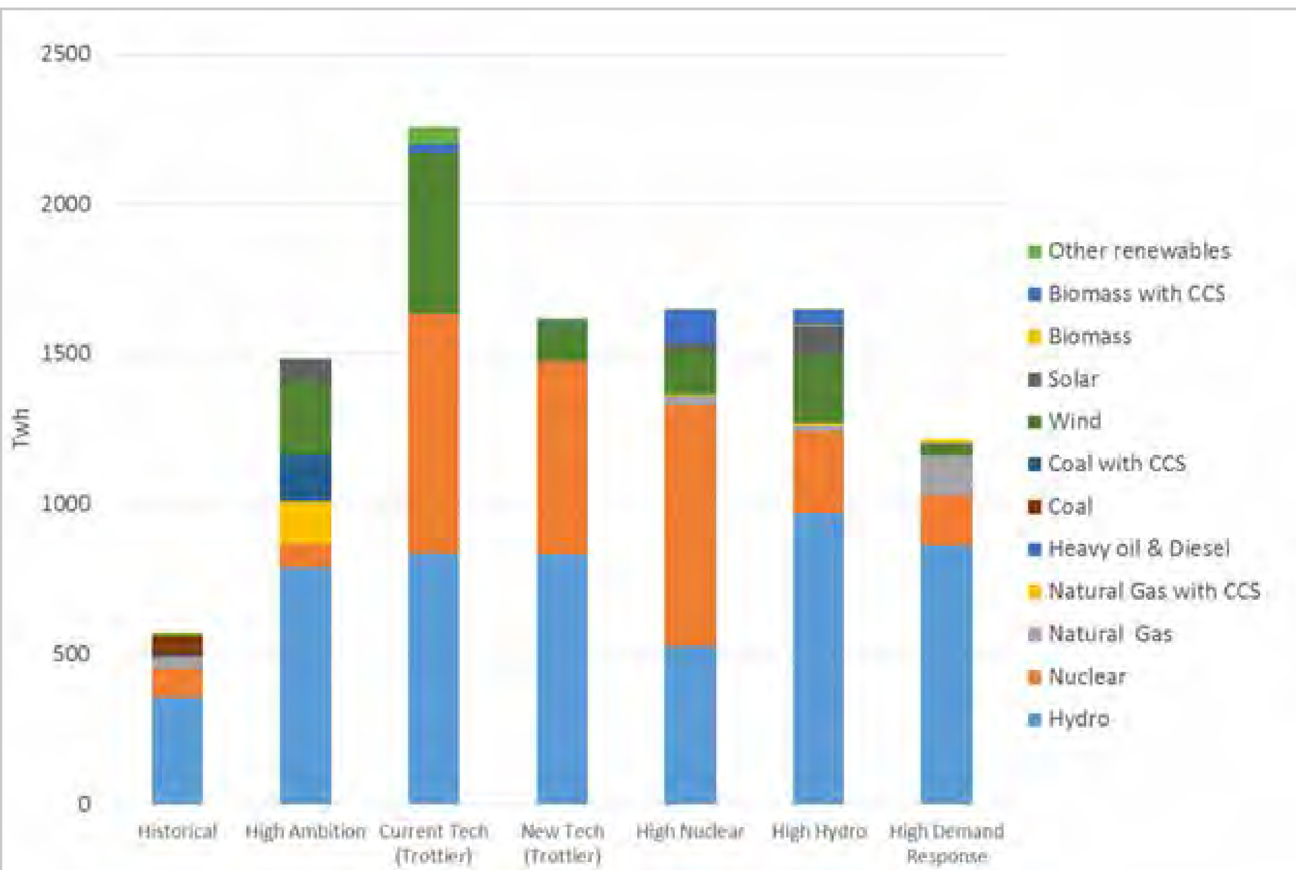
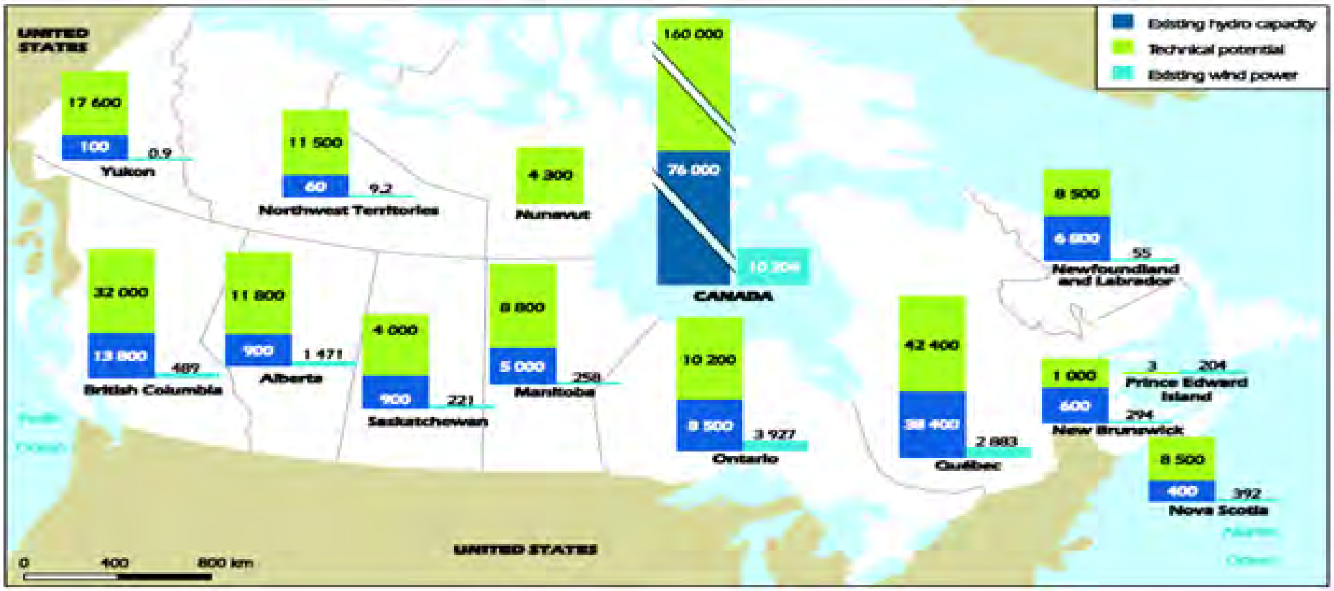


Figure 3: Canada's installed hydro power capacity against theoretical technical potential (MW), and installed wind power: by province and territory in 2014;



Source: International Energy Agency[28]

The different scenarios correspond to different levels of additional hydro capacity that needs to be built by 2050 to reach the greenhouse gas mitigation objectives. The DDPP scenario requires about 101,500 MW of additional capacity, while the Trottier scenarios require about 111,000 MW of additional capacity. ECCC's High Nuclear scenario would require 36,000 MW of capacity to be built, while the High Hydro scenario would require 130,000 MW to be built. Finally, ECCC's High Demand Response modelling run indicates that 108,000 MW of additional capacity would need to be built.

Although this is a significant increase in hydropower capacity, a study conducted for the Canadian Hydropower Association shows that in 2006 Canada had 160 GW of hydro potential, a large portion of which is economically viable. Canadian rivers provide close to 7% of the world's renewable water supply and this resource provides tremendous hydroelectric generating capability.[27] Currently, over 10 GW of hydro capacity have been proposed or planned in Canada, tapping the Churchill, Nelson, Slave, Athabasca, and Peace river systems. Over 3500 MW of this capacity is already under construction in Canada.

Figure 3 depicts the theoretical technical potential for hydro power generation by province. The above scenarios are all below the technical potential of hydro power capacity, indicating that this type of generation could be possible. The DDPP modelling exercise is 29% below technical potential, whereas both Trottier scenarios are 25% under this threshold. The High Nuclear scenario is 52% under technical potential, while the High Hydro scenario is closer, at 13%. Finally, ECCC's high Demand Response scenario is 22% below the technical potential of hydro power.

Hydro power also provides a good "coupling" to intermittent sources generated by renewables such as wind and solar power. Since renewable electricity is generated at intervals when the wind is blowing or the sun is shining, a high degree of coverage of electricity demand by wind or solar is possible only with access to energy storage or an adequate complementary form of electricity that can be ramped-up during periods of low generation. Fortunately, hydroelectric plants are well suited for this in Canada, and can store water in hydroelectric reservoirs that could be used when solar or wind generation is not available.

Hydro power may have negative implications, mainly based on the impact of dams on fisheries and water flows since dam reservoirs have an impact on flows, temperatures, and silt loads of rivers and streams. There have been examples of large dams blocking migrating fish from reaching their spawning grounds. For these reasons, the construction of future large hydro projects will require careful consultation processes.

27 National Energy Board, Canada's Energy Future 2016: Energy Supply and Demand Projections to 2040

28 International Energy Agency, Energy Policies of IEA Countries: 2015 Canadian Review.

Generally, further innovation will be required if hydro power is to increase substantially in Canada.[29] However, much of this increase in hydropower generation can be accomplished without building new dams. Many technologies allow for an increase in electricity generation from existing hydro dams, such as through increased efficiency turbines, at a relatively low cost.

While hydro power increases in all scenarios, nuclear energy varies depending on the modelling assumptions. The ECCC High Hydro scenario, assumes that nuclear power generation is maintained at today's levels, with the addition of expected refurbishments. The DDPP assumes that existing nuclear power is maintained, but no new capacity is added out to 2050. In comparison, under the Trottier analyses as well as the second ECCC GCAM analyses (High Nuclear) the model chooses a significant increase in nuclear power between now and 2050. Scenarios from the Trottier analyses show nuclear growing to about the same level as ECCC's High Nuclear scenario, although it grows slightly less for the New Technologies scenario, which assumes less electricity generation needs based on energy efficiency technologies.

The amount of nuclear capacity from the ECCC High Nuclear scenario, as well as the Current Tech Trottier scenario, corresponds to 797 TWh of generation per year in 2050, which is much higher than the current share of nuclear in the electricity mix, which corresponds to about 98 TWh of generation. There are significant challenges to building sizeable infrastructure projects like these, mainly because of high capital costs, delays in construction, and other potential issues. However, benefits to nuclear power include emissions free generations, reliable baseload capabilities, and a lower levelised cost of electricity. As such, new and emerging nuclear technologies could become an increasingly attractive option for a

29 Potvin, C. et al., *Acting on Climate Change: Extending the Dialogue Among Canadians: Some reflections on Climate Change Response Policy.*

POTENTIAL INNOVATIVE NUCLEAR TECHNOLOGIES

In the short term, Canadian Deuterium-Uranium (CANDU) reactors enable the use of alternative fuels in current nuclear generation. Canadian industry is currently working with China to run CANDU reactors on depleted uranium by-products and spent fuel recycled from other reactors.

Canadian and international developers are working on Small Modular Reactors (SMRs), which are compact nuclear reactors that can be scaled to generate power to communities ranging from several hundred people up to 300,000 homes. Compared with conventional nuclear power plants, SMRs require lower capital investment and offer scalability, siting flexibility, and enhanced safety features—including passive features that could prevent meltdowns even in the absence of power. SMRs are seen as a potential replacement for coal-fired power plants, or as a complement to intermittent renewables in transitioning remote communities off of diesel generation.

A transition from uranium to thorium-based fuels is possible over the longer term. Thorium is three to four times as abundant as uranium, and thorium-based fuels could reduce the amount of nuclear waste produced by reactors. Advanced nuclear reactors, including those using thorium-based fuels, could also achieve higher efficiencies than existing nuclear plants. China is investing heavily into thorium technologies, including the potential for CANDU reactors—which can support thorium fuel cycles more readily than other currently-available reactor types—and development of an advanced thorium reactor it hopes to demonstrate within the next decade.

Nuclear fusion represents a potentially game-changing technology for clean energy. Fusion differs widely from fission, the process used in conventional nuclear power generation. A Canadian company is developing a novel fusion reactor that could unlock large amounts of energy from hydrogen, a near-infinitely abundant resource on earth, in a process that would not generate any long-lived radioactive waste and entails no risk of a meltdown. For these reasons, nuclear fusion is a potentially transformative technology. While it still has hurdles to pass before making it to market, if it were to succeed, it would alter the landscape of clean energy permanently.

GHG-constrained energy system by 2050 (*see feature box on Potential Innovative Nuclear Technologies*).

Both ECCC High Non-Emitting scenarios point to a higher penetration of wind energy. Wind energy generation in 2050 represents 154 TWh, 9% of total generation, in Scenario 1, and 228 TWh, 14% of total generation, in Scenario 2. In comparison, wind energy increases to 17% of the generating mix in the DDPP analysis, whereas it increases to 24% in the Current Tech Trottier scenario and 8% in the New Tech Trottier scenario. Although these scenarios represent sizeable figures, a Pan-Canadian Wind Integration study[30] has demonstrated that Canada can reliably and cost-effectively integrate enough wind energy to meet 35% of Canada's electricity demand.

In both High Non-Emitting scenarios, solar power generation increases significantly reaching levels of 18 TWh, 1% of total generation, and 99 TWh, 6% of total generation in 2050. In comparison, solar energy increases to 5% of the generating mix in the DDPP analysis, and is only part of the solution for Alberta and Saskatchewan in select Trottier scenarios. The Trottier project notes that when deriving minimum cost solutions for electricity generation in Canada, solar did not compete well with wind.

However, the National Energy Board notes that Canada has a strong solar photovoltaic (PV) potential that is largely unexploited and that certain prairie cities including Regina, Calgary and Winnipeg have well above-average solar potential. Furthermore, it noted that in much of Canada, solar potential is higher than in Germany, the country with the most installed solar PV capacity in the world in 2014.[31]

In order to fully exploit Canada's solar potential, solar PV generation must reach competitive delivery costs to stimulate the large scale investments needed for significant deployment. Incentive programs such as Ontario's Feed-in-Tariff and microFIT programs may determine the pace of growth of solar generation across Canada in the near term. Household production of solar electricity through rooftop solar panels can also be beneficial and could provide more electricity than the household uses, providing an opportunity to sell electricity back to the grid. Fully realising the potential of distributed PV will likely require utility investments to upgrade existing distribution networks to handle two-way power flow. The NEB also highlights potential technological breakthroughs, such as utility-scale electricity storage options, which could provide a boost to the solar industry in Canada (*see box on energy storage*).

In the Deep Decarbonisation Pathways Project analyses, natural gas and coal with carbon capture and storage (CCS) technology is apparent throughout the projection period. In Saskatchewan, CCS was retrofitted to the Boundary Dam coal-fired electricity-generation plant in 2014 and is expected to generate reductions of up to 1 megatonne CO_2 per year. The project, implemented by SaskPower, shows that generating reliable, low-emitting electricity using coal is feasible. The project is key to better understanding the technical, economic, and environmental performance of CCS technology and could produce worldwide spillover effects if other countries choose to implement similar projects. The DDPP analysis also features natural gas generation with CCS as a significant proportion of electricity generation in 2050. Although no large scale demonstration projects have gone forward with this technology, it has the benefit of allowing CCS technology developed for coal electricity generation plants to extend to natural gas generation, which provides more flexibility to utilities in reducing emissions from their generation. Furthermore natural gas with CCS is estimated to be generally cheaper than using coal with CCS because of the lower capital cost of natural gas plants and their lower GHG intensity.[32]

Current Tech Trottier (in figure 2) models Canada's electricity generation with current technologies, a better interconnection between provinces, and allows the use of lowest cost electricity technologies available anywhere in Canada. In comparison, New Tech Trottier models the same GHG reduction target with a set of new technologies reaching market, including CCS and energy efficiency technologies. This technology application results in energy efficiency measures in end-use applications, reducing required electricity demand from 2,257 to 1,622 TWh between the two scenarios.

Other renewable energies offer potential in the mid-to-long term. For example, generating zero-emitting electricity with geothermal power is possible using hot subsurface water or steam coming from underneath the earth's surface. Standard well drilling technology can provide access to high temperature sources and power to turbines that offer reliable electricity.

Tidal energy is a type of renewable energy produced from ocean currents. Since tides are predictable, the generation potential of tidal energy is more

30 GE Consulting Group, *Pan-Canadian Wind Integration Study.*
31 National Energy Board, Canada's Energy Futures 2016: Energy Supply and Demand Projections to 2040.

32 Bataille, C. et. al., *Policy Uncertainty and Diffusion of Carbon Capture and Storage in an Optimal Region.*

INDIGENOUS RENEWABLE ENERGY INITIATIVES

Indigenous peoples, communities and organisations across Canada are implementing a range of climate change initiatives.[33] A database compiling Indigenous climate change initiatives has so far identified 79 renewable energy initiatives with a web-based presence, 16 of which are presented on the Nations' or communities' websites.[34] Renewable energy initiatives can yield multiple benefits, such as protection of the land, air and water, while creating much-needed employment.

The T'Sou-ke Nation of Vancouver Island in British Columbia, dubbed Canada's first Aboriginal Solar Community, developed three community-owned solar demonstration projects. These include a stand-alone system with battery storage on a community office building, a grid-connected solar PV system that can be used as a backup power source, which that can sell surplus power back to the grid for communities that wish to have net-zero energy use, and a kilowatt grid-connected, net-metered solar PV system on the community canoe shed, which powers its administration buildings. Surplus energy created in summer is sold to the grid and bought back in winter.

Additionally, the T'Sou-ke have installed solar hot water on 42 of the 86 private residences in the community, begun a comprehensive energy conservation program for all houses, and installed two solar-powered electric car charging points. The Government of Canada has just announced funding for a partnership between T'Sou-ke Nation and Schneider Electric to develop energy storage for a worldwide market. In Quebec, the First Nation's political and administrative organisations of Mashteuiatsh, Pekuakamiulnuatsh Takuhikan, and the Regional County Municipalities of Maria-Chapdelaine and Domaine-du-Roy in Saguenay-Lac-Saint-Jean have formed a non-profit 100% regional partnership to identify and develop renewable energy projects using a sustainable development approach. Since its creation, the partnership has contributed to the development of two mini hydro projects. Company profits are transferred to the communities.

Many power project developments occur in the traditional territories of Indigenous Peoples and many in remote areas. By proactively partnering in power developments, Indigenous Peoples can create long-term sustainable value for their members through investment, employment, infrastructure and new business opportunities. By working with the power developers at the earliest stages of project planning, indigenous communities have input into the design to meet local needs which include reducing environmental impacts. For example, "First Nations Power Authority" was mandated to facilitate the development of First Nations-led power projects and promote indigenous participation in procurement opportunities with the crown utility in Saskatchewan, SaskPower.[35]

predictable than that of wind and solar sources. These water flows can turn underwater turbines without the use of dams or reservoirs. Similarly, wave energy is generated by harnessing the motion of waves. Canada has significant tidal and wave energy resources, which can, in the future, contribute to emission free electricity generation. These technologies are currently at the demonstration stage and it is therefore too early to consider modelling their potential contribution to Canada's energy mix.

Additionally, as an alternative to fossil fuels, biomass can be used to generate renewable and sustainable energy. While trees and other plants grow, they absorb carbon from the atmosphere. Over time, the carbon dioxide sequestration from growing trees and plants will offset the short-term carbon dioxide emission from bioenergy, and could deliver substantial carbon savings when compared to fossil fuel use over time (*see more on biomass in Chapter 6*).

33 Assembly of First Nations, *Gap Analysis First Nations Climate Change Adaptation South of 60 Degrees Latitude.*
34 Sustainable Canadian Dialogues, *Acting on Climate Change: Indigenous Innovation.*
35 First Nations Power Authority; *About First Nations Power Authority.*

As mentioned, wind, solar, and run of river (or low-head hydro) only produce electricity when their resource is available (e.g., when the wind is blowing). For this reason, it is necessary to pair these technologies with hydro or other firm power sources, or with grid interties or management operations (*see box on energy storage*). Energy storage, grid interconnects, and smart grids could improve grid-stabilisation and buffer peak electricity demands, which could in-turn, support a larger share of renewables in the electricity grid.[36]

Storage technologies and smart grids may also be particularly useful in incorporating renewable technologies in remote and off-grid communities, since they have the potential to reduce or eliminate transmission costs. Between today and 2050, it is likely that significant developments will occur in storage technology with the potential to transform the energy system.

36 National Energy Board, *Canada's Energy Future 2016: Energy Supply and Demand Projections to 2040.*

37 International Energy Agency, *Energy Policies of IEA Countries, 2015 Canada Review.*

3.4 Interprovincial, interjurisidictional, and intercontinental cooperation will enhance integration of clean electricity generation to satisfy growing demand. Canada's contribution towards global GHG abatement could include providing clean power to our continental neighbours, as well as clean power services to the international community.

Canada, and North America's, electricity future will be shaped by interprovincial, interjurisdictional, and intracontinental cooperation. Since Canadian provinces and territories have purview over energy decisions within their jurisdictions, they have traditionally designed electricity infrastructure with consideration towards meeting their own energy demands. However, interprovincial electricity trade is becoming an important component of many provinces' supply and demand considerations. This type of cooperation becomes more important when considering climate change objectives, including maximising use of non-emitting sources (e.g., hydro), as well as when increasing the amount of intermittent electricity sources in the grid (e.g., solar, wind, tidal, wave). The recent Ontario-Quebec Trade and Cooperation Agreement provides a good example of interprovincial electricity trade.

Figure 4: Electricity exports and imports between Canada and the U.S., by province, 2014[38]

Expansion of electricity grid interties could allow more areas with surplus hydropower, or other forms of non-emitting generation, to sell electricity to other provinces or U.S. States that rely on fossil fuels. The integration of electricity markets between Canada and the U.S. includes 35 physical interconnections crossing the border and over $2.3 billion in Canada-U.S. electricity trade revenue.[38] In August 2015, the U.S. Environmental Protection Agency released the final version of the *Clean Power Plan* which could reduce GHG emissions from the U.S. power sector by 32% from 2005 levels. Under certain conditions, U.S. states can help meet their emissions reductions targets through imported clean electricity from Canada.

This is expected to create a significant new market opportunity for Canadian electricity exports and increase the profitability of various clean electricity projects, such as large hydroelectric facilities.

It will be important to maximise the benefits from this trade from both an economic as well as a global greenhouse gas standpoint. Under the North American Leaders' Statement on Climate, Clean Energy, and Environment Partnership, leaders announced a goal for North America to strive to achieve 50% clean power generation by 2025, which will require further cross-border transmission projects, including for renewable energy.

REDUCING CANADIAN NORTHERN, REMOTE AND INDIGENOUS COMMUNITIES' RELIANCE ON FOSSIL-FUEL GENERATED ENERGY

According to the Remote Communities Energy Database, there are 288 remote and off-grid communities in Canada, 190 of which rely on diesel fuel for their electricity needs, either completely or partially.[39] Most of these communities also rely on diesel fuel for home heating.[40] In addition to remote communities, a number of governmental and private buildings also rely on diesel fuel for electricity and heating. Sixty percent of Canada's remote and off-grid communities are First Nations, Inuit, or Métis communities. In many cases the diesel must be flown in at great expense.

There are various environmental and human health concerns associated with the transportation, storage and combustion of diesel fuel. Further, high fuel costs associated with diesel generation and power plants already operating at capacity represent barriers to improving living conditions and facilitating economic development. The cost of producing off-grid electricity from diesel generators in Canada's northern and remote communities can be up to 10 times higher than electricity generated on the main grid, and can significantly add to the cost of living for northern and remote communities.[41]

Circumstances of specific communities will affect the costs and viability of options to increase the share of non-emitting electricity generation. While connecting small and distant communities to existing grid infrastructure is not economically feasible, in some cases, hybrid wind/solar-diesel generation systems could be deployed in communities to decrease reliance on diesel fuel. Other potential non-emitting energy alternatives to diesel generation include hydro, tidal, geothermal, small modular nuclear reactors, and biomass. Diesel is also used to provide home heating in northern and remote communities. There may be opportunities to further displace diesel with lower emitting technologies.

A number of renewable energy projects have already been deployed to displace diesel in northern and remote communities. In many circumstances, diesel infrastructure is reaching the end of its life providing an opportunity to shift to cleaner technologies. Although the upfront capital costs to building non-emitting supply are high, these may be partially offset by lower operating/fuel costs. Long-term planning and investment is pertinent to the success of this transition.

38 National Energy Board, *Electricity Exports and Imports Summary.*

39 Natural Resources Canada, *Remote Communities Database.*

40 Carleton School of Public Policy and Administration, *Report of the State of Alternative Energy in the Arctic.*

41 Government of Canada, *Status of Remote/Off-Grid Communities in Canada.*

Moreover, non-emitting electricity infrastructure investments can help address issues of energy security for Indigenous communities and help set the conditions required for stable, and favorable policy climates for establishing mini and micro grids for rural and remote electrification, including those that are First Nation community or family owned.

Currently, the electricity sector requires major investments in new infrastructure, as many facilities are about to be retired or refurbished. The majority of investments in the sector will be in electricity generation; however, transmission and distribution will also see significant investments. There are estimated investment requirements of as much as $350 billion in electricity infrastructure in Canada between now and 2030.[42] The Deep Decarbonisation Pathways Project estimates that $16 billion in additional annual investments will be necessary to achieve Canada's low-carbon future, of which 87% ($13.5B) will be required in the electricity sector.[43] As conventional new sources of low-carbon electricity become less viable, or available (e.g., hydro), new investments in emerging technologies will become increasingly targeted.

Given the long-term nature of electricity related infrastructure, planning and investment decisions will need to be made in the near term to have the desired effect on the 2050 time horizon. For example, infrastructure spending, loan guarantees, and low-interest loans could potentially help fund new hydro projects and transmission lines to facilitate clean electricity projects.

3.5 Energy conservation and energy efficiency measures should increase and be implemented alongside efforts to reduce emissions from electricity generation. Electricity savings should underlie decarbonisation pathways: demand side management and reducing equipment and transmission losses makes electrification far more effective and feasible.

Improvements in energy efficiency and demand side management are core elements of a long-term low-GHG strategy and present economic opportunities. In many cases, energy efficiency is a cost-effective way to reduce GHG emissions as it provides substantial monetary savings for residential consumers and businesses through lower electricity bills, as well as other benefits such as reduced maintenance and improved durability. In addition, several commercialisation opportunities exist; for example the International Energy Agency (IEA) estimates the global energy efficiency market at $221 billion in 2015. The IEA also notes that efficiency investments helped drive a global energy intensity improvement of 1.8% in 2015 however "the intensity improvement needs to immediately step up to 2.6% per year from now until 2030 to get on a 2°C pathway".[44]

The IEA argues that energy efficiency is key to reaching global emissions levels consistent with the 2°C temperature goals. They estimate that electricity savings, through efficiency measures, could avoid 5,100 GW of new capacity by 2050. Likewise, Torrie Smith Associates notes that low-carbon future analysis typically include per capita levels of fuel and electricity use that are about half the current Canadian average, and energy productivity (GDP/energy) four times higher than current Canadian levels.[45] Energy efficiency trends are already positive in Canada as energy efficiency improved from 1990 to 2013 by 24%.[46] The National Energy Board projects that total end-use energy demand will increase at an average annual rate of 0.7% from 2014 to 2040, almost half the rate of increase from 1990 to 2013.

Higher electricity efficiency can be achieved with targeted demand-side management measures and technological improvements. Changes in behaviours such as consuming electricity during low-demand periods could reduce peak power demand which could contribute to reduce GHG emissions from load generation.[47] Energy efficiency can also defer transportation and distribution investments, reduce line losses and avoid capacity reserve requirements. As technology develops, further electricity productivity gains should be realised with devices like smart meters helping to reduce and optimise end-use.

42 Conference Board of Canada, *Canada's Electricity Infrastructure: Building a Case for Investment.*

43 Bataille C., *Pathways to Deep Decarbonization in Canada.*

44 International Energy Agency, *Energy Efficiency Market Report.*

45 Torrie, R., *Acting on Climate Change: Extending the Dialogue Among Canadians; Some Reflections On Climate Change Response Policy.*

46 Natural Resources Canada, *Improving energy efficiency in Canada.*

47 Energy efficiency can also defer transport and distribution (T&D) investments, reduce line losses and avoid capacity reserve requirements (IEA 2016)

Modernizing the electricity grid could also contribute to improved electricity efficiency by reducing losses when electricity is generated and transmitted. Grids generally follow north-south orientations since most of Canada's population live in southern jurisdictions along the international border with the United States, while the largest hydroelectric projects are located in scarcely inhabited areas to the north. Since the Canadian transmission networks extend over 160,000 km, losses are significant between generation and end-use sources. However, by 2050, it is highly probable that distributed generation will play a bigger role, reducing the requirement for electricity to travel long distances from point of generation to end use.

ENERGY STORAGE

The principal challenge with variable renewable energy such as wind or solar is that they are intermittent, meaning that power is not available when the wind is not blowing or the sun is not shining. As such, improvements in energy storage would make these intermittent sources much more attractive to grid operators, ensuring that power is available to meet demand cycles. Additionally, increase in energy density and charging rates for battery energy storage technologies can provide the improvements in the transport sector that will be required for a widespread adoption of electric means of transportation.

Incorporating intermittent power flows to existing grids requires added flexibility elsewhere on the grid, which can increase system costs. However, such costs could be offset by the adoption of technologies that can store excess power for weather conditions that are unfavorable to power generation and support the grid during peak demand time. Storage technologies could also allow households to rely on their own energy production, thus increasing the growth of local energy production, potential of smart grid systems, and energy availability for remote communities.

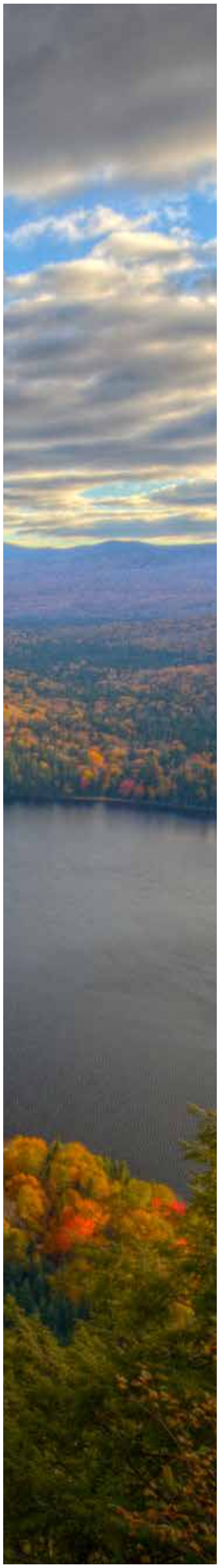
Figure 5 : Technology Roadmap : Energy Storage

Source: International Energy Agency, 2014. Technology Roadmap: Energy Storage

The private sector has been a major leader in energy storage research. Specifically, battery storage technologies for cellphones, computers and electric vehicles, have seen tremendous growth in recent years. Already, the costs of lithium ion batteries are being significantly reduced by the production of electric transportation companies, such as Tesla Motors. Moreover, other cheaper and more efficient options are being developed, with possibilities for the entire energy sector. For example, sulfur-based and graphene-based battery technologies offer tremendous potential for cheaper and more powerful battery storage. Other energy storage options are available, with some of them already adopted by Canadian electricity providers. Recently, the Toronto Hydro Company's compressed air energy storage pilot project was deployed in Lake Ontario and now provides 1 MW of storage capacity that can be sent to the city grid during peak demand times. Thermal energy storage is also being used in the community of Okotoks, Alberta. Nevertheless, the most promising option for some Canadian provinces is likely to be pumped storage hydropower (PSH). The technology is readily available, has low operation and maintenance costs, and is not limited by cycling degradation.

Although recent improvements achieved by the private sector are encouraging, much more innovation is needed to allow for widespread renewable energy production by 2050. Consequently, due to the essential role of energy storage technologies in the electrification of numerous processes, including transportation, it is fundamental that energy storage technologies continue to improve over time. In order to accomplish this, governments and private actors have a shared responsibility to scale up investments throughout the innovation chain in order to allow breakthrough technologies as well as incremental improvements to be brought to market.

4 Energy Consumption in End Use Applications



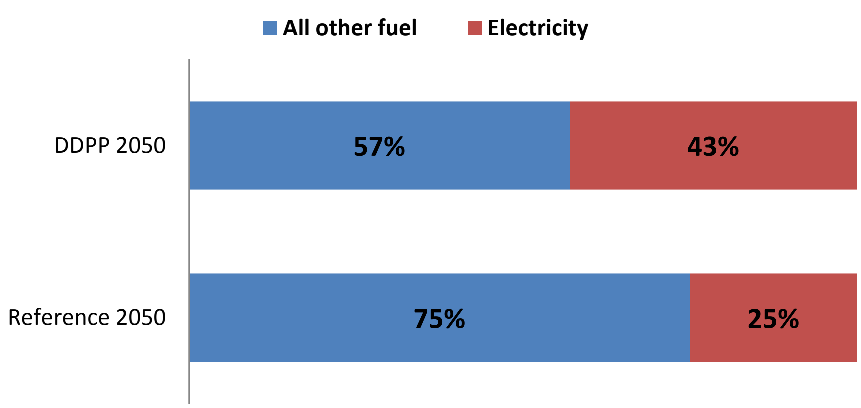
Under a low-carbon future, Canada's electricity demand is expected to increase substantially by 2050, partly as a result of traditional pressures such as population and industrial growth, but also because of the electrification of end use applications that currently use other forms of energy. Many applications (e.g., cars, trucks, boilers, heaters) can use clean electricity to fulfil their power requirements, reducing emissions by switching away from refined petroleum products, natural gas, and other fossil fuels. This greater use of electric power is often accompanied by important efficiency gains, especially in the transportation sector, leading to an expected reduction in overall energy demand under low GHG scenarios. Maximising the abatement potential from electrification requires the simultaneous near decarbonisation of existing electricity generation and the large expansion of new zero or low emissions electricity sources, as discussed in the previous chapter.

All academic and expert analyses that pertain to low-GHG pathways show an increase in electricity supply and greater proportion of electricity in total energy demand. For example, the *Deep Decarbonization Pathways Project* shows electricity rising to 43% of total energy by 2050 compared to 25% currently, more than doubling the current supply between now and 2050. Moreover, the *Trottier Energy Futures Project* shows electricity generation more than tripling between now and 2050.

Given Canada's relatively cheap and clean electricity generating portfolio, implicit carbon costs for electric power are lower than in many other countries. This means that clean electricity is a comparative advantage for Canada. It will be important to examine any change or rise in electricity costs associated with the new demand requirements, and ensure that Canada continues to have access to affordable and reliable electricity going forward.

Apart from electrification technologies, renewable and low carbon fuels are low or non-emitting options to fulfil many of Canada's energy requirements. These fuels will be particularly important in areas where electrification is not currently possible or too costly, such as aviation and marine transport, some heavy freight transportation, and many industrial activities. Likewise, renewable or low carbon fuels can often be used in existing cars and trucks or building furnaces in higher blends, without affecting equipment performance, safety or warranties.

Figure 6: Electricity as a share of National energy consumption



Source: Bataille, *C. et al. Pathways to deep decarbonization in Canada.*

It is important to recognize that all energy related emissions reduction activities work best when paired with increasing energy efficiency. For example, increasing the number of homes heated by clean electricity will be much more viable when building envelopes are designed to minimise heat loss. Importantly, a reduction in demand through energy efficiency, conservation, and demand side savings will partially offset the increased Canadian electricity requirements from the electrification of end use applications.

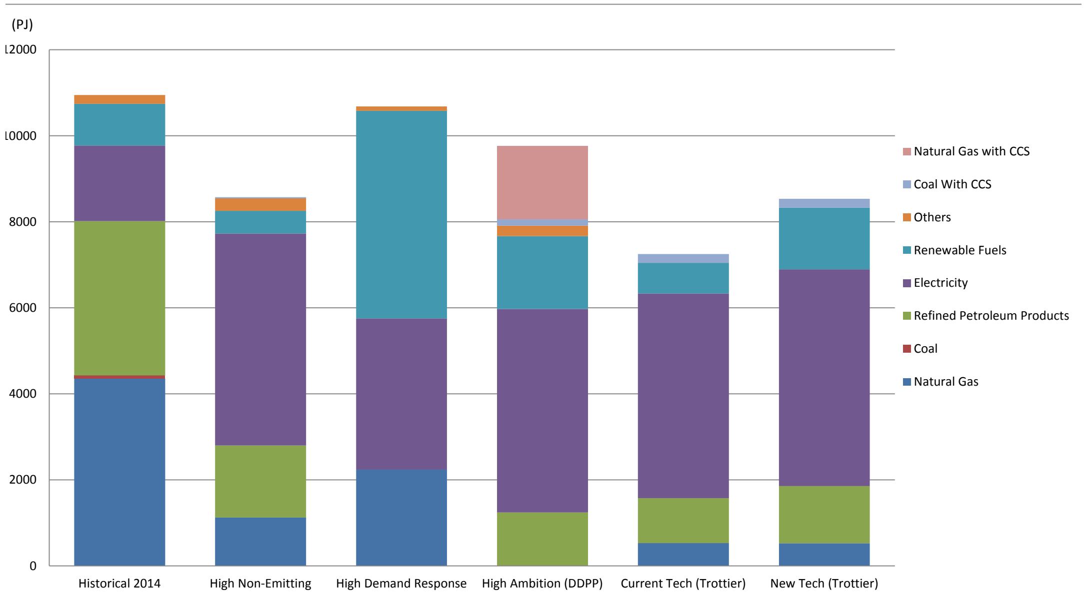
Figure 7 presents several analyses of total energy use in Canada by 2050 under low-GHG scenarios. The current energy use (2014) is presented, as well as DDPP and Trottier Institute 2050 results. While there is population and economic growth during the period, even stronger energy efficiency gains allow for decreases in total energy consumption in most analyses. For example, total energy consumption decreases from 10 950 PJ in 2014 to 7971 PJ on 2050 (ECCC GCAM scenario, labelled "High Non-Emitting") or even 7 251 PJ in 2050 (New Tech Trottier). The central role of energy efficiency gains in the projections is consistent with Chapter 2 that depicted energy conservation as the "first fuel", the foremost criteria to meet the 2050 GHG emissions reduction levels.

Apart from a reduction in total energy consumption, the switch from fossil fuels use to electricity and renewable fuels alternatives is another cross cutting theme of all scenarios presented. Clean electricity production across the country, achieved before 2050 in all scenarios, allows for deep GHG emission reductions from the electrification of end uses and industrial processes. Electricity use in 2050 is predicted to reach between 40 to 72% of total energy consumption, up from 16% in 2014.

Renewable fuels provide the last alternative in most scenarios to decarbonise the intensive GHG sectors of the economy. In key sectors, notably in heavy industry and freight transport, renewable fuels replace conventional petroleum and natural gas usage. Those alternative fuels are essential to attain deep GHG emissions reductions, since it is not likely that technological advances will allow electrification of all sectors of the economy by 2050.

Specifically, ECCC presents two scenarios where electricity generates either 33% (High Demand Response) or 57% (High Non-Emitting) and renewable fuels supply either 45% (High Demand Response) or 6% (High Non-Emitting) of total energy consumption in Canada by 2050. ECCC's High Non-Emitting projection estimate refined petroleum products will still account for around 20% of total energy consumption by 2050, with natural gas generating 13%. ECCC's High Demand Response scenario projects a use of natural gas falling to 21% of total energy consumption by 2050, and no future use of refined petroleum products. In contrast, the DDPP estimates that electricity will generate 48% of total energy consumption in Canada by 2050, with 17% supplied by renewable fuels, 17% by natural gas (with Carbon Capture Storage Technologies [CCS]), 2% by coal (with CCS) and 13% by refined petroleum products. Trottier estimates electricity to take between 59-66% of total energy consumption in Canada, with renewable fuels supplying either 9 and 17%, refined petroleum products supplying between 14-16%, natural gas 6-7%, coal 2-3% (retrofitted with CCS).

Figure 7: 2050 Projections of Total Energy Consumption by End Use Fuel



4.1 Transportation

KEY MESSAGES:

- Electrification of the transportation sector presents the potential for significant emission reductions; for personal vehicles, electric vehicle technology is commercially available and continues to improve.
- Greater uptake and broad use of electric vehicles will require more widespread acceptance of the technology supported by information and understanding around: cost of ownership and performance, charging availability and times, and range expectations. All of which are expected to improved significantly over the coming years.
- Low-carbon and renewable fuels are consistent with low-GHG scenarios, particularly in areas that face challenges with electrification.
- Freight transport is a challenging sector, but there are a number of solutions that show potential towards deeper emissions reductions.
- Emerging technologies such as energy storage or advanced lightweight materials will increase energy efficiency and decrease emissions; innovative approaches to moving people and freight are likely to become more widely adopted by mid-century.
- Modal shifts, such as moving passengers and freight to less GHG intensive modes, could offer notable emissions reductions, which would be further strengthened through clean technology deployment, such as electrified passenger rail.
- 62% of Canada's black carbon emissions arise from the Transportation sector. In addition to being linked to climate warming, black carbon emissions are also a public health concern. Canada continues to take complementary action to reduce black carbon emissions.

4.1.1 Electrification of the transportation sector presents the potential for significant emission reductions; for personal vehicles, electric vehicle technology is commercially available and continues to improve.

The transportation sector plays a vital role in the lives of Canadians and in the Canadian economy. Almost 82% of Canadians live in urban areas and 80% of commuters drive to work in their own vehicles. Canada's transportation system moved over $1 trillion worth of goods to international markets and employed 896,000 Canadians (5% of total employment) in 2014. Compared to other countries, Canada depends heavily on cars for urban mobility, and has a relatively high share of large cars. Canada has large distances between its cities, increasing intercity travel emissions.

Currently, the transportation sector is a major contributor to Canadian GHG emissions. Roughly one quarter (28%) of Canada's GHG emissions come from the transportation sector, such as from cars, buses, trucks, motorcycles and recreational vehicles.[48] About 57% of these emissions come from passenger transport, while heavier freight transport accounts for 37% of transport emissions.[49] However, given increasing efficiency improvements in passenger vehicles (mainly driven by federal regulations) and challenges in achieving efficiency improvements in freight, the share (and net amount) of GHG emissions from freight transportation is expected to increase into the future.

Road transportation activity can be broken down into two components: how people and freight travel (mode choice) and how far they travel (activity level).[50] Emissions reductions could result from a greater market penetration of alternative vehicle technologies and modal shifts (e.g., away from single-occupancy vehicles). Activity level changes could be achieved through consumption patterns shifting with technological advances (e.g., teleworking) or urban densification. Canada will continue to encourage cities to improve public transit and bike lanes, and design urban spaces that reduce the need for vehicle transportation.

Battery electric vehicles provide the opportunity to emit zero GHG emissions when renewable or

48 Environment and Climate Change Canada, *National Inventory Report 1990-2014: Greenhouse Gas Sources and Sinks in Canada.*

49 Based on Canada's *Emission Trends Report 2014.*

50 Conference Board of Canada, *A Long, Hard Road: Reducing GHG Emissions in Canada's Road Transportation Sector by 2050.*

clean electricity is used. In addition, electric vehicles reduce local air pollutant emissions. Electric vehicle technology is well known, proven, and available for purchase in Canada with increasing variation and choice: in total, there are 22 different plug-in models on the road in Canada, made by 12 different manufacturers.[51] Alternatively, plug-in hybrid vehicles offer increased driving range by switching to fossil fuels when the electric battery charge diminishes. While these vehicles still use fuel, most of them are used in a way that relies solely on electricity about 90% of the time. [52]

4.1.2 Greater uptake and broad use of electric vehicles will require more widespread acceptance of the technology supported by information and understanding around: cost of ownership and performance, charging availability and times, and range expectations. All of which are expected to improved significantly over the coming years.

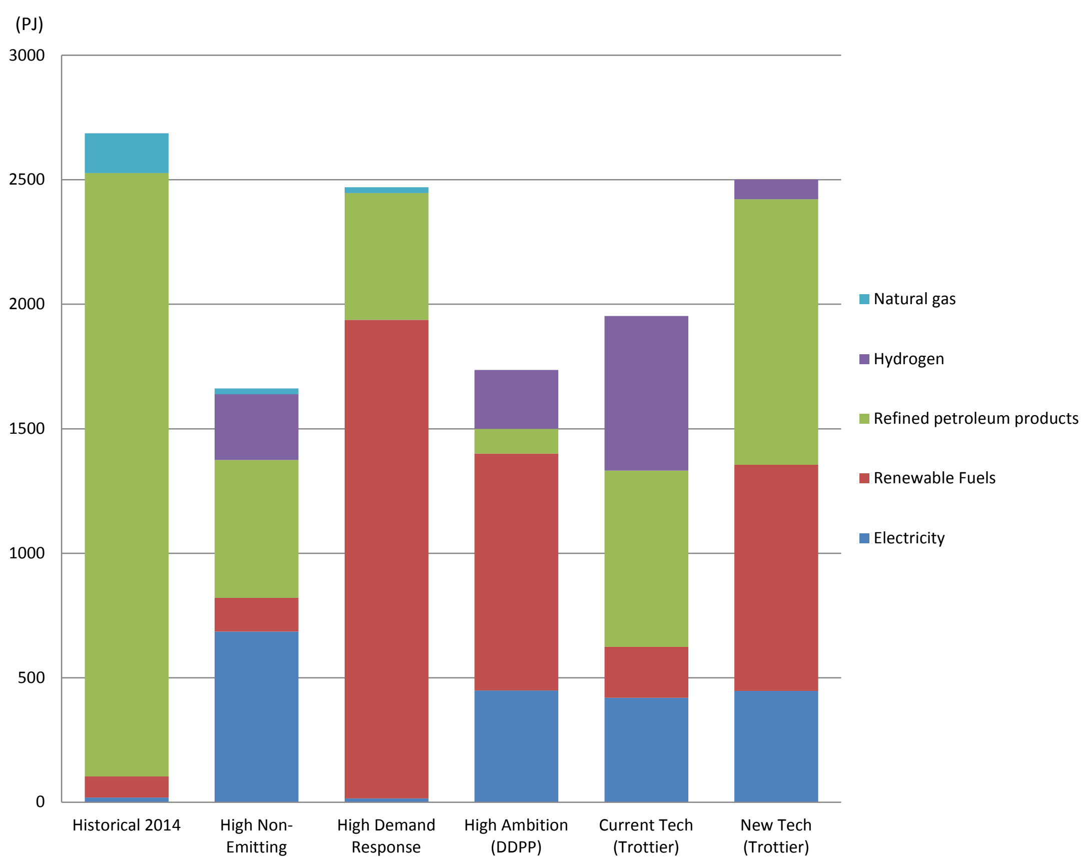
51 CAA, *Electric Vehicles: What You Need to Know.*
52 EVObsession, *Best Electric Car for the Average American.*

In spite of Canada's ambitious mitigation objectives and clean electricity portfolio, we lag behind many of our peer countries with respect to electric vehicle penetration. For example, Norway reached annual sales of almost 40,000 fully electric vehicles in 2015, reaching a market share of 23% of passenger vehicles sold. China has grown its electric vehicle fleet by 207,000 passenger vehicles in 2015, with an additional 123,700 electric buses and commercial trucks on the road.[53] Meanwhile, there are now more than 40,000 electric vehicle charging stations in Japan, including in personal homes and commercial buildings. Charging stations are now more common than the roughly 35,000 gas stations in the country.[54]

Although only about 24,000 plug-in vehicles have been sold in Canada thus far, sales increased by 32% between 2014 and 2015, and are projected to continue to increase as prices converge with those of conventional vehicles, charging infrastructure is built out, and more vehicle selection becomes available.[55] For example, out of the roughly 400,000 reservations

53 International Energy Agency, *Energy Technology Perspectives 2016.*
54 Coulter, T., *Japan Has More Car Chargers Than Gas Stations.*
55 Fleet Carma, *Electric Vehicle Sales in Canada: 2015 Final Numbers.*

Figure 8: 2050 Transportation Sector Energy Use Projections (PJ)



of the upcoming Tesla Model 3 electric vehicle, an estimated 36,000 have been made in Canada.[56]

While the production costs of electric vehicles remain higher than traditional gasoline vehicles, a more significant challenge limiting electric vehicle adoption is consumer concerns regarding the range of the battery charge. Charging speeds and battery range currently do not allow for comparable refueling times when benchmarked against traditional gasoline vehicles. In some circumstances, cold weather can also reduce electric vehicle driving range. However, studies have found that the current battery range for electric vehicles is sufficient to satisfy close to 90% of personal vehicle use. For example, a study from the Massachusetts Institute of Technology used GPS data to estimate the energy requirements of personal vehicles across the United States, determining that 87% of requirements could be met with current electric vehicles.[57]

In addition, there are significant efforts put in place to increase fast charging infrastructure in some Canadian jurisdictions, which can allow the average electric car to charge 80% of its battery capacity in 30 minutes. Although needs for infrastructure investments will be important in the coming years, it is important to note that chargers will not need to be as abundant as fuel dispensers are today, as more than 95% of charging is done at home, and public charging stations generally only need to be used when motorists travel long distances.

4.1.3 Low-carbon and renewable fuels are consistent with low-GHG scenarios, particularly in areas that face challenges with electrification.

Low-carbon, renewable fuels, and hydrogen are of particular importance for areas that are hard to electrify. A number of renewable fuels are already commercially available such as ethanol, biodiesel or biofuels. Fuel blends contain varying renewable content, and environmental benefits expand when second-generation biofuels are used. Unlike other modes of transportation, the aviation industry has few options available for reducing GHG emissions. Improved technological and operational measures will have their role, but only low-carbon alternative fuels (biojet) have the potential to offer significant life-cycle GHG emission reductions.

Renewable natural gas offers the potential to achieve considerably greater emissions reductions than natural gas. Biogas, generated from biomass from landfill sites, agriculture, wastewater, or other sources is upgraded to natural gas quality. It can then be directed to the grid for use in buildings or transportation applications in the form of compressed natural gas (CNG) or liquefied natural gas (LNG).

Natural gas vehicles are used in several fleets around the world. Up to a 25% reduction in carbon dioxide equivalent emissions can be achieved on a well-to-wheel basis when replacing gasoline with compressed natural gas in light-duty vehicles. Natural gas can be an effective solution for transportation that is harder to electrify such as on-road freight, marine shipping and rail, featuring relatively quick refueling times and long ranges. As such, it has been a key area for research and development for these modes. Natural gas also has the advantage of significantly improving air quality and reducing noise when compared to diesel.

Hydrogen fuel cell technology can also help decarbonise the transportation sector. The process of producing electricity with a fuel cell involves hydrogen and oxygen as inputs, and produces water vapor and heat at the tailpipe, therefore emitting no GHG emissions. However, hydrogen production currently either requires significant amounts of electricity to be produced through electrolysis, or can be produced with methane reforming, which is an emitting process.

Hydrogen fuel cell vehicles provide the benefit of having similar refueling times when compared with internal combustion engine vehicles, but they also face important barriers such as the cost of fuel cells, cost and energy intensity of hydrogen production, and the need for new infrastructure for hydrogen refueling stations. Nonetheless, hydrogen is a key component of several modelling exercises including the IEA and Deep Decarbonization Pathways Project. For example, the IEA has modelled different levels of Fuel Cell Electric Vehicle adoption. So far, Toyota and Hyundai have commercialised fuel cell electric vehicles in Europe, South Korea, California, Vancouver and Japan and further investments could help to accelerate infrastructure deployment. For example, there are already several hydrogen stations and buses in Whistler, British Columbia. Hydrogen is used widely in industry for ammonia production and refining, and can be used for storing the energy in excess renewable electricity. Canada is well placed in the development of hydrogen and alternative fuels with companies such as Westport innovations and Ballard, developing and exporting these low carbon technologies.

56 Model 3 Tracker, *Known Sport of Model 3 Vehicles by Status.*
57 Needell, Z., *Potential for Widespread Electrification of Personal Vehicle for Travel in the United States.*

Modelling results from very low greenhouse gas scenarios for 2050 point to various avenues to power Canada's transportation sector (*see description of models and scenarios in Modelling and Scenario Box in Chapter 2*). Currently, refined petroleum products (e.g., gasoline, diesel) power over 90% of Canada's transportation energy requirements. Under scenarios where aggregate Canadian emissions decline dramatically in 2050, the energy portfolio of the transportation sector shifts considerably (*see Figure 8).*

Under ECCC's first High Non-Emitting scenario, electricity powers 41% of transportation energy requirements in 2050, whereas renewable low-carbon fuels account for 8%. The remaining requirements are met with hydrogen (16%) and natural gas (1%), although refined petroleum products continue to power 33% of the vehicle fleets including air and marine transportation. In comparison, ECCC's High Demand Response model points to renewable and low-carbon fuels dominating the transportation energy portfolio (78%). In this modelling scenario, electric vehicles do not penetrate the market.

The Deep Decarbonization Pathway Project also points to a high penetration of renewable and low-carbon fuel powered vehicles (55%). Electricity makes up 26% of the power requirements from the transportation sector, whereas hydrogen accounts for 14%. Under the Trottier analyses scenarios, renewable or alternative fuels power 10-18% of the transportation requirements in 2050. Electricity powers 18-21% and hydrogen powers 3-32%. Refined petroleum products continue to power 36-43% of the sectors energy requirements.

4.1.4 Freight transport is a challenging sector, but there are a number of solutions that show potential towards deeper emissions reductions.

Freight transportation, *such as heavy duty on road vehicles, aviation and marine is a challenging area for GHG mitigation*. Improving the fuel efficiency of freight transportation is essential to reducing greenhouse gas emissions from this subsector. Moreover, alternatives to conventional internal combustion engines exist including vehicles that run on fuels such as biofuel blends, liquefied petroleum gases, or natural gas. The use of these fuels can reduce the GHG intensity of road transportation, sometimes significantly.

Electrification of freight transport is currently limited due to technological constraints such as insufficient range for long-haul shipping, long charging times for delivery requirements, as well as the significant energy requirements and engine sizes required to transport heavy loads. However, some companies have revealed plans to develop electric freight transport in the coming years. For example, last July

CANADIAN BUSINESSES ADOPTING LIGHT FREIGHT ELECTRIFICATION

A number of Canadian companies, and companies operating in Canada, have opted to green their fleet through the use of hybrid-electric vehicles or fully electric vehicles. For couriers and other shipping companies, fleet management and fuel use has a major impact on operating costs, and is constantly being reviewed to minimise costs and increase performance. Some companies have opted for electric vehicle technology for both economic and environmental benefits.

As a few examples, Canada Post, Purolator, the United Postal Service, Fedex, and Novex have moved towards more sustainable transportation solutions for shipping. Other initiatives, such as a fully electrified taxi company, have been developed, for example in Montréal by Téo Taxi. Although information gaps appear to be an important barrier to adoption of electric vehicles by small and medium enterprises, several companies are providing support services to demonstrate the business case for greening vehicle fleets. This involves procedures such as calculating expenditure impacts, renting out vehicles to allow for trials, and providing technical support for charging infrastructure management.

Another company, Communauto, North America's oldest and largest car-sharing company, has recently announced its purchase of 600 hybrid-electric or fully electric vehicles. Among these vehicles, 515 are destined to the Québec market, while the remainder will be distributed to Communauto's European market. Ride-sharing services also displace a significant amount of personal vehicle requirements, thereby reducing GHG emissions further.

Mercedes-Benz unveiled its latest electric prototype, the Urban eTruck, conceived for dense urban areas. The fully electric vehicle has two electric motors, can hold 3 batteries, and will be able to support up to 26 tons. Conceived for short distances (200 kilometers) and use in heavy traffic, Mercedes-Benz expects to commercialise the vehicle by 2020.[58]

Despite continuous progress, there are some challenges associated with reducing emissions from freight transportation. Finding economical means of producing biofuels and alternative means of transporting merchandise will be key.

Figure 9: An Urban eTruck[59]

A large deployment of heavy electric trucks may take longer than cars since the turnover rate of heavy trucks is significantly lower than for cars (30 years for trucks compared to 20 years for cars). Emissions from aviation, marine, and rail transport are also challenging to reduce due to the high energy density of fuel required with these modes. Despite these challenges, the energy intensity of the freight transportation sector decreased from 1.38 MJ/Tkm in 2011 to 1.30 MJ/Tkm in 2013. A recent report from the Conference Board of Canada suggests that much greater performance and efficiency improvements will be needed to help bring Canada to deep decarbonisation in the transportation sector.[60]

In 2013, new federal regulations imposing GHG emission standards for new on-road heavy-duty vehicles and engines were implemented to align with U.S. national standards and move the Canadian heavy truck fleet toward more fuel efficient vehicles. In the marine and rail sectors, where fuel represents a significant share of overall costs, operators are actively seeking improvements in fuel efficiency and GHG performance through new technologies, designs and system efficiencies, and are exploring a shift to low-carbon fuels. For marine shipping, mandatory technical and operational emissions reduction measures established by the International Maritime Organization (IMO) are also driving efficiency improvements. However, significant emissions reductions will take time as the existing stock of ships and locomotives turn over. Electric and alternative fuel solutions can also achieve meaningful reductions from port and cargo handling equipment at transportation hubs.

4.1.5 Emerging technologies such as energy storage or advanced lightweight materials will increase energy efficiency and decrease emissions; innovative approaches to moving people and freight are likely to become more widely adopted by mid-century.

Looking forward, improvements in energy storage technology will facilitate the adoption of electric vehicles. The most anticipated technological development related to battery storage is the use of graphene in batteries, which would allow for a significantly higher energy density (battery capacity per unit of weight), significantly faster recharging times, and lower costs. Graphene is abundantly available and the emergence of graphene batteries could be a tipping point where electric vehicles will become more affordable and convenient, broadening adoption.

Connected and automated vehicles, combined with smart infrastructure, are expected to be increasingly deployed by automakers, and have the potential to not only make driving more convenient, but considerably safer, and more efficient, which can lead to improved environmental outcomes. While not as significant as the impact of electrifying transportation, efficiency improvements from autonomous driving could be important. With quicker reaction times than humans, connected and autonomous vehicles can circulate with less distance between cars, allowing for much more efficient traffic movement (e.g., reduced idling, smoother acceleration), and perfectly safe slipstreaming (i.e., cars avoiding wind resistance by following others closely), resulting in less energy wasted. The expected safety improvements and reduced congestion could add up to large fuel savings, with significant co-benefits for the economy and the environment.

Finally, advanced lightweight materials and manufacturing methods will need to be integrated

58 Mercedes-Benz, *Electric Truck for the City.*
59 Mercedes-Benz, *Urban eTruck.*
60 Conference Board of Canada, *A Long Hard Road: Drastically Reducing GHG Emissions in Canada's Road Transportation Sector by 2050.*

ELECTRIFIED PUBLIC TRANSPORT AND SMART URBAN PLANNING

In the transition to a low-carbon economy, public transportation provides significant GHG emission reductions as compared with personal vehicles, but diesel buses still emit a sizeable amount. More recently, advances in the development of batteries for electric vehicles have spilled over to city buses. For example, the city of Gothenburg has been using three electric buses on one line of its public transport service, and has been using seven hybrid electric buses. Although the buses are significantly more expensive than diesel buses upon purchase, the fuel savings rapidly compensate this difference. The buses are charged for six minutes between trips, allowing for more than enough range for the route they serve, while providing outlets to charge phones and providing Wi-Fi to users inside the buses.[61] Similar projects are under way in Montreal, starting with hybrid-electric buses.[62]

Another important consideration in transitioning to a low carbon economy is how to plan and design cities in order to support low-emission technologies and lifestyles, and correct for the traffic congestion levels that are seen in large Canadian cities. Congestion is an important cost to the economy, evaluated in 2008 as costing the regional economy of the Greater Toronto and Hamilton Area, directly and indirectly, $6 billion annually.[63] This kind of structural change will take time to realise, but governments can start building momentum in the short-term by deciding to take a holistic approach to development through integrating land use, transportation, energy production and community planning.

More and more, cities are looking into innovative solutions to reduce congestion on their roadways. For example, the city of Edmonton is one of two Canadian cities taking part in a North American program aimed at developing Connected Vehicle Technology.[64]

This technology can improve many elements of transportation in cities, by preventing collisions between cars, by guiding drivers through detours when there is a slowdown or an accident on the road, and even adjusting traffic lights along the detour routes to minimise congestion. Other technological advances are leading to autonomous vehicles and greater use of vehicle sharing, which stand to have important impacts of the future movement of people within cities. Technological advances also help pave the way for new management approach by cities and governments, such as the use of efficient pricing of tolling mechanisms. For example, High Occupancy Tolls Lanes allow for both vehicles with enough passengers and permit holders to drive in these lanes, allowing for reduced congestion and revenues that can be invested into public transit.

across all modes of transportation to increase efficiency, from on-road electric vehicles to aviation. Other considerations to reduce transportation emissions include: retrofit of heavy-duty vehicles including tractors with GHG-reducing technologies (aerodynamics, auxiliary power units) and the scrappage of less efficient vehicles.

61 Electricity, *The electric bus – quiet, exhaust emission-free and passenger-friendly.*

62 Canadian Press, *Electric bus pilot project to hit Montreal streets in 2015.*

63 Urban Transportation Task Force, *The High Cost of Congestion in Canadian Cities.*

64 City of Edmonton, *On the Front Edge of Smart Vehicle Technology.*

4.1.6 Modal shifts, such as moving passengers and freight to less GHG intensive modes, could offer notable emissions reductions, which would be further strengthened through clean technology deployment, such as electrified passenger rail.

Given the emissions profile and current limitations in electrifying freight transportation, a shift towards rail transit for a majority of freight could reduce the amount of energy needed to move goods around the country. Although rail transportation entails issues such as longer shipping times, and less flexibility in terms of routing of goods, it has the potential to reduce emissions per unit of goods moved by about 75% compared with on-road vehicles for the same distance travelled.[65] As for passenger transportation,

65 Association of American Railroads, *Freight Railroads Help Reduce Greenhouse Gas Emissions.*

rail offers another potential avenue for intercity travel, which could reduce emissions compared to personal vehicles or bus transportation. Other benefits to shifts toward rail transportation include reduced wear and tear on roads and reduced road congestion.

In addition to being less GHG-intensive than on-road modes of transportation, there may be an opportunity to reduce emissions even further through electrification of Canada's passenger rail systems moving on dedicated tracks. Heavily populated corridors, such as the Windsor-Quebec axis, represent prime areas for such a system. Although this type of project requires significant capital expenditures, important savings can be realised through reduced energy costs, increased performance allowing better optimisation (e.g., allowing more units to be attached to the same locomotive), and reduced maintenance costs.[66] Electrification of trains also provides other benefits in the form of smoother rides, reduced power load at higher altitudes compared with diesel, and service to underground locations (which is not possible for diesel given emissions of pollutants).

Electric light-rail trains represent an interesting mode of transportation for public transit, as it is up to 10 times cheaper than underground metro systems for the same distance covered.[67] At this cheaper cost per kilometer, light-rail trains become particularly appealing for bringing commuters from suburban areas into cities faster, while reducing the amount of vehicles in downtown areas. Light-rail trains are also easier to electrify than buses, which makes it a less GHG-intensive transit option than buses, while also reducing the cost of electrification.

4.1.7 62% of Canada's black carbon emissions arise from the Transportation sector. In addition to being linked to climate warming, black carbon emissions are also a public health concern. Canada continues to take complementary action to reduce black carbon emissions.

The transportation sector emits significant amounts of black carbon mostly through diesel engines and vehicles. Canada continues to take regulatory action to address air pollutant emissions from transportation, which also reduces black carbon, including regulations for on- and off-road diesel vehicles and engines manufactured or imported for sale in Canada. Regulations to implement the North American Emissions Control Area to reduce emissions from shipping also reduce black carbon emissions.

In addition to being linked to climate warming, black carbon emissions are also a public health concern. As a component of $PM_{2.5}$, black carbon particles are small enough to be inhaled and absorbed into the lungs and bloodstream. Reductions in black carbon emissions from the transportation sector have important co-benefits for the health of Canadians.

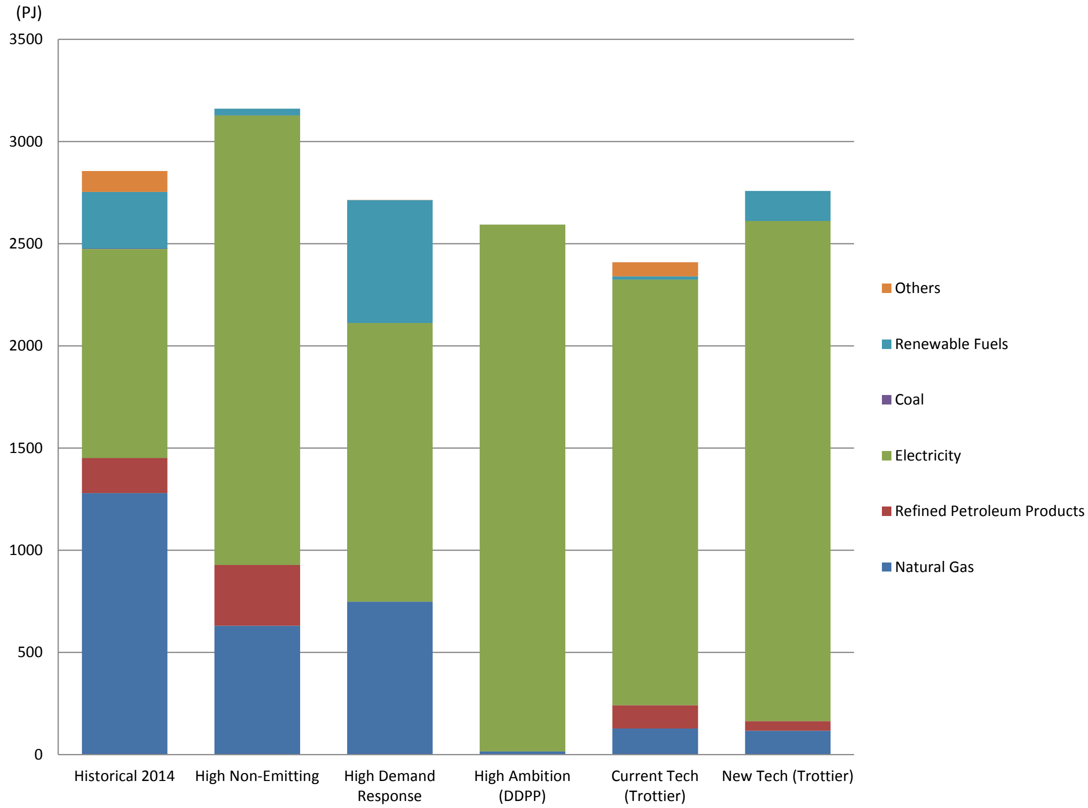
4.2 Buildings

KEY MESSAGES:

- Over one third of Canadian homes are already heated and cooled with clean electricity; emerging technologies will make this option increasingly economically attractive.
- Natural gas continues to play an important role in heating and power requirements. Renewable Natural Gas is a small but growing part of the supply mix meeting those energy needs.
- The electrification of the building sector should be matched with a scale-up of energy efficiency measures.
- District heating for residential and commercial buildings could help lower GHG emissions since heat is generated in a centralised location with non-emitting fuel options.
- Life cycle assessment quantifies holistic environmental impacts of buildings, enabling optimal decisions in sustainable design.
- Retrofitting existing buildings will be necessary to address the inefficient building stock that could otherwise stand well beyond mid-century.
- Smarter, more sustainable cities are key to a prosperous future.

66 Professional Engineers Ontario, *Towards a clean train policy: diesel versus electric.*
67 Condon P., *Don't Waste Billions on Bad Transit Projects.*

Figure 10: 2050 Building Sector Energy Use Projections



4.2.1 Over one third of Canadian homes are already heated and cooled with clean electricity; emerging technologies will make this option increasingly economically attractive.

Emissions from the buildings sector arise from residential, commercial, and institutional buildings, as well as the equipment in them. The building sector is currently one of the most GHG-intensive in Canada and is the third largest emitting sector representing 12% of Canada's emissions - with emissions currently projected to grow through 2030. However, a number of measures can help to achieve reductions in the sector including fuel-switching and energy efficiency.

Some Canadian homes and commercial buildings already rely on clean electricity to power their heating, cooling, lighting and appliances. Current technology such as electric boilers, electric baseboards, space heaters, and heat pumps can be used instead of fossil fuels, resulting in zero greenhouse gas emissions when combined with a non-emitting electricity portfolio. In 2011, 39% of Canadians households used electricity for their heating equipment. Electricity was the predominant energy sources for heating in Quebec (66%), Newfoundland and Labrador (56%) and New Brunswick (48%). [68]

Current technologies that may become more cost effective in the future include electrically driven geothermal and air source heat pumps, and increased use of ambient solar heating. Air-source heat pumps can draw heat from the air and transfer warm air inside during the winter or outside during the summer.[69] Ground-source heat pumps, also called earth-energy systems, can use energy from the ground to produce heating and cooling and are being increasingly used across Canada. Due to their high efficiency, ground-source heat pumps can yield energy savings of up to 40% higher than an air-source pump but require higher up-front installation costs.

Solar energy for homes also offers many advantages and helps lower grid-related energy requirements. New technologies are emerging to better generate photovoltaic energy for homes such as: solar roadways, solar shingles, solar panels installed on the sides of buildings, and thin solar films that can be applied to any metal roofing.

68 Statistics Canada, *Households and the Environment: Energy Use (11-526-S)*
69 Natural Resources Canada, *Coming to Terms with Heat Pumps*

Figure 10 illustrates the current use of energy in the building sector as comprising of natural gas (45%), electricity (36%), renewable fuels (10%) and refined petroleum products (6%). Modelling projections for a low GHG economy in 2050 take into account a variety of factors such as potential provincial energy codes amendments, regulations on new buildings requirements and technological costs. Note that the projections do not take into account a potential increase in the use of clean district heating systems in Canada.

In all of the low-GHG analyses, the share of energy met through clean electricity increases from today's levels. The first ECCC low-GHG analyses (High Non-Emitting) illustrates electricity at 70% of the energy use of the building sector by 2050, while the second projection (High Demand Response) estimates electricity to be 50% of energy use in the sector (renewable fuels represent 22%).

The DDPP scenario demonstrates that electricity increases to fulfill 99% of the building sector's energy requirements in 2050 (with 1% remaining for natural gas). The Trottier Institute, demonstrates two scenarios where the share of electricity increases to 86-89% of total energy use in the sector by 2050, where the remaining requirement is fulfilled through natural gas (4-5%), renewable fuels (4-5%) and refined petroleum products (2-5%).

4.2.2 Natural gas continues to play an important role in heating and power requirements. Renewable Natural Gas is a small but growing part of the supply mix meeting those energy needs.

Across most scenarios, natural gas, a relatively lower emitting fossil fuel, continues to power some heating and other requirements in the building sector. Natural gas can also be substituted for Renewable Natural Gas where desirable, without replacing capital or infrastructure, such as natural gas home furnaces. Generally, Renewable Natural Gas is fully interchangeable with conventional natural gas.

Methane that is released from sources such as landfills, agricultural residues, livestock production, sewage treatment plants, and forestry waste can be recovered, cleaned, and can be directly substituted for conventional natural gas.

4.2.3 The electrification of the building sector should be matched with a scale-up of energy efficiency measures.

Increasing energy efficiency is particularly important in the Canadian building sector, as Canadian households consume an average of 11,000 KWh of electricity per year (2010). By comparison, this is just under the U.S. average (12,960 KWh), and well above Australia (7,350 KWh) and EU countries' average such as France (5,760 KWh), the United Kingdom (4,510 KWh) or Germany (3,515 KWh).[70] This is generally attributable to Canada's cold climate and relatively large sizing in residential housing.

Energy efficiency improvements can be realised either through the design of a building's system, including air sealing, better construction materials, passive heating, insulation, white roofs, triple pane windows; or more energy efficient equipment and appliances including heat pumps, condensing boilers, high efficiency cooling, energy-efficient lighting and appliances, and energy management control systems. Development of highly efficient heating and cooling technologies, such as energy management systems and smart thermostats, can reduce costs and improve performance of heating, ventilation, and air conditioning.

In Canada, provincial and municipal building energy codes and federal energy-efficiency standards are important tools for driving energy productivity improvements. Future policies will need to ensure that energy efficiency programs and energy supply fuel-switching both correspond to low-GHG objectives.

Energy efficiency in the buildings sector has numerous co-benefits such as infrastructure resilience and lower operating and maintenance costs, as well as positive effects on national income and employment. Moreover, several studies have pointed to increased health benefits from better designed buildings in terms of lower risks of respiratory and cardiovascular conditions, rheumatism, arthritis or allergies. Lastly, energy efficiency savings can be beneficial for lower income Canadians.

4.2.4 District heating for residential and commercial buildings could help lower GHG emissions since heat is generated in a centralised location with non-emitting fuel options.

District heating (also known as heat networks or teleheating) is a system for distributing heat

70 World Energy Council Indicators, *Average electricity consumption per electrified household,*

generated in a centralised location for residential and commercial heating requirements such as space heating and water heating. These systems have the potential to help reduce GHG emissions, by utilising low-carbon fuel options such as waste heat or biofuel.

District heating is the dominant heating system in Nordic countries (except for Norway). In those countries, biomass, natural gas, and municipal solid waste biogas are commonly used as energy sources for district heating. Specifically, biomass is used as fuel for 60% of district heating system in the Swedish building sector, 40% in Denmark, and 70% in Finland. Canada has similar geographical and climatic conditions and has thus a vast and untapped potential for extensive district heating systems.[71]

4.2.5 Life cycle assessment quantifies holistic environmental impacts of buildings, enabling optimal decisions in sustainable design.

Life cycle assessment (LCA) is a scientific method for measuring the environmental footprint of materials, products and services over their entire lifetime. Applied to a building, LCA measures environmental impacts like energy consumption and greenhouse gas emissions at every stage of a building's life. It includes raw resource extraction, product manufacturing and transportation, building construction, operation and repair, and demolition.

LCA helps building designers consider the total environmental impact of material choices and other design decisions. Designers use LCA to examine trade-offs and alternatives, for the lowest possible lifetime environmental footprint of the building. This data-driven process allows building designers to test and validate their sustainability decisions.[72]

4.2.6 Retrofitting existing buildings will be necessary to address the inefficient building stock that could otherwise stand well beyond mid-century.

According to the *Canadian Housing and Mortgage Corporation*, Canadian residential construction has grown at an average rate of 1.5% in the past five years.[73] At this rate, the built residential environment would double in Canada in approximately 50 years from today, well past mid-century. New construction has been addressed in the previous sections, but the dominating remaining building stock could mostly remain standing in 2050. According to the IEA, close to 75% of the OECD countries building stock from 2010 will still be standing in 2050.

Therefore, new building energy code regulations on their own will not be enough to achieve significant GHG emissions reductions from by 2050 and additional efforts will be needed to address existing buildings. The same is true in the industrial and commercial building subsectors.

Making existing buildings more energy-efficient through retrofitting is an important step towards reducing GHG emissions reductions in Canada. Retrofitting requires investments, especially in the case of deep retrofits where significant parts of the building must be refurbished. Different retrofit rates are found around the world depending on type of buildings, climate and costs. For example, EU member countries have an energy savings retrofit target rate of 3%/year for government owned buildings.[74] Similarly, Germany has a target of thermal retrofitting 2% of total residential buildings per year.[75]

Energy management practices, including energy benchmarking, audits, and on-going building optimisation can help generate better understanding of buildings energy usage and costs, identify areas of opportunities, and make improvements where and when necessary. They can also provide green solutions for systems that are embedded in the building and may be harder or more costly to replace.[76]

4.2.7 Smarter, more sustainable cities are key to a prosperous future

Urban planning and design will be key to making building sites and designs work together to enable lower GHG solutions. In a low-GHG economy, for example, communities should be making effective use of local energy sources ranging from on-site renewable energy to waste heat and organic waste, allowing optimal use of clean energy grids. District energy networks will distribute thermal energy for

71 International Energy Association, *Canada Review 2015.*
72 O'Connor, J., and Bowick, M., *Advancing Sustainable Design with Life Cycle Assessment.*
73 Statistics Canada, 2011 Census of Canada. Canadian Mortgage and Housing Corporation, Total Housing Starts, Canada, Provinces and Metropolitan Areas, 1990–2015 (units).
74 Official Journal of the European Union, *Directive 2012/27/EU of the European Parliament and of the Council of 25 October 2012 on Energy Efficiency Amending Directives 2009/125/EC and 2010/30/EU and Repealing Directives 2004/8/EC and 2006/32/EC.*
75 Germany Federal Ministry of Economics and Technology, *Germany's New Energy Policy Heading Towards 2050 with Secure, Affordable and Environmentally Sound Energy.*
76 Natural Resources Canada. *Commissioning Guide for New Buildings.*

LOW EMISSIONS OPERATIONS AND GOVERNMENT PROCUREMENT

Governments have an important leadership role to play in the transition to a low-carbon economy given the size of their operations. By implementing ambitious policies, federal, provincial and territorial governments can lead by example on many aspects of the low-carbon transition. Canada's Federal Sustainable Development Strategy has developed objectives for greening government operations.[77] The federal government has adopted a target to reduce emissions by 40% from 2005 levels by 2030, with the aspiration to achieve it earlier, potentially by 2025. Furthermore, the government has committed for all operations run by Public Services and Procurement Canada to use 100% of their electricity purchased from clean power, and to significantly increase the energy efficiency of federal buildings, with the goal of cutting emissions almost in half. Several provinces, such as British Columbia, Quebec, and Ontario, have also adopted targets to reduce emissions or to achieve carbon neutral operations.

Governments can lead the way in many areas, such as green procurement, green buildings, energy efficiency measures, and other green investments. New government buildings could require a certain type of environmental certification, as green buildings are generally recognised to have a positive effect on the asset value.[78] For older buildings, the use of deep retrofits would help to substantially reduce energy costs and GHG emissions. The use of energy performance measurement could help to better understand and improve energy use. Governments could also encourage the use of public and active transportation as well as flexible working arrangements such as telework.

Green procurement is one way in which the government can reduce its environmental footprint and increase domestic demand for clean technologies and other environmentally preferable goods and services. For example, the federal government's Policy on Green Procurement targets specific environmental outcomes where procurement can effectively be used to mitigate the impact of environmental issues, such as climate change. Allowing climate considerations to be streamlined into the procurement process, such as the disclosure of climate performance, could more accurately benchmark and compare different product and services. The purchasing power of governments could also be used to support the development of green technologies. Governments could also help to accelerate the adoption of certain green products such as electric vehicles with charging stations at work locations.

In some sectors, there are opportunities to take a more important role in greening their operations. The defense sector is increasingly recognising the strategic importance of having alternative sources of power and the potential cost savings. The Pentagon has become the second largest purchaser of long-term renewable electricity contracts in the U.S., according to Bloomberg data.[79] Low-carbon opportunities exist for Department of National Defense and other government departments that have large fleets.

It is important that governments explore best practices on greening government operations by learning from other jurisdictions. This is important for developing knowledge and raising ambition over time in order to be innovative and creative in finding solutions.

heating and cooling, while smart electrical grids manage local energy supply and demand. Energy storage systems could help to balance variations in supply and demand for heating, cooling and power while local industrial, commercial, and agricultural enterprises approach energy in an integrated way. Finally, businesses could take advantage of waste heat, use renewable fuels, and capitalise on opportunities as energy producers.

77 Government of Canada, *Shrinking the Environmental Footprint – Beginning With Government.*
78 The Royal Institution of Chartered Surveyors, *Green Value.*
79 Financial Post, *How the Pentagon is Waging America's Wars Using Renewable Energy.*

AN ELECTRIFICATION SUCCESS STORY

Mining vehicles typically require energy-dense fuels to move and lift heavy loads. However, in 2008, SBC Case Industries, PapaBravo's parent company, initiated an R&D project to develop electric vehicles for use in potash mines. Later, PapaBravo developed a business plan based on R&D technology with the support of the National Research Council's Industrial Research Assistance Program. The company was able to develop many vehicles such as the Marmot-EV and a second-generation truck able to function in environments other than potash mines. The vehicles have a range of about 120 kilometres and can recharge in less than an hour. The Saskatoon firm PM&P which acquired PapaBravo in 2015 is now a global competitor in electric mining vehicles and is doing business in Canada, South Africa, Australia, and New Zealand.[80]

4.3 Industry

KEY MESSAGES:

- National circumstances represent challenges for the decarbonisation of Canadian industrial sectors.
- Electrification of industrial operations offers emissions reduction potential.
- Cogeneration reduces waste heat and generates thermal and electric energy, thereby producing environmental and economic benefits.
- Other improvements in energy efficiency through innovative ways of optimising energy production and consumption will be essential.
- Carbon capture and storage, fuel switching to non-emitting fuels, and recycling can also reduce emissions. These technologies continue to improve.
- Nevertheless, there remain challenges in reducing emissions from some sectors, for which innovation and research and development will be necessary.

4.3.1 National circumstances challenge the decarbonisation of Canadian industrial sectors

Historically, Canada has benefited from an internationally competitive economy based on low-cost natural resources and accompanying industrial activities. These activities face significant challenges to decarbonisation:

- Canada's energy sector is an important driver of the Canadian economy. Canada's exports of energy, extracted resources, and agricultural commodities are significant contributors to the gross domestic product. Also, Canada is a net energy exporter. It is the world's fourth largest exporter of crude oil and fifth largest exporter of natural gas.
- Canada's oil and gas sector is GHG intensive due to the energy required in the primary extraction of fossil fuel and other natural resources.
- Industries are concentrated in particular areas of the country, making distributional impacts of abatement policies a particular concern. Regional cooperation and progressive mitigation policies will be key to ensure that decarbonisation efforts do not disproportionally affect certain regions.
- Over 75% of Canada's total industrial energy use is consumed in the mining, pulp and paper, iron and steel, cement, smelting and refining,

80 National Research Council Canada, Revolutionizing Canada's Mining Industry with Electric Vehicles.

chemicals, and petroleum refining sectors. The greatest portion of energy (about 70%) is used for heating purposes such as thermal treatment (mainly in heaters and furnaces), drying, and steam generation. These emissions are more challenging to reduce than in other sectors due to the high heat requirements of certain processes. Technology solutions exist, often with deep GHG reduction potential, however market barriers to adoption are such that significant investments may be required to achieve large-scale commercial uptake.

4.3.2 Electrification of industrial operations offers emissions reduction potential

Many Canadian industries are already electrifying their operations or discovering other innovative ways to lower GHG emissions. For example, motor systems such as pumps, fans, conveyers, and compressors are almost entirely powered by electricity in some sectors. Electrified operations can be set for production during off-peak electricity periods to benefit from lower electricity prices. Specific sub-sectors, such as the aluminium industry, where smelting processes are highly energy intensive, are already relying on non-emitting electricity to fulfil their power demands. The energy intensity of aluminium plants has also decreased over time, leading to reduced electricity demand per unit of output.

In the iron and steel sector, some Canadian plants operate with electric arc furnaces that produce steel from recycled metal and require significantly less energy compared to conventional processes using ore. In the glass industry, electric glass melting tanks can be used, while in the pulp and paper industry, electricity can be used for mechanical pulping. In the mining sector, hybrid diesel-electric equipment could be used in underground mines and fully electric vehicles could further reduce emissions and diminish needs for ventilation.

In Canada's oil sands, extracting and upgrading bitumen is an energy-intensive process where large amounts of thermal energy and electricity are used. Further electrification of processes, including the electrification of heat (for example electro-thermal or radio frequency electromagnetic heating), provides an avenue to decarbonisation, but requires a clean electricity source.

The adoption of electric steam generators to replace natural-gas fired steam generators could reduce direct emissions. Electric steam generators use electric resistance elements to produce steam and heat, and the conversion of electricity into thermal energy is very efficient. It is technically possible for the separation of bitumen, hydrogen production for upgrading, and refining and pipelining operations to use electricity instead of natural gas.

A study by the Canadian Energy Research Institute has looked at scenarios for the electrification of oil sands production using hydropower and increased electricity transmission capacity. Overall, the study finds that the use of hydropower could potentially reduce the GHG emissions of oil sands operations by 13-16%. Reductions are possible from a range of technologies that could require significant investment in infrastructure as well as the application of new technologies. The potential for reductions could be even higher with the development of in-situ extraction using electricity for heating purposes, but many of these technologies are still under development.

In general, several options exist to decarbonise heavy industry, but significant R&D, piloting, and commercialisation support are required to allow their penetration.

4.3.3 Cogeneration reduces waste heat and generates thermal and electric energy, thereby producing environmental and economic benefits.

Cogeneration, also called combined heat and power (CHP), produces electrical and thermal energy simultaneously by using a single fuel for heating or cooling applications. Cogeneration allows for gains in energy efficiency as it can use waste from one process as an energy input into another. The main types of cogeneration systems include steam turbines, gas turbines, reciprocating engines, microturbines, combined cycle gas turbines and organic rankine cycles. Cogeneration requires maximizing electricity production, while matching thermal load requirements to the extent possible in terms of quantity and energy quality.[81] The energy savings from cogeneration relative to standalone generation range from 5% to 35%.

In Canada, about 7% of electricity generation is produced from cogeneration. Most energy generated from cogeneration (both electric and thermal) is from the utility, paper and wood products, and oil and gas extraction sectors. Growth in cogeneration occurred during two periods. In the

81 Canadian Industrial Energy End-Use Data and Analysis Centre, Cogeneration Facilities in Canada 2014, p. 7.

1970s cogeneration capacity increased in response to a significant increase in energy prices. The second period of growth occurred in the 1990s as a response to many socio-economic factors including increasing cost-effectiveness and full retail access to the electricity grid in Alberta. Cogeneration has the potential to achieve significant energy savings, particularly in the oil sands sector, as the extraction and upgrading processes require large amounts of heat and steam.

In order to fully maximise the potential of cogeneration to reduce GHG emissions, the adoption of certain technologies may be necessary, including those that optimise load matching, improve operations in harsh environments, and allow for biomass gasification, advanced power cycles, and high-penetration of renewables into fossil thermal cycles (e.g., solar thermal pre-heating of the inlet air to gas turbines).

4.3.4 Other improvements in energy efficiency through innovative ways of optimising energy production and consumption will be essential

Energy efficiency measures that improve processes and reduce heat loss can be implemented across sectors using current best available technologies. Heat management practices can improve heat production and heat transfer to and within process users. Innovative waste heat recovery technologies can help reduce energy consumption, production costs, and emissions in industrial facilities.

Energy efficiency measures include process optimisation; operation and control improvement; waste heat recovery and upgrading for heat, cold, or power production; and new technology and process development. Examples of process optimisation include adopting proper motor sizes to optimise power use, and using adjustable-speed drives. Frequent and proper maintenance and repair can also improve energy efficiency of equipment. In some industries, there are potential solutions which involve entirely changing production processes to reduce energy requirements. For example, the pulp and paper industry can use chemical additives to reduce the heat required to dry paper.[82]

For the oil and gas sector, energy efficiency and energy use optimisation can amplify the emissions abatement potential of electrification and other options. For example, deploying energy management systems to oil and gas facilities and improving energy efficiency through programs and standards could help drive significant reductions in the demand for energy. Although electrification is key, the recovery and use of waste heat should be pursued across subsectors concurrently. Other innovative ideas that could support energy use optimisation include the development of industrial eco-parks which facilitate the exchange of excess energy and industrial by-products, and minimise transportation requirements between facilities.

In oil sands operations, the adoption of innovative low-carbon extraction processes offers potential GHG emission reductions. Advanced technologies, such as solvent and electrothermal-based extraction methods for in situ, or direct contact steam generation, are at a stage of development whereby they offer a substantial opportunity to reduce emissions. These innovations could offer up to 50% GHG emissions reductions per barrel produced and could prove pivotal in delivering economically and environmentally competitive fossil fuel supplies to a decarbonising global market. Vacuum-insulated tubes can also be used to save heat in the process of moving the steam down the well and could accelerate the pre-heating process of the well significantly.[83] Further, some of these innovative extraction techniques leave the heavier contents of the bitumen in the reservoir, meaning less diluent is needed in pipelines. Not having to store these heavier contents, for which there are fewer markets, also reduces operating costs and GHG emissions.

In the mining industry, ventilation-on-demand can be adopted to reduce the energy consumption required to ventilate underground metal mines. For example, a medium-size nickel mine with diesel equipment and 10 operating levels emits about 10,000 tonnes of CO_2 annually. Estimated energy cost savings from the adoption of ventilation on demand technology can reach 50% depending on the size of the mine.

4.3.5 Carbon capture and storage, fuel switching to non-emitting fuels, and recycling can also reduce emissions. These technologies continue to improve

Beyond the electricity sector, carbon capture and storage (CCS) also has potential in the oil and gas, iron and steel, pulp and paper, chemical, and cement sectors. CCS is currently being used to capture emissions from steam methane reformers. The Shell Quest Project, which has been in operation since November 2015, captures and

82 Energy Economics, Optimizing the Energy Efficiency of Conventional Multi-Cylinder Dryers in the Paper Industry, p.35.

83 Council of Canadian Academies, Technology and Policy Options for a Low-Emission Energy System in Canada, p. 92.

THE USE OF BIOMASS FOR CEMENT MANUFACTURING

Bioenergy as a replacement for fossil fuels in cement making is currently at the commercial demonstration phase in Canada. For example, the Lafarge plant in Bath, Ontario, was funded under the ecoENERGY Innovation Initiative to demonstrate a 10% coal-to-biomass fuel switching project. This includes processing the raw materials into a useful form, developing and installing an injection system, running fuel trials, and compiling the results of the carbon savings resulting from this process. The results of these trials will inform the permanent use of low-carbon fuels at the Bath plant and could be used by other companies in the cement industry.[84]

sequesters 1 million tonnes of CO_2 per year from the Shell Scotford steam methane reformers. The Alberta Carbon Trunk Line (ACTL), a project under development, is a 240 km pipeline that will capture and use CO_2 emissions for enhanced oil recovery from the facilities in the Alberta Industrial Heartland. The initial industrial facilities that will capture and supply CO_2 are Agrium Inc. and the Sturgeon Refinery. The ACTL will have the capacity to permanently store about 14.6 million tonnes of CO_2 annually as of 2017.

Some barriers for deployment of CCS technology in these sectors remain, such as lack of economic capture technology and infrastructure to connect carbon source with sequestration formations. This will require significant investments and pipeline network construction. In the upstream oil and gas sector, relevant carbon capture technology for in-situ boilers and cogeneration units could be available within a 10 to 15 year timeframe. However, more technological advances would be required to make CCS economic. With the knowledge and technological advancements spurred from projects currently underway, the cost of CCS could go down in the future and be applied in other industrial sectors.

Fuel-switching options are also available to industrial sectors. As mentioned previously, the oil and gas sector can use solvents instead of natural gas in SAGD applications, despite being relatively expensive at the moment. Using electricity instead of fossil fuels is also a possibility. Finally, biomass waste can be used by many sectors, including oil and gas and cement, to replace more carbon intensive energies.

The recycling of materials in many industrial sectors is another option to reduce GHG emissions as it reduces needs for energy, raw materials, and landfill space. For example, in the pulp and paper sector, recovered paper can be recycled through chemical pulping instead of producing paper from new feedstocks.

84 Natural Resources Canada, Low Carbon Fuel Demonstration Pilot Plant.

Another example is the reuse of recycled plastic in the chemical and petrochemical sector as a substitute to polymer based inputs. Plastic waste that cannot be recycled can be used as an energy input - In the iron and steel sector it can be burned as a replacement for coal or coke – or as a feedstock in other sectors. The use of recycled scrap metal materials to produce iron and steel can also lead to emission reductions as producing iron and steel from iron ore requires more energy than from scrap.[85]

Figure 11 (below) illustrates the world GHG reduction potential estimated by the IEA from four types of industrial GHG emissions reductions technologies for IEA's low-demand and high-demand scenarios. According to the IEA, energy efficiency improvements, switching to low-carbon fuels, increased recycling, and new innovative processes such as CCS will all be needed to decarbonise large industrial emitters.

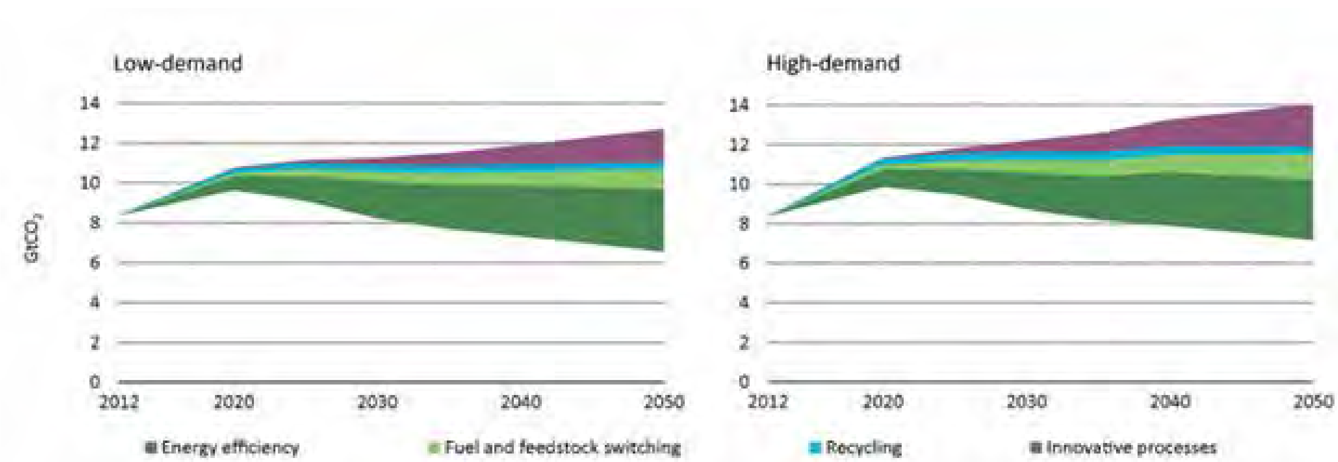
4.3.6 Nevertheless, there remain challenges in reducing emissions from some sectors, for which innovation and research and development will be necessary

Emissions-intensive industrial sectors often face challenges in reducing GHG emissions as many of their emission sources are difficult to address through cost-effective electrification, energy efficiency, or fuel-switching. These challenges are compounded as many industries also face competitive pressures due to their exposure to international trade competition, and their low profit margins. Bargaining power of suppliers and buyers, the threat of substitutes and new entrants, and the level of rivalry between competitors are some of the factors that determine how competitive industries are in global markets. Many companies face global prices for their outputs, meaning that they must contain their production costs in order to remain competitive. Canadian oil producers operate in a global market and they are essentially price takers for their outputs, which requires them to look at ways of reducing their production and transportation costs in order to remain competitive. Moreover, these companies may face additional challenges associated with decreasing global demand for their goods in the future as governments act to mitigate GHG emissions. Canadian natural gas producers are currently competing in a continental market. In the future, with additional liquefied natural gas plants expected to come online, the global natural gas market is expected to be increasingly integrated.

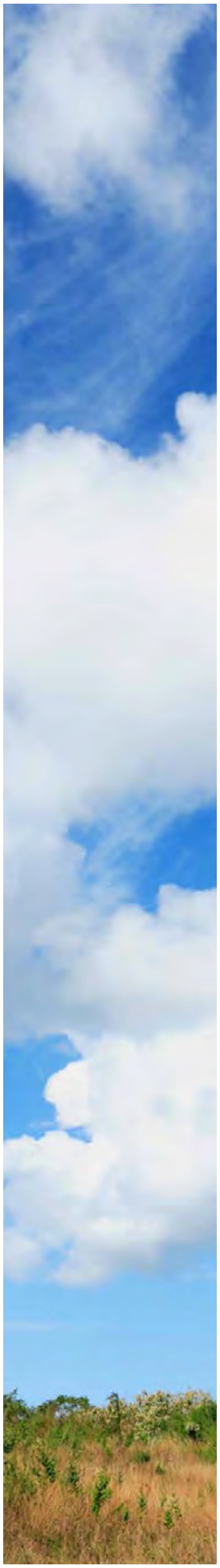
Innovation in these sectors is likely to yield significant benefits to companies that can improve processes and technologies to reduce emissions. Government and private sector funding will be required for further research and development to promote technology innovations in many strategic areas pertaining to industrial emissions. These include CCS technologies to reduce costs and improve efficiency, industrial efficiency improvements, fuel switching to bioenergy and the conversion of biomass into bio-based products and bioenergy, technologies to address process emissions, and enhanced recycling capabilities.

85 International Energy Agency, Energy Technology Transitions for Industry.

Figure 11: World reduction potential from existing technologies for large industrial emitters



Source: International Energy Agency, Energy Technology Perspectives 2015



5 Non-Carbon Dioxide Emissions

KEY MESSAGES:

- Non-carbon dioxide climate warming emissions include short-lived climate pollutants (SLCPs) and nitrous oxide, a long-lived GHG. Non-carbon dioxide emissions have significantly greater warming effects per tonne than carbon dioxide.
- The only way to meet the 1.5 to 2°C temperature goal encompassed in the Paris Agreement is to take early global action on carbon dioxide and short-lived non-carbon dioxide emissions together.
- Reducing short lived climate pollutants has considerable benefits beyond those that are climate related, such as improving air quality, human health, and environmental and ecosystem outcomes.
- Current technology and know-how has the potential to significantly reduce non-carbon dioxide emissions, often helping to slow the rate of near-term warming.

5.1 Non-carbon dioxide climate warming emissions include emissions of short-lived climate pollutants (SLCPs) and nitrous oxide, a long-lived GHG. Non-carbon dioxide emissions have significantly greater warming effects per tonne than carbon dioxide.

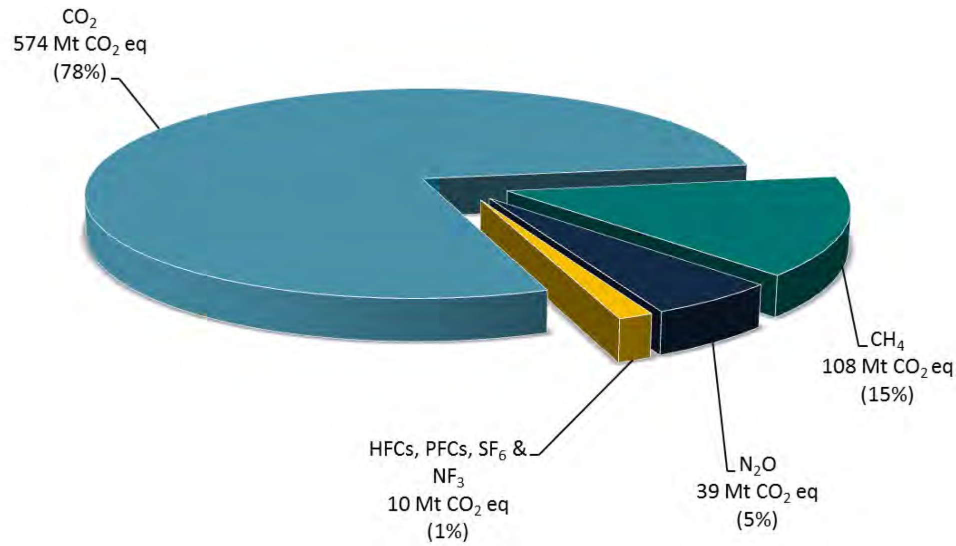
Short-lived climate pollutants (SLCPs) are potent greenhouse gases (GHGs) and air pollutants. They have relatively short atmospheric lifetimes compared to longer-lived GHGs such as carbon dioxide (CO_2), and have a warming impact on the climate. SLCPs include methane, hydrofluorocarbons (HFCs), and ground-level ozone, as well as black carbon, a component of particulate matter. Black carbon is also an air pollutant, resulting from the incomplete combustion of fossil fuels and biomass. Ground-level ozone is also an air pollutant and key contributor to smog, which is associated with adverse impacts on human and ecosystem health. Nitrous oxide is a long-lived GHG.

Figure 12 below illustrates Canada's greenhouse gas emissions in terms of CO_2 equivalency where non- CO_2 emissions account for around 21% of total emissions. Methane and nitrous oxide are the two main non-CO_2 GHGs emitted and originate mostly from fossil fuel related activities, livestock farming, and industrial processes. Although HFC emissions are not currently a significant contributor to total GHG emissions in Canada, in the absence of the recent phase-down amendment to the Montreal Protocol, they were projected to more than triple between 2013 and 2030.

Methane emissions, which account for 15% of total GHG emissions in Canada,[86] are significant contributors to climate impacts. In addition, methane contributes to the formation of ground-level ozone. The oil and gas sector accounted for 44% of Canada's methane emissions in 2014, largely from oil and natural gas fugitive sources, including venting . The remainder of Canada's methane emissions arises largely from agriculture and solid waste disposal.

86 The GHG estimate of 108 Mt for methane (15% of total Canadian GHG emissions) uses a global warming potential of 25 consistent with the IPCC fourth assessment report.

Figure 12: Canada's Emissions Breakdown by Greenhouse Gas (2014)



Source: National Inventory Report 1990-2014: Greenhouse Gas Sources and Sinks in Canada – Executive Summary, Environment and Climate Change Canada, 2016.

Nitrous oxide emissions account for 5% of total Canadian GHG emissions. The burning of fossil fuels results in the oxidization of the nitrogen contained in the fuel and the air creates nitrous oxide emissions. These emissions come mainly from coal-fired power plants as well as cars and trucks. Industrial processes, particularly those involved in the production of nitric and adipic acid, also cause nitrous oxide emissions through the oxidization of nitrogen compounds. Over 70% of total nitrous oxide emissions emitted in Canada are from the agricultural sector, mainly from crop and animal production. In crop production, nitrous oxide emissions arise mostly from the use of synthetic fertilizers where the addition of nitrogen to soils helps the nutrient absorption of plants and allows bacteria contained in the soil to produce extra energy to grow. Microbial processes involved in these activities then produce releases of nitrous oxide emissions.

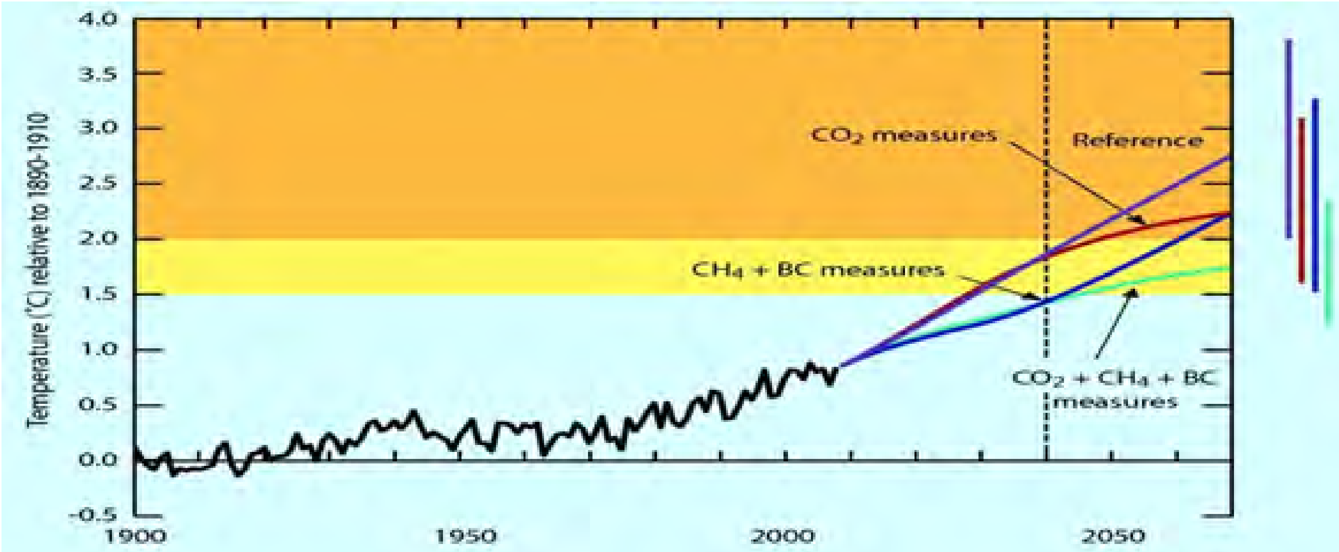
HFCs are synthesized chemicals used as replacements for ozone-depleting substances. Internationally, atmospheric observations show that the volume of HFCs in the atmosphere is increasing rapidly, about 10 to 15% per year. To address concerns regarding an estimated increase in HFC emissions to 10% or more of total CO_2 equivalent emissions by 2050, the 197 Parties to the Montreal Protocol agreed to an amendment to phase-down the use and production of HFCs on October 15th, 2016. The "Kigali Amendment" could help to avoid almost 0.5°C of global warming by the end of the century. Canada was a strong supporter of the HFC Amendment and will continue to play a leadership role in implementing the Montreal Protocol, including the HFC amendment, notably by hosting the 29th Meeting of the Parties in 2017, which marks the Montreal Protocol's 30th anniversary.

The potency of HFCs varies by species and ranges from <1 to 10,800 times that of CO_2 over a 20-year period, and <1 to 12,400 that of CO_2 over a 100-year period.[87] HFCs are used in the same applications which ozone-depleting substances have been used. In Canada, HFC use is mainly confined to the following sectors: insulating foam products (50%), refrigeration and air-conditioning equipment in buildings and industrial operations (30%), air-conditioning in vehicles (13%), and aerosols (7%). Since HFCs are being used as replacements for ozone depleting substances, including hydrochlorofluorocarbons (HCFCs) that are still in the process of being eliminated, their use and emissions are increasing as HCFCs are being phased out. In addition, in the absence of the recent phase-down amendment to the Montreal Protocol, HFC emissions would be expected to increase because of greater demand for refrigeration and air conditioning throughout the economy.

According to Canada's black carbon emissions inventory, 43 kt of black carbon were emitted = in 2014. Black carbon emissions are estimated to be the third largest contributor to current global warming, after CO_2 and methane. Black carbon

87 Myrhe et al., Anthropogenic and Natural Radiative Forcing.

Figure 13: Global Temperature Projections Relative to 1890-1910 averages



Source: UNEP Integrated Assessment of Black Carbon and Tropospheric Ozone, Summary for Policy Makers
Note: Bars on the right show estimated ranges for 2070.

influences the climate in multiple ways: by directly heating surrounding air when suspended in the atmosphere; by reducing the reflectivity of the earth's surface when deposited, an effect particularly strong over snow and ice; and through additional indirect effects related to interaction with clouds. Black carbon is estimated to be 3,200 (270 to 6,200) times more potent a warming agent than CO_2 over a 20-year period.[88] Reducing uncertainties related to quantifying the overall warming effects of black carbon represents an active area of scientific research internationally. Black carbon also has significant effects on human health, including respiratory and cardiovascular effects, as well as premature death. The transportation sector accounts for 62% of Canada's black carbon emissions, followed by residential wood-burning, accounting for about 27% of national emissions.

Ozone is not directly emitted, but forms in the atmosphere as a product of precursor gases including nitrogen oxides (NO_X), volatile organic compounds (VOCs) - including methane - and carbon monoxide (CO). Ground-level ozone is a powerful GHG, a significant contributor to current warming, and a key component of smog. It has deleterious effects on human health, damages plants, and affects agricultural crop production. In Canada, the transportation and oil and gas sectors are key sources of ozone precursors. Residential wood combustion is also a significant source of CO emissions.

88 GWP20 from Bond et al. (2013). Bounding the role of black carbon in the climate system: A scientific assessment. The use of the GWP here is to help communicate the potential contribution of black carbon mitigation to reducing near-term warming. Given the very different ways black carbon and CO_2 influence climate and their vastly different lifetimes in the atmosphere, there is not yet scientific consensus on a metric to quantify black carbon relative to CO_2. Further research to reduce uncertainties and develop more appropriate metrics is needed.

5.2 The only way to meet the 1.5 to 2°C temperature goal encompassed in the Paris Agreement is to take early global action on carbon dioxide and non-carbon dioxide emissions together.

Recent scientific studies indicate that the only way to meet temperature commitments in the Paris Agreement is to take early global action on CO_2 and SLCPs, together. The *United Nations Environmental Program's (UNEP) Integrated Assessment of Black Carbon and Tropospheric Ozone* concludes that reducing black carbon and tropospheric ozone now will slow the rate of climate change within the first half of this century.

The UNEP assessment notes that deep and immediate CO_2 reductions are required to limit long-term warming, and this cannot be achieved by addressing short-lived climate forcers alone. However, it goes on to note that implementation of measures on black carbon and methane globally by 2030 could reduce future global warming by 0.5˚C by 2050 and by as much as 0.7˚C in the Arctic by 2040, and together with early action on CO_2, this is the only way to limit the global average temperature rise to well below 2˚C (Figure 13).

The expected climate benefits of such an approach are particularly relevant for Canada as an Arctic nation. In Canada, the Arctic warmed by 2.2°C between 1948 and 2013 resulting in significant impacts to local populations and sensitive ecosystems. Black carbon is of particular significance in the Arctic due to its additional warming effect when deposited onto snow or ice, which accelerates melting.

5.3 Reducing short lived climate pollutants has considerable benefits beyond those that are climate related, improving air quality and human and ecosystem health.

Given that many SLCPs are also air pollutants, reducing emissions also provides a key opportunity to also improve air quality, generating local health benefits for Canadians and reducing impacts to ecosystems and agricultural productivity.

Ground-level ozone, a potent GHG, has several other deleterious environmental effects. As a key component of smog, ozone leads to significant human health impacts such as respiratory and cardiac problems. These health problems result in significant losses to Canada's economy through hospital visits and lost productivity.

Ground-level ozone also influences crop yield by interfering with the ability of sensitive plants to produce and store food, subsequently increasing their vulnerability to certain diseases, insects, harsh weather, and other pollutants. These negative impacts may translate into reduced crop yields and, consequently, lower sales revenue for crop producers. In addition, ground-level ozone may increase the risk of illness or premature death within sensitive wildlife or livestock populations, potentially resulting in significant treatment costs or economic losses for the agri-food industry. Thus, reducing emissions of ozone precursors, namely methane, VOCs, CO and NO_x, can reduce mortality and morbidity rates in the Canadian population, improve quality of life, as well as increase economic productivity.

Short-term and long-term exposure to $PM_{2.5}$, of which black carbon is a component, is also associated with a broad range of human health impacts, including respiratory and cardiovascular effects as well as premature death. In its 2012 assessment of the health effects of black carbon, the World Health Organization (WHO) noted that black carbon is a "carrier" of other pollutants, delivering them deep into the respiratory system, and further that a reduction in exposure to $PM_{2.5}$ containing black carbon should lead to a reduction in the health effects associated with $PM_{2.5}$.

5.4 Current technology and know-how has the potential to significantly reduce non-carbon dioxide emissions, often helping to slow the rate of near-term warming.

Many solutions exist to reduce important sources of non-CO_2 emissions. In general, measures that help promote the transition towards cleaner energy sources will reduce both CO_2 and SLCP emissions over the long term by reducing the use of fossil fuels. However, slowing the rate of near-term warming requires more targeted SLCP emissions reductions strategies, as many are emitted from a large number of small sources. Canada has made a number of recent significant commitments to advance SLCP mitigation priorities together with continental partners, under the Leaders' Statement on a North American Climate, Clean Energy and Environment Partnership (NALS Statement), including the commitment to develop and implement a national methane strategy that will consider how to address methane from key sources.

Most methane emissions from the oil and gas sector come from venting and fugitive emissions. These include venting from wells and batteries, fugitive equipment leaks, storage tanks, pneumatic devices, well completions, and compressors. Cost-effective technologies are readily available and tackling methane emissions from the oil and gas sector is one of the lowest cost reduction opportunities to achieve significant GHG reductions. Canada has committed to reducing methane emissions from the oil and gas sector by 40 to 45% below 2012 levels by 2025. To implement this commitment, Canada intends to publish proposed regulations to reduce venting and fugitive methane emissions from oil and gas sources by early 2017. Canada has also endorsed the World Bank's *Zero Routine Flaring by 2030* initiative, which will support reductions in black carbon emissions resulting from routine flaring at oil production facilities. Canada has been consulting with provinces, territories, industry, non-governmental organizations and Indigenous peoples on the development of the federal regulatory approach.

Accurately quantifying non-CO_2 emissions is challenging, particularly fugitive emissions. This can be explained by the fact that methane leaks are often only detected and repaired sometime after they start. Another source of uncertainty relates to fugitives arising from the hydraulic fracturing process required to extract shale gas, a growing source of natural gas supply in Canada. As a result, current inventory techniques are likely underestimating fugitive emissions. In response to this issue, many scientific initiatives have been initiated to better estimate these sources including research and development to estimate emissions such as undertaking atmospheric measurement campaigns, and new measurement technology such as infrared imagery.[89] The use of both top-down and bottom-up estimates will support improved understanding of methane from oil and gas sources. Canada has committed to working with continental partners to enhance the effectiveness of emission inventories for methane emissions from the oil and gas sector.

The March 10, 2016, Canada-U.S. Joint Statement recognizes the importance of improving the quantification of emissions. Canada is committed to working with continental partners to improve emission inventories of methane emissions from the oil and gas sector.

In the waste sector, technology for landfill gas recovery and utilization is well established and readily available for both new and existing landfills. Depending on landfill age and access to infrastructure, landfill gas recovery and utilization can also be highly cost-effective. Under the NALS Statement, Canada has committed to take action to reduce emissions from landfills, and to implement voluntary measures to reduce and recover food waste.

Technologies to reduce black carbon emissions from the transportation sector are also proven. Canada's low sulphur content in fuel regulations enable the use and effective operation of vehicle and engine exhaust after-treatment systems, such as diesel particulate filters, which can nearly eliminate black carbon emissions. Transportation sector air pollutant regulations for on- and off-road vehicles and engines are helping to drive down black carbon emissions from this sector.

Further reducing emissions from Canada's largest sources of black carbon emissions, existing diesel vehicles and engines, and wood-burning appliances, will require targeted actions to address barriers related to long vehicle, engine and appliance lifetimes, and influencing the consumers that own many of these small, distributed sources to retrofit or replace them with cleaner technologies.

Measures to address ozone precursors are often part of air quality policies, driven primarily by human health concerns. Measures to reduce ozone precursors in the transportation sector also often reduce black carbon as a co-benefit. Ozone precursors from industrial sources should also be addressed.

Adjusting fertilizer rates with plant needs, placing fertilizer near plant roots, applying fertilizer more frequently instead of only once, and using slow-release forms can limit nitrogen in soils and reduce nitrous oxide emission. In the same fashion, using manure more efficiently can also reduce nitrous oxide emissions. Other practices such as increased use of legumes as a nitrogen source, use of cover crops to remove excess available nitrogen, less use of summer fallow, and adjusting tillage intensity can also contribute to reducing emissions in the agriculture sector.[90] These options can yield co-benefits such as reducing the cost of production (as less fertilizer is used), saving on the use of fossil fuels needed to produce fertilizers, and reducing the pollution resulting from nitrates, ammonia, and other nitrogen substances released in the environment.

In the industrial sector, adipic acid plants can use proven and commercially available technology using catalytic and thermal destruction techniques with reduction efficiencies ranging between 90% and 99%. In nitric acid plants, the use of non-selective catalytic reduction and selective catalytic reduction is possible to reduce nitrous oxide emissions by as much as 90%.[91]

89 Glancy, R., Quantifying Fugitive Emission Factors from Unconventional Natural Gas Production Using IPCC Methodologies.

90 Agriculture and Agri-Food Canada. Nitrous Oxide.

91 International Energy Agency. Abatement of other Greenhouse Gases – Nitrous Oxide.

Several Canadian companies and end users have developed and implemented innovative technologies to transition from current HFC technologies, and have an opportunity to take a lead role in the transition to non-HFC technologies. For instance, some Canadian supermarkets are converting their refrigeration systems to enable the use of refrigerants with very low global warming potentials, that are more energy efficient, and yield significant cost savings. For example, Sobeys has converted over 70 of its stores to climate-friendly, home-grown innovative technologies and plans to extend such conversions to its 1,300 stores across the country.

Meanwhile, major automobile manufacturers operating in Canada have started to manufacture new models with air conditioners using climate-friendly alternatives instead of HFCs. Those actions are also helping to increase energy efficiency. For example, for some applications, replacing HFCs with climate-friendly refrigerants and technologies can improve energy efficiency by up to 50%. The Government of Canada plans to publish proposed regulatory measures to phase down HFCs in Canada, including prohibitions on the manufacture and import of products and equipment containing or designing to contain HFCs by the end of 2016.

6 Forests

KEY MESSAGES:

- The Paris Agreement highlights the critical role that forests play in achieving the global net-zero emissions objective in the second half of the century. With its vast managed forest land, Canada has significant potential for long-term forest-based GHG mitigation.
- Choices about mitigation strategies will be influenced by the slow-growing nature and high rate of natural disturbances in Canada's forests.
- Forest-related mitigation can involve either reducing or avoiding emissions, or enhancing carbon sequestration. The potential becomes even clearer when impacts are assessed on a life-cycle basis.
- A substantial reduction in emissions and increase in removals by 2050 is possible through measures such as changes in how forests are managed, greater domestic use of long-lived wood products, greater use of bioenergy from waste wood, and afforestation.
- There are a number of emerging opportunities in which the forestry sector could contribute to mitigation outcomes that require further consideration.

6.1 The Paris Agreement highlights the critical role that forests play in achieving the global net-zero emissions objective in the second half of the century. With its vast forest land, Canada has significant potential for long-term forest-based GHG mitigation.

Forests play an important role in the carbon cycle by sequestering a significant amount of carbon, thereby reducing net CO_2 emissions to the atmosphere. It is estimated that globally, forests offset the equivalent of about 24% of anthropogenic emissions from the atmosphere.[92] As noted in the Paris Agreement, a balance between emissions and removals of greenhouse gases in the second half of the century is needed to ensure that global warming is limited to well below two degrees Celsius.[93] It is therefore important to recognise that without actions to protect, conserve, and sustainably manage forests globally, it will not be possible to achieve the net-zero emissions required to reach this objective.

Considering the vast size and economic impact of its forest, Canada has a responsibility to carefully consider the mitigation potential of its forest sector. Canada's forest is the third largest in the world, at 347.6 million hectares,[94] and Canada's forest industry contributes significantly to the economy as a major employer nationwide, with nominal GDP of $22.1 billion in 2015.[95] By value, Canada is the world's leading exporter of softwood lumber, newsprint and chemical wood pulp.[96] Canada's forward-looking forest-related mitigation actions can thus have a significant impact.

Given their traditional relationship with forests, Indigenous peoples have an important role to play in planning and managing forest resources. In 2011, 70% of Indigenous

92 Smyth et al., Quantifying the biophysical climate change mitigation potential of Canada's forest sector.
93 United Nations Framework Convention on Climate Change, Paris Agreement, Art. 4.
94 Canada's National Forest Inventory Resources, Statistical Summaries for Canada: Forest Area.
95 Natural Resources Canada's calculations based on Statistics Canada's CANSIM table 379-0031.
96 Natural resources Canada, The State of Canada's Forests 2015.

communities were located in forested areas.[97] Indigenous peoples account for 4.8% of the total forest sector workforce in Canada, compared to 3% of the total workforce.[98] The participation of Indigenous people in land-use decisions and sustainable forest management will be a key component of the long-term contribution of Canada's forests to climate change mitigation.

6.2 Choices about mitigation strategies will be influenced by the slow-growing nature and high rate of natural disturbances in Canada's forests.

A large proportion of Canada's forests are old and slow-growing. When harvested, much of the biomass is converted to wood products that can store the carbon for a long period of time, depending on the product. Harvest residues left in the forest decompose over time or may be burned to reduce the risk of wildfire. All forests harvested on public land must be regenerated according to policies and legislation on sustainable forest management,[99] but it takes time for trees to grow in Canada's cold, northern conditions. Mitigation strategies that rely on forest growth to sequester carbon must therefore be implemented soon in order for significant mitigation benefits to be realised by 2050.

The factors described above, as well as considerations related to natural disturbances such as forest fires and the impact of climate change on the forest, will influence the development of forest-related mitigation. Sustainable forest management already balances multiple objectives but now must also increasingly tackle the twin challenges of mitigation and adaptation. This underscores the importance of developing a long-term strategy that will build on actions planned in the short- to medium-term and ensure that forest-related mitigation can make a substantial contribution to the mid-century target.

6.3 Forest-related mitigation can involve either reducing or avoiding emissions, or enhancing carbon sequestration. The potential for forest-based mitigation becomes even clearer when impacts are assessed on a life-cycle basis.

As noted in the IPCC Fourth Assessment Report, it is important to examine total mitigation effects across the forest and forest products system on a life-cycle basis, taking into account emissions and removals in the forest, storage of carbon in harvested wood

97 Government of Canada, Indigenous Peoples and Forestry in Canada.
98 Natural Resources Canada, Aboriginal Participation in the Forest Sector.
99 Ibid, p.26. All areas of provincial Crown land that are harvested for timber are required to be regenerated using natural or artificial means (i.e., planting and seeding), or a mix of the two. Standards and regulations for achieving successful regeneration vary by province.

products (HWP), land-use changes, and avoided emissions in other sectors from the substitution of HWP or bioenergy for other more emissions-intensive products and fossil fuels.[100]

Assessment of mitigation strategies must take into consideration biophysical, technical and economic factors. The biophysical mitigation potential sets the boundaries around what is physically possible to achieve in the forest, while the technical and economic costs determine what is feasible to accomplish.[101]

6.4 Analyses show that a substantial reduction in emissions and increase in removals by 2050 is possible through measures such as changes in how we manage forests, greater domestic use of long-lived wood products, greater use of bioenergy from waste wood, and afforestation.

Realising forest-related GHG mitigation potential will require a focus on actions that help reduce emissions and increase the carbon stored in trees, soils, and forest products. In general, in the short- to medium-term, options that avoid emissions and maintain forest and HWP stocks may offer the largest mitigation results. In the longer-term, significant mitigation can result from options that increase harvesting over time and substitute forest biomass for more emissions-intensive products and energy sources. In order to achieve longer-term mitigation, however, action is required in the near-term, even if mitigation benefits are not immediately visible. Moreover, in some cases, options that provide the greatest short-term results may not always provide the greatest mitigation in the long term. Therefore, when assessing forest-related mitigation options, it is important to consider the potential for a longer-term contribution to a low-carbon economy and not just the potential in the short and medium term.

Analyses show that the mitigation actions with the greatest potential for medium and long-term emissions reductions by mid-century in Canada include an integrated approach to changes in forest management practices, increased afforestation, increased use of harvested wood for long-lived products, and increased use of waste wood for bioenergy in place of fossil fuels. These findings are in line with the findings of the Fourth Assessment Report of the IPCC that indicate that sustainable forest management that produces harvested wood products annually while maintaining or increasing forest carbon stocks will generate the largest sustained mitigation benefit in the long run.[102]

6.4.1 Change in Forest Management Practices

Given that close to 90% of forests in Canada are owned by provinces and territories,[103] these jurisdictions will need to identify and implement changes in forest management practices most relevant to their region. Mitigation actions must be balanced with other sustainable forest management priorities, but could include higher utilisation of residual and harvested wood, reduced burning of harvest residues in the forests, increased planting to rehabilitate forests after natural disturbances, and increased planting intensity to improve forest growth after harvest.

In addition to their substantial long-term mitigation potential, changes in forest management practices could create co-benefits, including increased employment in the forest sector, reductions in black carbon emissions (where there is a reduction in slash burning), and increased adaptation efforts to improve the resilience of forests.

6.4.2 Afforestation

A future vision for Canada could include an expanded forest area, however this would need to be achieved without negatively affecting food production. There has historically been relatively little afforestation in Canada,[104] but this could provide substantial carbon sequestration in the long-term. Various levels of afforestation using mixes of fast-growing species and slower-growing species could be used. Because of the time it takes for trees to grow in Canada it would take time for afforestation activities to begin to show substantial carbon reductions.

Investments in afforestation could lead to co-benefits such as the diversification of rural economies, reduced forest fragmentation and enhanced forest habitat for wildlife, improved soil quality and watershed protection. Plantations generate revenue over the long term through harvesting and re-growth which act as an incentive to long-term management by landowners. Challenges in achieving large-scale afforestation include the need to ensure a sufficient

100 Nabuurs et al., Forestry: Contribution of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change.
101 Smyth et al., Quantifying the Biophysical Climate Change Mitigation Potential of Canada's Forest Sector.
102 Nabuurs et al., Forestry: Contribution of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change.
103 Natural Resources Canada, The State of Canada's Forests 2015, p. 50.
104 Natural Resources Canada, The State of Canada's Forests 2015, p. 23.

supply of seedlings and to engage the interest of a sufficient number of landowners, as well as concerns about the resilience of some tree species to changes in climate and natural disturbances.

6.4.3 *Increased use of residual and harvested wood products for long-lived products*

Life cycle research demonstrates that increased use of sustainably produced wood products could lead to avoided GHG emissions in other sectors. In particular, the substitution of wood-based materials for more emissions-intensive materials (such as concrete and steel) for construction and for fossil fuel in heating and energy applications provides some of the highest mitigation opportunities. Canada can further invest in projects and activities that increase the use of harvested wood products in domestic construction such as tall and mid-rise residential buildings, commercial and industrial buildings, and bridges.

The expansion of wood end-uses could also contribute to increasing the competitiveness of the Canadian forest sector by diversifying market opportunities and helping to maintain or create jobs. While the technologies to implement this option are already demonstrated, commercialised, and widely used in other countries, Canada will need to analyse its National Building Code to ensure that it promotes the use of wood products in building design.

6.4.4 *Increased use of harvested wood products for bioenergy, advanced bio-material, and bio-chemicals*

There are potential mitigation benefits from adopting waste wood biomass as a fuel source for electricity or commercial, residential, and industrial heating in place of fossil fuels or as a feedstock in the manufacturing of advanced bio-material and bio-chemicals. Mitigation benefits come from using local sustainably-sourced wood for bioenergy, with priority given to harvest residues and waste wood, which have lower emissions on a life-cycle basis compared to the use of fossil fuels.[105] Positive mitigation benefits from bioenergy-related harvesting could occur in remote communities where local electricity is produced from fossil fuels (e.g., diesel) that have been transported over long distances.

The co-benefits of using biofuels include diversification of market opportunities, leading to increased growth and competitiveness of the Canadian forest sector. In addition, there are direct and indirect benefits for rural forest-based communities including energy autonomy, regional investment, and employment opportunities. Technology to support this option includes modern wood heating systems such as biomass-fueled boilers and stoves and furnaces that use sustainable wood-based feedstock. While this technology is commercially available, a bioenergy heating initiative would depend on securing additional energy infrastructure investments as up-front costs would be high, particularly where the infrastructure in not in place.

Bio-based materials and chemicals are likely to gain importance over the long term. There is a general consensus that the mid-century will bring a larger, more urban population and along with this comes the need for primary resources to sustain urban growth. This, in turn, highlights the potential of forest-based cellulosic material to replace not only a vast array of other materials used in building and energy, as noted above, but also to replace materials and chemicals used in the manufacturing sector at large. The mitigation potential of cellulose-based products, their renewable nature, and their potential to further be recycled or to biodegrade is likely to spur increasing demand for these high value products. For example, natural fibers have already become crucial in technical composite applications due to the demand for recyclable and biodegradable raw materials. The mitigation potential of cellulose-based products is highly dependent on their life cycle and end uses as well as the uptake of bio-based material as substitutes for traditional alternative feedstock and cannot be clearly ascertained yet.

As a country advantaged with significant biomass resources and forest and agriculture sectors poised for transformation, the bioeconomy represents a substantial opportunity to generate wealth and jobs for Canadians.

6.5 There are a number of emerging opportunities in which the forestry sector could contribute to mitigation outcomes that require further consideration.

6.5.1 *Reducing deforestation*

Unlike tropical countries where deforestation is a major driver of emissions, deforestation (permanent forest loss) in Canada is relatively low. Of the approximately 0.01% of Canada's forest land that is lost annually, most is driven by agriculture and the

105 Nabuurs et al., Forestry: Contribution of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change.

expansion of the oil and gas industry.[106] Given that the main drivers of deforestation vary across the country – and that the drivers of deforestation are usually outside of the forest sector – there has been limited ability within the forest sector to influence these emissions to date.

Nonetheless, reducing deforestation and its associated emissions is an area that Canada can explore, especially considering the role Canada plays in supporting reducing emissions from deforestation and forest degradation in developing countries, and that Canada is a signatory to the New York Declaration on Forests, which aims to end global net deforestation by 2030. Collaboration with provinces and territories is required given the need to consider how to address deforestation across jurisdictions and diverse sectors.

6.5.2 Research and Development in Advanced Bio-materials, Bio-chemicals, Bioenergy and Biofuels

The mitigation potential of using harvested wood products for bioenergy and biofuels can be further explored. Bioenergy with carbon capture and storage (BECCS) has received considerable global attention because it can generate negative emissions. A longer-term option for bioenergy could focus on reducing costs along the supply chain and increasing investments in research and development of second-generation biofuel production, advanced materials, and new platform chemicals, for example, converting cellulosic biomass into bio-crude and refining it into other biofuel products (e.g., biodiesel, bio-kerosene and bio-chemicals), as well as gasifying or liquefying biomass for power production. Further investment in research, development and deployment of such technologies could identify new areas with mitigation potential.

6.5.3 Urban Forestry

Urban forests provide a number of co-benefits in addition to sequestering GHG emissions, such as energy conservation through cooling and shade, provision of wildlife habitat, noise buffering and improved aesthetics and increased property values. Future research and analysis in improved monitoring and research to capture mitigation potential and enhance resiliency of urban forests is an option for Canada to explore.

106 Natural Resources Canada, The State of Canada's Forests 2015, p. 23.

7 Agriculture

KEY MESSAGES:

- The potential for greenhouse gas mitigation exists across the entire food system. There are opportunities and for consumers, farmers, food processors and municipalities to reduce and recycle energy and nutrients.
- Agricultural emissions result mostly from biological processes rather than from energy use.
- Technological innovations and sustainable land management practices will ensure that agricultural soils remain a net carbon sink in Canada over the long-term.
- Promoting the adoption of existing and emerging technologies and management practices could increase efficiency and reduce emissions from crop and livestock systems.
- The Agriculture sector has the potential to provide renewable energy solutions and bio-products to help reduce emissions in other sectors. In evaluating these options, consideration should be given to the full life-cycle environmental costs and benefits.

7.1 The potential for greenhouse gas mitigation exists across the entire food system. There are opportunities for consumers, farmers, food processors and municipalities to reduce and recycle energy and nutrients.

Addressing GHG emissions from agriculture requires the examination of the entire food system's life cycle from fertilizer manufacturing through to on-farm activities, food processing, distribution, and consumption. Moreover, the ultimate fate of food products, either as food waste, compost, or wastewater, needs to be taken into account.

This *holistic* approach seeks to improve the efficiency of the overall food system from "cradle to grave to cradle", and can often draw out synergies between the environmental and health impacts of food choices. In this respect, more can be done to foster positive societal engagement and cooperation to help lower GHG emissions. There are increasingly higher expectations for transparency and product environmental attributes, including the relative amount of GHGs embodied in different food choices.

In the context of a global and growing demand for food products, alternative approaches like local food movements, organic and/or urban agriculture or family farmers networks can play an important role in shaping the future of agriculture.[107] Any approach that helps to minimise waste (see Chapter 8) and helps to conserve energy and water will decrease emissions in other sectors indirectly related to agriculture, for example, during fertilizer manufacturing, or by removing nitrogen and phosphorus from wastewater.

107 Equiterre, Family Farmers Network.

7.2 Agricultural emissions result mostly from biological processes rather than from energy use.

Primary agriculture is at the heart of a complex and integrated agri-food system which provides one in eight jobs and accounted for more than 6% of GDP in 2014.[108] The agriculture sector contributes to making Canada one of very few countries currently in a position to produce more food than it consumes, and Canada is the fifth largest exporter of agriculture and agri-food products internationally.[109] Efficiency gains, sustainable land management, and innovation will enable Canadian agriculture to reduce emissions, store carbon, and meet a growing global food demand.

Most agricultural greenhouse gas emissions are not driven by energy use but rather take the form of methane and nitrous oxide resulting predominantly from biological processes inherent to animal and crop production. Nitrous oxide emissions can originate from field-applied fertilizers, crop residue decomposition, cultivation of organic soils, and from the storage of manure. Methane emissions are mainly a result of enteric fermentation in ruminant animals and decomposition of stored manure.

108 Agriculture and Agri-food Canada, *An Overview of the Canadian Agriculture and Agri-Food System 2016.*

109 Ibid.

Total emissions from agriculture have been relatively stable since the year 2000 and are not projected to significantly increase toward 2030.[110] In 2014, non-energy emissions accounted for 59 megatonnes of carbon dioxide equivalent (Mt CO_2 eq) – approximately 8% of Canada's total GHG emissions – while GHG emissions from on-farm fuel use generated 14 Mt CO_2 eq.[111] The two main sources of non-combustion agricultural emissions are enteric fermentation and fertilizer application.

7.3 Technological innovations and sustainable land management practices will ensure that agricultural soils remain a net carbon sink in Canada over the long-term.

For over twenty years, Canadian farmers in the Prairie provinces have been able to increasingly substitute conventional tillage with no-till or conservation tillage seeding techniques due to innovations such as improved seeds, fertilizers and pesticides, and changes in machinery and farm equipment, including the evolution of technologies such as global positioning systems. Increased crop rotation

110 Environment and Climate Change Canada, *Canada's Second Biennial Report on Climate Change.*

111 Environment and Climate Change Canada, *National Inventory Report 1990-2014: Greenhouse Gas Sources and Sinks in Canada.*

REDUCING METHANE EMISSIONS FROM ENTERIC FERMENTATION

Enteric fermentation is a natural process that occurs in the digestion of feed by livestock. The digestion process is not 100% efficient and releases methane as a by-product. In Canada, GHG emissions from enteric fermentation were 25 Mt CO_2e in 2014 down from 31 Mt in 2005. Dairy and beef cattle produce around 95% of these emissions while others ruminants such as buffalo, goats, horses, sheep and swine, make up the rest of the emissions.

There are a number of options to reduce methane emissions from enteric fermentation but many of these are still in the research phase. Since the demand for meat and milk is expected to increase in the future, decreasing methane output per unit or animal is important. For example, it is possible to select lower-methane producing animals through consideration of genetic characteristics. In addition, research into methane vaccines and inhibitors is ongoing in some jurisdictions.

High quality feed could lead to more efficient digestion and reduce emissions. For example, research has shown that mixing seaweed in cattle feed could reduce methane emissions. In this respect, a company from Prince Edward Island, North Atlantic Organics Ltd., is proposing organic seaweed products that can be used by dairy cattle.[112] The use of seaweed for animal feed is in fact a traditional method that has been used by coastal farmers in the past.

112 NAO organics. http://www.naorganics.com/index.asp

options have also allowed reduced reliance on summer fallow (the practice of allowing land to lie idle during the growing season).

As a result, agricultural soils in Canada have been a net sink of carbon since 2000 and will remain so over the long-term, although the rate at which carbon will be sequestered is projected to slowly diminish. Greater use of cover crops, biochar application and the use of precision agriculture to avoid disturbance of more fragile soils, among other sustainable land management practices, will help maintain the agricultural carbon sink in the future.

7.4 Promoting the adoption of existing and emerging technologies and management practices could increase efficiency and reduce emissions from crop and livestock systems.

On-farm GHG emissions are closely tied to management practices and technologies such as fertilizer types and application methods, manure storage and spreading methods, land management and tillage regimes, feeding and nutrition, as well as crop and animal genetics.

Mitigation options aimed at enhancing fertilizer use efficiency and reducing methane emissions from livestock are promising as innovative technologies such as methane inhibitor feeding additives, livestock genetics, smart-fertilizers, and precision agriculture approaches are being developed.

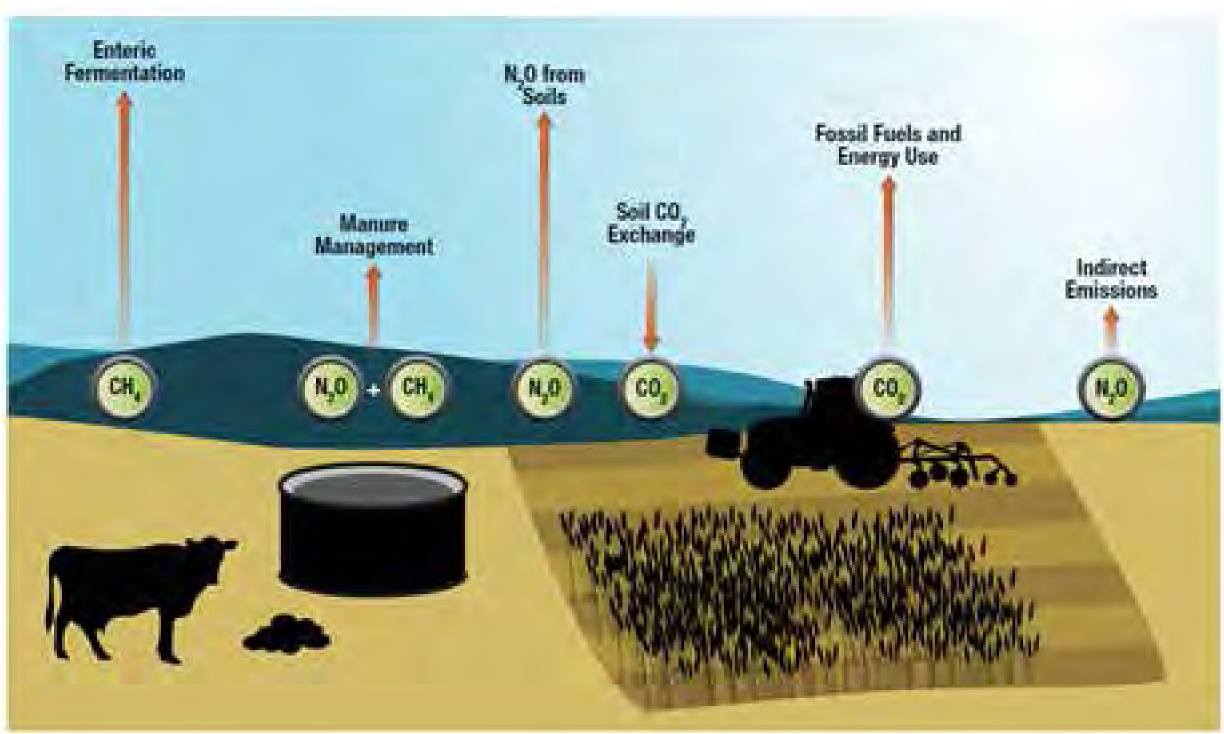
Encouraging the continued adoption of nutrient management practices, such as soil nutrient testing, optimisation of the timing of fertilizer application, incorporation of solid and liquid manure and fertilizer, and increased manure storage capacity, will continue to increase performance while minimising emissions in the sector.[113] For example, in the beef cattle sector, Canadian farmers have made significant improvements in feeding and breeding practices, and as a result, cattle reach slaughter weight sooner, and spend fewer days eating, ruminating, producing methane, and generating manure.[114]

In the livestock sector, upcoming methods to reduce methane emissions are showing significant potential.

113 Agriculture and Agri-Food Canada, *Farm Environmental Management Survey 2011.*

114 Agriculture and Agri-Food Canada, *Environmental Sustainability of Canadian Agriculture: Agri-Environmental Indicator Report Series – Report #4.*

Figure 14: Agricultural GHG emissions in Canada in 2011



The arrow length is proportional to the magnitude of the emissions; arrow direction upwards indicates a source and downwards indicates a sink. Source: *Environmental Sustainability of Canadian Agriculture: Agri-Environmental Indicator Report Series – Report #4*

These include switching to lower-methane producing ruminants, methane inhibitors and feed supplements, or even vaccines to reduce methane production in the rumen.

Technology will also continue to make a profound impact on agricultural production. Bioengineering, precision agriculture, sensors, robotics, and automated data capture and transfer, all hold promise for further agriculture GHG emission reductions. Although additional scientific validation work is still needed, preliminary, partial results point to substantial reductions in nitrous oxide emissions when an optimised nutrient management approach is adopted.

Continuing to seek improvements in efficiencies can yield further emission reductions but this will depend on the development and deployment of transformative technologies (e.g., methane inhibitors and smart-fertilizers), some expected to be ready for commercial deployment over the short-term (i.e., 5 years) while others could possibly be made available over the medium-term (i.e., 10-15 years).

On the farm inputs side, deeper penetration of precision agriculture practices, technologies and equipment should translate into lower consumption of production factors such as fertilizers and fuels, with a corresponding decrease in the GHG emissions associated with the use of these inputs. More efficient and precise production decisions should also lessen the pressure on natural resources like land and water.

As a more specific example, the province of Saskatchewan highlights the underdeveloped use of pulse crops to mitigate the use of fertilizers, as well as the potential associated with seeding marginal land for carbon sequestration, through permanent covers like legumes, or by converting them into forest stands. The province is also hopeful that advances in beef genetic selection, genomics and food additives will significantly lower the rate in which the agriculture sector emits GHG emissions. The province notes that the role of innovation and increased research in mitigation options for the agriculture sector is critical due to the challenge represented by a global population growth and the subsequent pressure on global food demand and production.

7.5 The Agriculture sector has the potential to provide renewable energy solutions and bio-products to help reduce emissions in other sectors. In evaluating these options, consideration should be given to the full life-cycle environmental costs and benefits.

From a life cycle perspective, the agriculture sector could also contribute to long-term mitigation by helping to reduce emissions in other sectors through displacement of more emission-intensive materials and fossil fuels with biomass-based energy and products.

There is an opportunity to convert growing agricultural waste, as well as agricultural by- and co-products into eco-efficient, bio-based products with direct benefits for the environment, the economy, and consumers, for example, sustainable bio-energy, bio-fertilizers and bio-chemicals. Both feedstock and technology exists to convert more wastes, agriculture and forest biomass into high quality, low GHG-emitting biofuels, for use in road transportation to air travel.

In evaluating these options, consideration should be given to net GHG savings along the full life cycle, as well as to other environmental impacts, that could result from the intensification of agricultural production.

8 Waste

KEY MESSAGES:

- The waste sector directly accounts for 3% of Canada's GHG emissions; however from a life cycle perspective, waste related activities are responsible for significant indirect GHG emissions from various sectors of the economy not typically associate with waste.
- Currently, the relatively low cost of waste disposal at landfills in many parts of Canada provides a disincentive for waste prevention and diversion activities.
- Effective management strategies, focusing on waste prevention and diversion, can bring deep cuts in direct and indirect waste-related GHG emissions.
- New policies could instigate behavioral change away from wasteful consumption patterns, as well as shift the responsibility for end-of-life management of products from consumers to producers.
- Co-benefits of waste prevention, diversion, and landfill gas capture include: greater food security, increased supply of renewable natural gas and electricity, creation of a soil amendment (i.e., compost); and a reduction in volatile organic compounds emissions, smog formation and unpleasant odours.
- In the future, progress in landfill gas capture and flaring technologies could further reduce any remaining direct landfill emissions.

Canada has performed poorly in terms of quantity of waste generated per capita compared to its OECD peers. At 777 kg of municipal waste generated per capita in 2008, the average Canadian city generated more waste than any other OECD country, twice as much as an average Japanese city, and slightly more waste than an average American city (722 kg).[115] While substantial efforts have been taken by municipalities and provinces/territories across the country, for example Nova Scotia has reduced waste generation to 386 kg per capita as of 2012, much more needs to be done.[116]

8.1 The waste sector directly accounts for 3% of Canada's GHG emissions, however from a life cycle perspective; waste related activities are responsible for significant indirect GHG emissions from various sectors of the economy not typically associate with waste.

The waste sector officially accounts for 3% of total GHG emissions and 22% of Canada's total methane emissions. This includes emissions from municipal solid waste landfills, wood waste landfills, wastewater treatment, as well as waste discharge, incineration, and open burning.

115 Conference Board of Canada, *Municipal Waste Generation. Note: For comparison purposes, construction, renovation and demolition waste were not included in the OECD definition.*

116 Conference Board of Canada, *Waste Generation: Provincial and Territorial Ranking. Readers should note that municipal waste generation per capita and waste generation per capita differs slightly, the latter being slightly more important.*

As the IPCC's fourth assessment report indicates, a life cycle approach is required to evaluate the emissions reductions potential for waste prevention and diversion. As such, waste management activities will affect GHG emissions accounted for under sectors such as transportation, forestry, energy and industrial processes. For example, the U.S. Environmental Protection Agency (EPA) estimated that approximately 42% of total U.S. greenhouse gas emissions are associated with the energy used to produce, process, transport, and dispose of commodities and food.[117] Waste prevention and diversion strategies would therefore reduce emissions in other sectors.

8.2 Currently, the relatively low cost of waste disposal at landfills in many parts of Canada provides a disincentive for waste prevention and diversion activities.

Waste disposal is relatively inexpensive in Canada compared to many peer countries. Available land for waste disposal is not in short supply in Canada, relative to many European countries. Canadian jurisdictions are using a variety of policy approaches to counter the low cost of landfill disposal. For example, Nova Scotia, Quebec, and Prince Edward Island have implemented material disposal bans from landfills (e.g., organic waste and in some instances recyclables). Quebec and Manitoba have also instituted landfill levies to provide an incentive for greater waste diversion and to support municipal recycling programs.[118] In 2014, the City of Edmonton opened its new *Waste-to-Biofuels and Chemicals Facility*, the first industrial scale waste to biofuels facility of its kind, that will help the city divert up to 90% of residential waste from landfills, as well as produce up to 38 million litres of ethanol each year.[119]

117 United States Environmental Protection Agency, *Opportunities to Reduce Greenhouse Gas Emissions through Materials and Land Management Practices.*

118 Giroux Environmental Consulting, *State of Waste Management in Canada.*

8.3 Effective management strategies, focusing on waste prevention and diversion, can bring deep cuts in direct and indirect waste-related GHG emissions.

The greatest untapped potential for GHG emissions reductions rests with waste prevention and diversion activities (e.g., composting or anaerobic digestion). Reducing avoidable food waste and increasing diversion of other organic material and recyclable materials from landfills could procure most significant emissions reductions for the sector.

In Canada, avoidable food waste is valued at $31 billion per year. Moreover, the national organics diversion rate stands as a low 7% of the total waste stream, with the recyclable materials diversion rates standing at 16%. In total, Canada's overall diversion rate stand at 25%, lower than other peers countries such as Germany or the US.[120] Nevertheless, it is important to remember that some Canadian municipalities are leading the way for diversion strategies, with Halifax, Hamilton, and Sherbrooke achieving total diversion rates between 40 and 60%.[121] An enforced target, such as the EU's 50% diversion rate by 2020, could prove useful to engage the different Canadian authorities in a concerted waste management effort. [122]

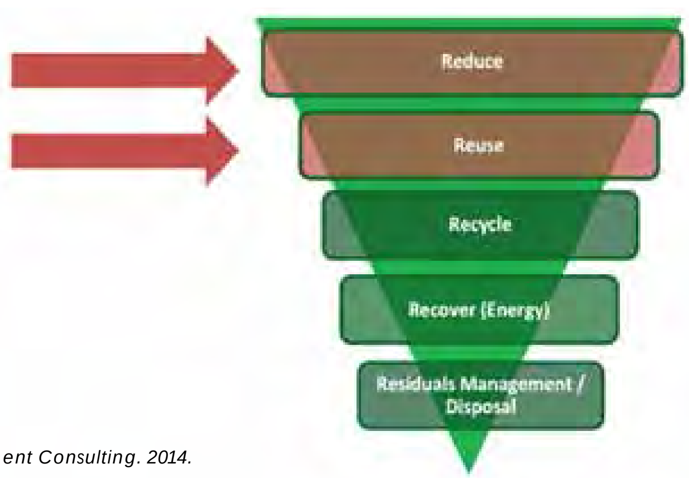
119 City of Edmonton, *Waste to Biofuels and Chemicals Facility.*

120 Statistic Canada, *Waste Management Industry Survey: Business and Government Sectors.*

121 Federation of Canadian Municipalities, *Waste Diversion Success Stories from Canadian Municipalities.*

122 Ontario Waste Management Association, *Rethink Waste: Evolution Towards a Circular Economy.*

Figure 15 - Location of Waste Prevention and Reduction in the Waste Management Hierarchy.



Source: Giroux Environment Consulting. 2014.

WASTE DIVERSION IN NOVA SCOTIA

The province of Nova Scotia is a North American leader in waste diversion, creating significant environmental benefit and economic advantage. Its disposal rate is 50% lower than the Canadian average and continues to decrease.

Starting in 1996 the Province implemented a strategy that included disposal bans on food and yard waste, some paper, plastic, metal and electronic items.

Some other highlights of Nova Scotia's successful and ongoing 'circular economy approach' to solid waste include:

- Financial incentives to municipalities based upon diversion performance
- A strong partnership with municipalities through a regional (solid waste) chairs committee
- Effective and sustained education, enforcement, and innovation programs
- Stewardship programs for beverage containers, tires, mercury containing products, and dairy containers
- Extended producer responsibility programs for electronics, paint, and cell phones
- Municipal commitments to implementing clear bag programs for garbage that decrease waste disposal by 15 to 30%

As a result, tonnes of materials that used to be wasted now contribute to Nova Scotia's economy, creating jobs and reducing GHG emissions.

8.4 New policies could instigate behavioral change away from wasteful consumption patterns, as well as shift the responsibility for end-of-life management of products from consumers to producers.

Effective policies can help increase waste diversion through source reduction, reuse, recycling, composting, and anaerobic digestion. For example, information and incentive programs can help shift public behavior to less wasteful practices by helping to close information gaps (e.g., public education programs), or providing financial incentives such as advance disposal fees policies. Another example can be found in the Swedish initiative to introduce a tax break for repairing activities, such as repairs of bicycles or appliances. Such policies are instrumental in shifting consumption behaviors towards waste prevention.

The true cost of landfill disposal also needs to be adequately reflected in tipping fees to account for loss of arable land and the creation of environmental liabilities. Regulatory or market-based policies could include disposal bans, higher landfill tipping fees, and differential tipping fees for unsorted waste. Practices such as keeping products for longer, reusing products, or repairing items and spare parts that can be re-used, are amongst the many ways that need to be promoted and rewarded by municipalities and provinces/territories. There are innovative solutions to reducing food waste by connecting consumers and producers in the food industry, such as industry and non-governmental organisation-led initiatives to encourage the sale and purchase of imperfect produce.

A significant step towards increasing diversion, and in turn reducing emissions associated with waste, is to shift the responsibility for end-of-life management of products from consumers and municipalities to producers. Over the past 20 years, significant progress on extended producer responsibility programs has been made in Canada on a wide variety of products and materials. The next phase will be to implement diversion programs for complex product categories such as construction, renovation, demolition materials, furniture, textiles and carpets.[123]

123 Canadian Council of Ministers of the Environment, *Progress Report on the Canada-wide Action Plan for Extended Producer Responsibility.*

Regulations and support for producers to minimise material inputs, optimise reuse and recovery of products, and develop markets for recycled materials will be essential.[124] Extended producer responsibility programs and performance-based regulations are two policies put forward to pursue that shift.[125] Improved systems for generators to manage certain materials on-site instead of relying on costly centralised infrastructure could also be further explored (e.g., plastic to oil conversion, renewable natural gas recovery from organics).

8.5 Co-benefits of waste prevention, diversion, and landfill gas capture include: Greater food security, increased supply of renewable natural gas and electricity, creation of a soil amendment (i.e., compost); and a reduction in volatile organic compounds emissions, smog formation and unpleasant odours.

There are many co-benefits to improve waste management strategies apart from reducing greenhouse gas emissions, in particular methane. Waste prevention increases food security and organic waste diversion can produce renewable biogas and/or a soil amendment. Recycling can save resources and energy, while limiting the amount of plastic discharged in the oceans. Landfill gas capture can also provide energy and electricity to municipalities and industries. In addition, cement manufacturers across the country have shown interest in using a variety of waste products (solid waste, carpets, wood waste, asphalt, non-recyclable plastics) as an alternative energy source.[126] Finally, the reduction of volatile emissions, smog formation, and unpleasant odours, will provide health and lifestyle benefits to landfill-adjacent neighborhoods and communities.

8.6 In the future, progress in landfill gas capture and flaring technologies could further reduce any remaining direct landfill emissions.

Even with waste prevention and diversion efforts, it is likely that landfill disposal will still be a practice in some parts of Canada in 2050 and that not all sources of GHGs will be diverted. In addition, there is a lag in the decomposition of organic waste in a landfill such that the organic waste disposed today, will be the source of emissions for decades to come if not mitigated. Currently, only 36% of total methane gases generated by landfills are captured, partly due to current stringency and performance standards on gas capture regulations across the country. Nevertheless, landfill gas capture technologies are widely available and expected development in flaring, gas capture and gas utilisation technologies could easily increase the ongoing reduction in landfill GHG emissions and produce more heat and electricity. In the future, thermal treatment facilities with energy recovery, small-landfill gas capture technologies or even waste mining, could become proven and commercially viable options in Canada.

124 Giroux Environmental Consulting, *State of Waste Management in Canada.*
125 Ibid.
126 Ibid.

9 Clean Technology Sector

As our society moves to address its environmental challenges, the clean technology sector has seen an increase in demand for its products and processes. Clean technologies are products or processes that significantly reduce environmental impacts of a given economic activity. This subset of the economy makes a compelling case for itself as it provides economic development while improving the environmental performance of the economy. As the world moves to deep decarbonisation, the clean technology sector is faced with a tremendous opportunity to produce further economic and social co-benefits for all Canadians.

KEY MESSAGES:

- The clean technology sector is growing very quickly both domestically and globally.
- Utilities, equipment suppliers, and policymakers should work together to identify strategies for reducing deployment costs of critical clean technologies and barriers to adoption.
- Further investments in RD&D and innovation in clean technology, combined with market pull mechanisms such as carbon pricing, will support Canada's competitiveness, creating high paying jobs and increased exports.
- Innovation will result in economic and environmental spill-over effects, thereby increasing resource efficiency and productivity in other sectors and reducing other types of pollution.
- Providing a clear and predictable signal for long-term investments and disclosing climate-related information will allow the market to better anticipate the transition to a low-carbon future.
- Canada has confirmed its commitment to clean energy innovation by joining the Mission Innovation international commitment, which aims to accelerate innovation by doubling investments in clean energy RD&D across the world.

9.1 The clean technology sector is growing very quickly, both domestically and globally.

Recent historical performance of the clean technology sector in Canada has been very strong, despite a leveling off between 2013 and 2014. The sector grew at a pace of 8% annually between 2011 and 2013, which represents more than three times the overall economic growth in Canada.[127] Over the same time period, global clean technology revenues increased by 10% annually. Employment in the clean technology sector in Canada has increased from 41,000 in 2012 to 55,600 in 2014, an increase of more than 16% per year.

Solutions from clean technology producers can help address challenges in high-emitting sectors, providing positive economic and environmental outcomes. Investment opportunities in clean technology are increasing at a rapid pace. For example, the

127 Analytica Advisors, *Canadian Clean Technology Industry Report.*

IEA estimates that around $1 trillion per year of incremental investment are required in renewable energy and energy efficiency investments to keep the global average temperature to well below 2°C in 2050.[128] This represents a significant opportunity for Canadian clean technology companies to tap into this growing market. Exports accounted for 50% of the clean technology sector's revenues in 2014, meaning Canadian firms are positioned to benefit from comprehensive efforts to export unique technologies and expertise to new and growing markets.

9.2 Utilities, equipment suppliers and policymakers should work together to identify strategies for reducing deployment costs of critical clean technologies and barriers to adoption.

To advance the deployment of clean technologies in Canada, it will be critical to coordinate between actors, in order to reduce the cost of achieving emission reductions and mitigate barriers to adoption. Important actors in the economy, such as Governments and utilities can play a key role in accelerating the development and adoption of clean technologies. Given their financial capacity, these actors can use their purchasing power to demonstrate clean technologies and provide a visibility that will encourage broader adoption.

Canada has a strong financial sector, which it can use as a powerful lever to encourage further low-carbon development both domestically and abroad. Although there are many significant low-cost GHG reduction opportunities in developing countries, barriers to investment such as higher perceived risk and imperfect information prevent these opportunities from being realised by Canadian companies. Through its $2.65 billion climate finance commitment, Canada will contribute to making these investments more accessible to Canadian companies, allowing for Canadian low-carbon technologies to help reduce emissions at a lower cost, while leading to significant export opportunities.

Private sector participation is of utmost importance at all stages of technology development. Technology developers and users are best positioned to bring forward new technologies that will ultimately succeed. Governments also need to play a role in providing the appropriate incentive framework for this to happen, as the private sector typically underinvests in R&D. For this to happen, there must be a good alignment of policies to allow for technology developers to most effectively advance their goals. Finally, sufficient investment is paramount to allowing good technology solutions to reach the market.

9.3 Further investments in RD&D and innovation in clean technology, combined with market pull mechanisms such as carbon pricing, will support Canada's competitiveness, creating high paying jobs and increased exports.

Clean technology is a sector that defines itself in the improvement of environmental outcomes related to economic activities in a broad sense. As such, it is a sector where innovation is of utmost importance, and therefore is very RD&D-intensive. RD&D can help solve environmental problems with current technologies, but it can also contribute to developing new clean technologies that will make it easier to reduce emissions in the future. However, for technologies to actually make a difference, successful commercialisation has to take place. For this to happen, market demand has to be there.

The right policies and frameworks can work to promote a low-carbon economy by helping to address the double market failure traditionally faced by the clean technology sector. As with innovation spending more broadly, there is a tendency for the private sector to underinvest in RD&D given that the benefits may not be fully captured by the investing firms. As well, there is the issue of businesses not accounting for environmental externalities in their decision-making. Existing and potential government policies can help address these market failures. For example, carbon pricing allows for the consideration of GHG emissions in the final price of a product, which provides a market value to the environmental benefits of clean technologies.

Other types of approaches, such as government procurement of clean technologies and regulations, could also increase demand for Canadian clean technologies. Governments will have to display leadership in providing broad support for clean technologies, coordinating innovation efforts and catalyzing private-sector involvement, particularly for early-stage R&D.

These initiatives would address an important barrier for Canada, which has historically struggled with demonstration and commercialisation of its clean technologies, increasing the challenge for companies to export untested products. Given the important growth of clean technology globally, this would position Canada favorably in terms

128 Hamilton T., *The $36-Trillion Question.*

of competitiveness in this market. Canada's competitiveness in the clean technology market would bring significant benefits to Canada, such as high paying jobs and significant increases in exports.

9.4 Innovation will result in economic and environmental spill-over effects, thereby increasing resource efficiency and productivity in other sectors and reducing other types of pollution.

Innovation in clean technologies, whether it is a breakthrough technology or one that drastically improves the efficiency of an existing process, can bring significant benefits to the economy as well as spill-over effects. Economic benefits of clean technologies can take different forms, depending on the nature of the technology. If a technology provides an efficiency improvement, benefits will be seen as reduced input costs, while they can take different forms in the case of a breakthrough technology. The internalisation of environmental externalities with the help of tools such as carbon pricing will ensure that technologies that reduce emissions have tangible economic benefits.

Another dimension where spill-over effects are tangible is the potential to reduce production costs and pollution through industrial ecology. Industrial ecology is a concept that could potentially transform the industrial sector into a highly efficient integrated ecosystem. Industrial ecology "seeks to emulate mature ecological systems in order to reduce environmental impacts through maximised efficiency of energy resource inputs and the minimisation of unutilized waste".[129] This concept promotes more interconnections between industrial sectors to optimise the flows of inputs and outputs from each industry such that all industrial processes together minimise energy use and disposal of waste products to improve resource efficiency and economic competitiveness. In other words, industrial ecology allows for output perceived as non-valuable (waste heat, wood residues, etc.) to be used as inputs by other companies within an industrial park, allowing for improved competitiveness and environmental outcomes.

9.5 Providing a clear and predictable signal for long-term investments and disclosing climate-related information will allow the market to better anticipate the transition to a low-carbon future.

> "Green investment represents a major opportunity for both long-term investors and macroeconomic policymakers seeking to jump-start growth."
>
> - Mark Carney, Governor of the Bank of England and Chairman of the G20's Financial Stability Board

The financing of climate-related initiatives is a crucial dimension of the climate change challenge with both a domestic and international component. Significant investments, most notably in adaptation measures, need to be made in order to deal with the costs of climate change, some of which may materialise over a long-term horizon. There are risks and opportunities associated with these investments that many businesses and political actors are taking steps to address. For example, the insurance sector has already been significantly exposed to climate change risks.[130] Those risks could be physical risks, where investments can be affected by major events like floods or disruption of global supply chains and could have important impacts for insurers and re-insurers. Liability risks could also arise as investors may be subject to lawsuits for carbon damages. Finally, transition risks may occur as structural change in the economy drive re-pricing of assets and values of companies.

Another key aspect of tackling climate change risks and opportunities is to provide investors with reliable and detailed information of climate change activities. Many companies, including 822 investors with US $95 trillion in assets, have chosen to disclose information on their action on climate change through the Carbon Disclosure Project or the Montréal Carbon Pledge. The Financial Stability Board's Task Force on Climate-related Financial Disclosures is working to develop voluntary, consistent climate-related financial risk disclosures for use by companies in providing information to investors, lenders, insurers, and other stakeholders. Such initiatives will allow a better understanding of the link between decarbonisation and the financial performance of firms. Further development of similar initiatives could create a virtuous circle where action is encouraged and best practices are shared. This would, in turn, provide a clear and predictable

129 McKinley A., *Industrial Ecology: A Review with Examples from the Canadian Mining Industry*, *Canadian Journal of Regional Science.*

130 Bank of England, *Breaking the Tragedy of The Horizon - Climate Change and Financial Stability - Speech by Mark Carney.*

signal for investments, allowing the market to better anticipate the transition. [131]

Finally, pricing carbon will give Canadian businesses, investors, and consumers a clear, predictable basis for decision making. Confidence that carbon pricing in Canada will continue to increase over time will encourage businesses and consumers to invest in cleaner appliances, vehicles, and technology. It will also encourage firms to invest in research into low-carbon technology, which will better position Canadian firms to compete in the rapidly-growing, low-carbon economy.

9.6 Canada has confirmed its commitment to clean energy innovation by joining the Mission Innovation international commitment, which aims to accelerate innovation by doubling investments in clean energy across the world.

On November 30, 2015, Canada announced its participation in the Mission Innovation international commitment, along with 20 other countries. This commitment is to double clean energy innovation investments from governments over the next five years, while encouraging greater levels of private-sector investment. This commitment also entails working with the Breakthrough Energy Coalition, an independent initiative that features 28 influential investors from 10 countries that commit to providing patient, early-stage capital (as opposed to venture capital, which seeks returns on investment on a much shorter time horizon) to advance clean energy technology innovation.

As part of this initiative, it is recognised that clean technology innovation often faces a so-called “valley of death”, which typically appears at the pre-commercialisation stage, where the conversion of a proven concept into a compelling product will determine whether a company will survive or not. This commitment aims to bridge that gap with increased government funding to enable more basic research, as well as more patient private capital, which will allow good concepts the time required to make it to market commercialisation. Given Canada’s particular challenges in commercialisation, this initiative could fill an important need for Canadian companies to succeed in clean energy innovation that can significantly reduce GHG emissions.

131 “[R]isks to financial stability will be minimised if the transition begins early and follows a predictable path, thereby helping the market anticipate the transition to a 2 degree world”. (Bank of England, Breaking the Tragedy of the Horizon - Climate Change and Financial Stability - Speech by Mark Carney.)

10 Achieving a Low-Carbon Future through Infrastructure Investments

Infrastructure investments are key to supporting Canada's deep decarbonisation efforts over the longer term and will help reshape the economy consistent with low-carbon pathways. Investing in infrastructure today will provide Canadians with increased employment opportunities, and cleaner, more modern communities, while also addressing climate change and air pollution.

Investing in public transit, green infrastructure, social infrastructure, Canada's trade and transportation corridors, as well as rural and northern communities, will provide a strong foundation for more inclusive and sustainable cities, and can also help to both address greenhouse gas emissions and enhance resilience to the impacts of climate change. For instance, Canadian communities building new urban transit networks and service extensions will transform the way that Canadians live, move and work.

In addition to committing significant resources (over $186 billion through to 2027-28), Canada is also establishing a new Infrastructure Bank, an arm's-length organization dedicated to increasing investment in growth-oriented infrastructure, transforming the way infrastructure is planned, funded and delivered across the country.

Considering the magnitude of investments required to develop key infrastructure projects, key linkages between infrastructure decision-making and long-term decarbonisation include:

- Investments are influential in setting long-term greenhouse gas pathways as the lifespan of infrastructure assets are long-lived, often ranging from 25 to 60 years.
- Once infrastructure investments are made, the behaviours and carbon emissions associated with infrastructure investments are more or less 'locked-in' and the shift to a new pathway can become very costly.
- Deploying infrastructure investments strategically can attract low-carbon infrastructure investments, creating a critical mass of funding for low-carbon solutions or the ability to 'anchor' future low-carbon investments. For example, making strategic investments in alternative fuel or electric vehicle infrastructure would underpin further investments in low-carbon vehicles.
- The transformative nature of infrastructure projects plays a complementary and enabling role to support the transition to a low-carbon economy. For instance, infrastructure that is designed to withstand the projected impacts of climate change can lead to cost savings over the longer term by avoiding maintenance and rehabilitation costs.

Canada is committed to working closely with all stakeholders, including provinces, territories and Indigenous peoples, to develop and implement an infrastructure plan that delivers investments across the country. As part of this plan, investments in green infrastructure and other streams, such as social and transportation, will reduce GHG emissions and support the resilience of infrastructure assets. Examples may include supporting further electrification of sectors currently reliant on fossil fuels, improving electricity transmission systems through inter-provincial transmission lines and the expansion of smart grids.

Investments in sustainable infrastructure will enable greater climate change adaptation and resilience; ensure that more communities can provide clean air and safe drinking water for their citizens; and support the transition toward more sustainable economic growth. Canada will ensure that our mid-century climate change objectives inform our infrastructure development going forward.

Conclusion

Dealing with climate change will ultimately require net-zero anthropogenic greenhouse gas emissions over the course of this century. Canada will need to fundamentally transform all economic sectors, especially patterns of energy production and consumption. Over time, this requires major structural changes to the economy and the way people live, work, and consume.

A low-greenhouse gas future also represents a massive opportunity to increase prosperity and the well-being of Canadians, to improve the livability of the built environment, modernise transportation, and enhance the natural environment. The benefits include: reducing air pollution and congestion, modernising infrastructure to provide more inclusive and sustainable cities, creating cleaner and more modern communities, growing Canada's clean technology sector, increasing economic productivity and efficiency, saving energy and reducing energy costs, and enhancing resilience to the impacts of climate change.

Much of the transformation can be achieved with existing technology, but innovation, such as through the Mission Innovation initiative, and significant investments in research, development, demonstration & deployment, and related infrastructure, will be fundamental to the transition.

Additional collaboration across industry leaders to identify common innovation priorities will be needed to seize opportunities to integrate innovation into business strategies. Funding environments, intellectual property regimes, research agendas, and communication strategies will need to be shaped to stimulate innovation investments.

Decarbonisation will require a sustained societal effort that will take many years to accomplish. This will require a technological ramp up of low greenhouse gas alternatives, and also societal engagement and action by all Canadians. Working collaboratively with Indigenous peoples by supporting their on-going implementation of climate change initiatives will be key. Likewise, all levels of government will need to implement a vast array of the various policy options that are available to them. In this respect, Canada will continue to work collaboratively with provinces and territories including through the pan-Canadian framework on clean growth and climate change. Although the pace of this transition may vary from Canadian jurisdiction to jurisdiction, the direction and orientation are clear.

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Annex 1: Detailed Modelling Results from 2050 Scenarios

This annex provides modelling results for the aggregate energy economy or total economy of Canada under the described low greenhouse gas modelling analyses (see model and scenario descriptions in Chapter 3). The tables are provided for illustrative purposes only and should not be interpreted as optimal pathways. Moreover, the sectoral aggregation may differ from one model to another.

The table below illustrates results from ECCC's modelling, where a 2050 target of 80% below 2005 levels is achieved by reductions in emissions from the energy sector, industrial processes, agriculture and waste. The reductions are influenced by a common price on greenhouse gas emissions.

As illustrated by the table, the greatest emissions reductions are projected to come from energy-related emissions (89% below the 2005 level), followed by emissions from waste (55% below the 2005 level), industrial process emission (50% below the 2005 level) and agriculture (36% below the 2005 level). As there are currently relatively few moderate cost reduction opportunities for industrial process sector, a project reduction in output drives the decline in emissions.

Table A1: Environment and Climate Change Canada - Gross Emissions (2050)

Canada's 1990–2050 GHG Emissions by Sector (Mt CO_2e)				
Greenhouse Gas Categories	1990	2005	2050	% Change Relative to 2005
TOTAL: EXCLUDING LULUCF	**613**	**748**	**149**	**-80%**
ENERGY	482	597	67	-89%
Stationary Combustion Sources	285	342	46	
Transport	148	195	38	
Fugitive Sources	49	61	6	
CO_2 Capture, Transport and Storage	-	0	-23	
INDUSTRIAL PROCESSES AND PRODUCT USE	56	58	29	-50%
Mineral Products	8	10	2	
Chemical Industry	17	10	19	
Metal Production	24	20	5	
Production and Consumption of Halocarbons, SF_6 and NF_3	1	6	1	
Non-Energy Products from Fuels and Solvent Use	5	12	2	
Other Product Manufacture and Use	0	1	0	
AGRICULTURE	49	61	39	-36%
Enteric Fermentation	23	31	20	
Manure Management	8	10	6	
Agriculture Soils	17	19	12	
Field Burning of Agricultural Residues	0	0	0	
Liming, Urea Application and Other Carbon-containing Fertilizers	1	1	0	
WASTE	26	31	14	-55%
Solid Waste Disposal	24	28	13	
Biological Treatment of Solid Waste	1	1	1	
Wastewater Treatment and Discharge	1	1	0	
Incineration and Open Burning of Waste	1	1	0	

The table below illustrates results from ECCC's modelling of a scenario in which a 2050 target of 80% below 2005 levels is achieved by a 65% reduction in the combined emissions of the energy sector, industrial processes, agriculture, and waste, plus an assumed contribution from credits due to improved land sector sequestration and internationally transferred mitigation outcomes.

As depicted in the table, the greatest reductions are projected to come from energy-related emissions (74% below the 2005 level), followed by emissions from waste (55% below the 2005 level), industrial process emission (28% below the 2005 level) and agriculture (15% below the 2005 level).

Table A2: Environment and Climate Change Canada-Net Emissions (2050)

Canada's 1990–2050 GHG Emissions by Sector (Mt CO_2e)				
Greenhouse Gas Categories	1990	2005	2050	% Change Relative to 2005
TOTAL: EXCLUDING LULUCF	**613**	**748**	**262**	**-65%**
ENERGY	482	597	155	-74%
Stationary Combustion Sources	285	342	86	
Transport	148	195	77	
Fugitive Sources	49	61	8	
CO_2 Capture, Transport and Storage	-	0	-17	
INDUSTRIAL PROCESSES AND PRODUCT USE	56	58	50	-15%
Mineral Products	8	10	4	
Chemical Industry	17	10	28	
Metal Production	24	20	12	
Production and Consumption of Halocarbons, SF_6 and NF_3	1	6	2	
Non-Energy Products from Fuels and Solvent Use	5	12	4	
Other Product Manufacture and Use	0	1	0	
AGRICULTURE	49	61	44	-28%
Enteric Fermentation	23	31	23	
Manure Management	8	10	7	
Agriculture Soils	17	19	14	
Field Burning of Agricultural Residues	0	0	0	
Liming, Urea Application and Other Carbon-containing Fertilizers	1	1	1	
WASTE	26	31	14	-55%
Solid Waste Disposal	24	28	13	
Biological Treatment of Solid Waste	1	1	1	
Wastewater Treatment and Discharge	1	1	0	
Incineration and Open Burning of Waste	1	1	0	

The table below illustrates modelling results from Trottier Energy Futures Project, where a 2050 target of 60% below the 1990 levels is achieved by reductions in emissions from the energy sector, industrial processes, agriculture and wastes. The table below illustrated the reductions when current technologies are available, with the addition of interprovincial interconnections to the electricity grid.

As illustrated by the table, the greatest reductions are projected to come from electricity emissions (99% below the 2015 level), followed by emissions from the residential sector (87% below the 2015 level), commercial emissions (76% below the 2015 level), transportation (71% below the 2015 level) and agriculture (64% below the 2005 level).

Table A3: Trottier Energy Futures Project (Current Technology Scenario)

Canada's 1990–2050 GHG Emissions by Sector (Trottier) Mt CO_2e			
Greenhouse Gas Categories	2015	2050	% Change Relative to 2015
CURRENT TECHNOLOGY SCENARIO:			
TOTAL (EXCLUDING PROCESS EMISSIONS)	488	171	-65%
TOTAL (INCLUDING PROCESS EMISSIONS)	560	282	-50%
AGRICULTURE	16	6	-64%
COMMERCIAL	36	9	-76%
INDUSTRIAL PROCESSES AND PRODUCT USE	53	35	-34%
RESIDENTIAL	43	6	-87%
TRANSPORTATION	169	49	-71%
ELECTRICITY	60	0	-99%
SUPPLY - COMBUSTION	112	66	-41%
SUPPLY – PROCESS	71	112	56%

The table below is also from the Trottier Energy Futures Project. It illustrates the reductions when other new technologies are available to reduce GHG emission reduction costs. The contribution of new technologies increases the reduction from agriculture, commercial, residential and supply-combustion.

As illustrated by the table, the greatest reductions are projected to come from electricity emissions (99% below the 2015 level), followed by emissions from the residential sector (89% below the 2015 level), commercial emissions (88% below the 2015 level), agriculture (66% below the 2015 level) and supply process emissions (56% below the 2005 level).

Table A4: Trottier Energy Futures Project (New Technology Scenario)

Canada's 1990–2050 GHG Emissions by Sector (Trottier) Mt CO_2e			
Greenhouse Gas Categories	2015	2050	% Change Relative to 2015
NEW TECHNOLOGY SCENARIO:			
TOTAL (EXCLUDING PROCESS EMISSIONS)	488	171	-65%
TOTAL (INCLUDING PROCESS EMISSIONS)	560	282	-50%
AGRICULTURE	16	5	-66%
COMMERCIAL	36	4	-88%
INDUSTRIAL PROCESSES AND PRODUCT USE	51	35	-32%
RESIDENTIAL	43	5	-89%
TRANSPORTATION	166	76	-54%
ELECTRICITY	64	0	-99%
SUPPLY - COMBUSTION	113	45	-60%
SUPPLY - PROCESS	71	112	56%

The table below illustrates modelling results from DDPP Study, where a 2050 target of 88% below the 2015 levels is achieved by reductions in emissions from all sectors of the economy except for agriculture, which was not included as part of this modelling work.

As illustrated by the table, the greatest reductions are projected to come from residential and commercial buildings emissions (99% below the 2015 level), followed by emissions from the personal transportation sector (97% below the 2015 level), freight transportation emissions (95% below the 2015 level), industrial minerals (93% below the 2015 level) and chemical products (75% below the 2005 level).

Table A5: Deep Decarbonization Pathways Project

Canada's 1990–2050 GHG Emissions by Sector (DDPP) Mt CO_2e			
Greenhouse Gas Categories	2015	2050	% Change Relative to 2015
TOTAL	**651**	**78**	**-88%**
Residential Buildings	37	0	-99%
Commercial Buildings	38	1	-99%
Transportation Personal	88	3	-97%
Transportation Freight	112	5	-95%
Chemical Products	13	3	-75%
Industrial Minerals (Cement & Lime)	16	1	-93%
Iron and Steel	12	4	-66%
Metal Smelting	11	3	-73%
Mineral Mining	5	3	-52%
Paper Manufacturing	6	1	-84%
Other Manufacturing	21	5	-77%
Waste	8	5	-44%
Electricity	86	6	-93%
Petroleum Refining	21	1	-96%
Petroleum Crude Extraction	134	19	-86%
Natural Gas Extraction	37	14	-62%
Coal Mining	2	2	-27%
Ethanol Production	2	0	-85%
Biodiesel Production	0	3	677%

Government of Canada Invests in Renewable Natural Gas

News Release

From Natural Resources Canada

March 15, 2017 Ottawa Natural Resources Canada

Investing in the production of renewable natural gas (RNG) from forest industry residue can diversify Canada's energy mix, reduce greenhouse gas emissions, improve industrial efficiency and create new economic opportunities for Canadian companies and good middle-class jobs that benefit rural communities.

Canada's Minister of Natural Resources, the Honourable Jim Carr, today announced an $800,000 investment in G4 Insights Inc. for the development of technology to convert forestry waste into RNG that can be distributed through existing natural gas pipelines in Canada.

G4 Insights is partnering with the Canadian Gas Association members Enbridge Gas Distribution, FortisBC, Gaz Metro, Union Gas, utility host ATCO, the Natural Gas Innovation Fund, Alberta Innovates, and FPInnovations, who are contributing a combined $1.35 million towards this project.

Renewable natural gas produced from sustainably managed forest residue can emit up to 85 per cent less greenhouse gas emissions than traditional fossil fuels. Forest residue, which includes all parts of the tree, can be converted into solid, liquid or gaseous biofuels such as RNG that can then be burned for energy or used as fuel substitutes for transportation or industrial processes.

G4 Insights will build a RNG demonstration plant and test it under operational conditions with a range of biomass types to generate relevant technical operating and economic data. The optimal site location has been chosen in Edmonton, Alberta to support all-season operation in outdoor conditions.

Today's announcement reaffirms the Government of Canada's commitment to preserving our natural environment and resources for future generations — to put in place real actions that will work toward Canada's climate goals.

Quotes

> "Our Government values innovation and we are proud to support this renewable natural gas project. By investing in clean technology industries we can help them be more innovative, more competitive and more successful."
>
> *Jim Carr*
> *Canada's Minister of Natural Resources*

> *"The support from Natural Resources Canada for renewable natural gas is essential to creating a pathway to greenhouse gas reductions that are affordable, reliable and sustainable. This project will advance G4 technology toward commercialization through field trials of enhanced subsystems for robust continuous operation and grid injection."*
>
> *Edson Ng*
> *Principal, G4 Insights Inc.*

"CGA and the natural gas delivery industry have made driving innovation a key focus for the last six years with initiatives and investments around the use of natural gas and natural gas delivery infrastructure. Improving the technology to convert biomass to RNG will support the industry's aspirational target of blending 10 percent RNG in the Canadian natural gas distribution system by 2030."

Timothy M. Egan
President and CEO, Canadian Gas Association

"The Natural Gas Innovation Fund is pleased to support the deployment of the G4 Insights technology in Alberta. Our funding for this project marks the first investment of our fund, and we are looking forward to partnering with NRCan and other energy stakeholders in Canada on projects like the one announced today to support innovation, ensure the availability of affordable energy for customers and reduce emissions."

John Adams
Managing Director, Natural Gas Innovation Fund

"Alberta Innovates and its subsidiary InnoTech Alberta are very pleased to support G4's technology demonstration to make renewable natural gas using Alberta biomass, and we recognize this as another important step in providing options to 'green' Alberta's energy grid."

Steve Price
Executive Director, Bioindustrial Innovation, Alberta Innovates

"ATCO is excited to host and sponsor G4 in Edmonton. RNG is a largely untapped renewable resource that Canadians can use to heat and power their homes and businesses using a carbon-neutral fuel. ATCO is supportive of RNG as a technology and is hopeful that their support will help accelerate the adoption of RNG in Alberta and commercialization of the G4 technology."

Dean Reeve
Sr. Vice President and General Manager, Gas Distribution
ATCO Pipelines & Liquids Global Business Unit

"This project demonstrates the importance of bringing together scientific expertise, industrial sector know-how and government support to solve the challenges of creating a clean tech economy. FPInnovations is proud to have provided facilities and technical support toward the development of G4 Insight's technology and looks forward to RNG becoming a viable renewable energy source in the future."

Pierre Lapointe
President and CEO of FPInnovations

Related Products

- Backgrounder — G4 Alberta Renewable Natural Gas Demonstration Project

Associated Links

- G4 Insights Market Opportunity
- NRCan Forest Bioenergy

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Date modified:
2017-03-15

Technical paper: federal carbon pricing backstop

Download the PDF version (0.45 MB)

The Pan-Canadian Framework on Clean Growth and Climate Change is Canada's plan to grow the economy while reducing greenhouse gas (GHG) emissions and building resilience to adapt to a changing climate. [1] A central component of the Pan-Canadian Framework is the commitment to pricing carbon pollution across the country by 2018.

Pricing carbon pollution is widely recognized as an efficient way to reduce GHG emissions and help achieve our objectives to protect the environment, stimulate investments in low-carbon innovation and create a sustainable clean-growth economy. Carbon pricing sends an important signal to markets and provides incentives to reduce energy use through conservation and efficiency measures, while also serving to drive fuel switching and technology advances. Applying carbon pricing to a broad set of emission sources across Canada, with increases in stringency over time, will help to reduce GHG emissions at the lowest cost to businesses and consumers, while supporting clean growth.

In October 2016, the federal government published a benchmark for ensuring that carbon pricing applies to a broad set of emission sources throughout Canada by 2018 with increasing stringency over time. [2] This benchmark provides provinces and territories with flexibility to implement their own carbon pollution pricing systems. In the benchmark, the federal government also committed to implement a federal carbon pricing backstop system that will apply in any province or territory that does not have a carbon pricing system in place by 2018 that aligns with the benchmark.

This technical discussion paper seeks to inform Canadians and stakeholders about the federal carbon pricing backstop and to obtain feedback on its design.

Interested parties are invited to provide written comments to Environment and Climate Change Canada (carbonpricing-tarificationcarbone@canada.ca) on or before June 30, 2017. There will be further opportunities to provide input as the details of the system are developed.

Federal carbon pricing benchmark

On October 3, 2016, the Government of Canada released “The pan-Canadian approach to pricing carbon pollution” – the benchmark [3] – outlining the criteria that carbon pricing systems implemented by provinces and territories need to meet. The goal of the benchmark is to ensure that carbon pollution pricing applies to a broad set of emission sources with increasing stringency over time in order to reduce GHG emissions at lowest cost to business and consumers and support innovation and clean growth.

The pan-Canadian approach to pricing carbon pollution provides jurisdictions the flexibility to implement either an explicit price-based system (a carbon tax such as the one in British Columbia, or a hybrid approach composed of a carbon levy and an output-based pricing system, such as in Alberta) or a cap-and-trade system (such as those in Quebec and Ontario).

The Pan-Canadian Framework includes a commitment for a review of the overall approach to pricing carbon by early 2022 to confirm the path forward. An interim report will also be completed in 2020, which will be reviewed and assessed by First Ministers. As an early deliverable, the review will assess approaches and best practices to address the competitiveness of emissions-intensive, trade-exposed sectors.

Federal carbon pricing backstop

The federal government plans to introduce new legislation and regulations to implement a carbon pollution pricing system – the backstop – to be applied in jurisdictions that do not have carbon pricing systems that align with the benchmark.

All elements of the backstop will apply in a jurisdiction that does not have a carbon pricing system in place. The backstop will also supplement (or “top-up”) systems that do not fully meet the benchmark. For example, the backstop could expand the sources covered by provincial carbon pollution pricing or it could increase the stringency of the provincial carbon price.

As committed in the October 3, 2016 document Pan-Canadian Approach to Pricing Carbon Pollution, the federal system will return direct revenues from the carbon price to the jurisdiction of origin. The federal government is open to feedback on the best mechanism to achieve this.

Backstop instrument

The federal carbon pollution pricing backstop will be composed of two key elements:

- A carbon levy applied to fossil fuels; and
- An output-based pricing system for industrial facilities that emit above a certain threshold, with an opt-in capability for smaller facilities with emissions below the threshold.

How GHG emissions are measured

Both the carbon levy and the output-based pricing system will price carbon on a CO2e basis. The United Nations Framework Convention on Climate Change (UNFCCC) reporting requirements apply to seven greenhouse gases (GHGs). [4] Each of these gases has a different impact on the climate. The use of CO2e is the internationally-recognized approach to establishing a standard carbon price (e.g., $10/tonne of CO2e) and translating that price to the appropriate price for each greenhouse gas. More detail on the calculation of CO2e is provided in Annex 1.

For both components of the backstop, emissions will be converted to a CO2e basis. For the levy, rates will be set out under the relevant legislation and will be based on the Canadian average CO2e emission factor for a fossil fuel (where factors differ by region for that fuel) and the technology that is most commonly used to combust that fuel. For the output-based pricing system, regulated entities will use the same factors to calculate their emissions following a methodology that will be specified in regulations.

The carbon levy component of the backstop

Scope of the carbon pricing levy

Coverage and rates of the carbon levy

Fossil fuels that will be subject to the levy include liquid fuels (e.g., gasoline, diesel fuel, and aviation fuel), gaseous fuels (e.g., natural gas) and solid fuels (e.g., coal and coke).

Carbon levy rates will initially be set for the period from 2018 to 2022. Rates for each fuel subject to the levy will be set such that they are equivalent to $10 per tonne of CO2e in 2018 and increase by $10 per tonne annually to $50 per tonne in 2022. The rates will be based on global warming potential factors and emission factors [5] used by Environment and Climate Change Canada to report Canada's emissions to the UNFCCC, and will be expressed in standard commercial units to facilitate the compliance with, and the administration of, the levy. Tables 1 to 3 below show the rates for liquid fuels, gaseous fuels, and solid fuels, respectively, over the initial 5-year period.

Table 1: Rates of levy on liquid fossil fuels from 2018 to 2022

Liquid fuel	Unit	2018 ($10/tonne)	2019 ($20/tonne)	2020 ($30/tonne)	2021 ($40/tonne)	2022 ($50/tonne)
Gasoline	¢/L	2.33	4.65	6.98	9.30	11.63
Diesel / Light Fuel Oil	¢/L	2.74	5.48	8.21	10.95	13.69
Heavy Fuel Oil	¢/L	3.19	6.37	9.56	12.75	15.93
Aviation Gasoline	¢/L	2.49	4.98	7.47	9.95	12.44
Aviation Turbo Fuel / Jet Fuel / Kerosene	¢/L	2.58	5.16	7.75	10.33	12.91
Methanol	¢/L	1.10	2.20	3.29	4.39	5.49
Naphtha	¢/L	2.25	4.51	6.76	9.02	11.27
Petroleum Coke	¢/L	3.84	7.67	11.51	15.35	19.19

Table 2: Rates of levy on gaseous fossil fuels from 2018 to 2022

Gaseous fuel	Unit	2018 ($10/tonne)	2019 ($20/tonne)	2020 ($30/tonne)	2021 ($40/tonne)	2022 ($50/tonne)
Marketable Natural Gas	¢/m3	1.96	3.91	5.87	7.83	9.79

Non-marketable Natural Gas	¢/m3	2.59	5.17	7.76	10.34	12.93
Propane	¢/L	1.55	3.10	4.64	6.19	7.74
Butane	¢/L	1.78	3.56	5.34	7.12	8.90
Ethane	¢/L	1.02	2.04	3.06	4.08	5.09
Gas Liquids	¢/L	1.67	3.33	4.99	6.66	8.32
Still Gas	¢/m3	2.70	5.40	8.10	10.80	13.50
Pentanes Plus	¢/L	1.78	3.56	5.34	7.12	8.90
Coke Oven Gas	¢/m3	0.70	1.40	2.10	2.80	3.50

Table 3: Rates of levy on solid fossil fuels from 2018 to 2022

Solid fuel	Unit	2018 ($10/tonne)	2019 ($20/tonne)	2020 ($30/tonne)	2021 ($40/tonne)	2022 ($50/tonne)
Low Heat Value Coal (i.e., Sub-bituminous Coal; Lignite)	$/tonne	17.72	35.45	53.17	70.90	88.62
High Heat Value Coal (i.e., Bituminous Coal; Anthracite)	$/tonne	22.52	45.03	67.55	90.07	112.58
Coke (coal)	$/tonne	31.80	63.59	95.39	127.19	158.99
Waste fuel / Tires	$/tonne	19.97	39.95	59.92	79.89	99.87

Application of the carbon levy

In general, the levy will apply to fuels that are used in a backstop jurisdiction, irrespective of whether the fuels were produced in, or brought into, the backstop jurisdiction.

In most cases, the levy will be applied early in the supply chain of each fuel used in a backstop jurisdiction, and will be payable by the producer or distributor. The final user of a fuel will not generally have any special rights or obligations in respect of the levy, as the user will purchase levy-paid fuel in most cases.

Fuel producers and certain distributors will be able to acquire and hold fuel without the levy being payable until the fuel is subsequently used by the producer or distributor, or, as discussed later, delivered to a final retailer or end-user.

For purposes of the levy, use will generally include fuel that is combusted, vented or flared. [6] Fuel used as a raw material, diluent or solvent in a manufacturing or petrochemical process in a manner that does not produce heat or energy will not be subject to the carbon levy. [7]

This general approach will be achieved by a series of application rules and registration requirements that are presented below.

Application framework of the carbon levy

Generally, the levy will apply to fuel that is produced, imported or brought into a backstop jurisdiction.

For the purposes of the levy, there will be four categories of persons within the fuel supply chain: Registered Fuel Distributors, Registered Fuel Importers,Registered Fuel Users, and other non-registered persons.

- Registered Fuel Distributors will generally be producers of fuel, large wholesale distributors of fuel, and natural gas retailers.
- Registered Fuel Importers will be entities that cannot become Registered Fuel Distributors and that import fuel from outside Canada at a location in a backstop jurisdiction, or that bring fuel into a backstop jurisdiction from another jurisdiction in Canada.
- Registered Fuel Users will be persons that cannot become Registered Fuel Distributors and that are required to report on fuel used in a backstop jurisdiction and, in certain circumstances, may be required to pay the levy [8] or be entitled to claim relief from the levy, where it has been previously paid. Registered Fuel Users will include inter-jurisdictional commercial transportation operators, and entities operating a facility covered by the output-based pricing system.
- Non-registered persons will generally be retailers (other than natural gas retailers) and end-users, including individuals and business consumers.

The levy will generally be payable when a Registered Fuel Distributor uses fuel in a backstop jurisdiction or delivers fuel to a person in the backstop jurisdiction that is not a Registered Fuel Distributor. Consequently, a Registered Fuel Distributor will be able to deal in fuel with other Registered Fuel Distributors without the levy being payable.

The levy will generally apply to fuel when it is imported or brought into the backstop jurisdiction by a Registered Fuel Importer. However, the levy will not be payable by a Registered Fuel Importer if the Registered Fuel Importer delivers the fuel to a person in the backstop jurisdiction that is a Registered Fuel Distributor, or delivers the fuel outside the backstop jurisdiction in a timely manner.

Registered Fuel Users that are operators of a facility covered by the output-based pricing system may be able to acquire fuel without the levy being payable, if the fuel is for use at that facility. Registered Fuel Users that are inter-jurisdictional commercial transportation operators will generally acquire fuel in a backstop jurisdiction on which the levy has been paid, except in limited circumstances as described below.

Generally, non-registered persons will acquire fuel on which the levy has been paid.

Fuels produced in a backstop jurisdiction

In the case of fuel that is produced by a Registered Fuel Distributor and used by that Registered Fuel Distributor in a backstop jurisdiction, the levy will become payable by the Registered Fuel Distributor at the time that it is used. In this case, the levy will be reported to the Canada Revenue Agency (CRA) by the Registered Fuel Distributor through a return and remitted to the Receiver General of Canada.

In the case of fuel that is produced by a Registered Fuel Distributor in a backstop jurisdiction and delivered to a purchaser in a backstop jurisdiction that is not a Registered Fuel Distributor, the levy will become payable by the Registered Fuel Distributor upon delivery to the purchaser. In this case, the levy will be reported to the CRA by the Registered Fuel Distributor through a return and remitted to the Receiver General of Canada. However, if the fuel is delivered to a purchaser that is another Registered Fuel Distributor, the levy will not become payable on that transaction. Instead, the levy will become payable by that other Registered Fuel Distributor at the time the fuel is used by that other Registered Fuel Distributor in a backstop jurisdiction, or at the time the fuel is subsequently delivered in a backstop jurisdiction to a person that is not a Registered Fuel Distributor.

- For example, if a Registered Fuel Distributor, such as an entity operating an oil refinery, delivers gasoline to another Registered Fuel Distributor, such as a wholesale distributor, then the levy will not be payable upon that delivery of the fuel. Rather, the levy will become payable when that other Registered Fuel Distributor (i.e., the wholesaler) delivers the fuel in a backstop jurisdiction to a purchaser that is not a Registered Fuel Distributor, such as a retail gas station.

The levy will not be payable on fuel that is produced by a Registered Fuel Distributor in a backstop jurisdiction and that is delivered outside a backstop jurisdiction.

- For example, gasoline that is produced in a refinery that is operated by a Registered Fuel Distributor in a backstop jurisdiction would ultimately not be subject to the levy if that gasoline is delivered outside a backstop jurisdiction.

Fuels brought into a backstop jurisdiction from another jurisdiction in Canada

Generally, anyone that brings fuel into a backstop jurisdiction from another jurisdiction in Canada will be required to register as either a Registered Fuel Distributor or, if they do not meet the minimal volume threshold or other requirements to become a Registered Fuel Distributor, as a Registered Fuel Importer.

A Registered Fuel Distributor will be able to bring fuel into a backstop jurisdiction on a levy-deferred basis. The levy will become payable by the Registered Fuel Distributor only at the time it uses the fuel in the backstop jurisdiction or delivers it in the backstop jurisdiction to a person that is not a Registered Fuel Distributor. In either case, the Registered Fuel Distributor will report to the CRA through a return and remit the levy to the Receiver General of Canada. If the fuel is instead delivered to another Registered Fuel Distributor, no levy will be applied to that transaction. The levy will become payable when the Registered Fuel Distributor that acquired the fuel uses it or delivers it to another person, unless that other person is another Registered Fuel Distributor.

Registered Fuel Importers will generally not be able to bring fuel into a backstop jurisdiction and hold it on a levy-deferred basis. The levy will apply to fuel that is brought into a backstop jurisdiction by a Registered Fuel Importer at the time the fuel is brought in. In this case, the Registered Fuel Importer will report to the CRA through a return and remit the levy to the Receiver General of Canada. However, if the Registered Fuel Importer brings in the fuel for delivery to a Registered Fuel Distributor, the levy will not become payable by the Registered Fuel Importer. The levy will become payable when the Registered Fuel Distributor that acquired the fuel uses it or delivers it to another person in the backstop jurisdiction, unless that person is also a Registered Fuel Distributor. If fuel is brought into a backstop jurisdiction by a Registered Fuel Importer for delivery to a Registered Fuel Distributor but is subsequently diverted for use in the backstop jurisdiction or delivery in the backstop jurisdiction to a person that is not a Registered Fuel Distributor, then the levy will become payable upon that use or delivery.

There will be special bringing-in rules for Registered Fuel Users that are inter-jurisdictional carriers, which are described below.

The levy will generally not be applicable on fuel that is brought into a backstop jurisdiction if the fuel is subsequently delivered outside the backstop jurisdiction in a timely manner. For example, the levy will not become payable if the fuel is merely in transit through a backstop jurisdiction, such as gasoline transiting in a tanker truck from one province to another through a backstop jurisdiction. If fuel is brought into a backstop jurisdiction by a Registered Fuel Importer for delivery outside the backstop jurisdiction but is subsequently diverted for use in the backstop jurisdiction or for delivery in the backstop jurisdiction to a person that is not a Registered Fuel Distributor, then the levy will become payable upon that use or delivery.

Fuels imported into Canada at a location in a backstop jurisdiction

Generally, anyone that imports fuel into Canada at a location in a backstop jurisdiction will be required to register as either a Registered Fuel Distributor or, if they do not meet the requirements of a Registered Fuel Distributor, as a Registered Fuel Importer.

Registered Fuel Distributors will be able to import fuel into a backstop jurisdiction on a levy-deferred basis. The levy will apply upon importation into Canada, but will become payable by the Registered Fuel Distributor that imported the fuel only at the time it uses the fuel in the backstop jurisdiction or at the time it delivers the fuel in the backstop jurisdiction to a person that is not a Registered Fuel Distributor. In this case, the Registered Fuel Distributor will report to the CRA through a return and remit the levy to the Receiver General of Canada. If the fuel is delivered outside a backstop jurisdiction, the levy will not become payable. If the fuel is instead delivered to another Registered Fuel Distributor, the levy will become payable when the other Registered Fuel Distributor uses it or delivers it to another person, unless that other person is also a Registered Fuel Distributor.

If a Registered Fuel Importer imports fuels for its own use in a backstop jurisdiction or for delivery in a backstop jurisdiction to a person that is not a Registered Fuel Distributor, then the levy will become payable at the time of importation. In this case, the Registered Fuel Importer will report to the CRA through a return and remit the levy to the Receiver General of Canada (i.e., the levy is not collected at the border upon importation).

If a Registered Fuel Importer imports the fuel for subsequent delivery outside the backstop jurisdiction in a timely manner, the levy will not be payable. If fuel is imported by a Registered Fuel Importer for delivery outside the backstop jurisdiction but is subsequently diverted for use in the backstop jurisdiction or for delivery in the backstop jurisdiction to a person that is not a Registered Fuel Distributor, then the levy will become payable upon that use or delivery.

If a Registered Fuel Importer imports fuel for delivery to a Registered Fuel Distributor, the levy will not become payable by the Registered Fuel Importer. The levy will become payable by the Registered Fuel Distributor when it uses the fuel or delivers it to another person in the backstop jurisdiction, unless that other person is also a Registered Fuel Distributor. If fuel is imported by a Registered Fuel Importer for delivery to a Registered Fuel Distributor but is subsequently diverted for use in the backstop jurisdiction or delivery in the backstop jurisdiction to a person that is not a Registered Fuel Distributor, then the levy will become payable upon that use or delivery.

If a non-registered person imports fuel at a location in a backstop jurisdiction, the person will report directly to the Canada Border Services Agency upon importation and remit the levy to the Receiver General of Canada at that time (i.e., the levy will be collected at the border upon importation).

Fuels imported into Canada at a location other than in a backstop jurisdiction for delivery in a backstop jurisdiction

Similar rules will apply to fuel that is imported into Canada at a location outside of a backstop jurisdiction if the fuel is for delivery in a backstop jurisdiction. For example, if a Registered Fuel Distributor imports gasoline into Canada at a location in a non-backstop jurisdiction, but the fuel is for delivery to a backstop jurisdiction, the levy will not be payable until the fuel is used in the backstop jurisdiction by the Registered Fuel Distributor, or is delivered to a person in the backstop jurisdiction that is not a Registered Fuel Distributor. In this case, the levy will be reported to the CRA by the Registered Fuel Distributor through a return and remitted to the Receiver General of Canada.

If a non-registered person imports gasoline into Canada at a location in a non-backstop jurisdiction, but the gasoline is for delivery to a backstop jurisdiction, the person will report directly to the Canada Border Services Agency upon importation and remit the levy to the Receiver General of Canada at that time.

Application of the carbon levy to natural gas

In addition to upstream entities that produce natural gas (e.g., gas batteries, gas production plants) in a backstop jurisdiction, natural gas retailers that deliver natural gas in a backstop jurisdiction will be required to become Registered Fuel Distributors.

The carbon levy will generally not be payable on natural gas until it is delivered to a final user (e.g., delivered to residential homes), at which time the levy will generally become payable by the natural gas retailer that delivers the fuel.

Where transactions occur in a backstop jurisdiction between natural gas distributors or producers, the levy will generally not be payable, as these would typically be transactions between Registered Fuel Distributors.

The levy will apply to natural gas that is used by a Registered Fuel Distributor in the natural gas supply chain and become payable by the Registered Fuel Distributor at the time the fuel is used. If a Registered Fuel Distributor delivers fuel to a person that is not a Registered Fuel Distributor, the levy will become payable by the Registered Fuel Distributor at the time the fuel is delivered.

Generally, the levy will not become payable on natural gas that is delivered outside a backstop jurisdiction.

Relief from the carbon levy

There will be certain situations in which relief from the levy will be provided, including in respect of:

- Fuel used at a facility whose emissions are accounted for under the output-based pricing system (once it comes into effect);
- Gasoline and diesel fuel used by registered farmers in certain farming activities;
- Fuel exported or removed from a backstop jurisdiction;
- Fuel used as international ships' stores (e.g., international aviation and marine fuels);
- In specified circumstances, fuel used as a raw material, diluent or solvent in a manufacturing or petrochemical process in a manner that does not produce heat or energy;
- Fuel purchased by visiting military forces and diplomatic representatives;
- Fuel in sealed, pre-packaged containers of one litre or less; and
- Biofuel portion of blended fuels (e.g., for gasoline or diesel blended with biofuels, the levy will apply to only the fossil fuel content).

The Government will develop a mechanism for providing relief (e.g., exemption certificate, rebate) for each of these circumstances.

Registration requirements

As noted above, certain persons will be required to register with the CRA as a Registered Fuel Distributor, a Registered Fuel Importer or a RegisteredFuel User.

The registrations will be administered on a fuel-by-fuel basis. Therefore, the registration status of a person may differ per type of fossil fuel subject to the levy.

Registered fuel distributors

Generally, all producers of fuels covered by the carbon levy operating within a backstop jurisdiction will be required to be registered as a fuel distributor with the CRA. This will include oil refiners and coal mine operators.

Large wholesale distributors (e.g., entities whose business essentially consists of purchasing fuels for purpose of resale other than at retail and above a specified annual volume threshold) of fossil fuels operating within a backstop jurisdiction will be able to become Registered Fuel Distributors. Generally, wholesale distributors of fuels are entities that purchase fuels for purpose of re-sale in a backstop jurisdiction to entities other than end-users. An entity will be considered a wholesale distributor and required to become a Registered Fuel Distributor, whether it acquires fuel from within the backstop jurisdiction or whether it imports or brings-in the fuel from another jurisdiction.

In addition to upstream entities that produce natural gas, natural gas retailers that deliver natural gas in a backstop jurisdiction will be required to become Registered Fuel Distributors.

In addition to the requirements noted above, there will be some restrictions on who will be able to become a Registered Fuel Distributor. For example, entities that will be considered as Registered Fuel Distributor of some fuels, including gasoline and diesel, may be restricted to those entities that deal in fuel above a specified quantity. In other words, for some fuel types, if an entity does not satisfy the specified minimum quantity requirement, it may not be eligible to become or to continue to be a Registered Fuel Distributor. Also, retailers and end-users will generally not be able to become Registered Fuel Distributors.

Registered fuel importers

Generally, any person that is not able to become a Registered Fuel Distributor and that imports fuel into Canada for delivery or use in a backstop jurisdiction or that brings fuel into a backstop jurisdiction from another jurisdiction in Canada will be required to become a Registered Fuel Importer.

However, a person that brings in or imports 200 litres or less will generally not be subject to this requirement.

Registered fuel users

Some persons will be required to become Registered Fuel Users, including the following:

- Commercial carriers (e.g., operators of transport trucks, operators of rail transportation, operators of marine transportation, air carriers) that operate in a backstop jurisdiction and at least one other jurisdiction;
- An operator of a facility whose emissions are covered under the output-based pricing system;
- Certain businesses that burn waste that is subject to the carbon levy (e.g., tires, asphalt shingles) in a backstop jurisdiction; and
- Certain businesses that use fuel as a raw material, diluent or solvent in a manufacturing or petrochemical process in a manner that does not produce heat or energy.

Inter-jurisdictional commercial transportation requirements

Commercial carriers (i.e., persons transporting passengers, freight, or both) that operate in a backstop jurisdiction, and in at least one other jurisdiction, will be required to be registered with the CRA as Registered Fuel Users.

Road and rail

For fuels consumed in commercial road and rail transportation, the levy will apply to only the fuel that is used within a backstop jurisdiction. In other words, the levy will apply both to fuel that is used during a journey that starts and ends in the same jurisdiction (intra-jurisdictional travel) and to fuel that is used during the portion of an inter-jurisdictional or international journey that occurs in a backstop jurisdiction.

- Inter-jurisdictional road and rail carriers will purchase fuel in a backstop jurisdiction with the levy embedded.
- These carriers will also be required to pay the carbon levy on fuel that was purchased outside the backstop jurisdiction, brought into the backstop jurisdiction and used in the backstop jurisdiction. Conversely, they will be entitled to relief for fuel that is purchased in the backstop jurisdiction but used outside the jurisdiction.
- To this end, inter-jurisdictional road and rail carriers will be required to file a return with the CRA and report fuel purchases made inside and outside each backstop jurisdiction, as well as the distance travelled inside and outside each backstop jurisdiction in order to self-assess the amount of carbon levy owing, or amount of relief to the carrier, as the case may be.
- All truck operators and commercial buses – domestic and international – that transit through a backstop jurisdiction will be required to register with CRA, report on levy paid and payable and file regular returns.

Marine

For fuels consumed in commercial marine transportation, the levy will only apply to fuel used in intra-jurisdictional travel. In other words, the levy will only apply to fuel used for commercial marine transportation that occurs between two points in the backstop jurisdiction.

- Marine carriers in a backstop jurisdiction will generally purchase fuel with the levy embedded. They will file regular returns and will be entitled to relief for levy paid on fuel that is used in inter-jurisdictional journeys (e.g., trips between a point in the backstop jurisdiction and a point outside the backstop jurisdiction).
- Further, these carriers will be required to self-assess on fuels purchased without the levy previously applied and used in intra-jurisdictional journeys. For example, if a ship ends a journey in a backstop jurisdiction with unused fuel and subsequently makes an intra-jurisdictional journey using that fuel, the marine carrier is required to self-assess on the fuel used in that journey.
- For fuel that is destined for international ships' stores, fuel could be delivered without the levy being payable if delivered by a Registered Fuel Distributor. If the fuel used for international ships' stores had levy embedded, relief will be provided for that fuel.

Aviation

To date, provinces that have introduced carbon pricing systems have either not covered GHG emissions from aviation fuels at all or not applied the carbon price to aviation fuels used in inter-jurisdictional flights within Canada. The Government recognizes that this exemption may have been made to address competitiveness concerns for local airports. The introduction of carbon pricing in all Canadian provinces and territories eliminates these inter-jurisdictional competitiveness concerns and presents an opportunity for this important source of GHG emissions to be covered across Canada. The federal government will engage with provincial and territorial governments and stakeholders to ensure that this emission source is properly covered, through a consistent national approach, and to determine which role the backstop should play in this regard, including in jurisdictions that have a carbon pricing system in place.

In the meantime, for fuels consumed in commercial aviation transportation, the backstop levy will only apply to fuel used in intra-jurisdictional travel. In other words, the levy will only apply to fuel used for commercial aviation transportation that occurs between two points in the backstop jurisdiction.

- Air carriers in a backstop jurisdiction will generally purchase fuel with the levy embedded. They will file regular returns and will be entitled to relief for levy paid on fuel that is used in inter-jurisdictional journeys (e.g., trips between a point in the backstop jurisdiction and a point outside the backstop jurisdiction).
- Further, these carriers will be required to self-assess on fuels purchased without the levy previously applied and used in intra-jurisdictional journeys. For example, if an aircraft lands in a backstop jurisdiction with unused fuel and subsequently makes an intra-jurisdictional journey using that fuel, the air carrier is required to self-assess on the fuel used in that journey.
- For fuel that is destined for international ships' stores, fuel could be delivered without the levy being payable if delivered by a Registered Fuel Distributor. If the fuel used for international ships' stores had levy embedded, relief will be provided for that fuel.

Transitional rules and rules related to rate changes

Persons that are required to register with the CRA will be able to do so on a provisional basis prior to the implementation date of the carbon levy.

Any person that possesses a quantity of fuel in a backstop jurisdiction that exceeds a minimum threshold on the implementation date of the levy will be required to self-assess and remit the levy on fuel in their possession. However, this requirement would not apply to a Registered Fuel Distributor that is registered as of the implementation date.

Registered Fuel Distributors will be required to pay the levy on fuel that is delivered in a backstop jurisdiction on or after the implementation date to a person, unless that person is a Registered Fuel Distributor.

Similarly, in respect of rate increases that occur after 2018, any person that possesses a minimum quantity of fuel in a backstop jurisdiction on the implementation date of a rate increase will be required to assess and remit the levy on fuels in their possession. This requirement would not apply to a Registered Fuel Distributor that is registered as of the implementation date of a rate increase.

Also, in respect of future rate increases, Registered Fuel Distributors will be required to pay the levy at the new rate on fuel that is delivered to a person in a backstop jurisdiction, unless that person is a Registered Fuel Distributor, on or after the implementation date of a rate increase.

Administrative aspects

Every Registered Fuel Distributor, Registered Fuel Importer and Registered Fuel User will be required to file monthly returns with the CRA. Registered persons will need to calculate in the return the total amount of levy payable for each backstop jurisdiction and remit that amount to the Receiver General of Canada.

The return for each registered person will have to be filed, and any amount payable will have to be paid, by the end of the first month following the fiscal month of the person. For example, assuming a registered person's fiscal month is also a calendar month, if a Registered Fuel Distributor delivers fuel to a purchaser that is not a Registered Fuel Distributor on June 15, the Registered Fuel Distributor will be required to file a return and remit the levy to the Receiver General of Canada by July 31. Similarly, if a Registered Fuel Distributor uses fuel it holds on June 15, the Registered Fuel Distributor will be required to file a return and remit the levy to the Receiver General of Canada by July 31.

Registered Fuel Distributors will generally need to provide information on quantities of fuels produced, brought into, and imported into each backstop jurisdiction, as well as quantities of fuels used and delivered within each backstop jurisdiction and delivered outside a backstop jurisdiction.

Registered Fuel Importers will generally need to provide information on quantities of fuels brought into and imported into, or for delivery or use into, each backstop jurisdiction, as well as quantities of fuels used and delivered within each backstop jurisdiction and delivered outside the backstop jurisdiction.

The information that Registered Fuel Users will need to provide will vary depending on the class of user (e.g., air carriers versus persons burning waste). Generally, they will be required to provide information to the CRA and determine the amount of levy payable or refundable for each backstop jurisdiction, as explained above.

Registered Fuel Distributors, Registered Fuel Importers and Registered Fuel Users will be required to keep books and records sufficient to enable a determination to be made of whether they have complied with payment requirements and other carbon levy rules in general. The basic period for retaining records will be 6 years after the end of the year in which they relate.

Registered Fuel Distributors, Registered Fuel Importers and Registered Fuel Users may be required to provide and maintain security in an amount and in a form satisfactory to the Minister of National Revenue.

To promote compliance with the carbon levy, its framework will include modern elements of an enforcement regime (e.g., interest, penalties, offences) aligned with those found in other statutes administered by the Canada Revenue Agency.

The output-based pricing system element of the backstop

The aim of an output-based pricing system is to minimize competitiveness and carbon leakage risks for activities for which those risks are high, while retaining the incentives to reduce emissions created by the carbon pricing signal.

The output-based pricing system will apply the carbon pollution price to the portion of a covered source's emissions that exceed those allowed by the emissions-intensity standard for the type of activity. Facilities in the system that emit less than the limit that corresponds to the relevant emissions-intensity standard will receive “surplus credits” from the Government of Canada that they can bank for future use or trade to another participant in the output-based pricing system. Facilities whose emissions exceed their limit will need to submit compliance units (surplus credits banked from a previous year or acquired from another facility or offset credits: see “compliance units” below) or pay the carbon price to make up the difference.

Under this system, only a portion of a covered source's emissions will be subject to a direct price obligation. However, the price incentive will apply to all of the emissions, as facilities can earn surplus credits that they can sell if they emit less than their regulatory limit.

Scope of the output-based pricing system

Facilities and sectors included in the output-based pricing system

The output-based pricing system will apply to all industrial facilities that emit 50 kilotonnes (kt) or more of CO2e per year. It will not apply to facilities in specifically listed sectors such as buildings (including municipal, hospitals, universities, schools, commercial), waste and wastewater, regardless of the quantity of their emissions.

Facilities in industrial sectors that emit less than 50 kt of CO2e per year will have the ability to “opt in” to the output-based pricing system, allowing similar treatment of competitors with varying emissions output. This will allow smaller facilities to choose between paying the carbon levy and fulfilling the administrative requirements to participate in the output-based pricing system. This will also avoid creating the perverse incentive to emit more in order to be eligible for treatment under the output-based pricing system.

Emissions covered in the output-based pricing system

The output-based pricing system will apply to emissions from fuel combustion as well as emissions of synthetically-produced greenhouse gases from industrial processes and product use.

Like the carbon levy, pricing will be applied on a CO2e basis. Because industrial emissions can include more greenhouse gases than those emitted from fuel combustion, the output-based pricing system will apply to emissions of all seven of the UNFCCC greenhouse gases – CO2, CH4, N2O, hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF6) and nitrogen trifluoride (NF3) – that can be quantified using robust and replicable quantification methodologies. This will cover emissions from all fossil fuels used by facilities subject to the output-based pricing system, including some venting, flaring and fugitive emissions. [9]

The output-based pricing system will also apply to other GHG emissions such as process emissions and emissions from solvent use.

At the outset, CO2 emissions resulting from the combustion of biomass will not be covered because these emissions are not counted in Canada's National Inventory total. [10]

Output-based standards

An output-based standard is an emissions-intensity standard for a type of activity or product (e.g., tonnes of CO2e per megawatt hour of electricity). The output-based standard will be set at a level that represents best-in-class performance (top quartile or better) in order to drive reduced emissions intensity.

Application of the output-based pricing system

Compliance reporting for the output-based pricing system will apply annually, based on a calendar year.

Determining a facility's emissions limit

The annual GHG emissions limit for a facility will be the sum of the emission limits for all activities that the facility undertakes.

For a single product facility, the annual emissions limit will be based on the applicable output-based standard and the facility's total output:

Annual Facility Emissions Limit (tonnes CO2e) = Output-based standard (tonnes CO2e/unit) x Units Produced (units)

For a multi-product facility, the same approach will apply. For example, for a facility that produces two products, the annual GHG emissions limit for the facility will be:

Annual Facility Emissions Limit (tonnes CO2e) = [Product 1 Output-based standard (tonnes CO2e/unit 1) x Product 1 Units Produced (units 1)] + [Product 2 Output-based standard (tonnes CO2e/unit 2) x Product 2 Units Produced (units 2)]

If a facility emits less than its emissions limit

A facility that emits less than its annual limit will receive surplus credits from the Government of Canada for the difference between its limit and its reported emissions, where each surplus credit represents one tonne of CO2e.

If a facility exceeds its emissions allocation

A facility that exceeds its annual emissions limit will have several options to meet its compliance obligation, including:

- Payment to the Government at the carbon price that will be set in the backstop legislation and based on the federal benchmark (i.e., $10/tonne CO2e in 2018, rising to $50/tonne CO2e in 2022);
- Use of eligible carbon offset credits (see below); and
- Use of surplus credits issued by the Government to facilities that emitted less than their regulated limits.

Facilities will have the flexibility to meet their full compliance obligation with any of these options or any combination thereof in a given year.

This flexibility will allow each regulated facility to achieve compliance at the lowest cost for its operation. Enabling the use of carbon offsets will spread the carbon price signal to all sectors of the economy that are not subject to direct carbon pricing, and allowing the use of surplus credits will encourage regulated facilities to reduce their emissions intensity as much as possible, regardless of the emissions-intensity standards that apply to them.

Compliance units

Output-based pricing system surplus credits: Credits will be issued by the Government of Canada to a regulated facility after confirming that the facility's reported emissions for the previous year were less than its limit. Subject to certain rules, surplus credits may be banked for future use or traded to another participant in the output-based pricing system.

Carbon offset credits: Credits can be generated from voluntary activities, namely those that are not subject to GHG emission reduction regulations, that are not required by law, that have not been supported by government financing, and that go beyond “business as usual” practices. The federal government will develop rules to determine which offset credits can be accepted for compliance under the output-based pricing system, which could include foreign compliance units (referred to as “internationally transferred mitigation outcomes”). This will be informed by the pan-Canadian offsets framework being developed by the Canadian Council of Ministers of the Environment.

A limit will be set on the start date for projects from which offset credits will be authorized for compliance purpose. The Government may restrict the number of years that offset credits can be banked, and may require regulated facilities to replace offset credits that are revoked or invalidated after they have been submitted for compliance. [11]

Reporting and verification requirements

After the end of each compliance year, each facility in the output-based pricing system will be required to quantify its emissions using prescribed methodologies for each of its activities. This will allow the facility to compare its reported emissions to its annual GHG emissions limit.

Each facility will also be required to submit an annual compliance report on its annual emissions limit and its emissions. These reports will need to be third-party verified to a reasonable level of assurance by verification bodies that are accredited to ISO 14065 by a member of the International Accreditation Forum.

Compliance reports will be submitted by March 31 following the calendar year of compliance (e.g., reports will be due March 31, 2020 for emissions associated with the facility from January 1 to December 31, 2019).

Administration of the output-based pricing system

Environment and Climate Change Canada will administer the output-based pricing system. Industrial facilities that are subject to the output-based pricing system will have to register with and submit compliance reports to Environment and Climate Change Canada. Verification bodies engaged by output-based pricing system participants will submit their reports directly to Environment and Climate Change Canada.

Compliance, penalties and enforcement

The output-based pricing system part of the backstop legislation will provide authorities for a modern enforcement regime aligned with the enforcement schemes found in other legislation administered by Environment and Climate Change Canada. This will include access to a variety of enforcement measures to encourage compliance or deter future non-compliance including written warnings, administrative penalties, compliance orders and prosecution.

Backstop implementation timing

The backstop will apply in a province or territory that does not have a pricing system that aligns with the benchmark.

The carbon levy will come into effect in 2018.

The output-based pricing system will not come into effect before January 1, 2019.

For the interim period between when the levy and the output-based pricing system come into force, the carbon levy will apply fully to fuels used by all industrial facilities.

How to provide input

Canadian stakeholders, businesses and the public are invited to submit feedback as part of the Government of Canada's consultation on the federal benchmark and backstop for carbon pricing.

Closing date: June 30**, 2017**

Written comments should be sent to: Carbonpricing-tarificationcarbone@canada.ca

In order to add to the transparency of the consultation process, the Government of Canada may make public some or all of the responses received or may provide summaries in its public documents. Therefore, parties making submissions are asked to clearly indicate the name of the individual or the organization that should be identified as having made the submission.

In order to respect privacy and confidentiality, when providing your submission please advise whether you:

- consent to the disclosure of your submission in whole or in part;
- request that your identity and any personal identifiers be removed prior to publication; and/or
- wish any portions of your submission to be kept confidential (if so, clearly identify the confidential portions).

Information received throughout this submission process is subject to the Access to Information Act and the Privacy Act. Should you express an intention that your submission, or any portions thereof, be considered confidential, the Government of Canada will make all reasonable efforts to protect this information.

Annex 1: CO2e

The concept of “global warming potential” allows for a comparison of the ability of each GHG to trap heat in the atmosphere relative to CO2. CO2e is a measure of the quantity of CO2 that would be required to produce a similar warming effect as another GHG over the same time horizon. It is calculated by multiplying the quantity of a GHG by its global warming potential. The United Nations Intergovernmental Panel on Climate Change regularly updates the measurement of global warming potential.

The combustion of fossil fuels results in three different GHG emissions being produced – carbon dioxide (CO2), methane (CH4), and nitrous oxide (N2O) – each of which has a unique atmospheric lifetime and heat-trapping potential. The total GHG emissions from combusting a fuel is the CO2e of all three GHG emissions added together.

The quantity of CO2 emitted is related to the carbon content in a given type of a fossil fuel and the amount of fuel combusted. The carbon content of some fuels can vary. For example, natural gas from different regions has different carbon content. As a result, natural gas from Western Canada will have a different level of GHG emissions per litre of fuel than natural gas from Eastern Canada.

The quantity of methane and nitrous oxide emitted is related to the amount of fuel combusted and the type of technology used to combust that fuel. For example, fuel that is used to heat a home will have different levels of methane and nitrous oxide emissions per litre than a fuel used in a heavy-duty vehicle.

For both components of the backstop, emissions will be converted to a CO2e basis using current global warming factors. For the levy, rates will be set out under the relevant legislation and will be based on the Canadian average emission factor for a fossil fuel (where factors differ by region for that fuel) and the technology that is most commonly used to combust a fossil fuel. For the output-based pricing system, regulated entities will use the same factors to calculate their emissions following a methodology that will be specified in regulations.

The output-based pricing system will apply to emissions from fuel combustion as well as emissions of synthetically-produced greenhouse gases from industrial processes and product use, and will cover all seven of the greenhouse gases included in the United Nations Framework Convention on Climate Change reporting requirements: CO2, methane (CH4), nitrous oxide (N2O), perfluorocarbons (PFCs), hydrofluorocarbons (HFCs), sulphur hexafluoride (SF6) and nitrogen trifluoride (NF3).

The global warming factors for both components may be updated from time to time when changes are made to requirements for inventory reporting under the United Nations Framework Convention on Climate Change.

1 Pan-Canadian Framework on Clean Growth and Climate Change

2 Pan-Canadian Approach to Pricing Carbon Pollution

3 Backgrounder: Pan-Canadian Approach to Pricing Carbon Pollution

4 The seven UNFCCC GHGs are CO_2, methane (CH_4), nitrous oxide (N_2O), perfluorocarbons (PFCs), hydrofluorocarbons (HFCs), sulphur hexafluoride (SF_6) and nitrogen trifluoride (NF_3).

5 For the purposes of determining the levy rates, the CO_2e of a fossil fuel includes the following GHG emissions: CO_2, CH_4 and N_2O.

6 Venting is the direct release of gas, which is predominately methane, into the atmosphere without combustion. Flaring is the controlled combustion of a gas from industrial activities, in maintenance or emergency circumstances that require a release of pressure by removing the gas.

7 Petrochemicals are organic chemicals made from crude oil and natural gas, such as methanol, ethylene, benzene, or butadiene, for use in industrial processes (i.e., feedstock to make other chemicals).

8 For example, inter-jurisdictional carriers may, depending on where they purchase fuel and where they actually travel, be required to remit the levy on fuel purchased outside a backstop jurisdiction or be entitled to a rebate of the levy on fuel purchased inside a backstop jurisdiction.

9 Forthcoming methane reduction regulations for the oil and gas sector will complement carbon pollution pricing.

10 For more information, please see Technical Guidance on Reporting Greenhouse Gas Emissions

11 To maintain program integrity, authorities will be able to revoke credits issued for projects that do not meet program requirements. In such cases, the Government would require the facility to replace compliance obligation made with the revoked credits.

Date modified:
2017-07-18

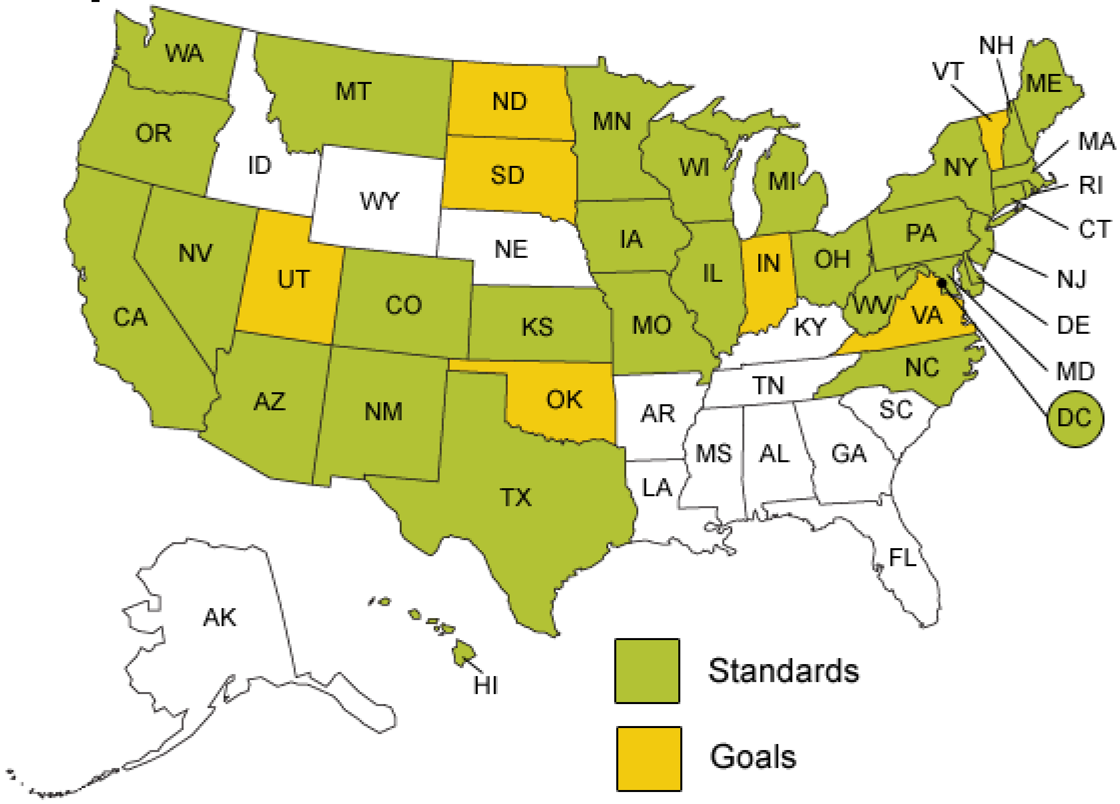
U.S. Energy Information Administration

Today in Energy

February 3, 2012

Most states have Renewable Portfolio Standards

States with Renewable Portfolio Standards (mandatory) or Goals (voluntary), January 2012



Source: N.C. Solar Center at N.C. State University, Database of State Incentives for Renewables and Efficiency (accessed July 2012). (Correction: Amended source corrects the source listed in original publication of February 3, 2012.)
Note: The map includes West Virginia as a State with a Renewable Portfolio Standard, although the Interstate Renewable Energy Council categorizes it as a goal State rather than an RPS State.

Renewable portfolio standards (RPS), also referred to as renewable electricity standards (RES), are policies designed to increase generation of electricity from renewable resources. These policies require or encourage electricity producers within a given jurisdiction to supply a certain minimum share of their electricity from designated renewable resources. Generally, these resources include wind, solar, geothermal, biomass, and some types of hydroelectricity, but may include other resources such as landfill gas, municipal solid waste, and tidal energy.

Although several RPS proposals have advanced part way through the U.S. Congress in recent years, there is currently no RPS program in place at the National level. However, 30 States and the District of Columbia had enforceable RPS or other mandated renewable capacity policies, as of January 2012. In addition, seven States had voluntary goals for renewable generation. These programs vary widely in terms of program structure, enforcement mechanisms, size, and application.

In California, for example, an RPS of 20% of retail sales was originally enacted in 2002. As of April 2011, the RPS requires California's electric utilities to derive 33% of their retail sales from eligible renewable energy resources in 2020. The law also established interim targets of 20% by the end of 2013, and 25% by the end of 2016.

A large range of policies are considered to be under the RPS umbrella. In general, an RPS sets a minimum requirement for the share of electricity to be supplied from designated renewable energy resources by a certain date/year. Often, the selected eligible resources are tailored to best fit the State's particular resource base or local preferences. Some States also set targets for specific types of renewable energy sources or technologies to encourage their development and use. Many State RPS programs have "escape clauses" if the extra cost of renewable generation exceeds a specified threshold. (Detailed descriptions of State RPS programs are available from the Database of State Incentives for Renewables & Efficiency.)

Another common feature of many State policies is a renewable electricity credit (REC) trading system structured to minimize the costs of compliance. Under these policies, a producer who generates more renewable electricity than required to meet its own RPS obligation may either trade or sell RECs to other electricity suppliers who may not have enough RPS-eligible renewable electricity to meet their own RPS requirement. In some cases, a State will make a certain number of credits available for sale. Such a system accommodates timing differences associated with planning and construction of new generation. Only one entity—the generator or the REC holder—may take credit for the renewable attribute of generation from RPS-eligible sources.

An RPS is one policy mechanism to encourage development of renewable energy. States with RPS policies have seen an increase in the amount of electricity generated from eligible renewable resources. At the same time, other States without RPS policies have also seen significant increases in renewable generation over the past few years resulting from a combination of Federal incentives, State programs, and market conditions. Increases in renewable generation have been driven by the availability of Federal tax incentives, as well as by State RPS policies.

State Renewable Portfolio Standards and Goals

8/1/2017 Jocelyn Durkay

States have been active in adopting or increasing renewable portfolio standards, and 29 states now have them. These standards require utilities to sell a specified percentage or amount of renewable electricity. The requirement can apply only to investor-owned utilities (IOUs) but many states also include municipalities and electric cooperatives (Munis and Co-ops), though their requirements are equivalent or lower.

Renewable energy policies help drive the nation's $44 billion market for wind, solar and other renewable energy sources. These policies can be integral to many state efforts to diversify their energy mix, promote economic development and reduce emissions. Twenty-nine states, Washington, D.C., and three territories have adopted an RPS, while eight states and one territory have set renewable energy goals.

Iowa was the first state to establish an RPS and Hawaii has the most aggressive RPS requirement. In many states, standards are measured by percentages of kilowatt hours of retail electric sales. Iowa and Texas, however, require specific amounts of renewable energy capacity rather than percentages and Kansas requires a percentage of peak demand. According to Lawrence Berkeley National Laboratory, 20 states and Washington, D.C., have percentage-based cost caps in their RPS bills to limit increases in ratepayers' bills. One state caps RPS gross procurement costs.

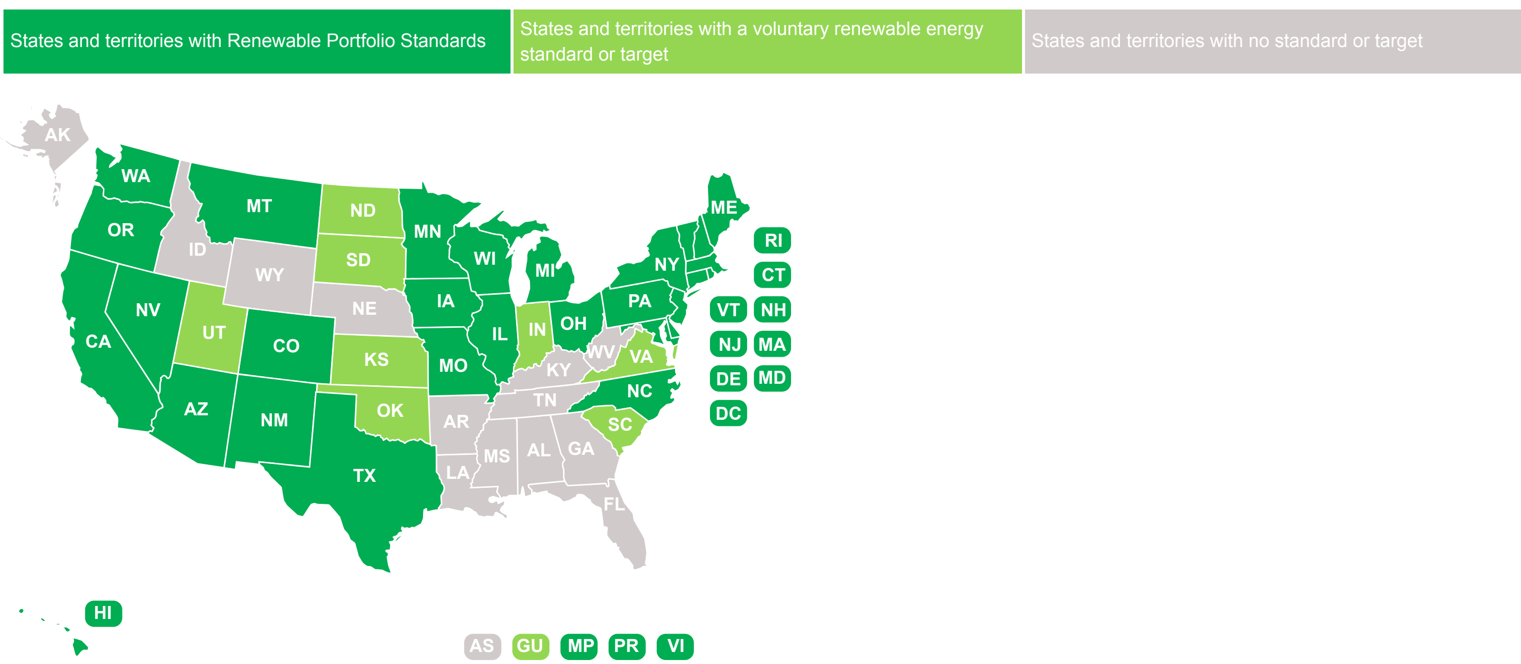


Table: Renewable Portfolio Standards or Voluntary Targets

Note: States and territories listed in italics have voluntary renewable energy goals.

Alaska

- **Enabling Statute, Code or Order:** *In the 2009-2010 legislative session, the Alaska legislature enacted* House Bill 306 *with the goal that "the state receive 50 percent of its electrical generation from renewable energy sources by 2025." This language does not appear in codified statutes.*

Arizona

- **Title:** Renewable Energy Standard.
- **Established:** 2006.
- **Requirement:** 15 percent by 2025.
- **Applicable Sectors:** Investor-owned utility, retail supplier.
- **Cost Cap:** None.
- **Details:** Distributed Generation: 30 percent of annual requirement in 2012 and thereafter. The state has several credit multipliers for different technologies.
- **Enabling Statute, Code or Order:** Ariz. Admin. Code §14-2-1801 et seq.

California

- **Title:** Renewables Portfolio Standard.
- **Established:** 2002.
- **Requirement:** 33 percent by 2020; 40 percent by 2024; 45 percent by 2027; 50 percent by 2030.
- **Applicable Sectors:** Investor-owned utility, municipal utilities.
- **Cost Cap:** Determined by the California Public Utilities Commission.
- **Details:** A 2013 amendment allows the California Public Utilities Commission to adopt additional requirements.
- **Enabling Statute, Code or Order:** Cal. Public Utilities Code §399.11 et seq.; Cal. Public Resources Code §25740 et seq.; CA A 327 (2013); CA S 350 (2015).

Colorado

- **Title:** Renewable Energy Standard.
- **Established:** 2004.
- **Requirement:** 30 percent by 2020 (IOUs); 10 percent or 20 percent for municipalities and electric cooperatives depending on size.
- **Applicable Sectors:** Investor owned utility, municipal utilities, cooperative utilities.
- **Cost Cap:** 2.0 percent.
- **Details:** Distributed Generation: 3 percent of IOU retail sales by 2020, 1 percent of cooperative retail sales by 2020 (for those providing service to 10,000 or more meters) or 0.75 percent of cooperative retail sales by 2020 (for those providing service to less than 10,000 meters). The state has several credit multipliers for different technologies.
- **Enabling Statute, Code or Order:** Colo. Rev. Stat. §40-2-124; CO S 252 (2013).

Connecticut

- **Title:** Renewables Portfolio Standard.
- **Established:** 1998.
- **Requirement:** 27 percent by 2020.
- **Applicable Sectors:** Investor-owned utility, local government, retail supplier.
- **Cost Cap:** 7.1 percent.
- **Details:** Class I renewable energy sources (including distributed generation): 20 percent by 2020. Class I or II (biomass, waste-to-energy and certain hydropower projects: 3 percent by 2010. Class III (combined heat and power, waste heat recovery and conservation): 4 percent by 2010.
- **Enabling Statute, Code or Order:** Conn. Gen. Stat. §16-245a et seq.; Conn. Gen. Stat. §16-1.

Delaware

- **Title:** Renewables Energy Portfolio Standard.
- **Established:** 2005.
- **Requirement:** 25 percent by 2025-2026.
- **Applicable Sectors:** Investor-owned utility, local government, retail supplier.
- **Cost Cap:** 3 percent; 1 percent (PV).
- **Details:** Photovoltaics: 3.5 percent requirement by 2025-2026. The state has multiple credit multipliers that apply to different technologies.

- **Enabling Statute, Code or Order:** Del. Code Ann. 26 §351 et seq..

Hawaii

- **Title:** Renewable Portfolio Standard.
- **Established:** 2001.
- **Requirement:** 30 percent by 2020; 40 percent by 2030; 70 percent by 2040; 100 percent by 2045.
- **Applicable Sectors:** Investor-owned utility.
- **Cost Cap:** None.
- **Enabling Statute, Code or Order:** Hawaii Rev. Stat. §269-91 et seq.; House Bill 623 (2015).

Illinois

- **Title:** Renewable Portfolio Standard.
- **Established:** 2001 (voluntary target); 2007 (standard).
- **Requirement:** 25 percent by 2025-2026.
- **Applicable Sectors:** Investor-owned utility, retail supplier.
- **Cost Cap:** 1.3 percent.
- **Details:** Distributed Generation: 1 percent of annual requirement beginning in 2015 for IOUs. Wind: 75 percent of annual requirement for IOUs, 60 percent of annual requirement for alternative retail electric suppliers. Photovoltaics: 6 percent of annual requirement beginning in 2015-2016.
- **Enabling Statute, Code or Order:** Ill. Rev. Stat. ch. 20 §688 (2001); Ill. Rev. Stat. ch. 20 §3855/1-75 (2007); Senate Bill 2814 (2016).

Indiana

- **Title:** Clean Energy Portfolio Goal.
- **Established:** 2011.
- **Requirement:** 10 percent by 2025.
- **Applicable Sectors:** Investor-owned utility, municipal utilities, cooperative utilities, retail supplier.
- **Details:** 30 percent of the goal may be met with clean coal technology, nuclear energy, combined heat and power systems, natural gas that displaces electricity from coal and other alternative fuels.
- **Enabling Statute, Code or Order:** Ind. Code §8-1-37.

Iowa

- **Title:** Alternative Energy Law.
- **Established:** 1983.
- **Requirement:** 105 MW of generating capacity for IOUs.
- **Applicable Sectors:** Investor-owned utility.
- **Cost Cap:** None.
- **Enabling Statute, Code or Order:** Iowa Code §476.41 et seq.

Kansas

- ***Title:*** *Renewable Energy Goal.*
- ***Established:*** *2009 (standard); 2015 (goal).*
- ***Requirement:*** *15 percent by 2015-2019; 20 percent by 2020.*
- ***Applicable Sectors:*** *Investor-owned utility.*
- ***Cost Cap:*** *Caps gross RPS procurement costs.*
- ***Details:*** *20 percent requirement for peak demand capacity.*
- ***Enabling Statute, Code or Order:*** Kan Stat. Ann. §66-1256 et seq.*;* Goal: Senate Bill 91.

Maine

- **Title:** Renewables Portfolio Standard.
- **Established:** 1999.

- **Requirement:** 40 percent by 2017.
- **Applicable Sectors:** Investor-owned utility, retail supplier.
- **Cost Cap:** 6.1 percent.
- **Details:** Includes a 10 percent requirement by 2017 for Class I (new) sources. The state also has separate goals for wind energy: 2,000 MW of installed capacity by 2015; 3,000 MW of installed capacity by 2020, including offshore and coastal; and 8,000 MW of installed capacity by 2030, including 5,000 MW from offshore and coastal. The state has a credit multiplier for community-based renewable energy.
- **Enabling Statute, Code or Order:** Me. Rev. Stat. Ann. 35-A §3210 et seq.; Me. Rev. Stat. Ann. 35-A §3401 et seq. (wind energy).

Maryland

- **Title:** Renewable Energy Portfolio Standard.
- **Established:** 2004.
- **Requirement:** 25 percent by 2020.
- **Applicable Sectors:** Investor-owned utility, local government, retail supplier.
- **Cost Cap:** 6.5 percent.
- **Details:** Solar: 2.5 percent by 2020. Offshore wind: 2.5 percent maximum by 2017.
- **Enabling Statute, Code or Order:** Md. Public Utilities Code Ann. §7-701 et seq.; Senate Bill 921; House Bill 1106 (2016 enrolled, 2017 veto override).

Massachusetts

- **Title:** Renewable Portfolio Standard.
- **Established:** 1997.
- **Requirement:** Class I: 15 percent by 2020 and an additional 1 percent each year after. Class II: 5.5 percent by 2015.
- **Applicable Sectors:** Investor-owned utility, retail supplier.
- **Cost Cap:** 8 percent.
- **Details:** Photovoltaic: 400 MW required. Class I resources are new sources. Class II (resources in operation by 1997) requirement includes 3.6 percent renewable energy and 3.5 percent waste-to-energy.
- **Enabling Statute, Code or Order:** Mass. Gen. Laws Ann. ch. 25A §11F.

Michigan

- **Title:** Renewable Energy Standard.
- **Established:** 2008; 2016.
- **Requirement:** 15 percent by 2021 (standard), 35 percent by 2025 (goal, including energy efficiency and demand reduction).
- **Applicable Sectors:** Investor-owned utility, municipal utilities, cooperative utilities, retail supplier.
- **Cost Cap:** 3.1 percent.
- **Details:** The state has several credit multipliers for different technologies.
- **Enabling Statute, Code or Order:** Mich. Comp. Laws §460.1001 et seq.; Senate Bill 438 (2016).

Minnesota

- **Title:** Renewables Energy Standard.
- **Established:** 2007.
- **Requirement:** 26.5 percent by 2025 (IOUs), 25 percent by 2025 (other utilities).
- **Applicable Sectors:** Investor-owned utility, municipal utilities, cooperative utilities.
- **Cost Cap:** None.
- **Details:** Xcel Energy has a separate requirement of 31.5 percent by 2020; 25 percent must be from wind or solar. Solar: 1.5 percent by 2020 (other IOUs); Statewide goal of 10 percent by 2030.
- **Enabling Statute, Code or Order:** Minn. Stat. §216B.1691.

Missouri

- **Title:** Renewable Electricity Standard.
- **Established:** 2007.
- **Requirement:** 15 percent by 2021 (IOUs).
- **Applicable Sectors:** Investor-owned utility.
- **Cost Cap:** 1 percent.
- **Details:** Solar-Electric: 2 percent carve-out.
- **Enabling Statute, Code or Order:** Mo. Rev. Stat. §393.1020 et seq.

Montana

- **Title:** Renewable Resource Standard.
- **Established:** 2005.
- **Requirement:** 15 percent by 2015.
- **Applicable Sectors:** Investor-owned utility, retail supplier.
- **Cost Cap:** 0.1 percent.
- **Enabling Statute, Code or Order:** Mont. Code Ann. §69-3-2001 et seq.

Nevada

- **Title:** Energy Portfolio Standard.
- **Established:** 1997.
- **Requirement:** 25 percent by 2025.
- **Applicable Sectors:** Investor-owned utility, retail supplier.
- **Cost Cap:** None.
- **Details:** Solar: 5 percent of annual requirement through 2015, 6 percent for 2016-2025. The state has a credit multiplier for photovoltaics and on peak energy savings.
- **Enabling Statute, Code or Order:** Nev. Rev. Stat. §704.7801 et seq.

New Hampshire

- **Title:** Electric Renewable Portfolio Standard.
- **Established:** 2007.
- **Requirement:** 24.8 percent by 2025.
- **Applicable Sectors:** Investor-owned utility, cooperative utilities, retail supplier.
- **Cost Cap:** 7.3 percent.
- **Details:** Solar: 0.3 percent by 2014. Requires at least 15 percent of requirement to be met with new renewables.
- **Enabling Statute, Code or Order:** N.H. Rev. Stat. Ann. §362-F.

New Jersey

- **Title:** Renewables Portfolio Standard.
- **Established:** 1991.
- **Requirement:** 24.5 percent by 2020.
- **Applicable Sectors:** Investor-owned utility, retail supplier.
- **Cost Cap:** 12.6 percent.
- **Details:** 20.38 percent Class I or Class II (resource recovery or hydropower) renewables by 2020-2021. 4.1 percent solar-electric by 2027-2028. Offshore wind: 1,100 MW.
- **Enabling Statute, Code or Order:** N.J. Rev. Stat. §48:3-49 et seq.

New Mexico

- **Title:** Renewables Portfolio Standard.
- **Established:** 2002.
- **Requirement:** 20 percent by 2020 (IOUs); 10 percent by 2020 (co-ops)
- **Applicable Sectors:** Investor-owned utility, cooperative utilities.
- **Cost Cap:** 3.5 percent.

- **Details:** Solar: 20 percent by 2020 (IOUs). Wind: 30 percent by 2020 (IOUs). Other renewables including geothermal, biomass and certain hydro facilities: 5 percent by 2020 (IOUs). Distributed Generation: 3 percent by 2020 (IOUs). The state has a credit multiplier for solar energy that was operational before 2012.
- **Enabling Statute, Code or Order:** N.M. Stat. Ann. §62-15; N.M. Stat. Ann. §62-16.

New York

- **Title:** Renewable Portfolio Standard; Reforming the Energy Vision (REV).
- **Established:** 2004.
- **Requirement:** 29 percent by 2015; 50 percent by 2030 (REV- *currently in process*)
- **Applicable Sectors:** Investor-owned utility, municipal utilities, cooperative utilities, retail supplier.
- **Cost Cap:** 1.7 percent.
- **Details:** Distributed Generation: 8.4 percent of annual incremental requirement.
- **Enabling Statute, Code or Order:** NY PSC Order Case 03-E-0188; 2015 New York State Energy Plan.

North Carolina

- **Title:** Renewable Energy and Energy Efficiency Portfolio Standard.
- **Established:** 2007.
- **Requirement:** 12.5 percent by 2021 (IOUs); 10 percent by 2018 (munis and coops).
- **Applicable Sectors:** Investor-owned utility, municipal utilities, cooperative utilities.
- **Cost Cap:** 1.4 percent.
- **Details:** Solar: 0.2 percent by 2018. Swine Waste: 0.2 percent by 2018. Poultry Waste: 900,000 MWh by 2015. The state offers credit multipliers for biomass facilities located in cleanfields renewable energy demonstration parks.
- **Enabling Statute, Code or Order:** N.C. Gen. Stat. §62-133.8.

North Dakota

- ***Title:*** *Renewable and Recycled Energy Objective.*
- ***Established:*** *2007.*
- ***Requirement:*** *10 percent by 2015.*
- ***Applicable Sectors:*** *Investor-owned utility, municipal utilities, cooperative utilities.*
- ***Enabling Statute, Code or Order:*** N.D. Cent. Code §49-02-24 et seq.

Ohio

- **Title:** Alternative Energy Resource Standard.
- **Established:** 2008.
- **Requirement:** 25 percent by 2026. Senate Bill 310 (2014) created a two-year freeze on the state's standard while a panel studied the costs and benefits of the requirement. The freeze was not extended in 2016.
- **Applicable Sectors:** Investor-owned utility, retail supplier.
- **Cost Cap:** 1.8 percent.
- **Details:** 12.5 percent Renewable Energy Resources. 12.5 percent Advanced Energy Resources (advanced energy resources includes co-generation, advanced nuclear power and clean coal). Solar: 0.5 percent.
- **Enabling Statute, Code or Order:** Ohio Rev. Code Ann. §4928.64 et seq.

Oklahoma

- ***Title:*** *Renewable Energy Goal.*
- ***Established:*** *2010.*
- ***Requirement:*** *15 percent by 2015.*
- ***Applicable Sectors:*** *Investor-owned utility, municipal utilities, cooperative utilities.*
- ***Enabling Statute, Code or Order:*** Okla. Stat. tit. 17 §801.1 et seq.

Oregon

- **Title:** Renewable Portfolio Standard.
- **Established:** 2007.
- **Requirement:** 25 percent by 2025 (utilities with 3 percent or more of the state's load); 50 percent by 2040 (utilities with 3 percent or more of the state's load); 10 percent by 2025 (utilities with 1.5–3 percent of the state's load); 5 percent by 2025 (utilities with less than 1.5 percent of the state's load).
- **Applicable Sectors:** Investor-owned utility, municipal utilities, cooperative utilities, retail supplier.
- **Cost Cap:** 4 percent.
- **Details:** Photovoltaics: 20 MW by 2020 (IOUs). The state has a credit multiplier for photovoltaics installed before 2016. The state's two investor-owned utilities must phase out coal generation by 2035.
- **Enabling Statute, Code or Order:** Or. Rev. Stat. §469a; Senate Bill 1547 (2016).

Pennsylvania

- **Title:** Alternative Energy Portfolio Standard.
- **Established:** 2004.
- **Requirement:** 18 percent by 2020-2021.
- **Applicable Sectors:** Investor-owned utility, retail supplier.
- **Cost Cap:** None.
- **Details:** Tier I: 8 percent by 2020-2021 (includes photovoltaic). Tier II (includes waste coal, distributed generation, large-scale hydropower and municipal solid waste, among other technologies): 10 percent by 2020-2021. Photovoltaic: 0.5 percent by 2020-2021.
- **Enabling Statute, Code or Order:** Pa. Cons. Stat. tit. 66 §2814.

Rhode Island

- **Title:** Renewable Energy Standard.
- **Established:** 2004.
- **Requirement:** 14.5 percent by 2019, with increases of 1.5 percent each year until 38.5 percent by 2035.
- **Applicable Sectors:** Investor-owned utility, retail supplier.
- **Cost Cap:** 9.5 percent.
- **Details:** The state has a separate long-term contracting standard for renewable energy, which requires electric distribution companies to establish long-term contracts with new renewable energy facilities.
- **Enabling Statute, Code or Order:** R.I. Gen. Laws §39-26-1 et seq.; R.I. Gen. Laws §39-26.1 et seq. (contracting standard); House Bill 7413a (2016).

South Carolina

- **Title:** Renewables Portfolio Standard.
- **Established:** 2014.
- **Requirement:** 2 percent by 2021.
- **Applicable Sectors:** Investor-owned utility.
- **Details:** Systems less than 1 MW: 1 percent of aggregate generation capacity, including at least 0.25 percent of total generation from systems less than 20kW. 1 – 10 MW facilities: 1 percent of aggregate generation capacity.
- **Enabling Statute, Code or Order:** House Bill 1189.

South Dakota

- ***Title:*** *Renewable, Recycled and Conserved Energy Objective.*
- ***Established:*** *2008.*
- ***Requirement:*** *10 percent by 2015.*
- ***Applicable Sectors:*** *Investor-owned utility, municipal utilities, cooperative utilities.*
- ***Enabling Statute, Code or Order:*** S.D. Codified Laws Ann. §49-34A-94; S.D. Codified Laws Ann. §49-34A-101 et seq.

Texas

- **Title:** Renewable Generation Requirement.
- **Established:** 1999.
- **Requirement:** 5,880 MW by 2015. 10,000 MW by 2025 (goal; achieved).
- **Applicable Sectors:** Investor-owned utility, retail supplier.
- **Cost Cap:** 3.1 percent.
- **Details:** Non-wind: 500 MW (goal).
- **Enabling Statute, Code or Order:** Tex. Utilities Code Ann. §39.904.

Utah

- ***Title:*** *Renewables Portfolio Goal.*
- ***Established:*** *2008.*
- ***Requirement:*** *20 percent by 2025.*
- ***Applicable Sectors:*** *Investor-owned utility, municipal utilities, cooperative utilities.*
- ***Enabling Statute, Code or Order:*** Utah Code Ann. §54-17-101 et seq.*;* Utah Code Ann. §10-19-101 et seq.

Vermont

- **Title:** Renewable Energy Standard.
- **Established:** 2005 (voluntary garget); 2015 (standard).
- **Requirement:** 55 percent by 2017; 75 percent by 2032.
- **Applicable Sectors:** Investor-owned utility, municipal utilities, cooperative utilities, retail supplier.
- **Cost Cap:** None.
- **Details:** Distributed Generation: 10 percent by 2032. Energy Transformation: 12 percent by 2032 (includes weatherization, thermal energy efficiency and heat pumps).
- **Enabling Statute, Code or Order:** Vt. Stat. Ann. tit. 30 §8001 et seq.; Standard: House Bill 40.

Virginia

- ***Title:*** *Voluntary Renewable Energy Portfolio Goal.*
- ***Established:*** *2007.*
- ***Requirement:*** *15 percent by 2025.*
- ***Applicable Sectors:*** *Investor-owned utility.*
- ***Details:*** *The state has several credit multipliers for different technologies.*
- ***Enabling Statute, Code or Order:*** Va. Code §56-585.2*.*

Washington

- **Title:** Renewable Energy Standard.
- **Established:** 2006.
- **Requirement:** 9 percent by 2016, 15 percent by 2020.
- **Applicable Sectors:** Investor-owned utility, municipal utilities, cooperative utilities.
- **Cost Cap:** 4 percent.
- **Details:** Standard is applicable to all utilities that serve more than 25,000 customers. Requirement also includes all cost-effective conservation. The state has a credit multiplier for distributed generation.
- **Enabling Statute, Code or Order:** Wash. Rev. Code §19.285; Wash. Admin. Code §480-109; Wash Admin. Code §194-37.

West Virginia

- ***Title:*** *Alternative and Renewable Energy Portfolio Standard-* ***REPEALED.***
- ***Established:*** *2009;* ***Repealed 2015.***
- ***Requirement:*** *10 percent from 2015-2019, 15 percent from 2020-2024, 25 percent by 2025.*
- ***Details:*** *Goal is applicable to IOUs that serve more than 30,000 residential customers. Goal includes alternative energy sources, including coal technology, coal bed methane, natural gas, combined cycle technologies, waste coal and pumped storage hydroelectric projects.*

- ***Enabling Statute, Code or Order:*** *W. Va. Code §24-2F; Repeal: H.B. 2001.*

Wisconsin

- **Title:** Renewable Portfolio Standard.
- **Established:** 1998.
- **Requirement:** 10 percent by 2015.
- **Applicable Sectors:** Investor-owned utility, municipal utilities, cooperative utilities.
- **Cost Cap:** None.
- **Details:** Standard varies by utility. 2011-2014: utilities may not decrease its renewable energy percentage below 2010 percentages. 2015: utilities must increase renewable energy percentages by at least 6 percent above their 2001-2003 average. Utilities may not decrease their renewable energy percentage after 2015.
- **Enabling Statute, Code or Order:** Wisc. Stat. §196.378.

Washington, D.C.

- **Title:** Renewable Portfolio Standard.
- **Established:** 2005.
- **Requirement:** 20 percent by 2020, 50 percent by 2032.
- **Applicable Sectors:** Investor-owned utility, retail supplier.
- **Cost Cap:** 7.6 percent.
- **Details:** Solar: 2.5 percent by 2023.
- **Enabling Statute, Code or Order:** D.C. Code §34-1431 et seq., Bill 650 (2016).

Guam

- ***Title:*** *Renewable Energy Portfolio Goal.*
- ***Established:*** *2008.*
- ***Requirement:*** *25 percent by 2035.*
- ***Applicable Sectors:*** *Investor-owned utility, municipal utilities, cooperative utilities.*
- ***Details:*** *Goal applies to net electricity sales.*
- ***Enabling Statute, Code or Order:*** Guam Public Law §29-62*.*

Northern Mariana Islands

- **Title:** Renewables Portfolio Standard.
- **Established:** 2007; goal reduced in 2014.
- **Requirement:** 20 percent by 2016.
- **Applicable Sectors:** Investor-owned utility, municipal utilities, cooperative utilities.
- **Cost Cap:** Data unavailable.
- **Details:** Requirement applies to net electricity sales. Requirement allows for non-compliance if it is not cost-effective.
- **Enabling Statute, Code or Order:** N. M. I. Public Law §15-23; House Bill 165 (2014).

Puerto Rico

- **Title:** Renewable Energy Portfolio Standard.
- **Established:** 2010.
- **Requirement:** 20 percent by 2035.
- **Applicable Sectors:** Investor-owned utility, municipal utilities, cooperative utilities.
- **Cost Cap:** Data unavailable.
- **Details:** Requirement does not take effect until 2015.
- **Enabling Statute, Code or Order:** PR S 1519 (2010); PR H 2610 (2010).

U.S. Virgin Islands

- **Title:** Renewables Portfolio Targets.

- **Established:** 2009.
- **Requirement:** 20 percent by 2015; 25 percent by 2020; 30 percent by 2025; up to 51 percent after 2025.
- **Applicable Sectors:** Investor-owned utility, municipal utilities, cooperative utilities.
- **Details:** Standard applies to peak demand generating capacity. Standard will increase until a majority of capacity is from renewable or alternative energy.
- **Enabling Statute, Code or Order:** VI B 9 (2009).

Sources:

Database of State Incentives for Renewables and Efficiency, Renewable Portfolio Standards. (Raleigh, N.C. State University, 2017).
Lawrence Berkeley National Laboratory.
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SEVENTH

NORTHWEST CONSERVATION AND ELECTRIC POWER PLAN

Northwest **Power** and **Conservation** Council

document 2016-02
February 25, 2016

SEVENTH NORTHWEST CONSERVATION AND ELECTRIC POWER PLAN

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Final Plan – Released February 25, 2016

CHAPTER 1: EXECUTIVE SUMMARY

The Pacific Northwest power system faces a host of uncertainties, from compliance with federal carbon dioxide emissions regulations to future fuel prices, resource retirements, salmon recovery actions, economic growth, a growing need to meet peak demand, and how increasing renewable resources would affect the power system. The Council's Seventh Power Plan addresses these uncertainties and provides guidance on which resources can help ensure a reliable and economical regional power system over the next 20 years.

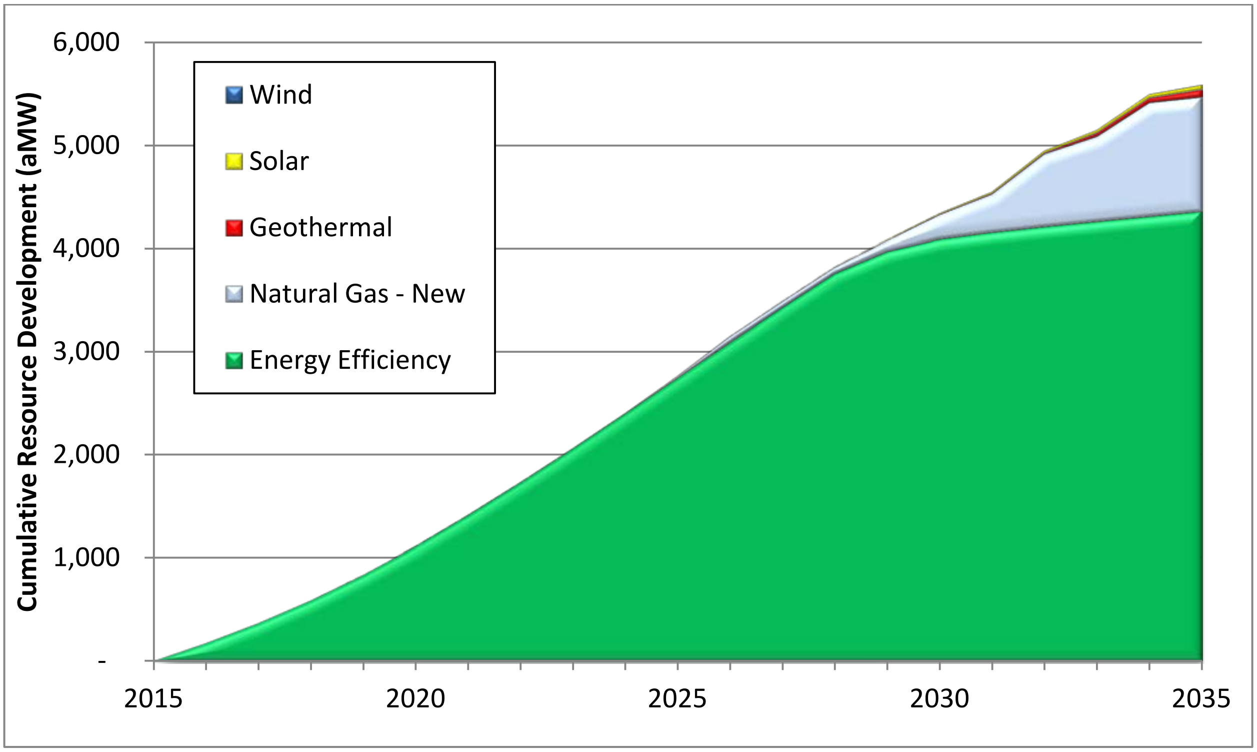
In developing its plan, the Council relies on feedback from technical and policy advisory groups and input from a broad range of interests, including utilities, state energy offices, and public interest groups.

The plan also recognizes that individual utilities, which have varying access to electricity markets and varying resource needs, may require near-term investments in resources to meet their adequacy and reliability needs. For example, some utilities face significant near-term resource challenges, particularly if there is limited access to surplus resources from others. These factors limit the ability of the regional resource strategy to be specific about optioning and construction dates for natural gas-fired resources, or for the types of natural gas-fired generation. As a result, new gas-fired generation may be required, even if utilities deploy demand response resources and develop the energy efficiency called for in the plan.

Using modeling to test how well different resources would perform under a wide range of future conditions, energy efficiency consistently proved the least expensive and least economically risky resource. In more than 90 percent of future conditions, cost-effective efficiency met *all* electricity load growth through 2030 and in more than half of the futures *all* load growth for the next 20 years. It's not only the single largest contributor to meeting the region's future electricity needs; it's also the single largest source of new peaking capacity. If developed aggressively, in combination with past efficiency acquisition, the energy efficiency resource could approach the size of the region's hydroelectric system's firm energy output, adding to the Northwest's heritage of clean and affordable power. Figure 1 - 1 shows the composition of the plan's resource portfolio.

Acquiring this energy efficiency is the primary action for the next six years. The plan's second priority is to develop the capability to deploy demand response resources or rely on increased market imports to meet system capacity needs under critical water and weather conditions. While the region's hydroelectric system has long provided ample peaking capacity, it's likely that under low water and extreme weather conditions we'll need additional peaking capacity to maintain system adequacy. Because the probability of such events is low (but real), demand response resources, which have low development and "holding" costs are best-suited to meet this need. However, whether and to what extent the region should rely on demand response or increase its reliance on power imports to meet regional resource adequacy requirements for winter capacity depends on their comparative availability, reliability, and cost.

Figure 1 - 1: Seventh Plan Resource Portfolio[1]



After energy efficiency and demand response, new natural gas-fired generation is the most cost-effective resource option for the region in the near-term. Similarly, after energy efficiency, the increased use of existing natural gas generation offers the lowest cost option for reducing regional carbon emissions. Combined with investments in renewable generation, as required by state renewable portfolio standards, improved efficiency, demand response resources, and natural gas generation are the principal components of the plan's resource portfolio.

A key question for the plan was how the region could lower power system carbon dioxide emissions and at what costs. The Council's modeling found that without additional carbon control policies, carbon dioxide emissions from the Northwest power system are forecast to decrease from about 54 million metric tons in 2015 to around 34 million metric tons in 2035,[2] the result of retiring the Centralia, Boardman, and North Valmy coal plants between 2020 and 2026; using existing natural gas-fired generation to replace them; and developing about 4,300 average megawatts of energy efficiency by 2035, which is expected to meet nearly all forecast load growth over that time frame.

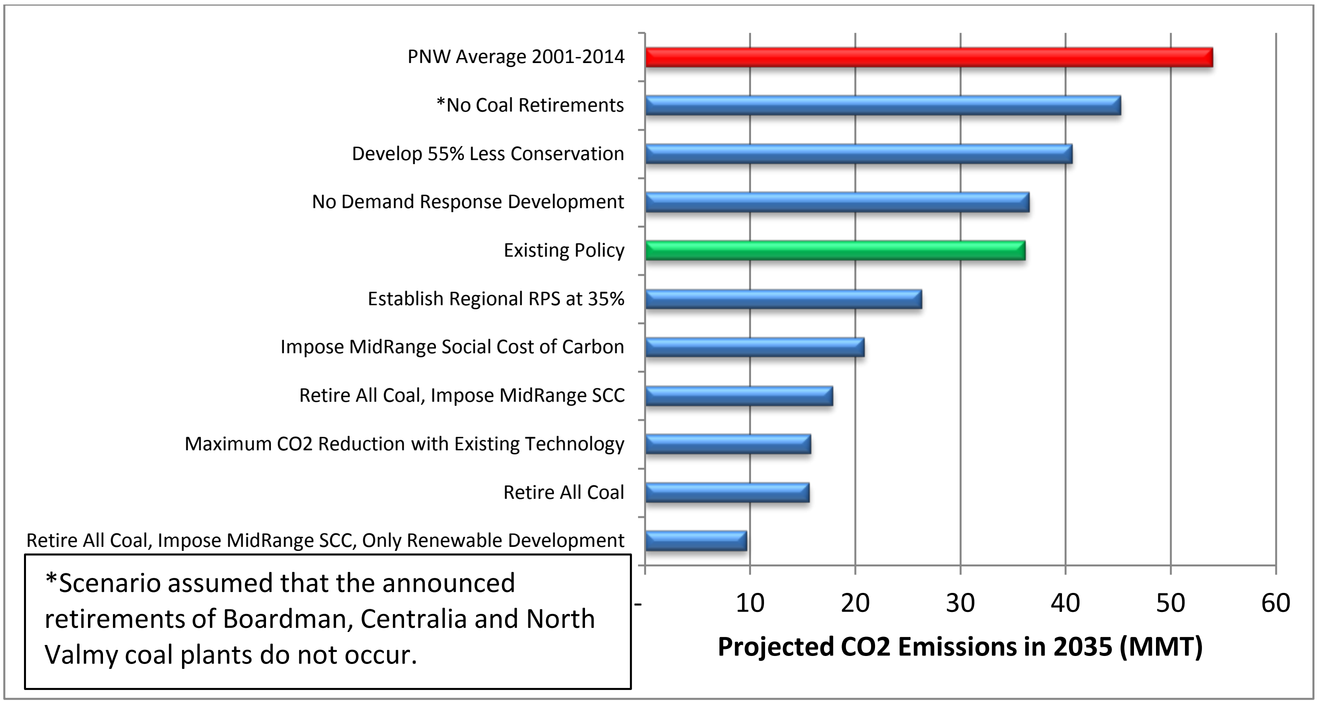
[1] Figure 1 - 1 shows the average resource development across all 800 futures tested in the Regional Portfolio Model. Actual development, particularly of non-energy efficiency resources, will depend on actual future conditions.

[2] This is the level of carbon dioxide emissions estimated to be generated to serve regional load under average water and weather conditions. Actual 2015 carbon dioxide emissions could differ significantly from this level based on actual water and weather conditions. Average regional carbon dioxide emissions from 2001–2014 were 54 million metric tons (MMT), but ranged from 43 MMT to 60 MMT.

In these circumstances, the region, as a whole, will be able to comply with the Environmental Protection Agency's (EPA's) carbon emissions limits, even under critical water conditions. However, since the Council did not evaluate compliance with the EPA's carbon emissions limits at the state level, individual Northwest states, especially Montana, may need to take additional actions to comply with these new emissions limits.

Figure 1 - 2 shows the forecast average carbon dioxide emissions in 2035 under the various scenarios tested in developing the plan.

Figure 1 - 2: Forecast Northwest Power System Carbon Dioxide Emissions in 2035 by Scenario



The Council also assessed alternative policies to further reduce emissions. With today's technology, carbon dioxide emissions could be reduced to about 16 million metric tons by 2035, 70 percent below historical average regional emissions levels. This would require retiring all the coal generation serving the region, which is responsible for more than 85 percent of system emissions, and acquiring additional energy efficiency and demand response resources. The estimated cost of doing this is nearly $16 billion or 20 percent over the cost of other resource portfolios that comply with federal carbon dioxide emissions limits at the regional level.[3] Reducing the region's power system carbon footprint below that level is technically feasible, but only if renewable resources are developed to replace retiring coal plants and a carbon cost equivalent to the federal government's

[3] The cost of resource strategies reported in the Seventh Power Plan generally exclude revenues from a carbon price in order to compare scenarios based only on power system costs. The text will identify whether carbon revenues are included or not. In practice, carbon revenue may not be considered a cost if all of it is returned to ratepayers, for example, in the form of a tax reduction.

mid-range estimate of the social cost of carbon (approximately $40 - $60 per metric ton) is imposed throughout the entire Western electricity market. While this would reduce projected carbon dioxide emissions to 10 million metric tons by 2035, or 80 percent below historical average regional emission levels, the cost of this strategy (excluding the carbon revenue) is $44 billion or 55 percent more than the cost of other resource portfolios that comply with federal carbon dioxide emissions limits at the regional level. The Council also found that reaching a zero-carbon emissions power system is not technically feasible without developing new technologies.

Investments to add transmission capability and improve operational agreements are important for the region, both to access growing site-based renewable energy and to better integrate low and zero-emissions resources into the existing power system. The Council also expects that there are small-scale resources available at the local level in the form of cogeneration or renewable energy opportunities. The plan encourages investment in these resources when cost-effective.

The plan encourages research in advanced technologies to improve the efficiency and reliability of the power system. For example, emerging smart-grid technologies could make it possible for consumers to help balance supply and demand. Providing information and tools to consumers to adjust electricity use in response to available supplies and costs would enhance the capacity and flexibility of the power system. Smart-grid development could also help integrate electric vehicles with the power system to aid in balancing the system and reduce carbon emissions in the transportation sector. Research on how distributed solar generation with on-site storage might affect system load shape is also encouraged.

Other resources with potential, given advances in technology, include geothermal, ocean waves, advanced small modular nuclear reactors, and emerging energy efficiency technologies. New methods to store electric power, such as pumped storage or advanced battery technologies may enhance the value of existing variable generation like wind.

Developing these technologies is a long-term process that will require many years to reach full potential. The region can make progress through investments in research, development, and demonstration projects.

FUTURE REGIONAL ELECTRICITY NEEDS AND PRICES

Pacific Northwest regional loads are expected to increase by between 1,800 and 4,400 average megawatts between 2015 and 2035 before accounting for the impact of the cost-effective energy efficiency called for in the Seventh Power Plan. This translates to an average increase of between 90-220 average megawatts per year, or a growth rate of between 0.4 – 0.95 percent per year. The regional peak load for power, which typically occurs in winter, is forecast to grow from about 30,000 - 31,000 megawatts in 2015 to around 31,900-35,800 megawatts by 2035. This equates to an average annual growth rate of between 0.3 – 0.8 percent.

Residential and commercial sectors account for much of the growth in demand. Contributing to this growth is increasing air conditioning load, new data centers, and growth in indoor agriculture. Also, summer peak electricity use is expected to grow more rapidly than annual energy demand. All of this growth in demand must be met by a combination of existing resources, energy efficiency, and new generation.

An important finding of the plan is that future electricity needs can no longer be adequately addressed by only evaluating average annual energy requirements. Planning for capacity to meet peak load and flexibility to provide within-hour, load-following, and regulation services will also need to be considered.

Requirements for within-hour flexibility reserves have increased because of the growing amount of variable wind generation in the region. While the plan doesn't foresee renewable resource development beyond what is required to satisfy existing state renewable portfolio standards, improved regional coordination could reduce the need for resources used to integrate existing renewables. For example, establishing energy imbalance markets could enable sharing resources reserved for integrating wind resources.

Wholesale electricity prices at the Mid-Columbia hub remain relatively low, reflecting the abundance of low-variable cost generation from hydro and wind, as well as continued low natural gas prices. The average wholesale electricity price in 2014 was $32.50 per megawatt-hour. By 2035, prices are forecast to range from $25 – $68 per megawatt-hour in 2012 dollars. The upper and lower bounds for the forecast wholesale electricity price were set by the associated high and low natural gas price forecast. Although the dominant generating resource in the region is hydropower, natural gas-fired plants are often the marginal generating unit for any given hour. Therefore, natural gas prices exert a strong influence on the wholesale electricity price, making the natural gas price forecast a key input. The region depends on externally sourced gas supplies from Western Canada and the U.S. Rockies.

Prices for natural gas have dropped significantly since reaching a high in 2008, and they're expected to remain relatively low going forward. Historically, natural gas prices have been volatile, so the plan uses a range of forecasts to capture most potential futures. The low price forecast range starts at $2.64 per MMBtu in 2015 and increases in real dollars to $3.56 per MMBtu by 2035. This low-range case represents a future with slow economic growth, low gas demand, and robust supplies. The high price forecast range climbs to $10 per MMBtu by 2035. This forecast represents a future with high economic growth, high demand for natural gas, and a limited gas supply.

Recent promulgation of federal regulations that limit carbon emissions from both new and existing power generation are expected to increase the demand for natural gas. These higher natural gas prices result in higher wholesale electricity prices. Therefore, some of the futures used to develop this plan include a wide range of possible natural gas and electricity prices. Additional carbon regulations or costs could further increase electricity costs for consumers. While higher prices reduce demand, they also stimulate new sources of supply and efficiency and make more efficiency measures cost-effective.

RESOURCE STRATEGY

The plan's resource strategy provides guidance to the Bonneville Power Administration and regional utilities on resource development to minimize the costs and risks of the future power system. Timing of specific resource acquisitions will vary for each utility.

Energy Efficiency: The region should aggressively develop energy efficiency with a goal of acquiring 1,400 average megawatts by 2021; 3,000 average megawatts by 2026; and 4,300 average megawatts by 2035. Efficiency is by far the least expensive resource available to the region, avoiding the risks of volatile fuel prices and large-scale resource development, while mitigating the risk of potential carbon pricing policies. Along with its annual energy savings, it helps meet future capacity needs by reducing both winter and summer peak demand.

Demand Response: In order to satisfy regional resource adequacy standards, the region should be prepared to develop significant demand response resources by 2021 to meet additional winter peaking capacity. The least-cost solution for providing new peaking capacity is to develop cost-effective demand-response resources, the voluntary and temporary reduction in consumers' use of electricity when the power system is stressed. The Northwest's power system has historically relied on the hydrosystem to provide peaking capacity, but under critical water and weather conditions we'll need additional capacity to meet the region's adequacy standard.

The Seventh Power Plan action plan recommends that the annual regional resource adequacy assessment compare the cost and economic risk of increased reliance on external market purchases to developing demand response resources to meet capacity. The Council will determine if the region has made sufficient progress toward acquiring cost-effective demand response or confirm the ability to import a minimum of at least 600 megawatts of additional peaking capacity in its mid-term assessment of the Seventh Power Plan.

Natural Gas: Increased use of existing natural gas generation is expected to replace retiring coal plants and meet carbon-reduction goals in the near term. Only low to modest amounts of new natural gas-fired generation is likely to be needed to supplement energy efficiency, demand response, and renewable resources, unless the region experiences prolonged periods of high load growth or additional coal plants beyond those already announced are retired. Even if the region has adequate resources, individual utilities or areas may need additional supply for energy, capacity or wind integration. In these instances, the strategy relies on natural gas-fired generation to provide energy, capacity, and ancillary services.

Renewable Resources: Modest development of renewable generation will meet existing renewable portfolio standards. On average, renewable resources developed to fulfill state RPS mandates will contribute about 100 - 150 average megawatts of energy, or around 300 megawatts of installed capacity. While wind generation has been the dominant renewable resource developed in the region, lower costs for solar photovoltaic technology are expected to make it more competitive. As a result, compliance is expected to be met through both wind and solar PV systems and conventional geothermal resources. However, except for geothermal resources, these renewable resources lack dependable winter peak capacity and also require within-hour balancing reserves. Therefore, the plan's resource strategy encourages research and demonstration of other potential renewable resources, such as geothermal and wave energy, which have more consistent output. The resource strategy also encourages developing other renewable alternatives that may be available at the local, small-scale level and are cost-effective now.

Regional Resource Use: Continue to improve system scheduling and operating procedures across the region's balancing authorities. These cost-effective steps will help minimize reserves needed to integrate renewable resources. The region also needs to invest in its transmission grid to improve market access for utilities, reduce line losses, and help develop diverse cost-effective renewable generation. Finally, the least-cost resource strategies rely first on regional resources to satisfy the region's resource adequacy standards. Under many futures conditions, these strategies reduce regional exports.

Carbon Policies: To support policies that cost effectively achieve state and federal carbon dioxide emissions reduction goals, while maintaining regional power system adequacy, the region should develop the energy efficiency and demand response resources called for in this plan and replace retiring coal plants with only those resources required to meet regional capacity and energy adequacy requirements. As stated earlier, after energy efficiency, increasing use of existing natural gas generation offers the lowest cost option for reducing regional carbon emissions. Developing new gas-fired generation to meet local needs for ancillary services, such as wind integration or capacity requirements beyond the modest levels anticipated in the plan, will increase carbon dioxide emissions. If Northwest electricity generation is dispatched first to meet regional adequacy standards for energy and capacity rather than to serve external markets, carbon dioxide emissions can be minimized.

Future Resources: In the long term, the Council encourages the region to expand its resource alternatives. The region should explore other sources of renewable energy, especially technologies that provide both energy and winter capacity; new efficiency technologies; new energy-storage techniques; smart-grid technologies and demand-response resources; and new or advanced low-carbon generating technologies, including advanced nuclear energy. Research, development, and demonstration funding should be prioritized in areas where the Northwest has a comparative advantage or where unique opportunities emerge.

Adaptive Management: The Council will annually assess the adequacy of the regional power system to guard against power shortages. Through this process, the Council will be able to identify when conditions differ significantly from planning assumptions so the region can respond appropriately. The Council will also conduct a mid-term assessment to review the plan's implementation and ensure the successful implementation of the Council's Columbia River Basin Fish and Wildlife Program.

Energy Efficiency

The dominant new resource in the Seventh Power Plan's resource strategy is improved energy efficiency. Figure 1 - 3 shows that under scenarios that consider carbon risk and those that do not, and even when natural gas and wholesale electricity prices are lower than expected, the region's net load after developing all cost-effective efficiency is basically the same over the next 20 years. In more than 90 percent of the 800 futures evaluated by the Council, across more than 20 different scenarios, the least-cost resource strategy developed sufficient energy efficiency resource to meet all regional load growth through 2030. Indeed, even in the scenario (Lower Energy Efficiency) that assumed only energy efficiency costing less than short-term wholesale market prices would be acquired, nearly all regional load growth in the medium forecast through 2025 was met with energy efficiency. However, it should be noted that developing this lower level of efficiency increased regional power system cost by $15 billion, an 18 percent higher cost compared to resource strategies that developed sufficient energy efficiency to meet all load growth through 2030.

This is because improved efficiency is relatively cheap, it provides both energy and capacity savings, and it has no major risks. It costs half of what other resources cost, without the risk of volatile fuel prices or costs of carbon reduction policies. It also has a short lead time and is available in small increments, both of which reduce risk. Therefore, improved efficiency reduces the cost of, and risks to, the power system.

Figure 1 - 3: Average Net Regional Load After Accounting for Cost-Effective Energy Efficiency Resource Development

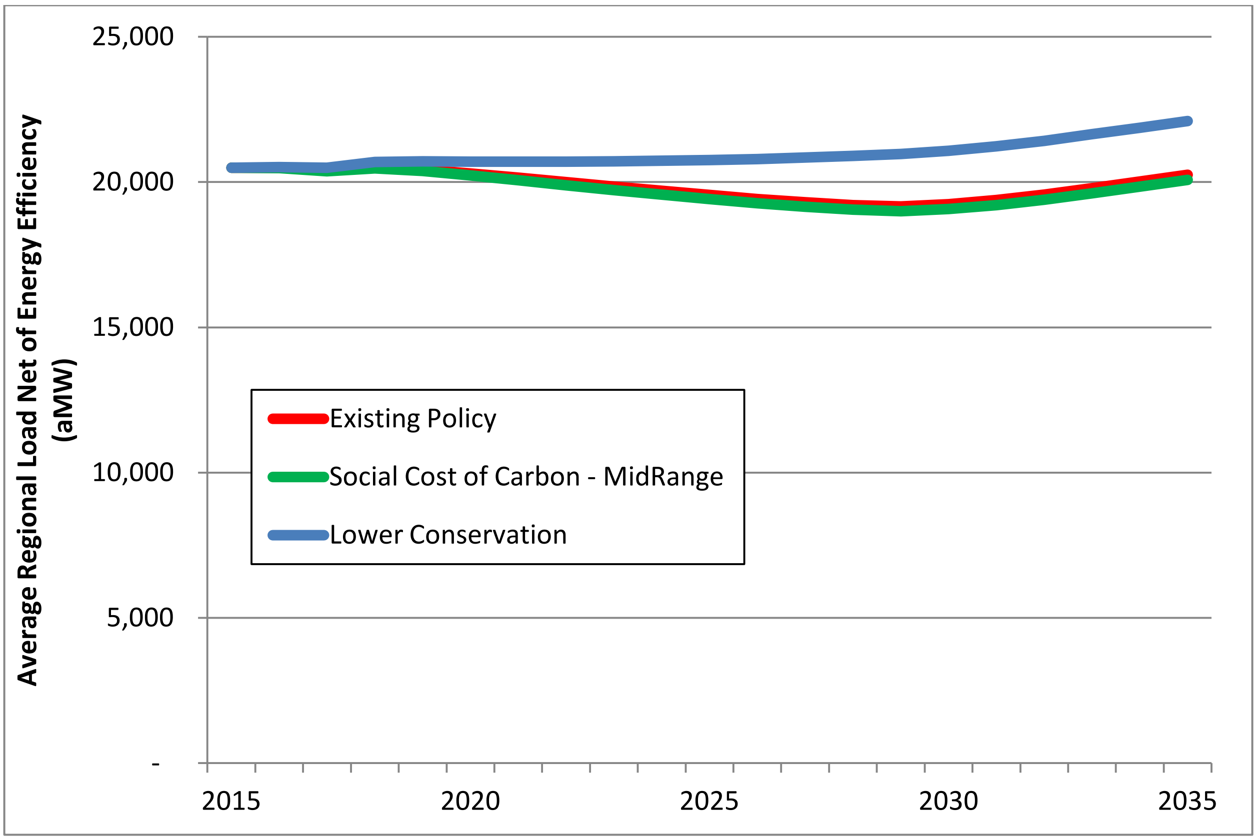


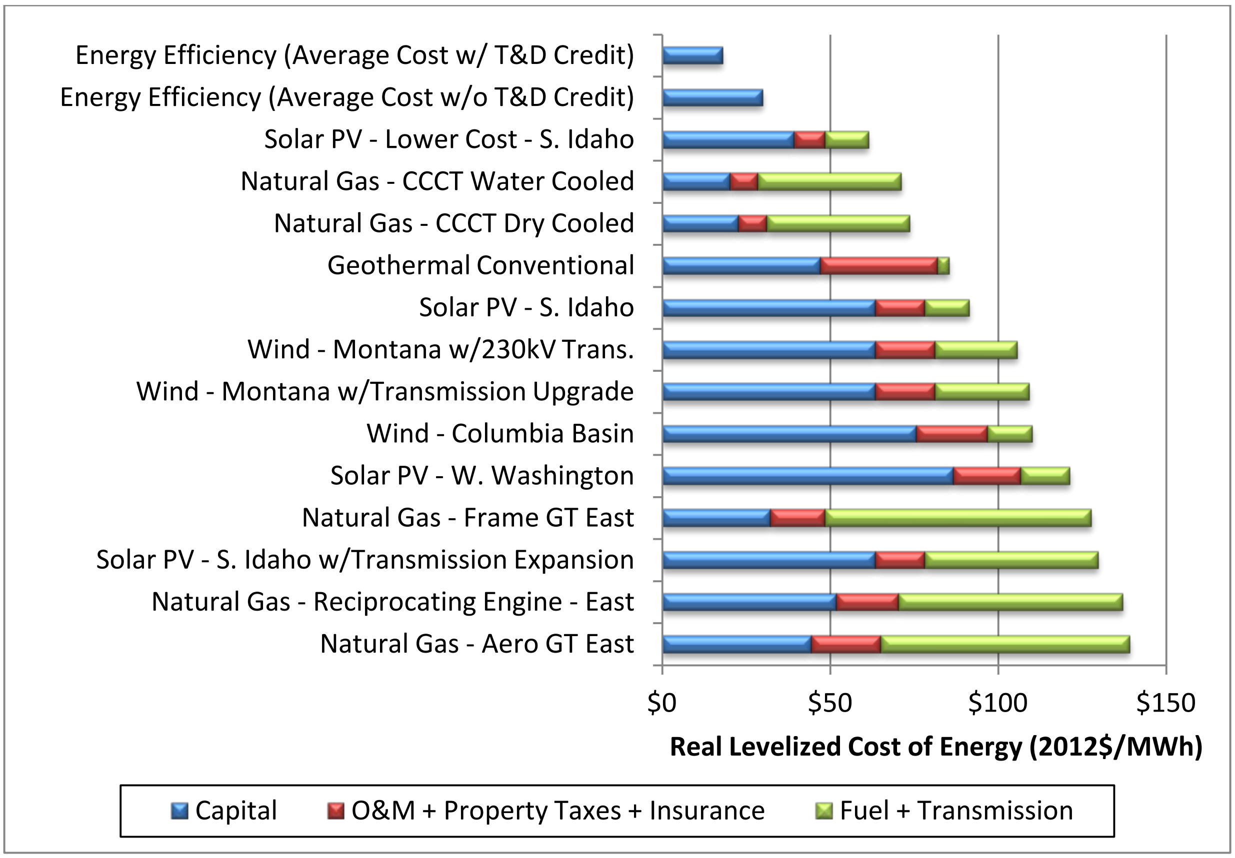
Figure 1 - 4 compares the average cost of energy efficiency resources and the cost of generating resources considered in the plan's development. Two estimates of the cost of energy efficiency are shown. The lower average cost ($18 per megawatt-hour) reflects energy efficiency's impact on the need to expand distribution and transmission systems. The higher cost ($30 per megawatt-hour) does not include these power system benefits.

The comparable estimated cost of a natural gas-fired combined-cycle combustion turbine is around $71 per megawatt-hour. The current cost of utility-scale solar photovoltaic systems is approximately $91 per megawatt-hour and Columbia Basin wind costs $110 per megawatt-hour. Significant amounts of improved efficiency also cost less than the forecast market price of electricity, since nearly 2,400 average megawatts of energy savings are available below the average cost of $30 per megawatt-hour.

In the Council's analysis, additional resources provide insurance against an uncertain future. Efficiency improvements are particularly attractive as insurance because of their low cost and modular size. When the resources aren't needed, the energy savings from low-cost energy efficiency resources can be sold in the market, paying for itself and then some.

In all of the scenarios and sensitivity studies examined by the Council, similar amounts of improved efficiency are found to be cost-effective even without carbon costs. If carbon reduction policies are enacted, efficiency improvements can help the region meet those goals. In all scenarios tested by the Council, the amount of cost-effective efficiency developed averaged between 1,200 and 1,450 average megawatts by 2021 and between 3,900 and 4,500 average megawatts by 2035.

Figure 1 - 4: Energy Efficiency and Generating Resource Cost Comparison[4]



[4] In Figure 1-4 the levelized cost of solar PV resources have been reduced by the impact of a 30% Federal Investment Tax Credit (ITC) until 2022 and a 10% ITC for the remainder of the planning period. Geothermal costs have also been reduced by a 10% ITC throughout the entire planning period. In addition, solar, wind and geothermal resource costs are also reduced by accelerated depreciation. No state or local tax or other financial incentives are reflected in resource costs. The cost of these resources also reflect integration costs equivalent to current integration rates for wind resources charged by Bonneville and Idaho Power Company's integration rates for solar PV systems. The integration cost of additional renewable resource development in the region may be higher.

Demand Response

Demand response resources are voluntary reductions in customer electricity use during periods of high demand and limited resource availability. The plan's resource strategy uses demand response to meet winter and summer peak demands, primarily under critical water and extreme weather conditions. The strategy doesn't consider other possible applications of demand response--to integrate variable resources like wind for example.

The Council's assessment identified more than 4,300 megawatts of regional demand response potential. A significant amount of this potential, nearly 1,500 megawatts, is available at relatively low cost; less than $25 per kilowatt of peak capacity per year. When compared to the alternative of constructing a simple cycle gas-fired turbine, demand response can be deployed sooner, in quantities better matched to the peak capacity need, deferring the need for transmission upgrades or expansions.

In particular, demand response is the least expensive means to maintain peak reserves for system adequacy. Its low cost is especially valuable because the need for peaking capacity in the region largely depends on water and weather conditions. The Council's analysis indicates that a minimum of 600 megawatts of demand response resources would be cost-effective to develop under all future conditions tested across all scenarios that don't rely on increased firm capacity imports. Moreover, even if additional firm peak power imports during winter months are assumed to be available, developing a minimum of 600 megawatts of demand response resources is still cost-effective in over 70 percent of the futures tested.

Alternatively, the region could rely on external power markets to meet its winter peak capacity needs. In one scenario tested by the Council, the region relied more on external markets (Canada, California, and the Southwest) which greatly reduced the need to develop demand response. That scenario relaxed the Council's current assumptions about the availability of firm power imports from out-of-region sources and from in-region market resources. Since that scenario's system cost and economic risk were lower than scenarios in which cost-effective demand response was acquired, the plan's resource strategy recommends that the Council's Resource Adequacy Advisory Committee reexamine all potential sources of imported energy and capacity to minimize cost and avoid the risk of overbuilding.[5]

Generation Resources

The Council analyzed a large number of alternative generating technologies. Each was evaluated in terms of risk characteristics, cost, and potential for improvements in its efficiency over time. In addition, resources were considered in terms of their energy, capacity, and flexibility characteristics, such as their ability to ramp up and down to accommodate variations in the output of wind and solar PV resources. In the near term, generating technology options that are technologically mature, meet the emissions requirements for new plants, and are cost-effective are limited in number.

[5] See Council Action Item 10.

Improvements in the efficiency and operation of natural gas-fired generation make it the most cost-effective option and the third major element in the plan's resource strategy. After energy efficiency, increased use of *existing* natural gas generation is the lowest cost option to reduce regional carbon dioxide emissions. It plays a major role in the least-cost resource strategies to reduce carbon dioxide emissions. Existing natural gas generation increases immediately in scenarios where carbon costs are imposed.

Across the scenarios evaluated, the optioning and completion of new gas-fired generating resources varied widely. New gas-fired plants are optioned (sited and licensed) so that they are available to develop if needed in each future. The plan's resource strategy includes optioning new gas-fired generation as local needs dictate. However, from an aggregate regional perspective, which is the plan's focus, the need for additional new natural gas-fired generation is very limited in the near term (through 2021) and only slightly higher in the mid-term (through 2026) under nearly all scenarios. That is, options for new gas-fired generation are brought to construction in only a relatively small number of futures.

Across most scenarios that did not assume additional coal plant retirements beyond those already announced, the probability of gas development is less than 10 percent by 2021. By 2026, the probability of constructing a new gas-fired thermal plant increases to almost 50 percent in scenarios where utilities are unable to develop demand response, and to over 80 percent in scenarios where existing coal plants and less efficient gas-fired generation are retired to lower carbon emissions.

While energy efficiency and the minimum amount of demand response and renewable resource development were fairly consistent across most scenarios, the future role of natural gas-fired generation varied depending on the specific scenario studied. The average build-out of new natural-gas fired generation over the 800 futures in most scenarios was less than 50 average megawatts of generation by 2026. Since the average nameplate capacity of a new combined-cycle combustion turbine assumed in the analysis is 370 megawatts, this implies that "on average" only a single plant, operating less than 15 percent of the time is needed. By 2035, the average build-out across all 800 futures was 300 to 400 average megawatts of annual output from new gas-fired generation--one or two additional plants. In the carbon-risk scenario, the amount of energy actually generated from new combined-cycle combustion turbines, when averaged across all 800 futures, is just 10 average megawatts, but close to 100 average megawatts in scenarios that assume no demand response resources are developed.

On the other hand, some utilities may need to develop new natural gas-fired generation, even if they deploy demand response and develop the plan's recommended efficiency. The regional transmission system hasn't evolved as rapidly as the electricity market, resulting in limited access to market power. Individual utilities may need within-hour balancing reserves or have near-term resource challenges.

The varying needs of individual utilities limit the ability of the regional resource strategy to be specific about optioning and construction dates for natural gas-fired resources or for the types of natural gas-fired generation. But it also underscores the value of a regional approach to resource development where resources are part of an interconnected system.

Renewable resource generation development in the plan is driven by state renewable portfolio standards. In the absence of higher standards, few additional renewable resources are developed.

The Council recognizes that additional small-scale renewable resources are available and cost-effective, and the plan encourages their development as an important element of the resource strategy. For example, Snohomish PUD recently completed the Youngs Creek hydroelectric project and Surprise Valley Electric Cooperative is developing the Paisley Geothermal Project, a low-temp geothermal power project in rural Oregon. There are many other potential renewable resources that may, with additional research and demonstration, prove to be cost-effective and valuable for the region to develop.

The amount of additional renewable energy acquired *on average* in the least-cost resource strategies across scenarios didn't vary significantly, even in scenarios that assumed a carbon cost of $40 to $60 per metric ton. This is because the two most economically competitive renewable resources available in the region, wind and solar PV, provide limited reliable peaking capacity, especially in winter. Partly because of the significant wind development in the region over the past decade, the Northwest has a significant energy surplus, yet under critical water conditions the region faces the probability of a peak capacity shortfall–again, because wind provides little winter capacity.

While wind continues to be the primary large-scale, cost-effective renewable resource, decreasing costs for utility-scale and distributed-scale photovoltaic systems have made them cost-competitive sources of energy supply. Consequently, the plan's resource strategy recommends that utilities, especially those with increasing summer peak demands, consider utility-scale solar resources to satisfy their renewable portfolio standard obligations.

Other generating resource alternatives may become available over time, and the plan recommends actions to encourage their development, especially those that don't produce greenhouse gas emissions.

In addition to utility scale renewable resource development, the Seventh Power Plan also recognizes the increasing adoption by homeowners and businesses of distributed solar PV systems. The use of these systems is forecast to dampen regional load growth. By the end of 2014, over 100 megawatts of distributed solar PV capacity had been installed in the region, lowering system energy requirements by an estimated 18 average megawatts. By 2035, the Council forecasts that 500 to 1,400 megawatts of solar PV systems will be installed in the region. On an annual basis, the energy generated from these distributed PV systems is forecast to reduce regional loads by 80 to 220 average megawatts. In addition, these distributed solar PV systems also reduce winter and summer peak loads. Summer peak impacts from distributed solar PV are forecast to be lower by as much as 600 megawatts by 2035.

Regional Resource Use

The existing Northwest power system is a significant asset for the region. The Federal Columbia River Power System provides low-cost and carbon dioxide-free energy, capacity, and flexibility. The network of transmission constructed by the Bonneville Power Administration and the region's utilities has supported a highly integrated regional power system. The Council's resource strategy assumes that ongoing efforts to improve system scheduling and operating procedures across the region's balancing authorities will, in some form, succeed. While the Council doesn't directly model the sub-hourly operation of the region's power system, its models presume resources located anywhere in the region can provide balancing reserve services to any other location in the region, within the limits of existing transmission. This assumption minimizes the need for new resources to integrate renewable resources.

Along with reducing physical and technical barriers, there are more efficient ways to dispatch and use existing regional resources that could minimize the need for new resource development. The analyses conducted for the Seventh Power Plan reveal in particular that the region could benefit from a different approach to using existing generation so as to keep more of that generation in the region serving load under longer-term arrangements.

The Council's analysis shows that the total cost to the region would be lower if more effective use of surplus power available from Bonneville and some of the region's utilities could be used in-region to offset the need that other utilities have to develop new generation to meet resource adequacy standards. The Council recognizes that significant equity, risk, institutional, and legal issues must be overcome to effect such a change. For example, Bonneville and other utilities in the region that control hydropower generation often, but not always, generate substantial surplus power above critical water conditions. Most of that surplus is sold into short-term markets, much of it leaving the region. The Council's analysis indicates that the region would benefit if, instead, some significant portion of this surplus hydropower generation could be sold to other utilities in the region under longer-term contracts to meet regional firm power needs. In order for this to happen, however, either the sellers or the buyers, or both, would have to take on some additional risk since the surplus generation would not always be available due to poor water conditions. As a result, the power price for such contracts would need to somehow reflect additional risk.

The region needs to be creative in crafting new power sales arrangements that address in an appropriate and equitable way the issues of risk inherent in any scheme to rely on this surplus generation to help meet regional adequacy standards. However, the Council encourages the region to find ways to overcome these barriers since the benefit to the region could be substantial.[6]

CLIMATE CHANGE POLICY

Evolving climate change policies to lower carbon emissions from power plants was identified by stakeholders as one of the most important issues for the plan to address. Most recently, with the promulgation by the Environmental Protection Agency's final rules limiting carbon dioxide emissions from both new and existing power generating facilities, the goal of those policies became clearer. [7]

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[6] Absent such an outcome, the trend over the past decade that shows the average revenue per kilowatt-hour for residential customers of investor-owned utilities increasing while the average revenue per kilowatt-hour for residential customers of public utilities has remained nearly flat will likely continue. Between 2005 and 2014, the average revenue per kilowatt-hour sold by IOUs increased from 7.7 cents to 9.9 cents, while the average revenue per kilowatt-hour sold for public utilities remained barely changed, increasing from 7.7 cents to 8.0 cents per kilowatt-hour. Similar trends have occurred for commercial and industrial customers.

[7] U.S. Environmental Protection Agency, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," 80 Fed. Reg. 64,662 (October 23, 2015). A coalition of states, utilities, utility organizations and others challenged the rule applying to existing sources in the federal D.C. Circuit Court of Appeals. The U.S. Supreme

However, since states are charged with developing and implementing plans to comply with EPA's regulations, uncertainty still exists about specific approaches Northwest states will follow to satisfy the regulation.

Reduced carbon dioxide emissions can be encouraged through various policy approaches, including regulatory mandates (renewable portfolio standards, energy efficiency resource standards, emission standards), carbon pricing policies, such as emissions cap-and-trade systems and emissions taxes or negotiated agreements to retire carbon dioxide emitting generation. To date, state policy responses within the region have focused on renewable portfolio standards and new generation emissions limits. Oregon and Washington also have carbon reduction targets adopted by statute. While regulatory and carbon pricing policies have been discussed at the national level, the EPA's new emissions limits are the most concrete policy option adopted.

The plan doesn't address whether carbon dioxide emissions should be reduced, by when or to what level. For now, these questions have been settled by EPA's regulations.[8] The questions for the plan are: What are the least-cost resource strategies to reduce carbon dioxide emissions and satisfy the federal emissions limits? And, what state (or regional) policies are likely to result in those least-cost resource strategies? The Council analyzed multiple carbon reduction scenarios, including three alternative carbon pricing policies and three regulatory policies.

The key findings from the Council's analysis of climate change policies include the following:

- Without any additional carbon control policies, carbon dioxide emissions from the Northwest power system are forecast to decrease from about 54 million metric tons in 2015 to around 36 million metric tons in 2035.[9] This reduction is driven by: 1) The retirement of three coal-fired power plants (Centralia, Boardman, and North Valmy) by 2026. These plants currently serve the region, but their retirement has already been announced; 2) Increased use of existing natural gas-fired generation to replace these retiring resources; and 3) Developing roughly 4,300 average megawatts of energy efficiency by 2035, which is sufficient to meet all forecast load growth over that time frame under most future conditions. If these actions do not occur, the level of forecast emissions is likely to increase. If these actions do occur, then

Court stayed the effectiveness of the rule in an order issued February 9, 2016, pending not just review on the merits by the court of appeals but also the resolution of any petition for further review in the Supreme Court following whatever decision is issued by the court of appeals. The litigation is ongoing as the Council completed the Seventh Power Plan.

[8] By "settled" the Council does not mean to imply that pending litigation over the EPA's regulations may not still alter those regulations. In this context, the Council simply means that in developing the plan it used EPA's draft and final regulations as the basis for its analysis of the cost and effectiveness of alternative carbon reduction policies.

[9] This is the level of carbon dioxide emissions estimated to be generated to serve regional load under average water and weather conditions. Actual 2015 carbon dioxide emission could differ significantly from this level based on actual water and weather conditions. Average regional carbon dioxide emissions from 2001 – 2012 were 54 MMTE, but ranged from 43 MMT to 60 MMT.

the region will have a very high probability (98 percent) of complying with the EPA's carbon emissions limits, even under critical water conditions.

- Retiring all of the coal plants serving the region could reduce regional power system carbon dioxide emissions from approximately 54 million metric tons today to about 16 million metric tons, a nearly 70 percent reduction. Implementing this resource strategy would increase the present value average power system cost by nearly $16 billion, 20 percent over the cost of resource strategies that are projected to satisfy the EPA's recently established limits on carbon dioxide emissions *at the regional level*.

- If all of the region's existing coal plants are retired and replaced exclusively with renewable resources and all generation is dispatched to reflect a mid-range estimate of the social cost of carbon, regional power system carbon emissions could be reduced to 10 million metric tons per year by 2035, 80 percent below historical levels. This is the equivalent to imposing the federal government's mid-range estimate of the social cost of carbon throughout the entire Western electricity market and developing only renewable resources to replace retiring generation. The cost of this strategy, excluding carbon taxes, is estimated to be $44 billion, or 55 percent over the cost of resource strategies that are projected to satisfy the EPA's recently established limits on carbon dioxide emissions *at the regional level*.

- At present, it's not possible to entirely eliminate carbon dioxide emissions from the power system without the use of nuclear power or emerging technology breakthroughs in both energy efficiency and non-carbon dioxide emitting renewable resource generation.

- Deploying renewable resources to achieve maximum carbon reduction presents significant power system operational challenges, in particular by dramatically increasing the need for balancing and flexibility reserves.

- The most cost-effective carbon dioxide emissions reduction policies are those that retire or significantly reduce the use of existing coal plants. The single policy option for reducing carbon dioxide emissions with the lowest cost per unit of emissions reduction imposes the equivalent of the federal government's mid-range estimate of the social cost of carbon throughout the entire Western electricity market. The single policy option for reducing carbon dioxide emissions with the highest cost per unit of emissions reduction establishes a regional renewable portfolio standard at 35 percent. The high per unit cost of carbon dioxide emissions reduction from this policy occurs because it does not retire or significantly reduce the use of existing coal plants.

FISH AND WILDLIFE PROGRAM AND THE POWER PLAN

The Columbia River Basin Fish and Wildlife Program is by statute incorporated into the Council's power plan. The fish and wildlife program guides the Bonneville Power Administration's efforts to mitigate the adverse effects of the Columbia River hydroelectric system on fish and wildlife. One of the roles of the power plan is to ensure the implementation of hydrosystem operations to benefit fish and wildlife while maintaining an adequate, efficient, economic, and reliable energy supply.

The hydroelectric operations for fish and wildlife have a sizeable impact on power generation. On average, hydroelectric generation is reduced by about 1,100 average megawatts compared to operation without constraints for fish and wildlife. Since 1980, the power plan and Bonneville have addressed this impact through changes in secondary power sales and purchases; by acquiring energy efficiency and some generating resources; by developing resource adequacy standards; and by implementing other strategies to minimize power system emergencies and events that might compromise fish operations.

In addition to operational changes, most of the direct and capital costs of the fish and wildlife program have been recovered through Bonneville revenues, and Bonneville has absorbed the financial effects of lost generation, resulting in higher electricity prices. The power system is less economical as a result of fish and wildlife program costs, but still affordable when compared to the costs of other reliable and available power supplies.

The future presents a host of uncertain changes that are sure to pose challenges to integrating power system and fish and wildlife needs: potential new fish and wildlife requirements; increasing wind generation and other renewables that require more flexibility in power system operations; conflicts between climate change policies and fish and wildlife operations; possible changes to the water supply from climate change that intensify conflict between fish and power needs; and possible revisions to Columbia River Treaty operations to match 21st century power, flood control, and fish needs.

Operations to benefit fish and wildlife have a significant biological value, and also a significant effect on the amount and patterns of generation from the hydrosystem. The Council encourages the federal action agencies to continue to monitor, evaluate, and report on the benefits and impacts to fish from flow augmentation and passage measures, including spill, and to work to revise and improve these evaluation methods as much as possible.

To address current operations and prepare for the challenges ahead, the Council will track changes and recommend actions by: annually assessing the region's power supply using its regional adequacy standard to ensure that events like the 2000-01 energy crisis, in which fish operations and power costs were affected, do not happen again; working with partners on its wind integration forum to help integrate wind generation into the power system; and completing a mid-term assessment of its power plan to measure our progress.

CHAPTER 2: STATE OF THE NORTHWEST POWER SYSTEM

Contents

INTRODUCTION

All planning processes start with information and assumptions about current conditions. This chapter summarizes the key assumptions regarding the state of the region that affected the Council's power system planning process or could potentially influence its implementation.

For example, the Northwest Power Act requires the Council's power plan to include a forecast of electricity demand for the next 20 years. Demand, to a large extent, is driven by economic growth, but it is also influenced by the price of electricity and other fuels. Therefore, recent economic trends and energy prices represent a starting point for plan development.

The Northwest Power Act also requires the Council's power plan set forth a forecast of the region's power resources need, including that portion that can be met by resources in each of the priority resource categories identified in the Act. Since the power plan treats cost-effective energy efficiency as a priority resource for meeting future electricity demand, an assessment of its potential must reflect recent accomplishments and factors, such as the impact of codes and standards on future demand. Similarly, assessments of the need for resource development must account for the status of existing generating resources, including planned additions and retirements.

In addition to the state of the region's economy and status of conservation and generating resources, other factors such as environmental regulations, public policy and technology trends also influence plan development. For example, recently finalized federal carbon dioxide emission regulations and changes in California's regulations, such as the state's renewable portfolio standards, may alter energy prices and wholesale market supplies.

The following discussion describes the key assumptions used as the starting point for the Council's analysis. For many of these assumptions, while the current status is known, there is significant uncertainty about the future. That uncertainty creates risks that are addressed in the Seventh Power Plan's resource strategy, set forth in Chapter 3.

KEY FINDINGS

- Since 2011, regional employment has grown by over 500,000 jobs per year. During the last five years, gross state product for Idaho, Montana, Oregon, and Washington increased by $110 billion (2012$). The regional economy grew at a nominal annual rate of 2.26 percent per year during 2010 to 2014.
- While overall regional loads have gradually returned to pre-recession levels, the increase has been slow. Regional electric loads finally returned to pre-recession levels in about 2014. On a weather-adjusted basis, total regional loads (excluding direct service industries or DSIs) reached a high of 20,454 average megawatts in 2008. This is identical to the regional weather-adjusted loads reported for 2014. However, since these loads are net of the energy-efficiency accomplishments over this period, they mask a far more robust underlying growth rate. Between 2010 and 2014, regional electricity efficiency savings totaled over 1500 average megawatts, exceeding the Sixth Power Plan's five-year goal of 1,200 average megawatts by 25 percent. Without those savings,

regional loads, exclusive of the DSIs, would have grown from 20,111 average megawatts in 2010 to 21,611 average megawatts in 2014, or by nearly 8 percent over five years.

- While the region's highest peak loads still occur during the winter months, summer peak demands are growing faster than winter peak demands. In fact, winter peak demands have not grown significantly since 1995, while summer peaks have been increasing at about 0.4 percent annually. Nevertheless, for the region as a whole, winter peak capacity is forecast to remain the more significant need for at least the next 10 to 15 years.
- The Council's forecast for future natural gas prices over the next twenty years spans a range from a low of $3.56 per MMBtu to a high of $10.00 per MMBtu by 2035. This is a lower range of future gas prices than was used in the Sixth Power Plan.
- In June of 2014, the Environmental Protection Agency (EPA) released its draft regulations limiting carbon dioxide emissions from existing power generation facilities under section 111(d) of the Clean Air Act. These regulations were finalized in August of 2015 and call for a 32 percent reduction in carbon dioxide emissions by 2030 compared to 2005. Along with releasing its final regulations for existing generation facilities, the EPA issued its final regulations limiting carbon dioxide emissions from *new* power generating facilities under Section 111(b) of the Clean Air Act. States have until 2018 to develop plans for complying with these new carbon dioxide regulations.
- Both the Sixth Power Plan and this plan include summer bypass spill requirements identified in the FCRPS Biological Opinion and also in the Council's 2014 Fish and Wildlife Program. Since the Sixth Power Plan, the bypass spill requirements have been adjusted to better reflect the intent of the biological opinion. While bypass spill continues to reduce the generation of the hydro system, these modifications have little impact on summer hydroelectric generation relative to the Sixth Power Plan. However, increasing reliance on the hydroelectric system to provide within-hour balancing needs[1] for wind generation has diminished the system's use to meet peak needs.
- In the Northwest, the retirements of three existing coal-fired plants serving the region have been announced. The 550 megawatt Boardman plant is now scheduled to shut down by 2020, avoiding the nearly $500 million in upgrades that would have otherwise been required. At the 1,340 megawatt Centralia plant, one unit is now scheduled to close in 2020 and the other is scheduled to close in 2025. In April of 2015, NV Energy announced the retirement of the 522 megawatt North Valmy plant, which serves a portion of Idaho Power Company's load. In addition, the J.E. Corette coal-fired power plant which does not serve the region, but is located in Montana, shut down in August of 2015.
- Also since 2010, one of region's non-utility owned existing natural gas plants, the 248 megawatt Big Hanaford combined cycle turbine in Washington State, has been retired as have the Elwha and Condit small hydroelectric power plants.

[1] For more information on balancing needs see Chapter 9 and Chapter 16.

- Since the Sixth Power Plan was adopted in early 2010, three new natural gas-fired generating resources have been added in the region. The largest is Idaho Power's Langley Gulch Power Plant located near Boise. Langley Gulch is a 300 megawatt combined-cycle project that entered service in July 2012. Portland General Electric built the 220 megawatt Port Westward II, a generating set of twelve reciprocating engines, in 2014 and is currently building the Carty Generating Station, a new 440 megawatt combined-cycle project at Boardman which is expected to be in service in 2016.
- From 2010 through 2014, 4,230 megawatts of wind nameplate capacity was added to the region – with nearly 2,000 megawatts coming online in 2012 alone. By the end of 2014, wind nameplate capacity in the region totaled about 8,700 megawatts. However, only about two-thirds of that nameplate capacity currently serves Northwest loads. The remaining one-third (~3,000 megawatts) of wind nameplate capacity is presently contracted to utilities outside the region, primarily California.
- Spot market prices for wholesale power continue to be quite low, due to increasing penetration of renewable resources with low variable operating costs and low natural gas prices, and do not provide an accurate representation of the avoided cost of new resources. The low spot market prices for power affect the region's utilities differently. Utilities with limited exposure to market prices may be largely unaffected. For example, utilities whose resources closely match their customers' demands have little need to buy or sell power in the wholesale spot market. On the other hand, utilities whose resources and loads are not as closely balanced can be greatly – and very differently – affected depending on whether their resources are surplus or deficit.
- The region exceeded the Sixth Power Plan's five-year goal of 1,200 average megawatts of energy efficiency for 2010-2014 by 25 percent, achieving over 1,500 average megawatts of energy and approximately 2500 megawatts of peak savings. Actual average utility costs for energy efficiency acquisitions have remained well below the cost of other types of new resources and wholesale market prices.
- The character of the region's power system is changing. Historically, needs for new resources were driven mostly by energy deficits. Today, however, needs for peaking capacity and system flexibility are also emerging, expanding the focus of the region's planning and development of new resources to address these system needs in addition to energy. Since 2000, about 5,900 megawatts of natural gas-fired generation has been added in the region. During that same period, about 8,700 megawatts of wind power has also been built in the region. The large increase in wind generation has meant that utilities must hold more resources in reserve to help balance demand minute-to-minute; hence the need for system flexibility has become a concern. The Council estimates that the region will have sufficient generation and demand side capability on its existing system to meet balancing and flexibility reserve requirements over the next six years if the Seventh Power Plan's energy efficiency and demand response development goals are achieved. The mechanism for accessing this capability, however, may not be available to all Balancing Authorities depending on market structure/availability.
- Conditions vary across the region and from utility to utility. Some have growing loads; others are flat or have lost large customers. Some have surplus resources and others face deficits. These differences affect utilities' incentives to acquire resources, including energy efficiency.

- Regional power supply planning matters are becoming increasingly linked with electric transmission and natural gas matters, requiring greater coordination.

STATE OF THE SYSTEM

Regional Economic Conditions

Employment and job creation in the Pacific Northwest remained sluggish during 2010 and 2011, growing from 6.11 million jobs in 2009 to 6.14 million jobs in 2011, adding just 150,000 jobs each year. Since 2011, however, employment has grown by over 500,000 jobs per year to 6.3 million jobs in the region in 2014. During the last five years, gross state product (expressed in constant 2012 dollars) for Idaho, Montana, Oregon, and Washington increased from about $560 billion dollars in 2010 to about $670 billion in 2014, a net increase of $110 billion. Based on these figures, the regional economy grew at a nominal annual rate of 2.26 percent per year during 2010 to 2014.

Sectors with economic growth during the last several years included durable goods manufacturing, information technology, health care, and technical services. Declining sectors included construction, mining, transportation, wholesale trade, and government services. Overall, these changes are consistent with an ongoing general structural shift in the regional economy towards less energy-intensive industries.

Forecasts used for the Seventh Power Plan showed the region's economy growing at a fairly healthy pace, consistent with long-term historical trends. The region's population is projected to grow to over 16 million by 2035 at an annual rate of 0.9 percent. Regional personal income, both in total and on a per-capita basis, has been on the upswing and is projected to continue, although at a slower rate. From 1989 through 2009 regional personal incomes grew by about 3.9 percent per year. The Seventh Power Plan forecasts personal income growth to average 2.9 percent per year over the coming two decades. Between 2015 and 2035, commercial employment is expected to grow at an annual rate of 0.9 percent, with total employment growing from 6.4 million in 2015 to about 7.7 million by 2035.

Economic conditions also vary within the region. For example, metropolitan areas with diverse economic bases have tended to fare better than rural areas, which have traditionally been more dependent on specific industries.

Electricity Demand

Between 2010 and 2014, regional electricity weather normalized loads, inclusive of the Direct Service Industries or DSIs (the large industrial customers historically served directly by Bonneville) increased slightly, growing from 20,617 average megawatts to 21,164 average megawatts. This five year increase of just under 550 average megawatts represents a total growth of just over 3 percent. If these large customer's loads are excluded, regional electricity loads grew from 20,111 average megawatts in 2010 to 20,454 average megawatts in 2014. This is an increase of 343 average megawatts or just under 2 percent growth over five years.

While overall regional loads appear to be gradually returning to pre-recession levels, the increase has been slow. On a weather-adjusted basis, total regional loads (excluding DSIs) reached a high of 20,454 average megawatts in 2008. This is identical to the regional weather-adjusted loads reported for 2014. Thus, regional electric loads finally returned to pre-recession levels in about 2014.

However, since these loads are net of the energy-efficiency accomplishments over this period, they mask a far more robust underlying growth rate. Between 2010 and 2014, the Council estimates, based on Bonneville, utility, Energy Trust of Oregon, and NEEA reporting, that regional electricity efficiency savings totaled over 1,500 average megawatts. Without those savings, regional loads, inclusive of the DSIs, would have grown from 20,617 average megawatts in 2010 to 22,660 average megawatts in 2014, or by nearly 10 percent over five years.

While the region's highest peak loads still occur during the winter months, summer peak demands are growing faster than winter peak demands. In fact, winter peak demands have not grown significantly since 1995, while summer peak demands have been increasing at about 0.4 percent annually. At least two of the region's investor owned utilities, Idaho Power Company and Portland General Electric, have summer peak demands that are higher or nearly equivalent to their winter peak demands. Nevertheless, for the region as a whole, winter peak capacity is forecast to remain the more significant need for at least the next 10 to 15 years.

One of the newer segments contributing to demand has been data centers. Custom and mid-tier data centers have been attracted to the Pacific Northwest by financial and tax incentives, low electricity prices, and a skilled professional base. The Seventh Power Plan forecasts that electricity use by data centers could increase from their current level of 350 to 400 average megawatts to as much as 900 average megawatts by 2035. More recently, as a result of the legalization of cannabis production in Washington and Oregon, indoor agriculture is anticipated to contribute to between 100 and 200 average megawatts of increased electricity demand over the next twenty years. The Council's Seventh Power Plan also anticipates significant growth in electricity use in the transportation sector, forecasting that plug-in electric vehicles could add 160 to 625 average megawatts to regional electricity use by 2035, a significant increase from 8 average megawatts of load in 2015 created by the region's over 22,000 existing electric vehicles.

Acting in the opposite direction are the anticipated impacts of new federal appliance, lighting, equipment standards and distributed solar photovoltaic (PV) systems. More than 30 new and revised federal standards have been enacted since 2010. These standards are forecast to reduce future load growth by nearly 1500 average megawatts over the 20 year period covered by the Seventh Power Plan.

The increasing adoption by homeowners and businesses of distributed solar PV systems are also forecast to dampen regional load growth. As of the end of 2014, over 100 megawatts of distributed solar PV capacity had been installed in the region, lowering system energy requirements by an estimated 18 average megawatts. By 2035, the Council forecasts that 500 to 1,400 megawatts of solar PV systems will be installed in the region. On an annual basis, the energy generated from these distributed PV systems is forecast to reduce regional loads by 80 to 220 average megawatts. In addition, these distributed solar PV systems also reduce winter and summer peak loads. Summer peak impacts from distributed solar PV are forecast to be lower by as much as 600 megawatts by 2035.

Natural Gas Markets and Prices

When the Council adopted its Sixth Power Plan in early 2010, market prices for natural gas had just dropped dramatically. U.S. average wellhead prices for natural gas, which averaged $8.24 per million British thermal units (MMBtu) in 2008, fell by more than half to $3.76 per MMBtu in 2009.

The rapid decline in natural gas prices was the result of the unanticipated, yet massive, transformation of the natural gas industry in the late 2000s. This change was driven by the sudden emergence of the huge potential to produce natural gas from shale formations using hydraulic fracturing techniques.

To a large degree, the natural gas price forecasts used in the Sixth Power Plan reflected the shale gas phenomenon. The forecasts were reasonably accurate during the first two years of the planning period. The plan's medium case forecast showed U.S. wellhead prices of $4.78 per MMBtu in 2010 and $5.07 per MMBtu in 2011. These forecasts turned out to be higher than actual market prices, which averaged $4.53 per MMBtu in 2010 and $3.91 per MMBtu in 2011.

Beginning in mid-2011, monthly wellhead gas prices fell fairly rapidly, reaching a low of $1.98 per MMBtu for the month of April 2012 before rebounding after that. Annual average prices averaged about $2.59 per MMBtu for 2012, significantly below the Sixth Power Plan's forecast of $5.10 per MMBtu.

The decline in market prices reversed and began to increase in April 2012, but since late 2014 prices began to decline due to a crash of world oil prices and glut of natural gas production from U.S. shale plays. Wellhead prices in 2014 averaged about $3.84 per MMBtu (in 2012 dollars). As of January 2015 the outlook for 2015 composite wellhead prices was $3.60 per MMBtu. Since January 2015, oil and natural gas prices have declined further. By September 2015, wellhead prices declined to $2.70 per MMBtu (in 2012 dollars).

The U.S. Department of Energy's (DOE) Annual Energy Outlook 2015 forecasts Henry Hub gas prices will average about $3.63 per MMBtu during 2015. DOE forecasts that by 2025, Henry Hub gas prices will increase to $5.35 per MMBtu. By 2035, DOE forecasts natural gas prices will range from a low of $4.00 per MMBtu to a high of $8.64 per MMBtu. The final Seventh Power Plan uses a bench mark price of natural gas at Henry Hub of $2.64 per MMBtu for 2015 and a range forecast of $2.60-$3.70 per MMBtu in 2016. However, the Council's forecast for future natural gas price over the next twenty years spans a wider range; from a low of $3.60 per MMBtu to a high of $10.00 per MMBtu by 2035.

Increasingly, because of its low prices and apparent adequate supplies, natural gas-fired generation is displacing coal-fired generation. Coal to gas fuel switching is partly the result of environmental concerns, but it also reflects changed economics. In particular, it appears that lower market prices for natural gas are combining with higher market prices for coal to make natural gas-fired generating facilities more cost-effective.

This has raised concerns about methane emissions from the natural gas production, storage and transportation sectors. During the development of the natural gas price forecast, the issue of increased reliance on natural gas was discussed by the Council's Natural Gas Advisory Committee. In the judgment of the advisory committee, the Council's high range of the gas price forecast was sufficient to reflect the potential regulatory cost of reducing methane emissions.

Emissions Regulations and Impacts

Since the Council issued the Sixth Power Plan there has been extensive environmental regulatory activity that affects the electricity industry, much of it (but not all) relating to the production of electricity from fossil-fueled and especially coal-fired power plants. The list includes:

- Clean Air Act/national ambient air quality standards: The EPA has adopted more stringent standards for NO2, SO2, and particulate emissions, and proposed more stringent standards for ground-level ozone, all of which affect coal-fired power plants.
- Clean Air Act/regional haze rule: Continuing assessments and modifications of coal plants are required.
- Clean Air Act/ mercury and air toxics rule: The U.S. Supreme Court recently struck down and remanded the rule to the lower appellate court for further review. Regardless of the appellate court's decision, the EPA is not likely to substantially alter the rule. Many coal-plant owners have already invested in compliance measures.
- Resource Conservation and Recovery Act/fly ash regulation: In 2015, the EPA issued a new final regulation for handling coal combustion residuals, including boiler bottom ash, fly ash (ash carried in the flue gas), boiler slag, and products of flue gas desulfurization
- Clean Water Act/proposed revisions to effluent standards: In 2013, EPA proposed revisions to the standards for effluent from steam-electric power generation. The purpose is to strengthen existing controls and reduce wastewater discharges of toxic materials and other pollutants, including mercury, arsenic, lead and selenium, from especially coal-fired generation. The final rule was issued on September 30, 2015.
- Clean Water Act/cooling water intake regulations finalized: The EPA recently issued final regulations establishing new requirements for cooling water intake structures in order to protect aquatic organisms.
- Clean Air Act / carbon dioxide emissions regulations: Most notably, EPA finalized regulations under Sections 111(b) and 111(d) of the Clean Air Act limiting carbon emissions from new and existing fossil-fueled power plants. The Section 111(d) regulations call for a 32 percent reduction in carbon dioxide emissions by 2030 compared to 2005. The regulations are the subject of litigation. [2]
- Nuclear Regulatory Commission regulations: In the wake of the Fukushima Reactor accident in Japan, the Commission is requiring upgrades to existing nuclear power generating facilities to better prepare for external events beyond ordinary design criteria.

[2] U.S. Environmental Protection Agency, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," 80 Fed. Reg. 64,662 (October 23, 2015). A coalition of states, utilities, utility organizations and others challenged the rule applying to existing sources in the federal D.C. Circuit Court of Appeals. The U.S. Supreme Court stayed the effectiveness of the rule in an order issued February 9, 2016, pending not just review on the merits by the court of appeals but also the resolution of any petition for further review in the Supreme Court following whatever decision is issued by the court of appeals. The litigation is ongoing as the Council completed the Seventh Power Plan.

- Clean Air Act/development of regulations to reduce fugitive methane emissions from the production and transportation of natural gas.
- Developing regulatory environment to protect eagles and other migratory birds from threats posed by the development and operation of wind and solar generating facilities.

Details about these regulatory efforts and their impacts are discussed elsewhere in the power plan, including Appendix I. Noteworthy here, is the collective effect of these environmental regulatory efforts, especially on the region's coal-fired power plants. In addition to the federal regulations, Northwest states' policies on carbon emissions and other environmental impacts have all but eliminated construction of *new* coal-fired generating facilities as an option for meeting future resource needs. The issue for the regional power system is the effect of the announced retirements of *existing* plants, and the effect on the power system of state and federal policies that may lead to the retirement of other existing plants.

The U.S. Energy Information Administration's (EIA's) Annual Energy Outlook 2014 (AEO2014) Reference Case projects that a total of 60 gigawatts of capacity will retire by 2020, which includes the retirements that have already been reported to the EIA. Retirements are being driven in some cases by the costs of complying with new environmental regulations or the need to reduce greenhouse gas emissions. Retirements are also being driven by the age of many existing plants and the need to refurbish them. In addition, as coal prices have risen over the last several years and natural gas prices have dropped, the operating cost advantage that coal has traditionally enjoyed has shrunk.

In the Northwest, the retirements of three existing coal-fired plants serving the region have been announced. The 550 megawatt Boardman plant is now scheduled to shut down by 2020, avoiding the nearly $500 million in upgrades that would have otherwise been required. At the 1,340 megawatt Centralia plant, one unit is now scheduled to close in 2020 and the other is scheduled to close in 2025. In April of 2015, NV Energy announced the retirement of the 522 megawatt North Valmy plant, which serves a portion of Idaho Power Company's load. In addition, the J.E. Corette coal-fired power plant which does not serve the region, but is located in Montana, shut down in August of 2015.

The trend toward retiring existing coal-fired power plants across the U.S. is having other spillover effects on the Northwest region. As domestic coal-fired generation falls, coal producers are turning their attention to offshore markets as a way to continue production. This includes major companies in the Powder River Basin of Wyoming that have ramped up efforts to market their coal to Asian markets and are seeking to ship coal through the Northwest to export terminals near the coast.

Meanwhile, Northwest cities and counties that have climate policies or initiatives include: Seattle, Anacortes, Bellingham, King County, Olympia, and Whatcom County in Washington; Portland, Bend, Corvallis, and Multnomah County in Oregon; Boise, Idaho; and Bozeman and Missoula in Montana.

Developments Affecting Power Imports from California

The Northwest and California are interconnected through AC and DC transmission interties with approximately 7,900 megawatts of maximum transfer capability, including 4,800 megawatts on the AC intertie and 3,100 megawatts on the DC intertie. Due to transmission loading on either end, the actual amount of transfer capability is closer to 6,000 megawatts and could be much lower if one of the lines is undergoing maintenance.

The two regions use these interties to share their power resources to help keep costs down. Because California's peak loads occur in the summer, that system normally has surplus capacity during the winter when Northwest loads are highest.

However, a number of changes have occurred in California since the Sixth Power Plan was adopted that have the potential to reduce the availability of winter imports to the Northwest and increase the need for new resources.

In May 2010, the California Water Resources Board adopted a statewide water quality control policy to meet the federal Clean Water Act's requirement to use the best technology available in power plant cooling processes. This is expected to force about 6,659 megawatts of older California generating plants into retirement by 2017. Other expected California resource retirements through 2017 are expected to reduce generation by an additional 1,030 megawatts.

Much of the retiring capacity in California is being replaced with modern gas-fired generation, including combined-cycle combustion turbines that are more fuel-efficient than the once-through-cooling plants and also have lower air emissions. Retiring capacity is also being replaced in California with fast responding simple-cycle combustion turbines that will provide capacity and help integrate renewables.

Also affecting the California market, both units at the San Onofre Nuclear Generating Station (SONGS), with about 2,200 megawatts of nameplate capacity, were taken out of service in January 2012 due to excessive wear in steam generator tubes. In June of 2013, the decision was made to retire the SONGS units.

Based on this information regarding California resources and considering California's load projections, the Council's Resource Adequacy Advisory Committee recommended limiting available on-peak spot market imports to 2,500 megawatts during winter and none during summer. A review of historical south-to-north intertie transfer capability for winter months led the advisory committee to also recommend limiting the maximum south-to-north transfer capability to 3,400 megawatts.

Prior to the development of the Seventh Power Plan, the Council commissioned a study of market supplies available from California. The Energy GPS[3] study concluded that power surpluses from California during winter months are highly likely to exceed the south-to-north intertie transfer capability.

Another major factor is California's increasing reliance on renewable resources to meet its energy needs. In 2011, the California legislature passed a law requiring the state's utilities to serve 25 percent of their retail customers' loads with qualified renewable resources by 2016; this requirement increases to 33 percent by 2020. The law also established new policies limiting the use of renewable

[3] Belden, Tim and Turkheimer, Joel, "Southwest Import Capacity", June 12, 2014, see www.nwcouncil.org/energy/resource/home/.

generation from outside California to meet the requirements. In September of 2015, the California legislature increased the minimum requirement to 50 percent by 2030. Many California utilities are already serving 20 percent or more of their customers' needs with renewable energy.

In order to meet these increasing renewable portfolio standards (RPS), California utilities have been increasingly turning to solar power development, as costs for photovoltaic systems have been falling rapidly. In 2014, solar power plants in California produced 10,555 gigawatt-hours (GWh) or 5.35 percent of the state's total electricity production. In August of 2015, California recorded its highest solar output to date, with 6,341 megawatts of solar capacity contributing to meeting that states electricity needs. The large scale of solar development in California, however, presents significant challenges for power system operations and affects Northwest power markets.

Since the RPS are based on an energy metric (i.e. RPS resources must meet a minimum share of annual retail electricity sales) and both solar and wind generation only operate a fraction of the hours in a year, the peak output of such systems is significantly (3 to 6 times) higher than the average output. As a result, integrating these resources into the existing power system requires that generation (usually gas-fired) must be ready to ramp-up or ramp-down to offset increases or decreases in wind and solar output. This gas-fired generation cannot be used to provide other types of reserves when it is designated for integration.

Separate from the physical integration challenges associated with increasingly larger amounts of wind and solar generation on the system, is the impact that these low-variable cost resources have on wholesale market prices. The spring and early summer months are when Northwest hydroelectric generation peaks due to spring runoff. This is also the period of the year when both wind and solar generation tend to be at their highest. The coincidence of the peak output of all three renewable resources, hydro, solar, and wind, can produce extremely low market prices due to supply far outstripping demand.

Unfortunately, wind resources contribute little to meeting peak demands and solar generation is typically much higher during summer months, which means less capacity would be available during the Northwest's peak season in winter. However, combustion turbines are used to provide within-hour balancing needs for renewable resources, some of their capacity might be available in winter for Northwest use. California is using summer-only demand response programs to help reduce its summer resource needs. This may reduce the amount of thermal generation peaking capacity available to serve Northwest loads in winter.

The final development affecting the California market's influence on the Northwest is that in June of 2014 the California Independent System Operator (CAISO) won approval from the Federal Energy Regulatory Commission (FERC) to expand its real-time energy imbalance market (EIM) beyond state borders, with PacifiCorp and NV Energy the first to join. In addition to PacifiCorp and NV Energy, at least three other non-California utilities, Portland General Electric in Oregon, Washington's Puget Sound Energy, and Arizona's Arizona Public Service have signed agreements to participate in the CAISO's EIM. All of the Northwest utilities had been participating in negotiations to create a regional EIM through the Northwest Power Pool.

Among the most significant issues raised by the CAISO's expanded footprint is whether it will grow into something more than a simple energy imbalance market that could lead to improved operational efficiencies for the 38 independently operated balancing authorities in the western interconnection.

Such developments were too speculative to consider in the analysis supporting the Seventh Power Plan, but could be a significant issue for the Eighth Power Plan.

Wholesale Power Markets and Prices

For the Seventh Power Plan, three factors were identified as being likely to significantly influence future conditions in wholesale power markets: market prices for natural gas; potential new regulatory requirements for generating resources that emit greenhouse gases; and development of renewable resources to satisfy requirements of state renewable portfolio standards. A range of forecasts of wholesale power prices was then prepared using alternative assumptions about these factors.

Since the Sixth Power plan was adopted in early 2010, developments across all three of these areas have occurred that will directly impact future wholesale power market prices. First, the supply-side impacts of shale gas continue to unfold, causing market prices for natural gas to remain at low levels. Second, there are now federal regulatory mechanisms to reduce greenhouse gas emissions. Third, renewable resource development has added significant amounts of new generating resources whose output has very low variable operating cost. The combination of large amounts of new renewable resources in the Western wholesale power market and large supplies of hydroelectric generation, both of which have low variable operating costs, is producing very low spot market prices for wholesale power more often.

These and other factors (modest growth in demand for electricity) have caused actual spot market prices for wholesale power supplies during the last several years to be at or even below the low end of the range of forecasts used for the Sixth Power Plan. For example, actual spot market prices for wholesale power supplies bought and sold at the Mid-Columbia trading hub averaged about $26 per megawatt-hour during the period July 2014 through June 2015. In contrast, average prices for calendar year 2008 were 240 percent higher. The Council's Seventh Power Plan forecast for spot market prices ranges from an average of $25 per megawatt hour to an average of $68 per megawatt hour over the next twenty years.

The low spot market prices for power affect the region's utilities differently. Utilities with limited exposure to market prices may be largely unaffected. For example, utilities whose resources closely match their customers' demands have little need to buy or sell power in the wholesale spot market. On the other hand, utilities whose resources and loads are not as closely balanced can be greatly – and very differently – affected depending on whether their resources are surplus or deficit.

Some of the region's hydro-based utilities have surplus power supplies at certain times of the year and depend on revenues from sales of their excess power into the wholesale market to keep power rates low. These utilities can experience significant revenue shortfalls and budgetary pressures when wholesale market prices are low. For hydro-based utilities, the impacts are magnified if the surplus energy they have to sell during the spring runoff coincides with surplus generation from other hydro systems, driving spot market prices to very low levels. This occurred during the period from April 2011 through July 2011, when spot market prices averaged well under $15 per megawatt-hour.

Conversely, utilities that do not have enough long-term resources to meet all of their customers' loads are net buyers in the short-term wholesale markets. When spot market prices are low, their power purchase costs are also low, reducing upward pressure on their retail electric rates. Relying on market purchases can be risky, as illustrated during the 2001 Western energy crisis. However, for now, these utilities are reaping the benefits of low market prices.

For all utilities, the depressed spot market prices for wholesale power are currently below the full cost of virtually any new form of generating resource.

Implementation of Bonneville Tiered Rates

In October 2011, the Bonneville Power Administration implemented tiered rates for its sales of wholesale power to the region's public utilities. Bonneville's tiered rates are designed to allocate the benefits of the existing federal power system and provide more direct price signals about the costs of new resources to meet load growth.

Under tiered rates, Bonneville's power sales are divided into two distinct blocks, or tiers. The rate for tier 1 power sales is based on the embedded cost of the existing federal power system. The tier 2 rate is set at Bonneville's cost to acquire power supplies from other sources. When a utility customer exceeds its allocation of tier 1 power, it can elect to buy tier 2 power from Bonneville, or it can acquire new resources itself. The alternatives include utility development of new energy-efficiency and/or generating resources, as well as wholesale power purchases from third party suppliers.

Currently, the average cost of Bonneville's tier 1 power is roughly $32 per megawatt-hour. With the exception of energy efficiency, this is below the typical cost to develop new resources. Ninety of Bonneville's public utility customers are projected to exceed their tier 1 allocations in 2017 and thus will have to acquire additional resources.[4] The prospect of exceeding their tier 1 allocation in the future may already be influencing their behavior. There is anecdotal evidence that some utilities are taking action to avoid spot market purchases. So to a certain extent, tiered rates are achieving the intended purpose of providing more efficient pricing signals to Bonneville's utility customers.

However, prices for wholesale power purchased in the wholesale market remain relatively low, often below the cost of new resources or even below Bonneville's tier 1 rate. While spot market prices can be quite volatile, the addition of large amounts of new renewable resources with low variable operating costs has contributed to low spot market prices. To the extent that Bonneville or utilities purchase power in the short-term market to meet their incremental resource needs, this mutes the tier 2 price signal.

Finally, there is also the matter of whether and how the price signal provided by Bonneville's tiered rates is passed through to each utility's retail electric customers. Retail customers are the end-users of electricity; their behavior affects load growth and load shapes. By incorporating Bonneville's price signals, utilities could influence their retail customers to reduce their total use of electricity and their peak demand by modifying their retail rate structures, by designing and executing energy efficiency and demand response programs, or a combination of these policies.

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[4] http://www.bpa.gov/power/pl/regionaldialogue/implementation/documents/docs/Formatted_Tables_RHWM_Process_2016_FINAL.xlsx

The Region's Utilities Face Varying Circumstances

Utilities across the region have experienced a variety of challenges and successes in the last few years. Some were expected and some are new, reflecting an ever-changing operating environment. As a result, the needs and incentives to acquire new resources also vary among the region's utilities.

Continued economic stagnation, particularly in the region's rural areas, has meant low overall load. Poor economic conditions have also triggered the loss of existing industrial loads as certain manufacturing facilities were shut down. For example, Snohomish County Public Utility District lost a big portion of its industrial load when customer Kimberly-Clark was forced to close its mill in early 2012.

Some utilities now find themselves with power supply resources that exceed their retail customers' demands. For these utilities, low spot market prices for wholesale power reduce the revenues they generate from sales of surplus power, putting pressure on utility budgets. In turn, this can create upward pressure on the utility's retail electric rates.

Meanwhile, those utilities that have not yet exceeded their entitlements to purchase power from Bonneville at tier 1 rates face lower near-term price signals than the cost of new resources. Consequently, their short-term economic incentives to acquire new energy-efficiency resources at costs above the tier 1 rate are reduced.

On the other hand, the region has been a hotbed for new data center loads as companies like Google, Microsoft, and Facebook take advantage of the mild climate and low electricity prices to develop facilities in the Northwest. For example, Amazon has recently built data centers in the Umatilla Electric service territory, increasing their load substantially. Several of the Mid-Columbia public utility districts have also seen significant growth as new data centers locate in their territory.

Certain utilities adding large new retail customers face the prospect of growing enough to become subject to higher state renewable requirements. These utilities may also exceed their entitlement to purchase power from Bonneville at tier 1 rates.

The first Centralia and Boardman coal-fired power plants will be retired in 2020 and the second Centralia and North Valmy coal-fired power plants will be retired in 2025. These planned retirements will eventually increase regional and individual utilities' needs for new resources, particularly among the region's investor-owned utilities.

As noted above, low spot market prices for wholesale power can be detrimental for utilities with surplus resources. However, low market prices can be beneficial for utilities whose long-term resources (including tier 1 purchases from Bonneville) are not sufficient to meet their retail customers' demands. Purchases from the short-term wholesale market can be a low-cost source of power to help fill these utilities' deficits. This can create an economic incentive to rely on short-term market purchases as an alternative to making long-term investments in higher-cost new resources, including energy efficiency.

Small and rural utilities face special challenges in acquiring efficiency resources. These include the absence of economies of scale enjoyed by larger utilities in urban areas and less availability of qualified contractors. Approaches to acquire energy efficiency must be tailored to meet their unique needs. Pursuant to actions recommended in the Sixth Power Plan, Bonneville, NEEA, and the Council's Regional Technical Forum established work groups and policies to address those needs. In addition, Bonneville also established a low-income working group to address the needs of those consumers in the region who lack the means to participate in utility programs but may have significant opportunities for energy efficiency in their residences.

Energy Efficiency Achievements

The Sixth Power Plan identified a range of likely energy efficiency resource acquisition during 2010 to 2014 of between 1,100 and 1,400 average megawatts. Within this range, the Sixth Plan recommended setting budgets and taking actions to acquire 1,200 average megawatts of savings from utility program implementation, market transformation efforts, and codes and standards.

The plan estimated that the region would ramp up its pace of acquisition during the initial five-year period. Despite a sluggish economy, which limited new building construction and equipment replacement, the region's overall acquisition exceeded the Council's ramp-up expectations surpassing the high end of the expected savings range.

Over the first five years of the Sixth Power Plan, the region's utilities, the Bonneville Power Administration, Energy Trust of Oregon, and Northwest Energy Efficiency Alliance (NEEA) acquired nearly 1,300 average megawatts of efficiency. In addition to the savings acquired by the utilities, Bonneville, Energy Trust, and NEEA, all four states recently adopted new building energy codes. NEEA estimates that improvements in state energy codes have produced 18 average megawatts of savings over the last five years.

Another significant contributor to savings in recent years is due to the adoption of minimum efficiency standards for energy-using products. Since 2009, the federal Department of Energy has issued final product standards for more than 36 products ranging from refrigerators to utility transformers. Some of these standards took effect in between 2010 and 2014, producing about 50 average megawatts of additional savings during that period. States have also begun to adopt minimum standards for products not covered by federal standards, such as battery chargers.

In addition, consumer uptake of efficient products, outside of direct utility-funded programs, has been particularly strong for lighting equipment since 2010. In part, this consumer uptake is due to prior utility programs pushing efficient products into markets and in part it may be due to consumer preference. Together, minimum product standards and consumer uptake added about 220 average megawatts of documentable savings outside of direct utility-funded programs in the 2010 to 2014 period.

All told, between utility-funded programs, state codes and standards, federal standards, and consumer uptake, the region captured just over 1500 average megawatts of energy and approximately 2500 megawatts of peak savings during 2010-2014, achieving 125 percent of the Sixth Power Plan goal and surpassing the high end of the expected energy savings range.

Demand Response Activities

The two regional utilities with the most experience in acquiring and using demand response (DR), PacifiCorp and Idaho Power, have continued to expand and refine their programs. Both are now exercising control over 700 megawatts of their in-region peak loads. While other regional utilities have not acquired DR to this extent, some are gaining experience with it. PGE has contracted for 28 megawatts of DR in the industrial and commercial sectors, and continues to conduct pilot programs, currently focusing on the residential sector. BPA continues to explore pilot programs and demonstration projects in cooperation with its utility customer, Energy Northwest, and EnerNOC, testing the capability of DR resources to provide winter peak reductions, within-hour balancing of variable energy resources, and strategic transmission relief. BPA has also arranged for 35 to 100 megawatts of contingent reserves to be provided by industrial customers.

Puget Sound Energy and Avista have both conducted demand response pilot programs in the recent past. However, while both companies have identified the technical potential of demand response and evaluated DR as part of their resource planning process, neither of these utilities is currently acquiring DR resources.

Renewable Resources Development

Since the adoption of the Sixth Power Plan, renewable generating resources development has increased significantly. This development was prompted by renewable portfolio standards (RPS) adopted in three of the four Northwest states and in California. Wind energy has been the principal focus of renewable resource development in the Pacific Northwest. From 2010 through 2014 about 4,100 megawatts of wind nameplate capacity was added to the region, with nearly 2,000 megawatts of capacity coming online in 2012 alone. By the end of 2014, wind nameplate capacity in the region totaled just over 8,700 megawatts. However, only about two-thirds of that nameplate capacity currently serves Northwest loads. The remaining one-third (~3,000 megawatts) of wind nameplate capacity is presently contracted to utilities outside the region, primarily California.

Snohomish PUD began producing power from its 7.5 megawatt Youngs Creek run-of-river hydroelectric project in October 2011. It is the first new hydroelectric power plant to be built in Snohomish County since the early 1980s.

As noted above, until recently, a considerable amount of wind power was developed in the Northwest for sale to California utilities subject to that state’s renewable portfolio standards. However, it is expected that few additional Northwest wind resources will be built for this purpose, despite California having raised its RPS requirement to 33 percent by 2020, and recently increased to 50 percent by 2030. The reason is that restrictions imposed by the California legislature in 2011 effectively block further imports from outside the state to meet RPS needs. Another contributing factor is that costs for solar photovoltaic generation have come down to the point where in-state solar is increasingly competitive with imported wind generation.

In terms of developing renewable resources to meet Northwest RPS needs, actual results have been generally consistent with the Sixth Power Plan. The Sixth Power Plan’s resource strategy incorporated projections that the region would add over 1,400 average megawatts of renewable resources over 20 years to meet renewable portfolio standards that the states have enacted. The new renewable resources were anticipated to be almost wholly wind power.

Notable differences between the Sixth Power Plan and this Seventh Power Plan in terms of renewables development include the following:

1. While the Sixth Plan assumed renewable resources would be developed to meet 95 percent of RPS targets, recent experience suggests most utilities are actually achieving 100 percent (and sometimes more) of their target levels several years in advance of the requirement.
2. Construction of renewable resources to serve the California market is expected to slow, if not end completely.

The quantity of reserves on the Bonneville system to provide balancing services has remained relatively constant, even as wind on the system has increased. Nevertheless, the ability of the hydro system to provide balancing services varies, and at times it has dropped to near zero. At such times, wind generation or delivery schedules are limited to maintain the power system supply and demand balance. This has occurred primarily during very high flow spring months when the hydro system must pass prescribed flow levels for flood control and environmental requirements constrain the ability to pass water over spillways. This occurs when the generation level is high and relatively fixed.

In addition to the limited ability to provide balancing services during these oversupply events, Bonneville has at times had trouble finding markets for its power at acceptable (non-negative) prices. It implemented a controversial policy of displacing wind resources with hydro generation under negative market price conditions when hydro turbine generating capability is available but it could not spill additional water without exceeding Clean Water Act limits on dissolved gas levels.

The Council convened an Oversupply Technical Oversight Committee to recommend actions to reduce oversupply events. The committee developed a number of recommendations to more cost-effectively deal with oversupply events. The region continues to develop methods to integrate wind generation into the grid and the last Bonneville oversupply event was in 2011.

Meanwhile, as noted, costs for solar photovoltaic generation have dropped dramatically during the last several years. In the Sixth Power Plan, the Council estimated that solar photovoltaic generation would cost about $254 per megawatt hour. The Seventh Power Plan's estimated cost of solar photovoltaic generation located in Southern Idaho now ranges from as low as $61 to $91 per megawatt hour – a 64 to 76 percent cost reduction. Although solar potential is lower in much of the Northwest compared to other areas such as the Southwest, the economic and commercial viability of solar power has improved such that in the best Northwest sites (e.g., Southern Idaho), the levelized cost of solar production is lower than the levelized cost of wind generation.

Additions and Changes to Fossil-Fueled Generating Resources

The Sixth Power Plan's resource strategy called for phased optioning (siting and licensing) of new natural gas-fired generation facilities, including up to 650 megawatts of single-cycle combustion turbines and 3,400 megawatts of combined-cycle combustion turbines. The Sixth Power Plan's resource strategy also recognized it may be necessary to develop additional natural gas-fired generation when individual utilities need to address local capacity, flexibility, or energy needs not captured in the plan's region-wide analysis.

Since the Sixth Power Plan was adopted in early 2010, the largest new natural gas-fired generating resource added in the region is Idaho Power's Langley Gulch Power Plant located near Boise. Langley Gulch is a 300 megawatt combined-cycle project that entered service in July 2012. Portland General Electric built the 220 megawatt Port Westward II, a generation set of twelve reciprocating engines, in 2014 and is currently building the Carty Generating Station, a new 440 megawatt combined-cycle project at Boardman which is expected to be in service in 2016.

Since the adoption of the Sixth Plan some utilities have issued requests for proposals (RFPs) to acquire generating resources. An informal survey conducted for the Mid-Term Assessment Report (2012-13) identified RFPs calling for over 3,100 megawatts of conventional generating resources, including base load, intermediate, and peaking resources. It is likely that some of their needs will be met by uncommitted power plants in the region.

For example, in late July 2012, Puget Sound Energy (PSE) and TransAlta announced a power sales contract that will supply base load generation from the Centralia coal-fired plant to PSE from December 2014 to December 2025, including 380 megawatts of coal-fired generation during the period December 2016 to December 2024.

After the Sixth Power Plan was issued, planned retirements of several generating resources were announced, including closure of the 550 megawatt Boardman coal plant in 2020 and closure of one 670 megawatt unit at the Centralia coal plant in 2020 and the other 670 megawatt unit in 2025. More recently the retirement of the 522 megawatt North Valmy coal plant in Nevada scheduled for 2025 was announced as well as the closure of the 172 megawatt J.E. Corette coal plant in Montana in 2015. In addition to coal plant retirements, the 248 megawatt Big Hanaford combined cycle natural gas generator, a non-utility owned plant, was taken out of service in 2014. The replacement of the energy and capacity lost as a result of these retirements is addressed in the Seventh Power Plan's resource strategy.

Hydroelectric System Operational Changes

The operational flexibility and generating capability of the Columbia River Basin hydroelectric system has been reduced since 1980 primarily due to efforts to better protect fish and wildlife. Over the past thirty years, the pattern of reservoir storage and release has shifted some winter river flow back into the spring and summer periods during the juvenile salmon migration period. In addition, minimum reservoir elevations have been modified to provide better habitat and food supplies for resident fish. The results of these changes have reduced the hydroelectric system's firm energy generating capability by about ten percent or by roughly 1,100 average megawatts. Most of these changes have occurred between 1980 and the early 2000s. More recent summer bypass spill requirements, identified in the FCRPS Biological Opinion and included in the Council's 2014 Fish and Wildlife

Program, for example, do not significantly affect hydroelectric generation. Since about 1995, the hydroelectric system's peaking capability devoted to meeting firm load has dropped by about 5,000 megawatts. This is due, in part, to the high development of wind resources and the correspondingly greater allocation of hydroelectric system capability toward providing within-hour balancing needs.[5]

Shifting Regional Power System Constraints

In most of the other regions of the country, power system planning and development tend to focus on making sure that resources will be adequate to meet customer demands during relatively short extreme peak periods such as cold winter or hot summer weather events. In those regions, if resources are adequate to meet peak demands, they are usually sufficient to meet energy needs throughout the year. This is largely because other regions mainly rely on fossil-fueled and nuclear power, whose fuel supplies are relatively abundant and controllable. These systems are described as capacity constrained.

In contrast, the Pacific Northwest power system has traditionally been characterized more as energy-constrained. The main reason for this has been our region's abundance of hydroelectric generation. Unlike other forms of generation that consume fossil or nuclear fuels, the amount of energy the hydro system can produce fluctuates with supplies of water, which in turn depend on uncertain streamflows and limited reservoir capacities. As a result, in the past, the Northwest power system had more than adequate resources to meet peak demands. When constraints occurred, they were usually related to the availability of energy across longer periods of time.

However, during the last decade or so, the Northwest power system has gradually become less energy constrained and more capacity constrained. New resources, partly to meet load growth and partly to meet state-mandated renewable portfolio standards, are driving this shift, and as these new resources have been added, hydro generation's share of the region's total portfolio of resources has gradually declined.

For example, since 2000, about 5,900 megawatts of natural gas-fired generation has been added in the region. During that same period, over 8,700 megawatts of wind power has also been built in the region. The large increase in wind generation has meant that utilities must hold more resources in reserve to help balance demand and resources minute to minute; therefore, the need for system flexibility has become a growing concern. The Council estimates that the region will have sufficient generation and demand side capability on its existing system to meet balancing and flexibility reserve requirements if the Seventh Power Plan's energy efficiency and demand response development goals are achieved. The mechanism for accessing this capability, however, may not be available to all Balancing Authorities depending on market structure/availability.

Persistent low spot market prices for wholesale power are another sign that the Northwest power system has become less energy-constrained. To a degree, low power prices are the result of low prices for natural gas. However, they also reflect direct and ongoing competition between hydro generation and newly-added wind power. Both have very low incremental operating costs and during

[5] For more information on balancing needs see Chapter 9 and Chapter 16.

periods of strong runoff and robust winds, competition between the two can drive spot market prices to very low levels.

The region is making progress developing a variety of additional mechanisms to integrate wind power, including recent activity in the region and California regarding the establishment of a sub-hourly energy imbalance market. Improving market liquidity across balancing authorities is likely to have a positive effect on the region's needs for peaking capacity and flexibility.

Looking forward, it is apparent that regional power planning needs to take into account shifting constraints on the system. These include reduced constraints for energy and increasing constraints for peaking capacity and for system flexibility.

Power and Transmission Planning

Momentum to coordinate power resource and transmission system planning activities has grown in the last few years. Several forces are driving this, including:

- Renewable resources development which, because of their variability, affect power markets and system operations;
- Changes to generation and/or transmission facilities in one area can often cause impacts in other areas;
- Recent major outages that have cascaded across multiple systems, including a widespread event that occurred in the Southwest in September 2011;
- More stringent and comprehensive reliability standards;
- A growing need for new transmission facilities; and
- Increasing costs to transmit and integrate renewable and other new generating resources.

In response, various activities and initiatives have been undertaken:

- Federal Energy Regulatory Commission (FERC) Order 1000 requiring transmission planning and cost allocation;
- Western Electricity Coordinating Council (WECC) Transmission Expansion Planning Policy Committee (TEPPC);
- Changing roles for WECC (pending division into two organizations);
- Planning activities of Columbia Grid, Northern Tier Transmission Group (NTTG), California Independent System Operator; and
- Activities to restructure the market and develop new practices (diversifying area control management, investigating energy imbalance markets).

Historically, a major focus for transmission planning was analyzing power flows under peak loading conditions and during contingency events. More recently, attention has broadened to include simulating power flows during various market and operating scenarios. As a result, production simulation models similar to those used for integrated resource planning are also being used for transmission system planning studies. Transmission studies also require assumptions about what new resources will be added by type, quantity, and location.

Past Council power plans have addressed various transmission issues, but intra-regional transmission system constraints and alternative approaches to address such constraints have not been extensively analyzed.

Given the changing situation, regional power and transmission system planning should coordinate by:

- Including the intra-regional transmission constraints and major planned transmission projects in the Council's power system analyses;
- Including the Council's power plan assumptions, forecasts, and results in transmission planning studies; and
- Cross-checking for consistency of major inputs to power and transmission planning studies.

The Council continues to work with ColumbiaGrid to identify areas for coordination and to improve coordination with other organizations, including WECC, TEPPC, and NTTG.

Power and Natural Gas System Convergence

During the last decade, natural gas-fired generation has become the leading fossil-fueled resource, both in the Pacific Northwest and nationally. Over 5,900 megawatts of gas-fired generation has been added in the region since 2000. Gas-fired generation is relatively flexible and can be used to supply energy and capacity, as well as help balance variable output from other resources, including wind power.

As gas-fired generation has become a bigger part of the power system, it has also become a significant source of demand on the existing natural gas pipeline and storage system. This has raised questions about the adequacy of the natural gas system to serve direct end users and to fuel electric generation. Challenges resulting from increased use of gas-fired generation which are being addressed in regional and national forums include:

- Different scheduling and operating practices used by the electric and natural gas industries;
- Gas-electric communication and coordination during extreme weather conditions or outage events;
- Planning and development of pipeline and underground storage infrastructure;
- Access to pipeline and storage facilities for local distribution companies and electric generation; and
- The impact of rapid swings in use of natural gas for generation to balance variable energy resources like wind power.

In response to these issues, several activities have been launched, including the following:

- The Pacific Northwest Utilities Conference Committee and the Northwest Gas Association formed a joint power and natural gas planning task force; this has established strong dialog and closer coordination.
- During the summer of 2012 and in February 2013, the Federal Energy Regulatory Commission held a series of technical conferences on gas-electric coordination.
- The Northwest Mutual Assistance Agreement was revamped and expanded to improve utility industry responses to emergency conditions.

- A committee of the Western Interstate Energy Board was convened to assess gas-electric issues in the Western U.S., including planning to ensure gas infrastructure remains adequate.

To date, the results of these activities have identified various opportunities to improve communication by the electric and natural gas industries. As natural gas continues to be used to generate electricity, further attention to power and gas convergence will likely be needed.

Fortunately, it is becoming apparent that our region's natural gas infrastructure is relatively robust when compared with other regions. For example, the Northwest has more underground gas storage capacity than some other regions. In addition, deliverability from interstate pipelines has not been significantly impacted by regional shifts in gas production due to rapid growth in shale gas production, as may be occurring elsewhere. Further, the great majority of natural gas-fired generating facilities in the Northwest have firm pipeline capacity rights, fuel-switching capability, or both.

Columbia River Treaty Review

One of the uncertainties with the Pacific Northwest power supply over the next decade is the fate of the Columbia River Treaty, the agreement with Canada executed in the early 1960s. Under the treaty, Canada agreed to build three projects in the portion of the Columbia River in British Columbia that stores more than 15 million acre feet of Columbia River runoff. BC Hydro manages the treaty storage projects primarily for flood control and power generation optimization. The U.S. delivers to Canada a share of the downstream power benefits known as the Canadian Entitlement, calculated by a method set forth in the treaty and an accompanying protocol. This delivery ranges from 1,176 to 1,369 megawatts (MW) of capacity and 465 to 567 annual average megawatts (aMW) of energy.

Under the treaty, the annual assured flood control operations ends in 2024, to be replaced with a "called upon" flood control operation which has yet to be specified in any detail. Unless the two nations agree to a new arrangement for flood control, there is a good chance flood control operations at both the U.S. and Canadian storage projects will change significantly after 2024, affecting generation patterns as well.

The treaty's provisions governing coordinated power operations do not change automatically in 2024. Either nation may terminate the treaty beginning in 2024, with at least 10 years' notice.

The Bonneville Power Administrator and the Corps of Engineers' Northwestern Division Engineer (together the designated U.S. Entity under the treaty) joined with other federal agency, state, and tribal personnel from 2011-13 to review the current treaty and recommend changes. Out of this effort came the "U.S. Entity Regional Recommendation for the Future of the Columbia River Treaty after 2024," delivered to the State Department in December 2013. The U.S. Entity regional recommendation recommended neither termination nor the status quo, calling instead for the two nations to negotiate a "modernized" treaty with modifications that respond to the current issues with flood control, coordinated power operations, ecosystem needs, and the calculation and sharing of benefits. The Province of British Columbia led a similar review, and produced what it called its "Columbia River Treaty Review: B.C. Decision" at the same time. Neither the U.S. State Department nor Foreign Affairs Canada has responded officially to the regional recommendations. The NW region is waiting for confirmation from the U.S. State Department that they are ready to begin negotiations which could commence within the year.

The main point for this assessment is that the region is heading into a period of uncertainty after many decades of relative certainty and international cooperation. For the purposes of the Seventh Power Plan, it is impossible to know at this time whether and how storage operations in Canada and thus flows across the border may change after 2024, nor what changes may need to be made to storage operations at U.S. projects, both affecting the generation output and patterns of the system. Nor is it possible to know whether and to what extent there will be a change in the power benefits the U.S. will deliver to Canada in the future. This is a level of uncertainty the Council needs to consider in its resource planning.

CHAPTER 3: RESOURCE STRATEGY

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KEY FINDINGS

The resource strategy for the Seventh Power Plan relies on energy efficiency, demand response, and natural gas-fired generation to meet the region's needs for energy and peaking capacity. In addition, the region needs to better utilize, expand, and preserve its existing electric infrastructure and research and develop technologies for the long-term improvement of the region's electricity supply. This resource strategy, with its heavy emphasis on low-cost energy efficiency and demand response, provides a least-cost mix of resources that assures the region an adequate and reliable power supply that is highly adaptable and reduces risks to the power system.

The resource strategy for the Seventh Power Plan consists of eight primary actions: 1) achieve the energy efficiency goals in the Council's plan, 2) meet short-term needs for peaking capacity through the use of demand response except where expanded reliance on extra-regional markets can be assured, 3) increase the near term use of existing natural gas fired generation, 4) satisfy existing renewable-energy portfolio standards, 5) increase the utilization of regional resources to serve regional energy and capacity needs, 6) support policies that cost effectively achieve state and federal carbon dioxide emission reduction goals while maintaining regional power system adequacy, 7) support the research and development of emerging energy efficiency and clean energy resources and 8) adaptively manage future resource development to match actual future conditions.

A RESOURCE STRATEGY FOR THE REGION

The Council's resource strategy for the Seventh Power Plan provides guidance for Bonneville and the region's utilities on choices of resources that will supply the region's growing electricity needs while reducing the economic risk associated with uncertain future conditions, especially those related to state and federal carbon emission reduction policies and regulations. The resource strategy minimizes the costs and economic risks of the future power system for the region as a whole. The timing of specific resource acquisitions is not the essence of the strategy. The timing of resource needs will vary for every utility. Some utilities now find themselves with power supply resources that exceed their retail customers' demands. For these utilities, low spot market prices for wholesale power reduce the revenues they generate from sales of surplus power, putting pressure on utility budgets. In contrast, the region has been a hotbed for new data center loads as companies like Google, Microsoft, and Facebook take advantage of the mild climate and low electricity prices to develop facilities in the Northwest. The addition of loads from these new data centers to service territory can dramatically change the utilities resource needs. The important message of the resource strategy is the nature and priority order of resource development.

Summary

The resource strategy is summarized below in eight elements. The first two are high-priority actions that should be pursued immediately and aggressively. The next five are longer-term actions that must be more responsive to changing conditions in order to provide an array of solutions to meet the long-term needs of the regional power system. The final element recognizes the adaptive nature of the power plan and commits the Council to regular monitoring of the regional power system to identify and adjust to changing conditions.

Energy Efficiency: The Council's analysis found that development of between 1300 and 1450 average megawatts of energy efficiency by 2021 was cost-effective across a wide range of scenarios and future conditions. The Seventh Power Plan's resource strategy calls upon the region to aggressively develop conservation with a goal of acquiring 1,400 average megawatts by 2021, 3000 average megawatts by 2026 and 4,300 average megawatts by 2035. Conservation is by far the least-expensive resource available to the region and it avoids risks of volatile fuel prices, financial risks associated with large-scale resources, and it mitigates the risk of potential carbon emission reduction policies to address climate-change concerns. In addition, conservation resources not only provide annual energy savings, but contribute significantly to meeting the region's future needs for capacity by reducing both winter and summer peak demands.

Demand Response: The Northwest's power system has historically relied on its large hydroelectric generators to provide peaking capacity. While the hydrosystem can typically meet the region's peak demands, that likelihood decreases under critical water and weather conditions, which increases the probability of not meeting the Council's resource adequacy standard without development of additional peaking resources.

The least-cost solution for providing new regional peaking capacity is to develop cost-effective demand-response resources – voluntary and temporary reductions in consumers' use of electricity when the power system is stressed. However, the Council's analysis also found that the need for demand response resources is sensitive to assumptions regarding the availability and prices of importing power from outside the region to meet peak demands under lower water and extreme temperature conditions. The Council's analysis indicates that a minimum of 600 MW of demand response resources would be cost-effective to develop under all future conditions tested across all scenarios which do not rely on increased firm capacity imports. Moreover, even if additional firm peak power imports during winter months are assumed to be available, developing a minimum of 600 MW of demand response resources is still cost-effective in over 70 percent of the futures tested.

In order to satisfy regional resource adequacy standards the region should develop significant demand response resources by 2021 to meet the need for additional peaking capacity. The Seventh Power Plan Action Plan recommends that the annual assessment of regional resource adequacy consider the comparative cost and economic risk of increased reliance on external market purchases versus development of demand response resources to meet winter capacity needs within the region. The Council will determine if the region has made sufficient progress towards acquiring cost-effective demand response or confirming import capability to provide the region with a minimum additional peaking capacity of at least 600 MW in its mid-term assessment of progress on the Seventh Power Plan.

Natural Gas: It is clear that after efficiency and demand response, new natural gas-fired generation is the most cost-effective resource option for the region in the near-term. Moreover, after energy efficiency, the increased use of existing natural gas generation offers the lowest cost option for reducing regional carbon emissions.[1] At the regional level, the probability that new natural gas-fired

[1] The Council recognizes that in addition to the carbon dioxide emissions produced by the combustion of natural gas, the fugitive methane emissions from natural gas production and transportation could have significant climate change impacts.

generation will be needed to supply peaking capacity prior to 2021 is quite low. If the region does not deploy the demand response resources and develop the level of energy efficiency resources called for in this plan, the need for more costly new gas-fired generation increases. In the mid-term (by 2026) there appears to be a modest probability that new gas fired generation could be needed to replace retiring coal generation or potentially to displace additional coal use to meet federal carbon-reduction goals. Nevertheless, even if the region has adequate resources, individual utilities or areas may need additional supply for capacity or wind integration when transmission and power market access is limited. In these instances, the Seventh Power Plan's resource strategy relies on new natural gas-fired generation to provide energy, capacity, and ancillary services.

Renewable Resources: The Seventh Power Plan's resource strategy assumes that only modest development of renewable generation, approximately 100 - 150 average megawatts of energy, or around 250 to 400 megawatts of installed capacity by 2035, is necessary to fulfill existing renewable portfolio standards. While the majority of historical renewable development in the region has been wind resources, recent and forecast further cost reductions in solar photovoltaic (solar PV) technology are expected to make electricity generated from such systems increasingly cost-competitive. In addition, solar PV systems, particularly when coupled with storage, can provide summer peaking services for which regional demand is increasing faster than winter peaking needs. As a result, solar PV systems should be seriously considered when determining which resources to acquire to comply with existing renewable portfolio standards. In addition, while to date regional development of geothermal resources has been limited, these resources offer significant potential and can provide both winter and summer capacity.

The Seventh Power Plan's resource strategy encourages the development of other renewable alternatives that may be available at the local, small-scale level and are cost-effective now. Because power production from wind and solar PV projects creates little dependable peak capacity and increases the need for within-hour balancing reserves the strategy also encourages research on and demonstration of different sources of renewable energy for the future, especially those with a more consistent output like geothermal or wave energy.

The Council did not evaluate whether the increased use of renewable resources would be a cost-effective alternative for state level compliance with federal carbon dioxide emissions regulations or state level carbon emissions goals. The Council did find that increasing the requirements of state renewable portfolio standards alone would not result in the development of the least cost resource strategy for the region nor the least cost resource strategy for reducing carbon at the regional level.

See Appendix I for more detailed discussion methane emissions from natural gas production and distribution. A discussion of how fugitive emissions of methane were considered in the development of the Council's resource strategy appears in the following section.

Regional Resource Utilization: The region should continue to improve system scheduling and operating procedures across the region's balancing authorities to maximize cost-effectiveness and minimize the need for new resources needed for integration of variable energy resource production. In addition, the region needs to invest in its transmission grid to improve market access for utilities and to facilitate development of more diverse cost-effective renewable generation. Finally, the Council identified least cost resource strategies for the region that rely first on regional resources to satisfy the region's resource adequacy standards. Under many future conditions, these strategies reduce regional exports.

Carbon Policies and Methane Emissions: To support policies that cost effectively achieve state and federal carbon dioxide emission reduction goals while maintaining regional power system adequacy the region should develop the energy efficiency and demand response resources called for in this plan and replace retiring coal plants with only those resources required to meet regional capacity and energy adequacy requirements. As stated above, after energy efficiency, the increased use of existing natural gas generation offers the lowest cost option for reducing regional carbon emissions in the near term. Utility development of new gas-fired generation to meet local needs for ancillary services, such as wind integration, or capacity requirements beyond the modest levels anticipated in this plan will increase carbon dioxide emissions. If Northwest electricity generation is dispatched first to meet regional adequacy standards for energy and capacity rather than to serve external markets, the increase in regional carbon dioxide emissions can be minimized.

The Northwest will likely have a competitive advantage if pricing policies are used throughout the western electricity market to reduce carbon dioxide emissions. The region's large existing non-carbon emitting resource base increases in value under most carbon pricing policies. If west-wide or national carbon prices are imposed, the value of low or no carbon content power exports will increase. Revenues from these exports will partially offset the regional cost of achieving carbon dioxide emission reductions.

As noted above, a central element in transitioning the Northwest power system to an even lower carbon footprint involves the increased use of natural gas, which consists primarily of methane. While burning natural gas produces significantly less carbon dioxide emissions per unit of electricity generation, its production and distribution releases methane into the atmosphere. Methane is a highly active greenhouse gas, with a global warming potential 28 to 36 times that of carbon dioxide.[2] The Seventh Power Plan's overall resource strategy seeks to minimize the need to develop new gas generation by meeting most future energy and capacity needs with energy efficiency and demand response. Successful implementation of this strategy provides time to take actions to reduce current fugitive methane emissions and minimize new methane emissions, so that the use of natural gas does produce a reduction in climate change impacts.

Future Resources: In the long term, the Council encourages the region to expand its resource alternatives. The region should explore additional sources of renewable energy, especially technologies that can provide both energy and winter capacity, improved regional transmission

[2] See Appendix I for a more complete description of methane's potential environmental impacts and the uncertainties surrounding fugitive emission sources and levels.

capability, new conservation technologies, new energy-storage techniques, smart-grid technologies and demand-response resources, and new or advanced low-carbon generating technologies, including advanced nuclear energy. Research, development, and demonstration funding should be prioritized in areas where the Northwest has a comparative advantage or unique opportunities. For example, the potential for developing geothermal and wave energy in the Northwest is significantly greater than in many other areas of the country.

Adaptive Management: The Council will annually assess the adequacy of the regional power system. Through this process, the Council will be able to identify whether actual conditions depart so significantly from planning assumptions that it would require adjustments to the plan. This annual assessment will provide the region time to take actions necessary to reduce the probability of power shortages. The Council will also conduct a mid-term assessment to review plan implementation.

SCENARIO ANALYSIS – THE BASIS OF THE RESOURCE STRATEGY

Scenarios combined elements of the future that the region controls, such as the type, amount and timing of resource development, with factors the region does not control, such as natural gas and wholesale market electricity prices. Sensitivity studies alter one parameter in a scenario to test how the least-cost resource strategy is affected by that input assumption. For example, several scenarios were run with and without future carbon cost to assess the impact of that input assumption on the various components of the least cost resource strategy.

All of the scenarios evaluated for the Seventh Power Plan include the same range of uncertainty regarding future fuel prices, hydropower conditions, electricity market prices, capital costs, and load growth. However, several scenarios were specifically designed to provide insights into the cost and impacts of specific alternative resource strategies and carbon dioxide emissions reduction policies. For example, the Council tested scenarios that excluded the development of demand response resources or required the development of a minimum amount of renewable resources.

To investigate policy options for reducing carbon dioxide emissions some scenarios included either the federal government's estimates of the societal damage cost of carbon dioxide emissions or the economic risk associated with future carbon dioxide regulation or pricing or "non-pricing" policies. Each of these scenarios assumed differing levels of carbon dioxide damage or regulatory cost. Also, as noted above, several sensitivity studies were conducted to assess the impact of such factors as the near term pace of conservation development, lower natural gas and wholesale electricity prices, greater reliance on external markets, or the loss of major resources.

The US Environmental Protection Agency (EPA) released its draft Clean Power Plan in June, 2014, and its final set of regulations in August, 2015. [3] These regulations establish carbon dioxide

[3] U.S. Environmental Protection Agency, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," 80 Fed. Reg. 64,662 (October 23, 2015). A coalition of states, utilities, utility organizations and others challenged the rule applying to existing sources in the federal D.C. Circuit Court of Appeals. The U.S. Supreme

emissions limits for both new and existing power plants. Eight of the scenarios summarized below: the two **Social Cost of Carbon** (**Mid-Range and High**), **Carbon Cost Risk**, **Regional Renewable Portfolio Standards at 35 Percent**, **Maximum Carbon Reduction – Existing Technology, Coal Retirement, Coal Retirement with the Social Cost of Carbon** and **Coal Retirement with the Social Cost of Carbon and No New Gas** were designed to test alternative policies that may be considered at the regional or state level to identify resource strategies that would comply with those regulations. Two other scenarios, the **Planned Loss of a Major Non-Greenhouse Gas (GHG) Emitting Resource** and the **Unplanned Loss of a Major Non-GHG Emitting Resource** were analyzed to provide insights into the effect of the loss of a major non-greenhouse gas-emitting would have on the region's ability to reduce power system carbon dioxide emissions.

Each scenario and sensitivity analysis tested thousands of potential resource strategies against 800 alternative future conditions to identify the least cost and lowest economic risk resource portfolios. Since the discussion of the elements of the resource strategy draws on those scenarios and sensitivity studies, an introduction to the scenarios and studies and their findings is needed. Each scenario or sensitivity study was designed to explore specific components of resource strategies (e.g. strategies with and without demand response).

The Seventh Power Plan's resource strategy is based on analysis of over 25 scenarios and sensitivity studies.[4] Eighteen of principal scenarios or sensitivity studies that informed the development of the Seventh Power Plan's final resource strategy are summarized below. Not all scenarios or sensitivity studies "stress test" the same element of a resource strategy or policy option, so not all provide useful insight regarding that element or policy. Therefore, the following discussion of findings compares different subsets or combinations of scenarios and sensitivity studies when discussing a specific element of the Seventh Power Plan's resource strategy.

- **Existing Policy –** The existing-policy scenario includes current federal and state policies such as renewable portfolio standards, new plant emissions standards, and renewable energy credits, but it does not assume any additional carbon dioxide regulatory cost or economic risk in the future. Specifically, it does not reflect any actions Northwest states may

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Court stayed the effectiveness of the rule in an order issued February 9, 2016, pending not just review on the merits by the court of appeals but also the resolution of any petition for further review in the Supreme Court following whatever decision is issued by the court of appeals. The litigation is ongoing as the Council completed the Seventh Power Plan.

[4] Ten scenarios were analyzed between the draft and final adoption of the Seventh Power Plan. These include updates to seven scenarios analyzed during the development of the draft plan and three new scenarios suggested by public comment. The draft plan's findings for any of the scenarios and sensitivity studies not updated for the final plan are described in Appendix O.

take in order to comply with recently finalized limits on carbon dioxide emissions from existing power generation. However, this scenario does serve as a point of departure for assessing the regional effect of carbon dioxide cost and economic risk when added to existing policies. Other major uncertainties regarding the future, such as load growth and natural gas and market electricity prices are considered.

Updated results for this scenario are reported in the final plan.

- **Social Cost of Carbon (SCC) –** Two scenarios, the **Social Cost of Carbon – Mid-Range (SCC-MidRange)** and **Social Cost of Carbon – High (SCC-High)**, use the US Interagency Working Group on Social Cost of Carbon's estimates of the damage cost of forecast global climate change. According to the Working Group:

    - *The SCC is an estimate of the economic damages associated with a small increase in carbon dioxide (CO2) emissions, conventionally one metric ton, in a given year. This dollar figure also represents the value of damages avoided for a small emission reduction (i.e. the benefit of a CO2 reduction).*

      Therefore, in theory, the cost and economic risk of the resource strategy that achieves carbon dioxide emissions reductions equivalent to the social cost of carbon would offset the cost of damage. The **SCC-MidRange** scenario uses the Interagency Working Group's mid-range estimate of the damage cost from carbon dioxide emissions based on a three percent discount rate. The **SCC-High** scenario uses the Interagency Working Group's estimate of damage cost that encompasses 95 percent of the estimated range of damage costs.[5]

      Updated results for the **SCC-MidRange** scenario are reported in the final plan. The final plan's findings for the **SCC-High** scenario would not be materially different than those reported in the draft plan, although due to the use of a lower range of natural gas prices the average system cost of this scenario would be slightly lower. The draft plan's findings for the **SCC-High** scenario are discussed in Appendix O.

- **Carbon Cost Risk –** The carbon cost risk scenario is intended to explore what resources result in the lowest expected cost and economic risk given existing policy plus the economic risk that additional carbon dioxide reduction policies will be implemented. Each of the 800 futures imposes a carbon dioxide price from $0 to $110 per metric ton at a random year during the 20 year planning period. Over time, the probability of a carbon dioxide price being imposed and the level of that price both increase. By 2035, the average price of carbon dioxide rises to $47 per metric ton across all futures. It should be noted, that the use of a carbon dioxide price does not presume that a "pricing policy" (e.g., carbon tax, cap and trade system) would be used to reduce carbon dioxide emissions. The prices imposed in this

[5] Chapter 15 provides the year-by-year social cost of carbon used in these scenarios.

scenario could also be a proxy for the cost imposed on the power system through regulation to reduce carbon dioxide emissions (e.g., caps on emissions).

This scenario was initially designed to represent the current state of uncertainty about future carbon dioxide control policies and develop a responsive resource strategy. It is identical to a scenario analyzed for the development of the Sixth Power Plan. While with the promulgation of Environmental Protection Agency's carbon dioxide emissions regulations there is less uncertainty regarding federal regulations, the specific form of state and/or regional compliance plans with EPA's regulations are unknown. Moreover, some states may choose to adopt additional policies beyond the federal regulations to limit power system emissions.

Updated results for the **Carbon Cost Risk** scenario are not reported in the final plan. The final plan's findings for the **Carbon Cost Risk** scenario would not be materially different than those reported in the draft plan, although due to the use of a lower range of natural gas prices the average system cost of this scenario would be slightly lower. The draft plan's findings for the **Carbon Cost Risk** scenario are discussed in Appendix O.

- **Regional Renewable Portfolio Standard at 35 Percent (Regional RPS at 35%) –** This scenario assumes that a region wide Renewable Portfolio Standard (RPS) is established at 35 percent of regional retail electricity sales across all four Northwest states. Presently, three states in the region have RPS. Montana and Washington require that 15 percent of the retail sales of be served by renewable resources. Montana's RPS must be satisfied in 2015 and Washington's by 2020. Oregon requires that 20 percent of retail sales be served by renewable resources by 2020. These state level RPS generally only apply to investor owned utilities and larger public utilities, while this scenario assumes that all of the region's retail sales are covered. Since this scenario was designed to test the cost and effectiveness of this policy for reducing regional power system carbon dioxide emissions, it did not include future carbon dioxide regulatory cost risk uncertainty or estimated damage cost. The cost-effectiveness of a policy that only requires use of additional renewable generation can, therefore, be compared to other scenarios that tested alternative policy options to reduce carbon dioxide emissions, including those use a combination of strategies such as limiting the type of new resources that can be developed and imposing a carbon price.

  Updated results for the **Regional Renewable Portfolio Standard at 35%** scenario are reported in the final plan.

- **Maximum Carbon Reduction – Existing Technology –** This scenario was designed to explore the maximum carbon dioxide emissions reductions that are feasible with current commercially available technologies. In this scenario all of the existing coal plants serving the region were assumed to be retired by 2026. In addition, the least efficient (i.e., those with heat rates exceeding 8,500 Btu/kWh) existing natural gas-fired generating facilities were assumed to be retired by 2031. No carbon dioxide cost risk or estimated damage cost was assumed, so this scenario can be compared to the cost-effectiveness of other policy options (e.g., **Carbon Cost Risk**, **Regional RPS at 35%**, **Social Cost of Carbon**, **Retire Coal w/SCC MidRange**, etc. scenarios) for reducing carbon dioxide emissions.

Updated results for the **Maximum Carbon Reduction – Existing Technology** scenario are reported in the final plan.

- **Maximum Carbon Reduction – Emerging Technology –** This scenario considers the role of new technologies might play in achieving carbon dioxide reduction. Due to the speculative nature of the performance and ultimate cost of technologies considered in this scenario the Council's Regional Portfolio Model (RPM) was not used to identify this scenario's least cost resource strategy. Rather, the RPM was used to define the role (e.g., capacity and energy requirements) that new and emerging technologies would need to play in order to achieve carbon dioxide reductions beyond those achievable with existing technology.

  Updated results for the **Maximum Carbon Reduction – Emerging Technology** scenario are not reported in the final plan. The results of the **Maximum Carbon Reduction – Emerging Technology** scenario would not differ materially from those reported in the draft plan. The draft plan's findings for the **Maximum Carbon Reduction – Emerging Technology** scenario are discussed in Appendix O.

- **Retire Coal –** This scenario is identical to the **Maximum Carbon Reduction – Existing Technology** scenario, except that it does not retire any existing natural gas generation. This scenario was designed to establish the lowest carbon dioxide emission level achievable by retiring all of the existing coal plants serving the region while assuming the continued operation of existing gas-fired generation. Since this resource strategy relies on existing gas generation rather than investing new resource development it could potentially have lower costs than the **Maximum Carbon Reduction – Existing Technology** scenario, but might produce similar carbon dioxide emissions. This scenario constructed based on public comment on the draft plan, and therefore was not considered during its development.

- **Retire Coal with Social Cost of Carbon Mid-Range (Retire Coal w/SCC MidRange) –** This scenario is identical to **Retire Coal** scenario, except that it assumes that the US Interagency Working Group on Social Cost of Carbon's Mid-Range estimate of the damage cost of forecast global climate change are reflected in fossil fuel costs. This scenario was designed to test the cost, economic risk and carbon emissions impacts that internalizing the damage cost of climate change would have on the resource dispatch and development. It was assumed that this scenario's resource strategy would rely more on renewable resources. Therefore, this scenario assumes greater availability and lower solar PV system cost for both utility scale projects and distributed systems. This scenario was constructed based on public comment on the draft plan, and therefore was not considered during its development.

- **Retire Coal with Social Cost of Carbon Mid-Range and No New Gas Generation (Retire Coal w/SCC MidRange & No New Gas) –** This scenario is identical to **Retire Coal w/SCC MidRange** scenario, except that it assumes that no new natural gas-fired generation resources can be constructed to replace retiring coal plants or existing gas generation if such plants are uneconomic to operate. This scenario was designed to test the cost, economic risk and carbon emissions impacts of restricting new resource development to renewable resources when compared to the **Retire Coal w/SCC MidRange** scenario. This scenario was constructed based on public comment on the draft plan, and therefore was not considered during its development.

- **Resource Uncertainty –** Four scenarios explored resource uncertainties and carbon dioxide regulatory compliance cost and economic risk. Two examined the effect that the loss of a major non-greenhouse gas-emitting resource might have on the region's ability to reduce power system carbon dioxide emissions. The **Unplanned Major Resource Loss** scenario assumed that a significant (approximately 1000 average megawatt) non-greenhouse gas emitting generator was unexpectedly taken out of service. The **Planned Major Resource Loss** scenario assumed that similar magnitudes of the region's existing non-greenhouse gas emitting resources were phased out over the next 20 years. Since both of these scenarios were designed to identify resource strategies that would maintain regional compliance with federal carbon dioxide emissions limits they assumed the cost of future carbon dioxide regulatory risk used in the **Carbon Cost Risk** scenario.

  The **Planned Major Resource Loss** scenario also provides insight into the resource implications that would occur in the event of the planned removal of any specific non-carbon resource in the region, including the removal of major hydroelectric projects such as the four federal dams on the lower Snake River The lower Snake River dams have a combined nameplate capacity of 3,033 megawatts. However, because of limited reservoir storage, their useful peaking capability (e.g. 10-hour sustained-period capacity) ranges from about 1,700 to 2,000 megawatts, which represents about 11 percent of the aggregate hydroelectric system's sustained peaking capability.[6] Annually, on average, these four projects produce about 1,000 average megawatts of energy or about 5 percent of the region's annual average load.

  The effect on the Council's resource strategy of removing these dams was assessed in the Sixth Power Plan.[7] In that assessment, however, generation from all four projects was removed in one year (2020). A more practical approach would be to remove the projects in sequence over a number of years to minimize disruption to both energy and fish needs as was assumed in **Planned Major Resource Loss** scenario in the Seventh Power Plan.

  While the Seventh Power Plan does not include an explicit analysis of the effects of removing the four lower Snake River dams, it does provide a scenario for the planned loss of a large (1,000 average megawatt) non-carbon resource in four stages over a period of 10 years. And, although this scenario is more generic, it better represents the timing of the loss of generation. What it does not include are details of potential shifts in generation at other

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[6] This range is based on information from the Bonneville Power Administration's 2015 White Book, Technical Appendix – Volume 2, Capacity Analysis (DOE/BP-4741), pages 246 and 247. From that data, the peaking capability of the four lower Snake River dams relative to the total regional hydroelectric peaking capability is 11 percent. The 1,700 to 2,000 megawatt range for the four lower Snake River dams was calculated by multiplying the Council's estimated regional firm (low water) 10-hour sustained peaking capability by 11 percent for each season (quarter) of the year.

[7] Sixth Northwest Conservation and Electric Power Plan, Chapter 10: Resource Strategy, pages 10-27 and 10-28. http://www.nwcouncil.org/media/6344/SixthPowerPlan_Ch10.pdf

hydroelectric projects that would result from the loss of the four lower Snake River dams. On a comprehensive scale, however, these shifts are relatively small and will even out in the long run because the hydroelectric system cannot simply make up for the loss of generation from the lower Snake River dams. Thus, the resulting effects on the resource strategy should be similar for both cases in the sense of the types and magnitude of replacement resources. If the Council had analyzed the timed removal of the four lower Snake River dams, resource strategies would have had to also account for the 1,700 to 2,000 megawatts of sustained peaking loss and not just the loss of 1,000 average megawatts of energy generating capability. This would have likely increased the magnitude of the requirement for replacement resources.

Two additional scenarios tested the economic benefits or cost resulting from a faster or slower near term pace of conservation deployment. The **Faster Conservation Deployment** scenario allowed the Regional Portfolio Model to increase the pace of acquiring conservation savings by 30 percent above the baseline assumption. The **Slower Conservation Deployment** scenario restricted the RPM's option to acquire conservation savings to a pace that was 30 percent below the baseline assumption. Since both of these scenarios were designed to test resource strategies that might reduce the cost or increase the economic risk of compliance with federal carbon dioxide emissions limits, they assumed the carbon dioxide regulatory cost risk used in the **Carbon Cost Risk** scenario.

Updated results for the **Resource Uncertainty** scenarios are not reported in the final plan. The results of these scenarios would not differ materially from those reported in the draft plan. That is, the replacement resource strategy and relative impact on regional carbon emissions would remain unchanged. However, since the final plan assumed lower natural gas and wholesale electricity prices the average system cost and economic risk of these scenarios would be slightly less due to the reduced the cost of fuel supplying replacement resources. The lower range of natural gas prices assumed in the final plan would also decrease the cost of the **Faster Conservation Deployment** and **Slower Conservation Deployment** scenarios, but not their cost relative to one another. The draft plan's findings for all four of the resource uncertainty scenarios are discussed in Appendix O.

- **No Demand Response –** This sensitivity study assumed that no demand response resources were available to meet future regional peak capacity needs. It estimated the cost and risk of not using demand response to provide regional capacity reserves under both the Existing Policy scenario and with the future carbon dioxide regulatory cost assumed in the Carbon Cost Risk scenario. Updated results for the **No Demand Response** scenario are reported in the final plan.

- **Low Natural Gas and Wholesale Electricity Prices –** This sensitivity study assumed that the range of future natural gas and wholesale electricity prices the region would experience was systematically lower than the baseline assumptions. It was designed to test the impact of lower gas and electricity prices on the amount of cost-effective conservation and on the best future mix of generating resource development. This sensitivity study was tested under both the **Existing Policy** scenario and with the future carbon dioxide regulatory cost assumed in the **Carbon Cost Risk** scenario. The final plan assumed lower natural gas and wholesale electricity market prices than the draft plan so results for the **Low Natural Gas and Wholesale Electricity Prices** sensitivity study are not reported in the final plan. The draft plan's findings for these two scenarios are discussed in Appendix O.

- **Increased Market Reliance –** This scenario explored the potential benefits and risk of increased reliance on out-of-region markets to meet regional resource adequacy standards. It evaluated the cost of meeting near-term peak capacity needs with demand response and other regional resources compared to reliance on external Southwest and Canadian markets. This sensitivity study was conducted using the **Existing Policy** scenario. Updated results for the **Increased Market Reliance** scenario are reported in the final plan.

- **Lower Conservation –** This sensitivity study explored the potential costs and benefits associated with less reliance on energy efficiency. Under this scenario, the acquisition of conservation was limited to what would be cost-effective to acquire based on short-run market prices, rather than full consideration of long-term resource costs and economic risks. This sensitivity study was conducted using the **Existing Policy** scenario, so no carbon dioxide regulatory cost risk or damage costs were assumed. Updated results for **Lower Conservation** scenario are reported in the final plan.

Results of these studies are compared in the discussion of the eight elements of the resource strategy in the following section. A discussion of the specific input assumptions for each of these scenarios as well as a more comprehensive discussion of carbon dioxide emissions, rate and bill impacts, and the Regional Portfolio Model appears in Chapter 15 and Appendix L.

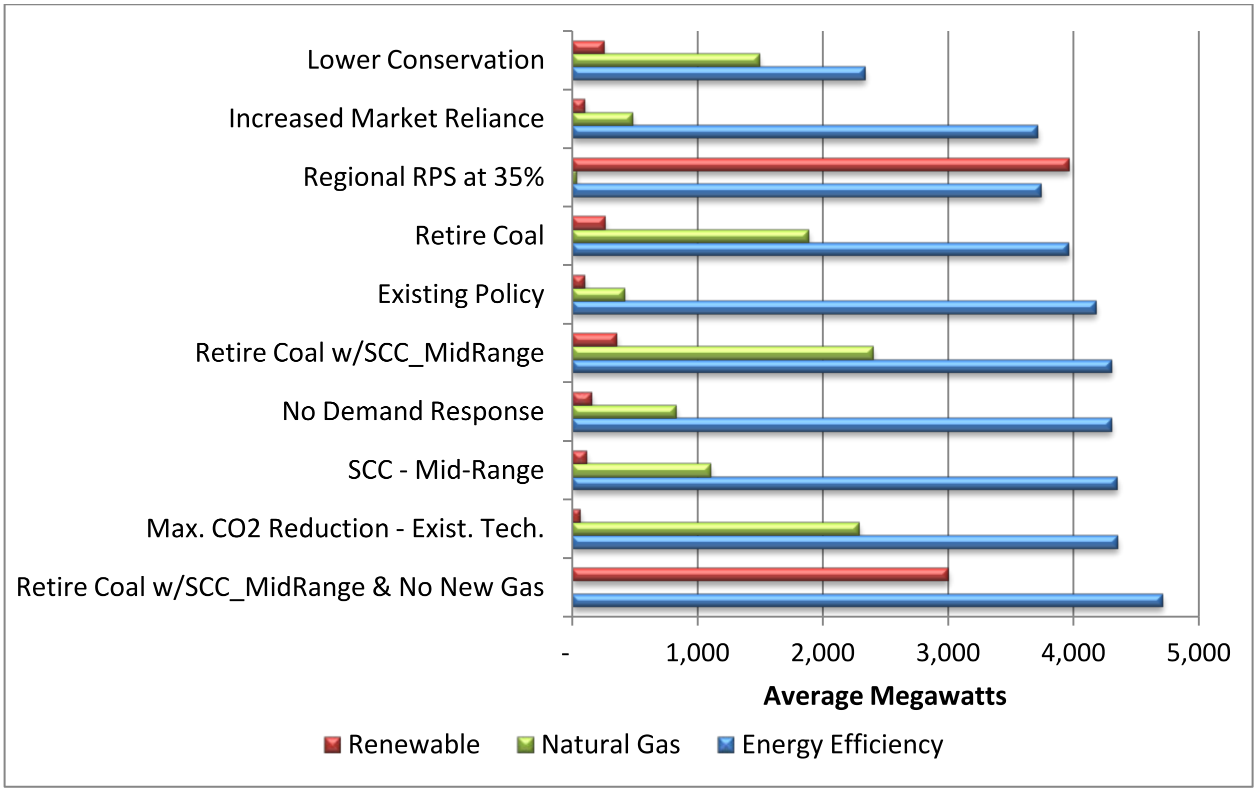
THE RESOURCE STRATEGY

The resource strategy of the Seventh Power Plan is designed to provide the region a low-cost electricity supply to meet future load growth. It is also designed to provide a low economic risk electricity future by ensuring that the region develops and controls sufficient resources to maintain resource adequacy, limiting exposure to potential market price extremes. Therefore the amount and type of resources included in the strategy are designed to meet loads, minimize costs, and help reduce the economic risks posed by uncertain future events.

Figure 3 - 1 shows the average resource development by resource type for the least cost resource strategy under the major scenarios and sensitivity studies carried out to support the development of the final Seventh Power Plan. The resource development shown in Figure 3 - 1 is the *average* over all 800 futures modeled in the Regional Portfolio Model (RPM). In the RPM the specific timing and level of resource development is unique to each of the 800 potential futures modeled. The Seventh Power Plan's principal of adaptive management is based on the reality that, as in the RPM, the timing and level of resource development in the region will be determined by actual conditions as they unfold over the next 20 years. However, what should not change are the Seventh Power Plan's priorities for resource development. In that regard, Figure 3 - 1 shows the significant and consistent role of energy efficiency across all scenarios. This is because of its low cost, its contribution to regional winter capacity needs and its role in mitigating economic risk from fuel price uncertainty and volatility.

After energy efficiency, the *average* development of new natural gas generation and renewable resources by 2035 varies significantly across scenarios. New natural gas-fired resources are developed to meet regional capacity needs and to replace existing coal generation in scenarios where all of those resources are assumed to be retired (e.g., **Retire Coal, Retire Coal w/SCC MidRange, Maximum Carbon Reduction – Emerging Technology).** Renewable resource development is driven by state renewable resource portfolio standards. Not shown in Figure 3 - 1 is the deployment of demand response resources because these resources primarily provide capacity (megawatts) not energy (average megawatts) and the increased dispatch of existing gas generation to replace already announced coal generation retirements. Both of these resources also play significant roles in the Seventh Power Plan's resource strategy. Each element of the resource strategy is discussed below.

Figure 3 - 1: Average Resource Development in Least Cost Resource Strategy by 2035 in Alternative Scenarios



Energy Efficiency Resources

Energy efficiency has been important in all previous Council power plans. The region has a long history of experience improving the efficiency of electricity use. Since the Northwest Power Act was enacted, the region has developed nearly 5,800 average megawatts of conservation. This achievement makes efficiency the second-largest source of electricity in the region following hydroelectricity.

As in all prior plans, the highest priority new resource in the Seventh Power Plan resource strategy is improved efficiency of electricity use, or conservation. Figure 3 - 2 shows that the region's net load after development of all-cost effective energy efficiency remains essentially the same over the next 20 years. This finding holds under scenarios that both consider damage cost and those that do not. The only scenario that developed significantly less energy efficiency was the scenario specifically designed to do so. The **Lower Conservation** scenario developed roughly 1800 average megawatts less energy efficiency by 2035 than the **Existing Policy** scenario. The **Lower Conservation** scenario had significantly higher ($15 billion) average system cost and exposed the region to much larger ($22 billion) economic risk than the **Existing Policy** scenario.[8] However, as Figure 3 - 2 shows, even under that scenario, the development of energy efficiency offsets nearly all regional load growth through 2025.

The attractiveness of improved efficiency is due to its relatively low cost coupled with the fact that it provides both energy and capacity savings and is not subject to major sources of economic risk. The average cost of conservation developed in the least cost resource strategies across all scenarios tested was half the cost of alternative generating resources. The average levelized cost of the cost-effective efficiency developed in the Seventh Power Plan's resource strategy is $30 per megawatt-hour.[9] The comparable estimated cost of a natural gas-fired combined-cycle combustion turbine is around $71 per megawatt-hour. The current cost of utility scale solar photovoltaic systems is approximately $91 per megawatt-hour and Columbia Basin wind costs $110 per megawatt-hour, including the cost of integrating these variable output resources into the power system.[10] The projected cost of conventional geothermal resources is around $85 per megawatt-hour, although this resource poses significant development risk. Significant amounts of improved efficiency also cost less than the forecast market price of electricity. Nearly 2,400 average megawatts of energy efficiency are available at cost below $30 per megawatt-hour.

Energy efficiency also lacks the economic risk associated with volatile fuel prices and carbon dioxide emission reduction policies. Its short lead time and availability in small increments also reduce its economic risk. Therefore, improved efficiency reduces both the cost and economic risk of the Seventh Power Plan's resource strategy.

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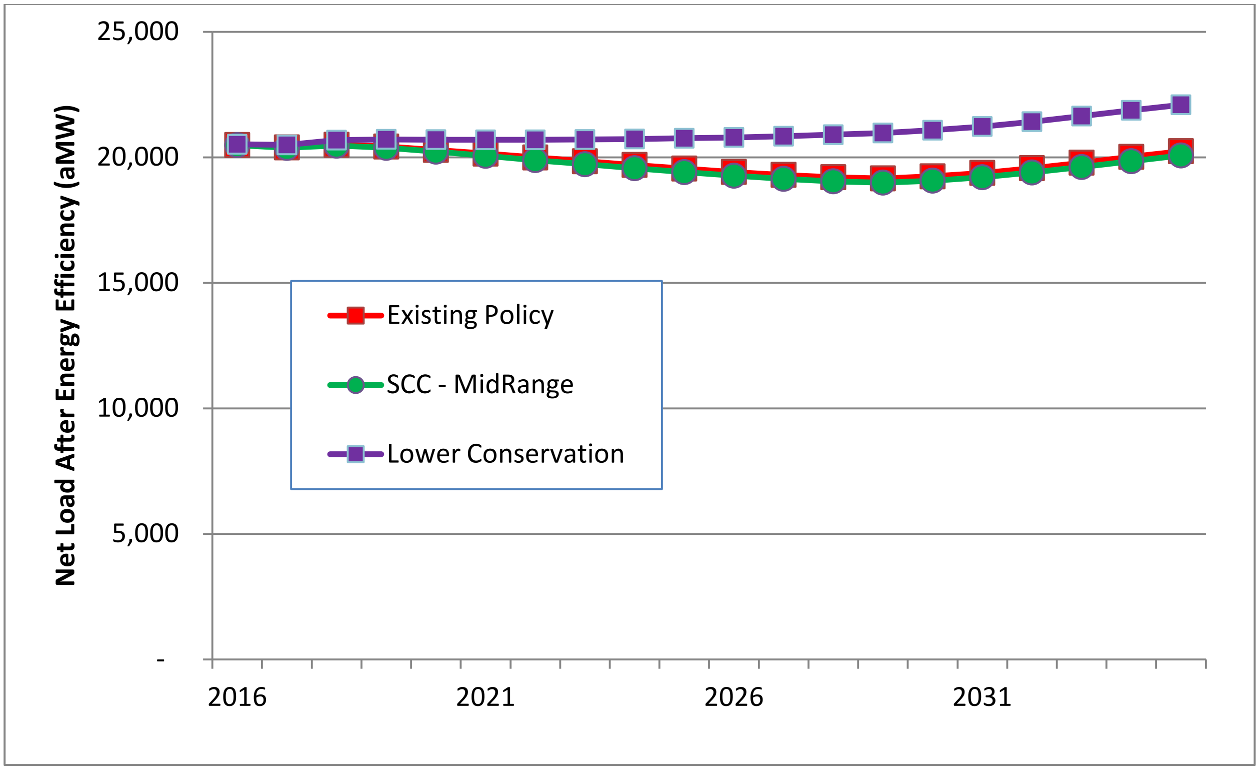
[8] The cost of resource strategies reported in the Seventh Power Plan generally exclude revenues from carbon prices in order to compare scenarios based only on power system costs. The text will identify whether carbon revenues are included or not. In practice, carbon revenue may not be considered a cost if all of it is returned to ratepayers, for example, in the form of tax reduction.

[9] This is the average real levelized cost of all conservation measures acquired in the resource strategy, excluding a cost-offset that is expected to occur as a result of lower load growth which defers the need to expand distribution and transmission systems. In evaluating conservation's cost-effectiveness in the RPM, this cost-offset was included, as well as other non-energy benefits, such as water savings from more efficient clothes washers. If the cost-offset benefits provided by energy efficiency's deferral of investments in distribution and transmission expansion are considered, the average levelized cost is $18 per megawatt-hour.

[10] The levelized cost of solar PV resources has been reduced by the impact of a 30% Federal Investment Tax Credit (ITC) until 2022 and a 10% ITC for the remainder of the planning period. Geothermal cost have been also been reduced by 10% ITC throughout the entire planning period. In addition, solar, wind and geothermal resource costs are also reduced by accelerated depreciation. No state or local tax or other financial incentives are reflected in resource costs. The cost of these resources also reflect integration costs equivalent to current integration rates for wind resources charged by Bonneville and Idaho Power Company's integration rates for solar PV systems. The integration cost of additional renewable resource development in the region may be higher.

Figure 3 - 2: Average Net Regional Load After Accounting for Cost-Effective Conservation Resource Development



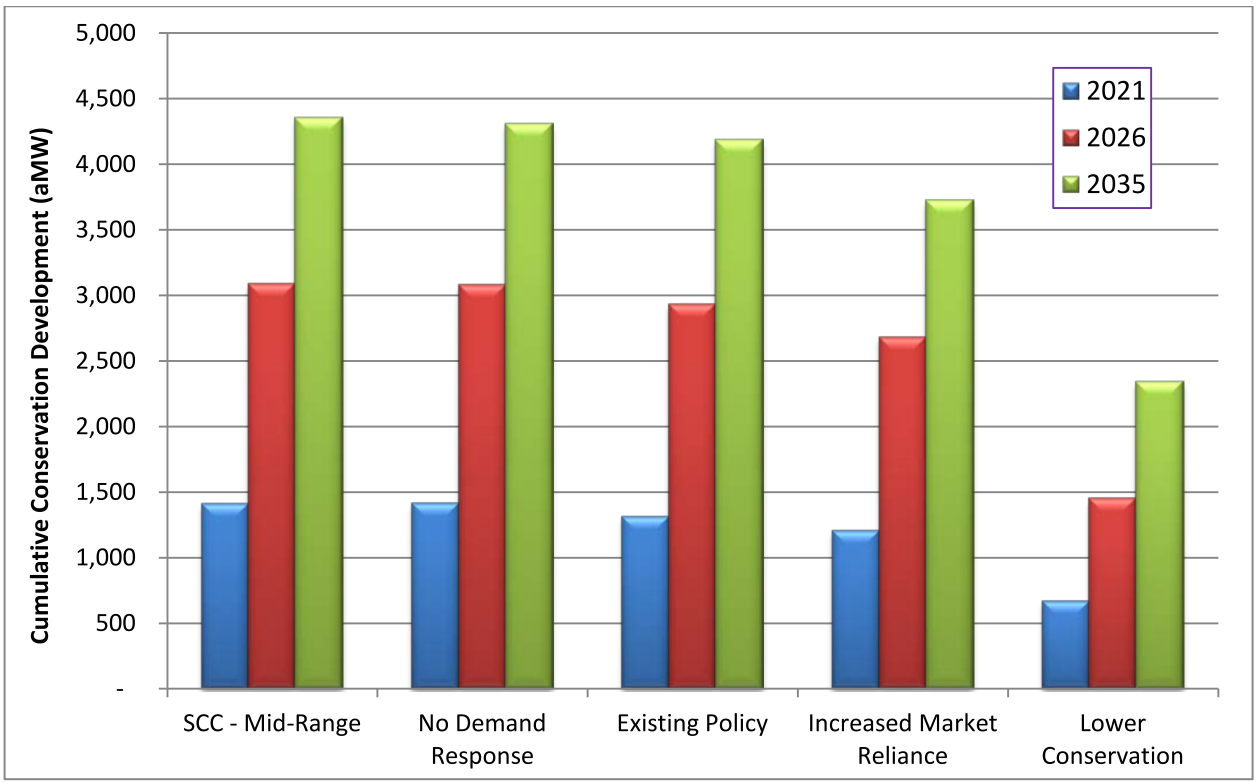
In the Council's analysis, additional resources are added to provide insurance against future uncertainties. Efficiency improvement provides attractive insurance for this purpose because of its low cost. In futures or time periods when the extra resources are not immediately needed, the energy and capacity can be sold in the market and all or at least a portion of their cost recovered. This is not true for generating resources, for in periods when market prices are at or below their variable operating cost; these resources cannot recover any of their capital cost. In addition, because of its low average cost to utilities, the development of energy efficiency offers the potential opportunity to extend the benefits of the Northwest's hydro-system through increased sales.

In all of the scenarios and sensitivity studies examined by the Council, similar amounts of improved efficiency were found to be cost-effective.[11] The selection of energy efficiency as the primary new resource does not depend significantly on whether carbon dioxide policies are enacted. However, since energy efficiency is being developed in part because it provides winter and summer peaking capacity the amount developed is related to other resource options for meeting winter and summer peak needs.

[11] The only exceptions are the **Lower Conservation** scenario which as explicitly designed to develop less energy efficiency and the **Increased Market Reliance** scenario which assumes that the region can rely more on imports to meets its peak capacity needs.

Figure 3 - 3 shows the average amount of efficiency acquired in various scenarios considered by the Council in the power plan by 2021, 2026, and 2035. In the **Existing Policy**, **Social Cost of Carbon-MidRange** and **No Demand Response** scenarios, the amount of cost-effective efficiency developed averages between 1,300 and 1,450 average megawatts by 2021 and 3,000 and 4,300 by 2035. In scenarios that assume that peaking capacity can be provided by demand response or increased reliance on external markets, the amount of cost-effective energy efficiency developed is slightly less, averaging 1200 aMW by 2021 and 2600 aMW by 2026 and 3700 aMW by 2035. The amount of conservation developed varies in each future considered in the Regional Portfolio Model. For example, in the **Social Cost of Carbon - MidRange** scenario, the average conservation development is 4,460 average megawatts, but individual futures can vary from just over 3900 average megawatts to as high as just under 4,900 average megawatts.

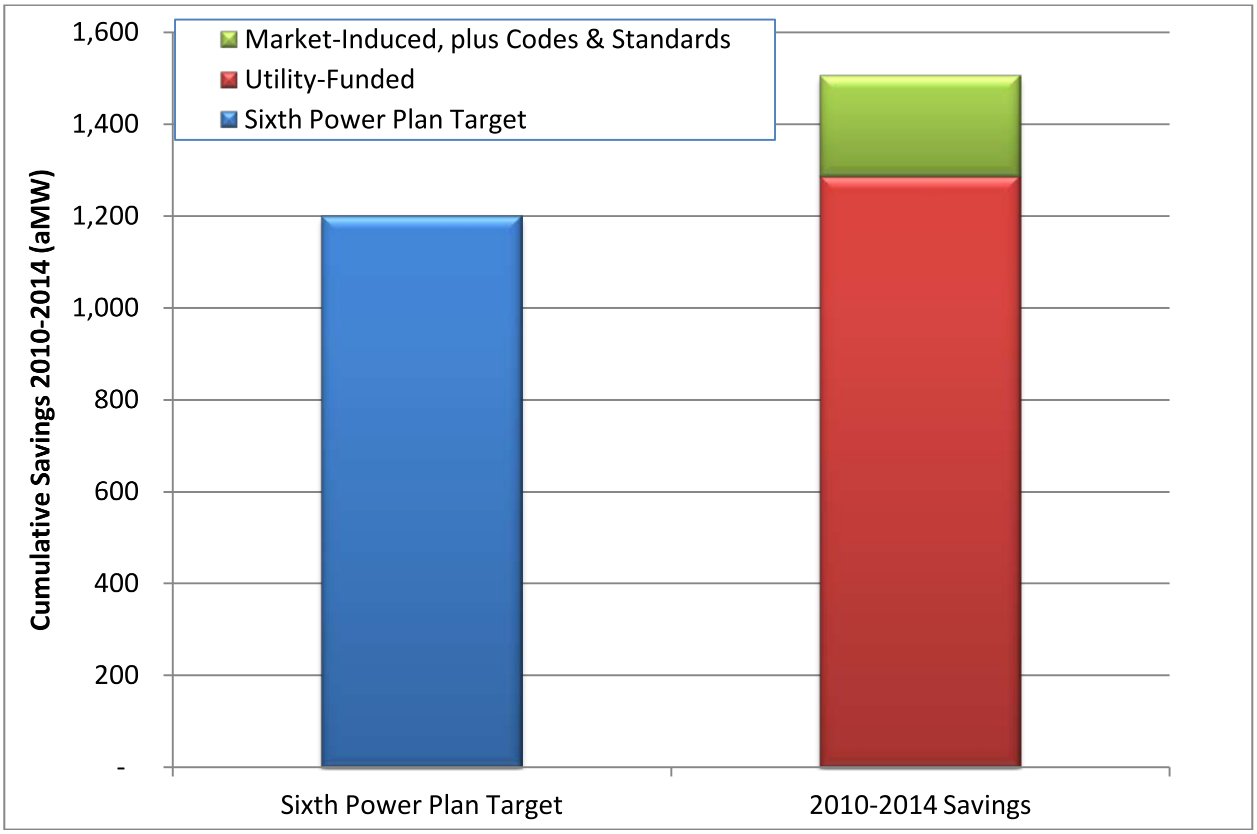
Figure 3 - 3: Quantity of Cost-Effective Conservation Resources Developed Under Different Scenarios



The nature of efficiency improvement is that the total cost is recovered over a smaller number of sales. Average cost per kilowatt-hour sold will increase, but because total consumption is reduced, average consumer electricity bills will be smaller. Consumers who choose not to improve their efficiency of use could see their bills increase. However, if the region does not capture the efficiency, the higher cost of other new generating resources will increase the average bill. The impact on both bills and average revenue requirement per megawatt-hour is discussed later in this chapter.

The amount of efficiency included in the Seventh Power Plan is comparable to that identified in the Council's Sixth Power Plan; even though the 20-year goal is lower (4,300 aMW vs. 5,800 aMW). To a large extent, this decrease is the result of regional energy efficiency program achievements since the Sixth Power Plan was adopted in 2010 as well as significant savings that will be realized as a result of federal standards and state codes enacted since the Sixth Power Plan was adopted. Figure 3 - 4 shows regional utility cumulative conservation program achievements from 2010 through 2014 compared to the Sixth Power Plan's conservation goal for the same period. In addition, Figure 3 - 4 shows the savings achieved from the combined impact of federal and state appliance and equipment standards, state building codes, and market-induced savings. In aggregate, actual achievements from 2010 through 2014 were over 1500 average megawatts, exceeding the Sixth Power Plan's five year goal of 1200 average megawatts by 25 percent.

Figure 3 - 4: Regional Conservation Achievements Compared To Sixth Plan Goals

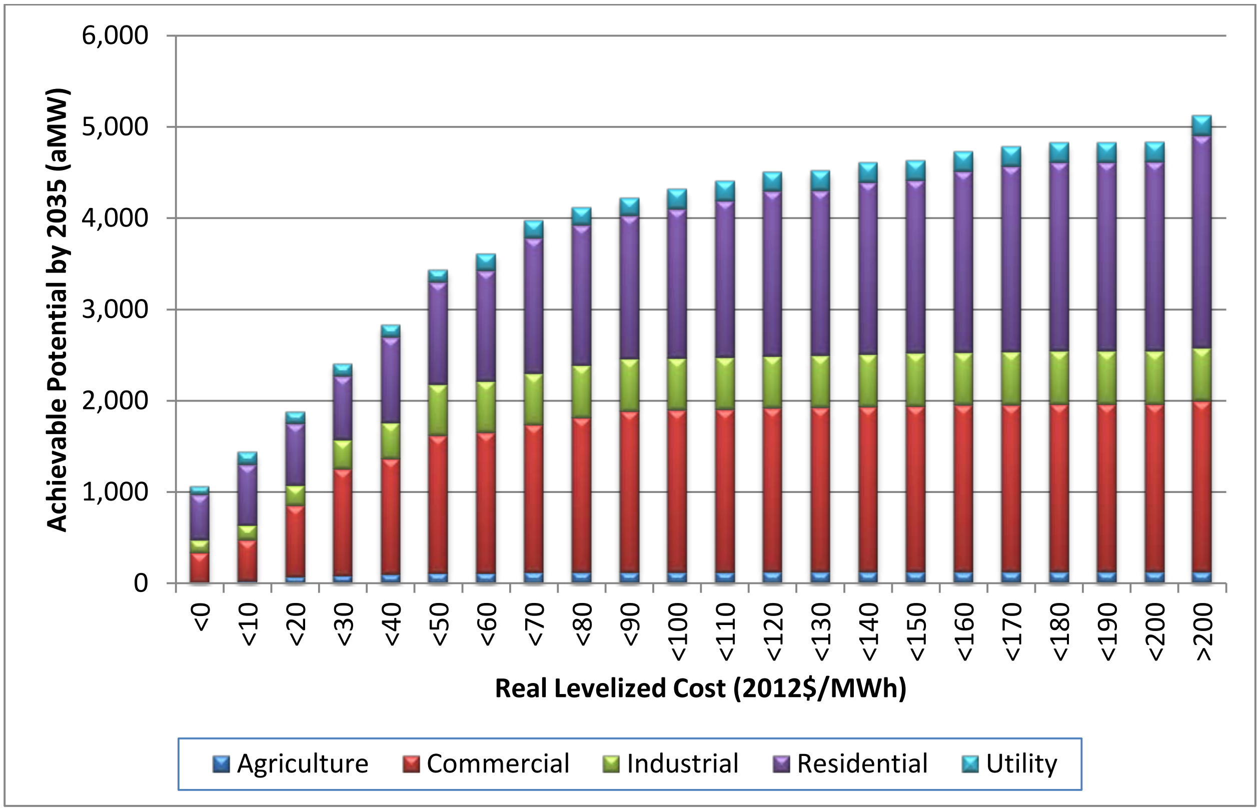


Since the adoption of the Sixth Plan, the US Department of Energy has adopted new or revised more than 30 standards for appliances and equipment that have or will take effect over the next 10 years. These standards reduce load growth by capturing all or a portion of the conservation potential identified in the Sixth Plan. The Council estimates that collectively these standards will reduce forecast load growth by nearly 1500 average megawatts by 2035.

The Council has identified significant new efficiency opportunities in all consuming sectors. Figure 3 - 5 shows by levelized cost the sectors of efficiency improvements. Additional information on the sources and costs of efficiency improvements is provided in Chapter 12 and Appendix G.

Improved efficiency contributes not only to meeting future energy requirements, but also provides capacity during peak load periods. The savings from conservation generally follow the hourly shape of energy use, saving more energy when more is being used. As a result, efficiency contributes

Figure 3 - 5: Achievable Energy Efficiency Potential by Sector and Levelized Cost by 2035



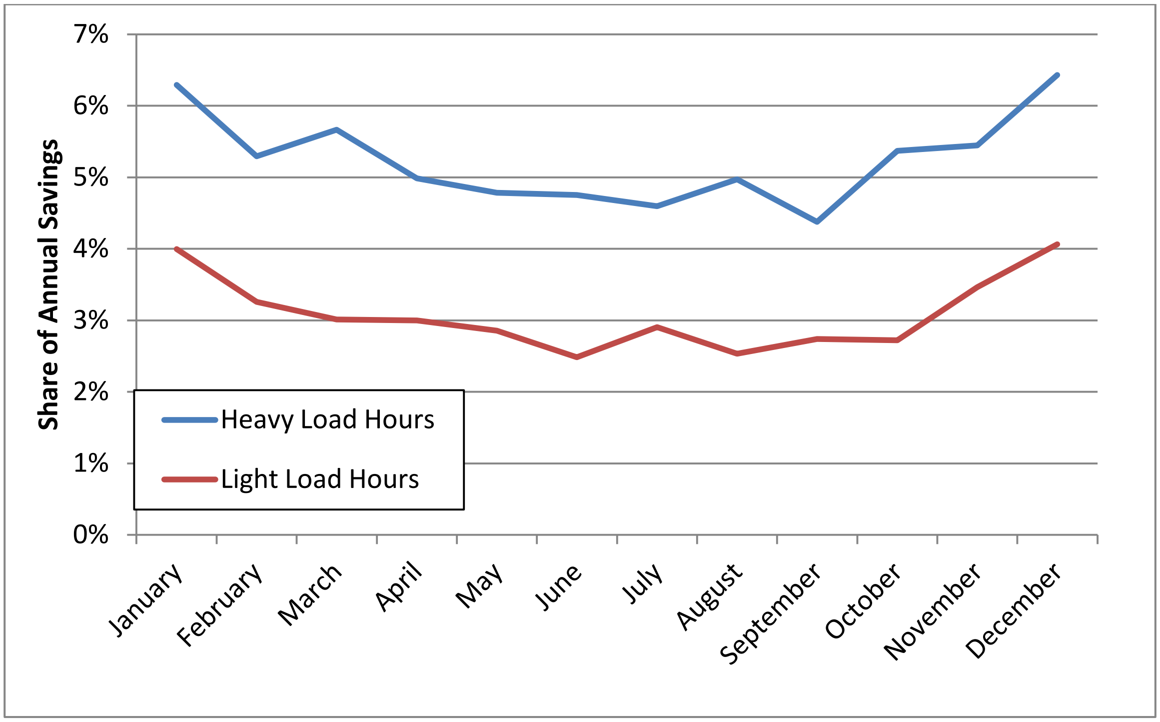
more to load reduction during times of peak usage. To model the impact of energy efficiency on the hourly demand for electricity, the Council aggregated the load shapes of efficiency savings from the hourly shape of individual end-uses of electricity and the cost-effective efficiency improvements in those uses. Figure 3 - 6 shows the shape of the savings for all measures during heavy and light load hours. As is shown, the energy savings are greater during the winter season than summer, in large part due to significant savings from conversion of electric resistance heating to more efficient heat pump technologies and increased use of efficient lighting during the winter period.

The capacity impact of energy efficiency is almost two times the energy contribution in winter. For example, efficiency improvements that yield average annual savings of 4,360 average megawatts create 9,060 megawatts of peak hour savings during the winter months.[12] This reduction in both system energy and capacity needs makes energy efficiency a valuable resource relative to generation because efficiency provides energy and capacity resources shaped to load. Because each efficiency measure has a specific shape, or capacity impact, the Seventh Power Plan explicitly

[12] See Chapter 12 for a description of how the capacity savings of energy efficiency measures are estimated and Chapter 11 for a description of how the system level capacity savings, or Associated System Capacity Contributions, of conservation and generation resources are estimated.

incorporates the value of deferred generation capacity in the cost-effectiveness methodology for measures and programs.[13]

Figure 3 - 6: Monthly Shape of 2035 Energy Efficiency Savings



Demand Response

Demand response resources (DR) are voluntary reductions (curtailments) in customer electricity use during periods of high demand and limited resource availability. As deployed in the Seventh Power Plan, demand response resources are used to meet fall, winter and summer peak demands primarily under critical water and extreme weather conditions. Other potential applications of demand response resources, such as the integration of variable resources like wind, were not explicitly modeled for the development of the Seventh Power Plan. However, this does not mean that such applications of demand response would not provide cost-effective options for providing such services. Therefore, the Seventh Power Plan resource strategy recommends that demand response resources be considered for the provision of other ancillary services, such as variable resource integration.

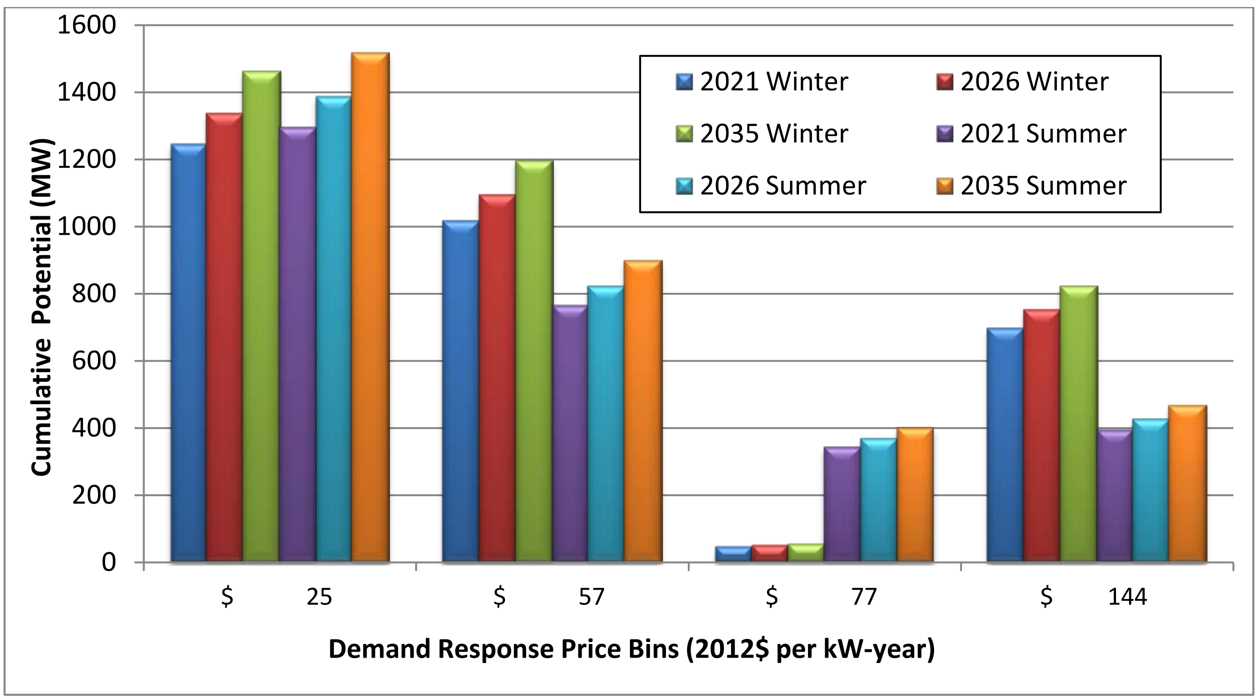
In many areas of the US, demand response resources have long been used by utilities to offset the need to build additional peaking capacity. In the Northwest, the existing hydropower system has been able to supply adequate peaking capacity, so the region has far less experience with deployment of demand response resources. To assess the economic value of developing demand response in the Northwest, the Council conducted sensitivity studies that assumed demand

[13] See action items RES-2 and RES-3 in Chapter 4 and Appendix G.

response resources were not available. The average net present value *system cost* and *economic risk* of the least cost resource strategy without demand response were $5.4 billion higher than in the least cost resource strategy that was able to deploy this resource. Therefore, from the Seventh Power Plan's analysis it appears that if barriers to development can be overcome and the Council's analysis of the cost of demand response are accurate; demand response resources could provide significant regional economic benefits.[14]

The Council's assessment identified more than 4300 megawatts of regional demand response potential. A significant amount of this potential, more than 1500 megawatts, is available at relatively low cost, under $25 per kilowatt of peak capacity per year. When compared to the alternative of constructing a simple cycle gas-fired turbine, demand response resources can be deployed sooner and in quantities better matched to the peak capacity need. Figure 3 - 7 shows the cumulative potential for each of the four blocks (i.e., price bins) of demand response modeled in the Regional Portfolio Model. Cumulative achievable potential by the years 2021, 2026, and 2035 is shown for both winter and summer capacity demand response programs. Note that the largest single block of estimated demand response potential is also the least costly.

Figure 3 - 7: Demand Response Resource Supply Curve



The low cost of demand response resources make them the most economically attractive option for maintaining regional peak reserves to satisfy the Council's Resource Adequacy Standards. The low cost of demand response resources also make them particularly valuable because the need for peaking capacity resources to meet resource adequacy in the region is a function of a combination

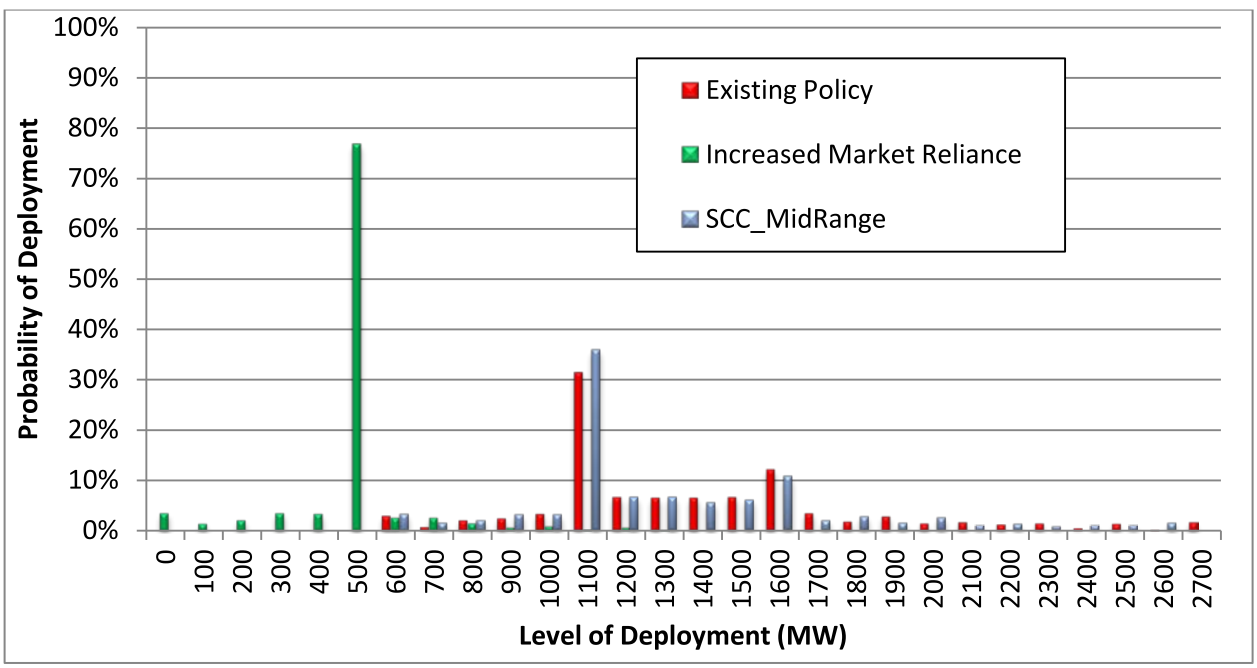
[14] See Action Items RES-4 and BPA-3 in Chapter 4 for the Seventh Power Plan recommends the region and Bonneville should engage to specifically address the barriers to development of demand response resources.

of water and weather conditions that have low probability of occurrence. This is illustrated by Figure 3 - 8 which shows the amount of demand response resource developed by 2021 across the 800 futures tested in the RPM across multiple scenarios.

Figure 3 - 8 shows that there is a wide range of both the amount and probability of development from zero up to 2700 MW, depending on what scenario is being analyzed. In the **Increased Market Reliance** scenario**,** more than 70 percent of the futures require 600 MW demand response development and only a two percent probability exists that none will be needed. Under the **Existing Policy** and **Social Cost of Carbon-MidRange** scenarios there is around a 30 to 35 percent probability that as much as 1100 MW of demand response will need to be developed by 2021 and just over a 10 percent probability that as much as 1600 MW would need to be developed.

From Figure 3-8 it is also clear that the probability of deploying demand response development in the **Increased Market Reliance** scenario**,** which assumed the region could place greater reliance on external power markets to meet its winter peak capacity needs is less than other scenarios that used the limits on external market reliance used in the Regional Resource Adequacy Assessment. The amount of demand response developed *on average* across all futures is around 700 MW in the **Existing Policy** and **Social Cost of Carbon-MidRange,** but only about 400 MW in the **Increased Market Reliance** scenario. In this scenario, net present value system cost and economic risk were also significantly ($5.4 billion) lower than the **Existing Policy** scenario. This highlights the sensitivity of the assumed limits on external market reliance used in the Council Regional Resource Adequacy Assessment and the potential value to the region if it can rely upon additional imports.

Figure 3 - 8: Demand Response Resource Development by 2021 Under Alternative Scenarios



Natural Gas-Fired Generation

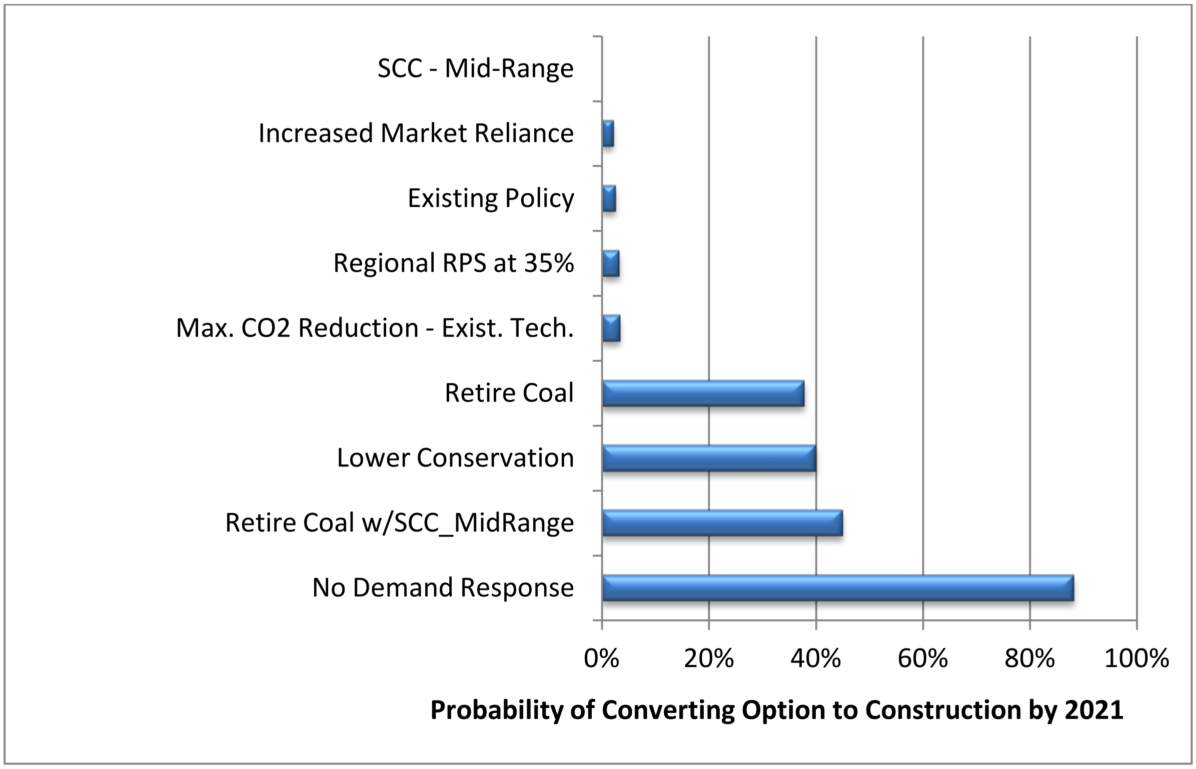
Natural gas is the third major element in the Seventh Power Plan resource strategy. It is clear that after efficiency and demand response, new natural gas-fired generation is the most cost-effective resource option for the region in the near-term. Moreover, also after energy efficiency, the Seventh Power Plan identified the increased use of existing natural gas generation as offering the lowest cost option for reducing regional carbon dioxide emissions. Other resource alternatives may become available over time, and the Seventh Power Plan recommends actions to encourage expansion of the diversity of resources available, especially those that do not produce greenhouse gas emissions.

Across the scenarios evaluated, there is significant variance in the amount of new gas-fired generating resources that are optioned and in the likelihood of completing the plants. New gas-fired plants are optioned (sited and licensed) in the RPM so that they are available to develop if needed in each future. The Seventh Power Plan's resource strategy includes optioning new gas fired generation as local needs dictate. However, from an aggregate regional perspective, which is the plan's focus, the need for additional new natural gas-fired generation is very limited in the near term (through 2021) and low in the mid-term (through 2026) under nearly all scenarios. That is, options for new gas-fired generation are taken to construction in only a relatively small number of futures. Figures 3 - 9 and 3 - 10 show the probability that a thermal resource option would move to construction by 2021 and by 2026. The scenarios are rank-ordered based on the probability of any new gas resource development by 2021 and by 2026. Scenarios with the lowest probability of development are at the top of the graphs.

As can be observed from a review of Figure 3 - 9, the probability of gas development is less than 10 percent by 2021 in five of the scenarios shown in the figure. The four scenarios where the probability of new gas development is 40 percent or higher are those that either develop significantly less energy efficiency or demand response and those that assume retirement of all of the region's existing coal generation by 2026.

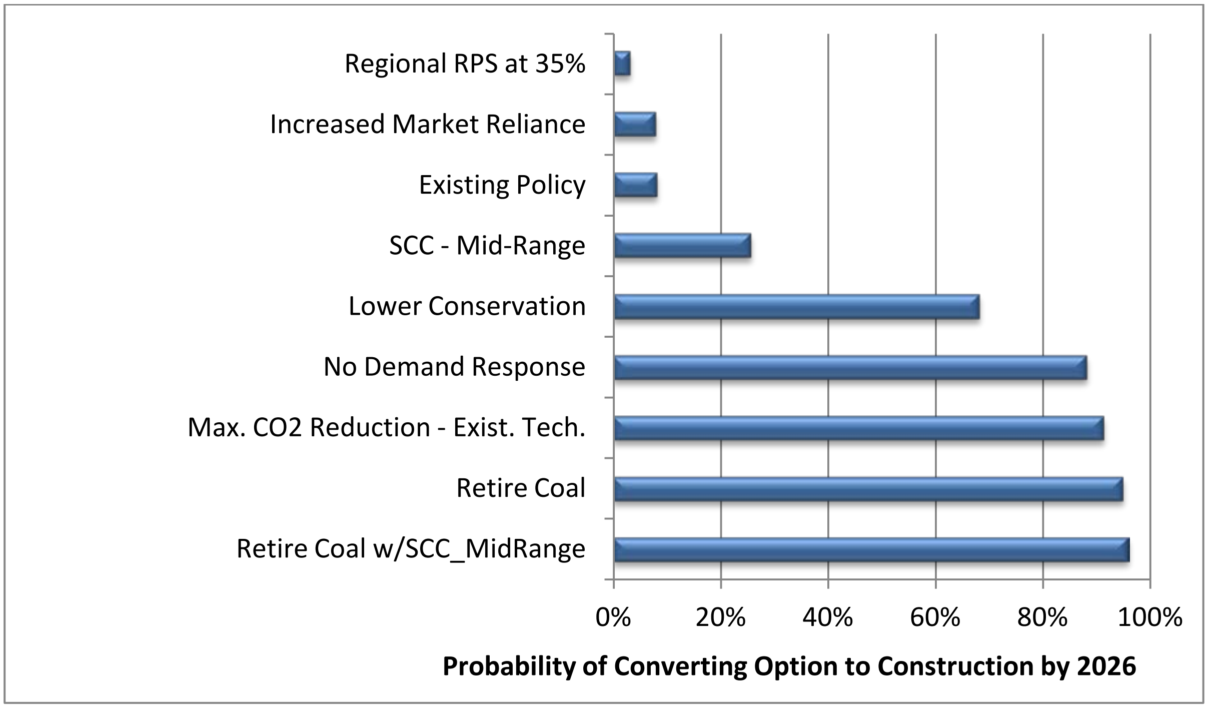
By 2026, Figure 3 - 10 shows that the probability of moving from an option to actual construction of a new gas-fired thermal plant increases to more than 65 percent in the **Lower Conservation** scenario and to above 80 percent in the **No Demand Response** scenario. All of the scenarios that assume the region's existing coal plants are retired by 2026, including **Maximum Carbon Reduction – Existing Technology** scenarios have a 90 percent probability or higher of constructing one or more new natural gas generating resources. This occurs because under these scenarios existing coal plants are retired and, in the scenarios that assume a social cost of carbon, inefficient gas-fired generation is displaced by new, highly efficient natural gas generation to reduce regional carbon dioxide emissions.

Figure 3 - 9: Probability of New Natural Gas-Fired Resource Development by 2021



The development of natural gas combined cycle combustion turbines is largest when there is a need for both new capacity and energy to meet regional adequacy standards. As can be observed from the data shown in Figures 3 - 9 and 3 - 10, this occurs in scenarios that must replace energy generation lost due to the retirement of resources, such as in the five scenarios that retire or decrease the use of existing coal and inefficient existing gas plants or those that assume no demand response resources or develop significantly less amounts of energy efficiency.

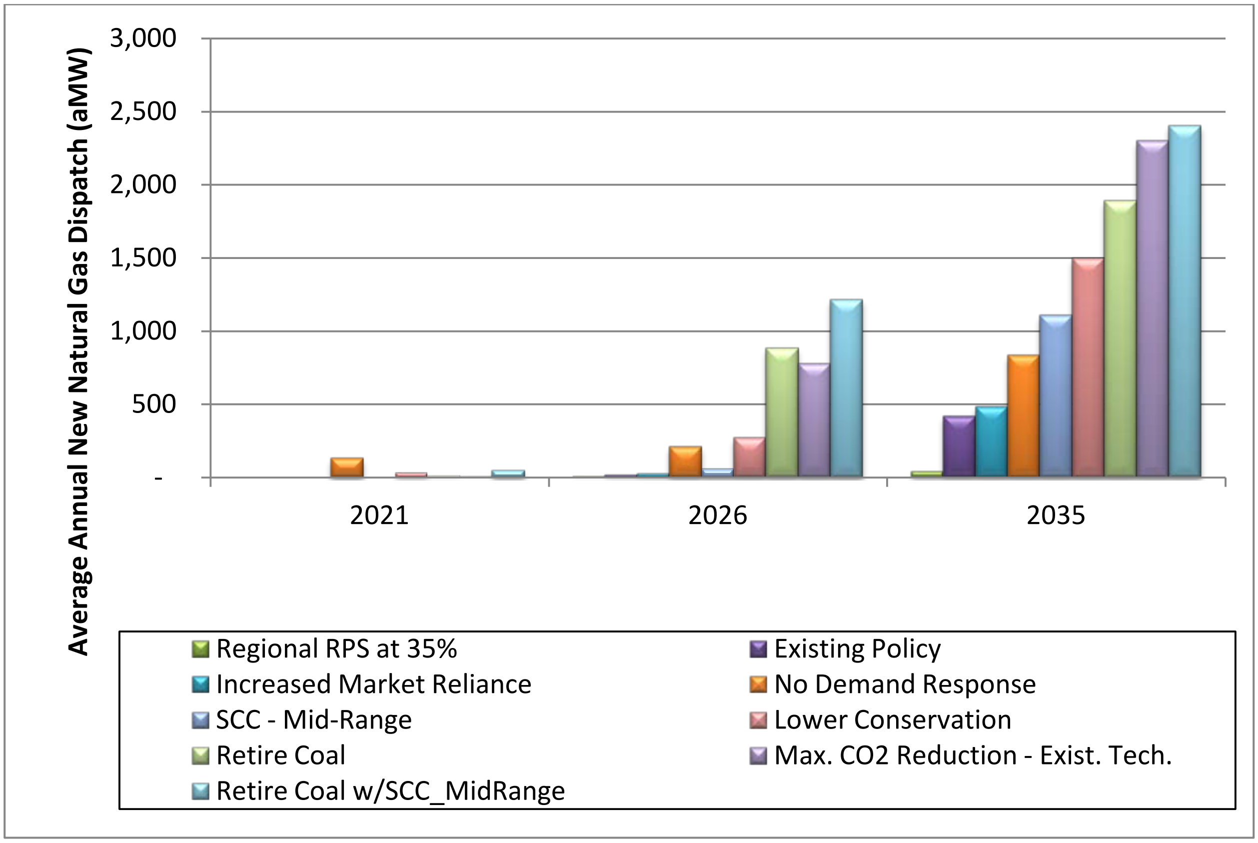
Figure 3 - 10: Probability of New Natural Gas-Fired Resource Development by 2026



As can be seen from the prior discussion, while the amounts of efficiency and the minimum amount of demand response were fairly consistent across most scenarios examined, the future role of new natural gas-fired generation is more variable and specific to the scenarios studied. Figure 3 - 11 shows the average amounts of gas-fired generation across 800 futures considered in each of the principal scenarios. The amount of new natural gas-fired generation constructed varies in each future. In most scenarios the average annual dispatch of new natural gas-fired generation is less than 50 average megawatts by 2021 and only between 300 to 400 average megawatts by 2026 except in scenarios that assume all existing coal plants are retired. In the **Existing Policy** scenario, the amount of energy generated from new combined cycle combustion turbines, when averaged across all 800 futures examined, is just 20 average megawatts in 2026. In contrast, the average amount generated across 800 futures is between 200 - 300 average megawatts in 2026 in the scenarios that assume no demand response resources are developed or that develop significantly lower amounts of conservation.

However, the role of natural gas is larger than it appears in the Council's analysis of the regional need for new natural gas fired generation for a number of reasons. First, the Council models the region as if it were a single utility, even though it is not. This understates the need for resource development because it does not capture the physical and institutional barriers present in the region. For example, the regional transmission system has not evolved as rapidly as the electricity market, resulting in limited access to market power for some utilities. Second, some utilities have significant near-term resource challenges, particularly if there is limited access to surplus resources from others. These factors limit the ability of the regional resource strategy to be specific about optioning and construction dates for natural gas-fired resources, or for the types of natural gas-fired generation. As a result, some amount of new gas-fired generation may be required in such instances even if the utilities deploy demand response resources and develop the energy efficiency as called for in Seventh Power Plan.

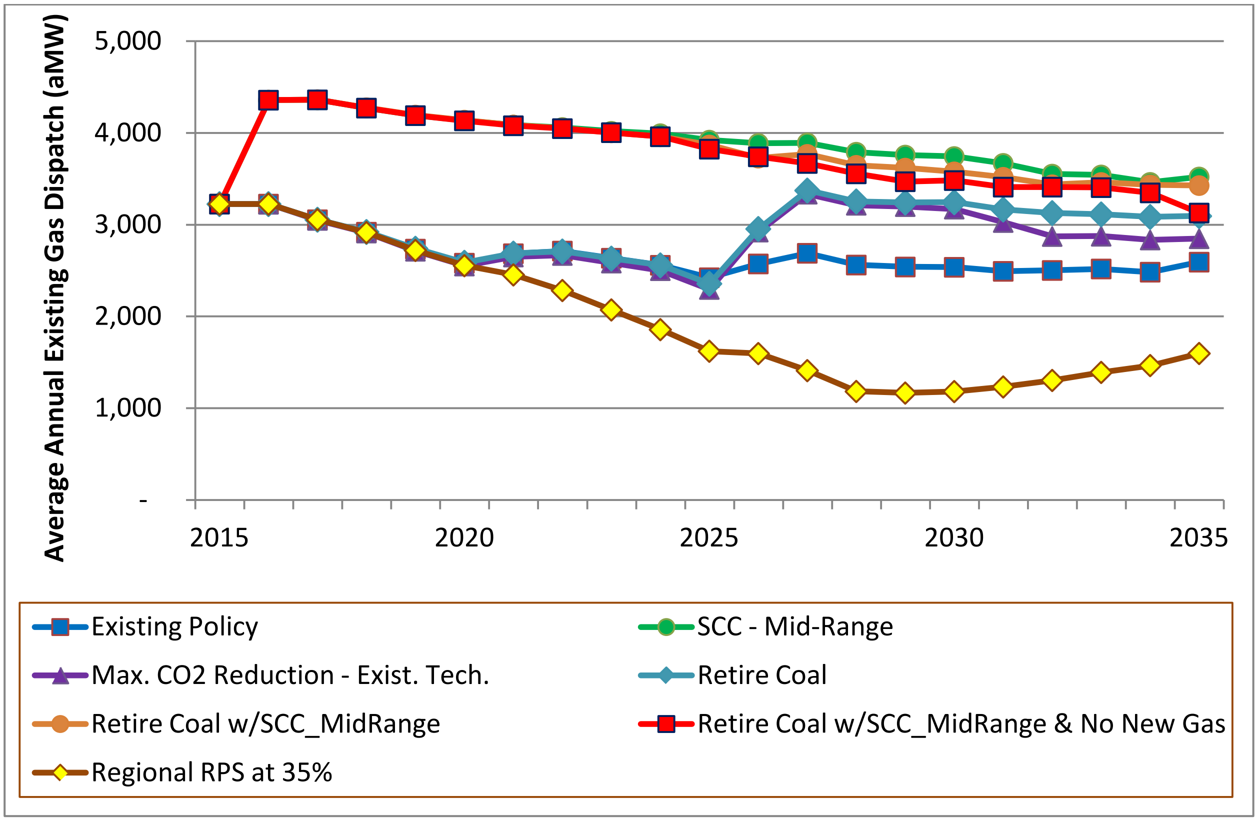
Figure 3 - 11: Average New Natural Gas-Fired Resource Development



Third, the increased use of the *existing* natural gas generation in the region plays a major role in many of scenario's least cost resource strategies, particularly those that explored alternative carbon dioxide emissions reduction policies. Figure 3 - 12 shows the average annual dispatch of the existing natural gas generation in the region through time for the six carbon dioxide reduction policy scenarios as well as the **Existing Policy** scenario. A review of Figure 3 - 12 reveals that the annual dispatch of existing natural gas generating resources increases in response to carbon dioxide emission reduction policies.

For example, under the three scenarios that assume the mid-range estimate of the social cost of carbon is imposed beginning in 2016, existing natural gas generation increases immediately following the imposition of carbon dioxide damage cost. In the three scenarios that assume all of the region's existing coal plants are retired in 2025, existing gas generation increases post-2025 when the entire region's existing coal-fired generation fleet is retired. Under the **Regional RPS at 35%** scenario, existing natural gas generation actually declines through time as low variable cost resources are added to the system, generally lowering market prices and diminishing the economics of gas dispatch.

Figure 3 - 12: Average Annual Dispatch of Existing Natural Gas-Fired Resources



Renewable Generation

Since the adoption of the Sixth Power Plan renewable generating resources development has increased significantly. This development was prompted by Renewable Portfolio Standards (RPS) adopted in three of the four Northwest states and in California. Wind energy has been the principal focus of renewable resource development in the Pacific Northwest. From 2010 through 2014 about 4,100 megawatts of wind nameplate capacity was added to the region, with 2,000 megawatts coming online in 2012 alone. By the end of 2014, wind nameplate capacity in the region totaled just over 8,700 megawatts. However, only about 5,550 megawatts of that nameplate capacity currently serves Northwest loads. The remaining 3,150 megawatts of wind nameplate capacity is presently contracted to utilities outside the region, primarily California.

Existing wind resources are estimated to provide about 2,400 average megawatts of energy generation per year in the region, or about 8 percent of the region’s electricity energy supply. However, on a firm capacity basis, existing wind resources only provide about 1 percent of the region’s total system peaking capability.[15]

[15] See Chapter 11 for the analysis of the ability of new wind resources to provide peak capacity.

Aside from hydropower, the renewable resources evaluated in the Regional Portfolio Model (RPM) are wind, utility scale and distributed solar photovoltaic (solar PV) and conventional geothermal.[16] The Council recognizes that additional small-scale renewable resources are likely available and cost-effective. These small-scale renewables were not modeled in the RPM but the plan encourages their development as an important element of the resource strategy. In addition, there are many potential renewable resources not captured in the resource strategy that are currently either too expensive or unproven technologies that may, with additional research and demonstration, prove to be valuable future resources.

New wind resources that have ready access to transmission produce energy at costs that are competitive on an energy basis with other generation alternatives. Recent and forecast reductions in solar PV system cost are making utility scale PV system's energy production cost increasingly cost-competitive. Even though conventional geothermal resources are currently estimated to have the lowest cost of all renewable resources in the region, only limited development of these resources has occurred, largely due of their exploration risk.

Despite the increasingly competitive cost per megawatt-hour of these renewable resources, renewable generation development in the scenarios tested for the Seventh Power Plan is driven by state renewable portfolio standards (RPS) and not economics. This is because in most of the futures tested in the RPM the region is short on peaking capacity and has surplus energy. Consequently, resource selection is based more on the each resource's cost per megawatt of peak capacity and less on its cost per megawatt-hour of energy output. Since, with the exception of geothermal resources, renewable resources have a very high cost per peak megawatt, the vast majority of renewable resource development in scenarios tested is in response to existing state mandates (RPS).

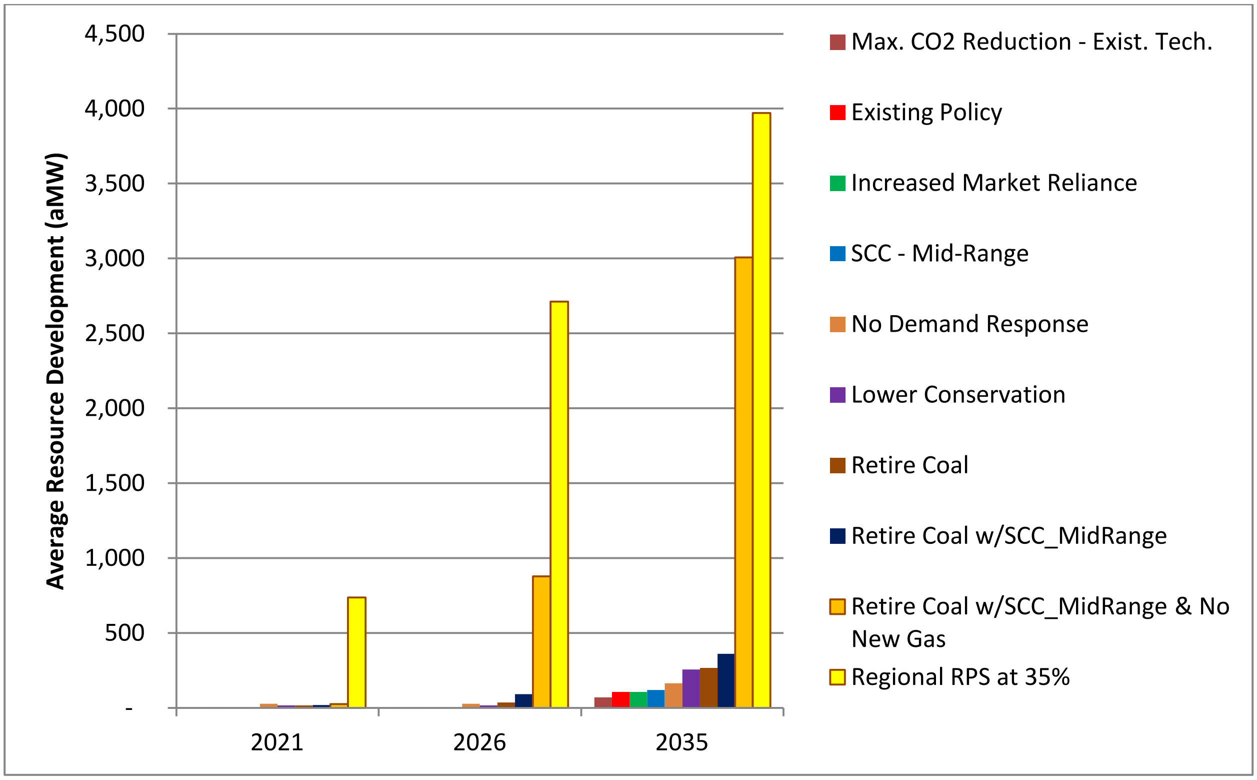
The amount of renewable energy acquired depends on the future demand for electricity because state requirements specify percentages of retail sales that have to be met with qualifying renewable sources of energy. Figure 3 - 13 shows the average development of renewable resources across scenarios analyzed for the Seventh Power Plan. As can be seen from this figure, under all least cost resource strategies for all scenarios, except in the **Regional Renewable Resource Standards at 35%** and **Retire Coal with SCC-MidRange & No New Gas** scenarios, less than 400 average megawatts of renewable resource development occurs, and then only later in the planning period (post-2026) after the Oregon and Washington renewable credit bank balances are forecast to be drawn down. Even in the **Social Cost of Carbon-MidRange** scenario where carbon damage cost of between $40 and $60 per metric ton are imposed, the amount of wind, solar PV and conventional geothermal resources developed on average is only about 120 average megawatts.

The significant development of renewable resources in the **Regional Renewable Resource Standards at 35%** scenario occurs because they would be required by law, while their development in the **Retire Coal with SCC-MidRange & No New Gas** scenario is because they are the only

[16] Distributed solar PV systems are evaluated in three scenarios, Retire Coal w/SCC MidRange, Retire Coal w/SCC MidRange and the Maximum Carbon Reduction – Emerging Technology. Distributed solar PV systems are also assumed to be installed in the baseline frozen efficiency forecast. See Chapter 7 and Appendix E for a more complete discussion.

resource option assumed to be available to replace retiring coal generation and meet future load growth.

Figure 3 - 13: Average Renewable Resource Development by Scenarios by 2021, 2026 and 2035



The explanation for the outcome described above is that while the two widely available renewable resources in the region, wind and solar PV, produce significant amounts of energy, they provide little or only modest peaking capacity. Partly as a result of the significant wind development in the region over the past decade, the Northwest has a significant energy surplus, yet under critical water and extreme weather conditions the region faces the probability of a peak capacity shortfall. In short, the generation characteristics of the currently economically competitive renewable resources do not align well with regional power system needs.

The Council's current analysis of wind, solar PV and geothermal resources ability to supply peaking capacity accounts for the ability of the region's existing power system to store energy as fuel or water when renewable resource generation is available for later use to meet peak demands. The contribution to peak of all resources, including renewable resources, modeled in the RPM were determined by comparing how much nameplate capacity must be added to the system to reduce capacity shortfalls by specific predetermined amounts. The peak capacity contribution of wind and solar resources is based on hourly modeling of their output against hourly system loads and takes into account their interaction with the region's existing power system.[17]

This analysis found that wind can only be relied upon to provide between 3 to 11 percent of its nameplate capacity (depending on the season of the year) toward meeting peak loads due to the variable nature of the resource. This means that, for example, a 100 megawatt wind farm can only be relied upon to provide 3 megawatts of peak capacity during the winter quarter.[18] Solar PV resources contribute more to meeting peaking needs, ranging from a low of 26 percent of nameplate capacity in the winter months to a high of just over 80 percent of nameplate capacity in the summer. Conventional geothermal resources are assumed to be able to provide peaking capability similar to gas generation across the year, but this resource has a much longer development lead time, high development risk and is more limited in supply.

As stated above, the development of renewable generation is driven by state renewable portfolio standards more so than regional energy need. Based on the analysis for the Seventh Power Plan, in the absence of higher renewable portfolio standards or limitations on the development of new natural gas generation little additional renewable development would take place, even under scenarios where a very high estimate of the social cost of carbon dioxide is imposed on the power system raising the cost of gas and coal generation.

Carbon Policies and Methane Emissions

The Northwest power system, due to its significant reliance on hydropower and its historical deployment of energy efficiency to offset the need for new thermal generation, has the lowest carbon emissions level of any area of the country. The Seventh Power Plan supports policies that cost-effectively achieve state and federal carbon dioxide emission reduction goals while maintaining regional power system adequacy. The plan calls upon the region to aggressively develop the energy-efficiency resources. In addition, the plan recommends replacing retiring coal plants with only those resources required to meet regional capacity and energy adequacy requirements. As stated above, after energy efficiency, the increased use of existing natural gas generation offers the lowest cost option for reducing regional carbon emissions. Utility development of new gas-fired generation to meet local needs for ancillary services, such as wind integration, or capacity requirements beyond the modest levels anticipated in this plan will increase carbon dioxide emissions. If Northwest electricity generation is dispatched first to meet regional adequacy standards for energy and capacity rather than to serve external markets, the increase in carbon dioxide emissions can be minimized.

As noted above, a central element in transitioning the Northwest power system to an even lower carbon footprint involves the increased use of natural gas, which consists primarily of methane.

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[17] See Chapter 11 for a more complete description of the derivation of the peak contribution of renewable and other resources modeled in the RPM.

[18] Winter quarter as modeled in the RPM includes January through March.

While burning natural gas produces significantly less carbon dioxide emissions per unit of electricity generation than coal, its production and distribution release methane into the atmosphere. Methane is a highly active greenhouse gas, with a global warming potential 28 to 36 times that of carbon dioxide.[19] Recent studies have indicated that fugitive emissions of methane from some natural gas production areas and existing gas pipelines could be as high as 10 percent. In contrast, fugitive methane emissions from new production facilities and pipelines have been shown to be far lower, on the order of one percent. In developing the resource strategy for the Seventh Power Plan the Council seriously considered whether the carbon dioxide reduction benefits of the increased use of natural gas would be significantly offset by increases in methane emissions.

Although there is no debate about methane global warming potential, there is considerable uncertainty around such issues as whether its impacts compared to carbon dioxide are over or under-stated, whether its increased use results in a proportional increase in fugitive emissions, whether accounting for the methane emissions from coal production would also raise that fuel's full life-cycle climate impacts and whether the cost of reducing methane emissions would significantly alter the price of natural gas. With respect to the last issue, even with the uncertainty surrounding the anticipated impact of regulations to reduce methane emissions in production and distribution, the best information available to the Council indicates that these emissions can be reduced to what is viewed by scientists as an acceptable level at a cost that leaves the price of natural gas well within the range of the natural gas prices assumed for the Seventh Plan's development.[20]

The Council also observed that increasing the region's use of existing gas generation or relying more on new gas generation, will likely draw on gas production from new wells which have lower fugitive emissions than the old fields/wells that appear to be the primary source of methane emissions. Moreover, pipeline leaks are a not significantly driven by throughput, they are primarily a function of a pipeline's total capacity which is fixed within a range of operating pressures. Therefore, unless new pipeline capacity is needed, fugitive emissions from pipeline leaks remain relatively constant. Consequently, existing gas generation can be supplied with existing pipeline capacity, so only new gas generation that requires additional pipeline capacity produces incrementally more methane emissions.

The Seventh Power Plan's overall resource strategy seeks to minimize the need to develop new gas generation by meeting most future energy and capacity needs with energy efficiency and demand response. Successful implementation of this strategy provides time to take actions to reduce current fugitive methane emissions and minimize new methane emissions, so that the use of natural gas does produce a reduction in climate change impacts.

The basis for the Seventh Power Plan's carbon dioxide policy recommendations are more fully described in the Carbon Dioxide Emissions section of this chapter.

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[19] See Appendix I for a more complete description of methane's potential environmental impacts and the uncertainties surrounding fugitive emission sources and levels.

[20] See Chapter 13 for a discussion of the potential impacts on natural gas prices from regulations designed to reduce methane emissions at new production facilities.

Regional Resource Utilization

The existing Northwest power system is a significant asset for the region. The FCRPS (Federal Columbia River Power System) provides low-cost and carbon dioxide-free energy, capacity, and flexibility. The network of transmission constructed by Bonneville and the region's utilities has supported a highly integrated regional power system. The Council's Seventh Power Plan resource strategy assumes that ongoing efforts to improve system scheduling and operating procedures across the region's balancing authorities will, in some form, succeed.

While the Council does not directly model the sub-hourly operation of the region's power system, both the Regional Portfolio Model and the GENESYS models presume resources located anywhere in the region can provide energy and capacity services to any other location in the region, within the limits of existing transmission. This simplifying assumption also minimizes the need for new resources needed for integration of variable energy resource production. To the extent that actual systems can be developed that replicate the model's assumptions, fewer new resources will be required. This likely means the region needs to invest in its transmission grid to improve market access for utilities, to facilitate development of more diverse cost-effective renewable generation and to provide a more liquid regional market for ancillary services.

Along with reducing physical and technical barriers, there are more efficient ways to dispatch and use existing regional resources that could minimize the need for new resource development. The analyses conducted for the Seventh Power Plan reveal in particular that the region could benefit from a different approach to using existing generation so as to keep more of that generation in the region serving load under longer-term arrangements.

The least cost resource strategies identified by the RPM often reduce regional exports in order to serve in-region demands for energy and capacity. That is, since the RPM treats the region as a single system, any resources that are available within the region to meet regional adequacy standards for energy and capacity are allocated to that purpose.[21] For example, in scenarios that retired or significantly reduced the dispatch of existing coal-fired generation serving the region, the vast majority of which serves investor-owned utilities, the RPM reduces regional exports in order to maintain resource adequacy. The RPM does not differentiate between investor-owned, publicly owned and Bonneville's generation when it balances regional loads and resources. The resource strategies that satisfied regional adequacy standards by inter-regional transfers resulted in lower total system cost and lower system economic risk because they delayed or avoided the need for new resource development within the region. Figure 3 - 14 shows the average net (i.e., exports minus imports) exports for their least cost resource strategies across these five scenarios.

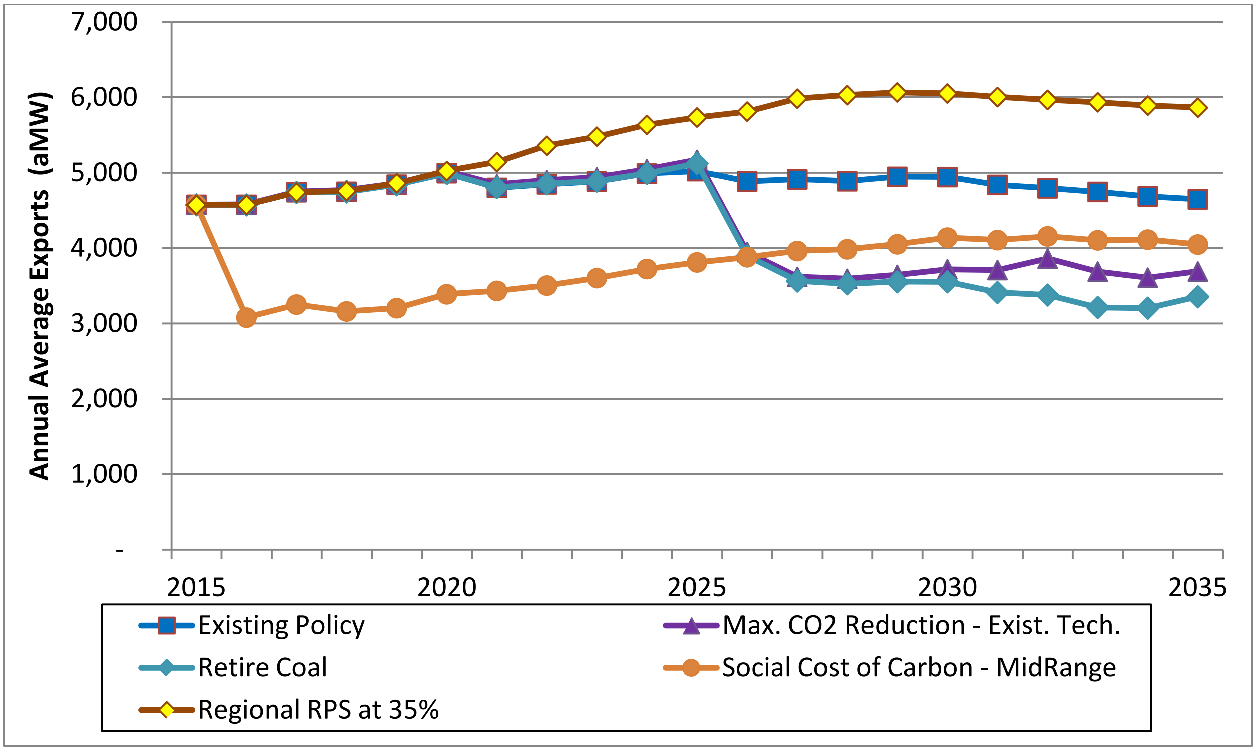
Inspection of Figure 3 - 14 reveals how net exports change across time in response to the resource strategy for each scenario. For example, under the **Existing Policy** scenario exports grow slowly until 2021 then decline slightly after 2021 and 2025 following the closure of coal plants currently

[21] See Chapter 11 for a more complete discussion of the Council's resource adequacy assessment.

serving the region. After 2030, under this same scenario, net exports continue to gradually decline as loads grow and conservation no longer offsets load growth.

In contrast, under the **Social Cost of Carbon - MidRange** scenario which assumes that carbon dioxide damage costs are imposed in 2016, net exports decline immediately. This reduction in exports offsets the reduction in regional coal plant dispatch in response to increased carbon dioxide costs. In the following years, exports gradually increase as highly efficient gas-fired generation developed in the region displaces less efficient generation outside the region. In the two scenarios shown in Figure 3-14 that assume all of the region's existing coal plants are retired by 2025, net

Figure 3 - 14: Average Annual Net Regional Exports for Least Cost Resource Strategies



exports drop immediately following their assumed closure and remain lower for the remainder of the planning period. At the other extreme, under the **Regional RPS at 35%** scenario, regional net exports expand significantly over time as the region develops large amounts of additional renewable resources. These resources have very low variable cost, which makes them competitive outside the region *and* they produce energy that is surplus to regional needs during many months of the year.

The Council's analysis shows that the total cost to the region would be lower if more effective use of surplus power available from Bonneville and some of the region's utilities could be used in-region to offset the need that other utilities have to develop new generation to meet resource adequacy standards. The Council recognizes that significant equity, risk, institutional and legal issues must be overcome to effect such a change. For example, Bonneville and other utilities in the region that control hydropower generation often, but not always, generate substantial surplus power above critical water conditions. Most of that surplus is sold into short-term markets, much of it leaving the region. The Council's analysis indicates that the region would benefit if, instead, some significant portion of this surplus hydropower generation could be sold to other utilities in the region under longer-term contracts to meet regional firm power needs. In order for this to happen, however, either the sellers or the buyers, or both, would have to take on some additional risk since the surplus generation would not always be available due to poor water conditions. As a result the power price for such contracts would need to somehow reflect additional risk.

The region needs to be creative in crafting new power sales arrangements that address in an appropriate and equitable way the issues of risk inherent in any scheme to rely on this surplus generation to help meet regional adequacy standards. However, the Council encourages the region to find ways to overcome these barriers since the benefit to the region could be substantial.[22]

Develop Long-Term Resource Alternatives

The seventh element of the Council's resource strategy recognizes that technologies will evolve significantly over the 20 years of the Seventh Power Plan. When the Council next develops a power plan, the cost-effective, available and reliable resources will most likely be different from those considered in the Seventh Power Plan. But the Seventh Power Plan identifies areas where progress is likely to be valuable and includes actions to explore and develop such resources and technologies. In many instances entities in the region can influence the development of technology and the pace of adoption.

Areas of focus in the long-term resource strategy include additional efficiency opportunities and the ability to acquire them, energy-storage technologies to provide capacity and flexibility, development of smart-grid technologies, expansion of demand response capability, and tracking and supporting the development of no-carbon dioxide or low-carbon dioxide emitting generation. The latter includes renewable technologies such as enhanced geothermal and wave energy and small modular nuclear generation.

Research, development, and demonstration of these technologies are an important part of the Council's resource strategy. Tracking these developments, as well as plan implementation and assumptions such as resource availability, cost and load growth, will identify needed changes in the power plan and near-term actions. These elements of the resource strategy are addressed primarily in the action plan.

[22] Absent such an outcome, the trend over the past decade that shows the average revenue per kilowatt-hour for residential customers of investor-owned utilities increasing while the average revenue per kilowatt-hour for residential customers of public utilities has remained nearly flat will likely continue. Between 2005 and 2014, the average revenue per kilowatt-hour sold by IOUs increased from 7.7 cents to 9.9 cents, while the average revenue per kilowatt-hour sold for public utilities remained barely changed, increasing from 7.7 cents to 8.0 cents per kilowatt-hour. Similar trends have occurred for commercial and industrial customers.

Adaptive Management

The eighth element of the Council's resource strategy is to adaptively manage its implementation. The Council's planning process is based on the principle that "there are no facts about the future." The Council tests thousands of resource strategies across 800 different futures to identify the elements of these strategies that are the most successful (i.e., have lower cost and economic risk) over the widest range of future conditions. This means that during the period covered by the Seventh Power Plan's Action Plan, actual conditions must deviate significantly from the conditions tested in the 800 futures explored in the Regional Portfolio Model before the basic assumptions and action items in the Seventh Power Plan are called into question.

However, the fact that a wide range of strategies were tested against a large number of potential future conditions in developing the Plan does not mean that *all* near term actions called for in the Seventh Power Plan will be perfectly aligned with the actual future the region experiences. Therefore, the Council will annually assess the adequacy of the regional power system to identify conditions that could lead to power shortages. Through this process, the Council will be able to identify whether actual conditions depart so significantly from planning assumptions as to require adjustments to the action plan.

The Council will also conduct a mid-term assessment to review plan implementation and compare progress against specific metrics. This includes assessing how successful plan implementation has been at reducing and meeting Bonneville's obligations, both the power sales contracts and the assistance the plan's resource scheme provides in the successful implementation of the Council's Columbia River Basin Fish and Wildlife Program.

CARBON DIOXIDE EMISSIONS

As in the Sixth Plan, one of the key issues identified for the Seventh Power Plan is climate-change policy and the potential effects of proposed carbon dioxide regulatory policies. In addition, the Council was asked to address what changes would need to be made to the power system to reach a specific carbon dioxide reduction goal and what those changes would cost. This section also summarizes how alternative resources strategies compare with respect to their cost and ability to meet carbon dioxide emissions limits established by the Environmental Protection Agency (EPA).

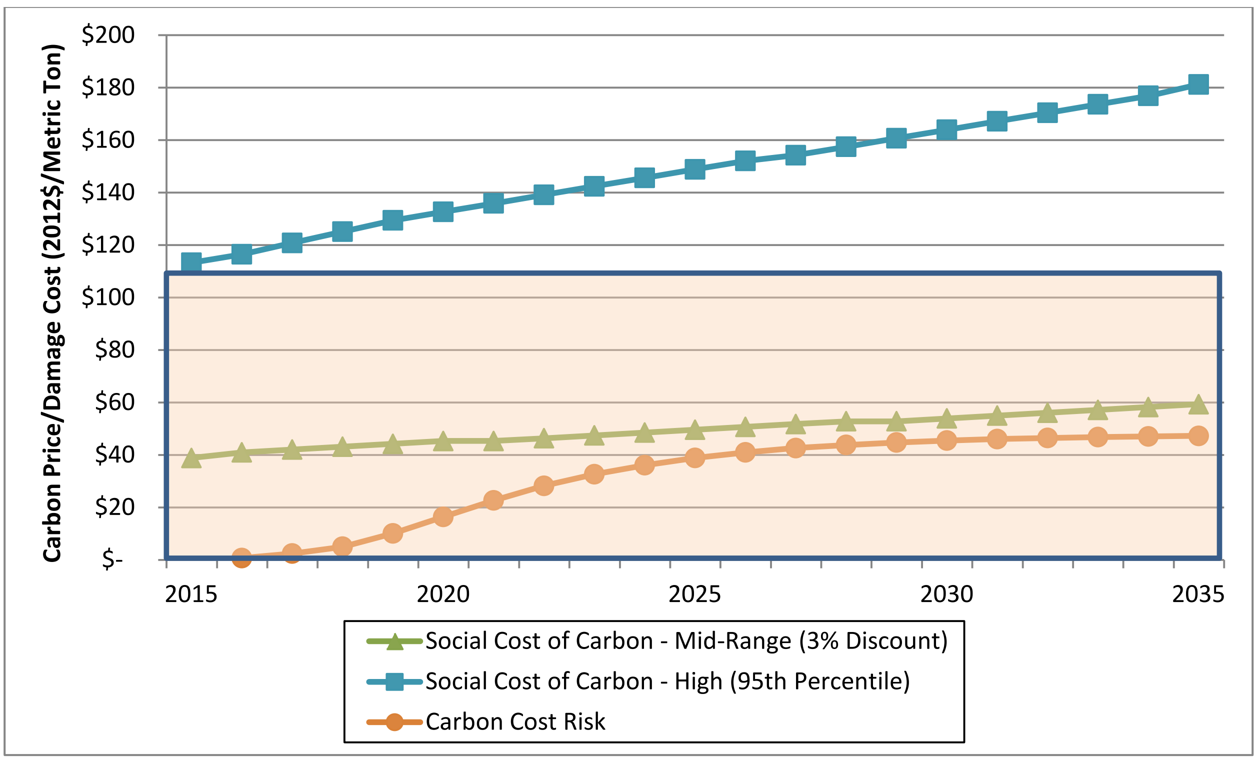
In providing analysis of carbon dioxide emissions and the specific cost of attaining carbon dioxide emissions limits, the Council is not taking a position on future climate-change policy. Nor is it taking a position on how individual Northwest states or the region should comply with EPA's carbon dioxide emissions regulations. The Council's analysis is intended to provide useful information to policy-makers. Chapter 15 discusses the results of the Council's analysis of alternative carbon dioxide emissions reduction policy scenarios in more detail.

Three "carbon dioxide pricing" policy options were tested. Two scenarios assumed that alternate values of the federal government's estimates for damage caused to society by climate change due to carbon dioxide emissions, referred to as the "social cost of carbon," are imposed beginning in 2016. The policy basis for these scenarios is that the cost of resource strategies developed under conditions which fully internalized the damage cost from carbon dioxide emissions would be the maximum society should invest to avoid such damage.

The third carbon dioxide pricing policy tested, **Carbon Cost Risk** is identical to the scenario analyzed in the Sixth Plan. This scenario exposes the power system to random changes in carbon dioxide pricing each year over the 20 year planning period. This scenario was designed to reflect the uncertainty regarding future carbon dioxide regulation. In this scenario, carbon dioxide pricing, reflecting differing levels of carbon dioxide regulatory costs, between $0 and $110 per metric ton were imposed randomly, but with increasing probability and at higher levels through time.

Figure 3 - 15 shows the two US Government Interagency Working Group's estimates used for the **SCC - MidRange** and **SCC-High** scenarios and the range (shaded area) and average carbon dioxide prices across all futures that were evaluated in the $0-to-$110-per-metric ton **Carbon Cost Risk** scenario.

Figure 3 - 15: Carbon Dioxide Regulatory Cost or Price and Societal Cost of Carbon Tested in Scenario Analysis



Four other carbon dioxide emission reduction policies were tested that did not involve using carbon dioxide pricing. The first of these, the **Maximum Carbon Reduction** - **Existing Technology** scenario was designed to reduce carbon dioxide emissions by deploying all currently available and economically viable technology. The second, the **Maximum Carbon Reduction** - **Emerging Technology** scenario was designed to reduce carbon dioxide emissions by deploying technology that may become commercially available and economically viable over the next 20 years. Under both of these scenarios all existing coal plants serving the region were assumed to be retired by 2026. In addition, all existing natural gas plants with heat-rates (a measure of efficiency) above 8,500 BTU/kilowatt-hour were retired by 2030. Also, in the **Maximum Carbon Reduction –**

Emerging Technology scenario, no new natural gas-fired generation was considered for development.

The **Maximum Carbon Reduction – Emerging Technology** scenario was designed to assess the magnitude of potential additional carbon dioxide emission reductions that might be feasible by 2035. As stated above, the Council created this resource strategy based on energy-efficiency resources and non-carbon dioxide emitting generating resource alternatives that might become commercially viable over the next 20 years. While the Regional Portfolio Model (RPM) was used to develop the amount, timing and mix of resources in this resource strategy, no economic constraints were taken into account. That is, the RPM was simply used to create a mix of resources that could meet forecast energy and capacity needs, but it made no attempt to minimize the cost to do so. The reason the RPM's economic optimization logic was not used is that the future cost and resource characteristics of many of the emerging technologies included in this scenario are highly speculative. This scenario was not updated for the draft plan. However, draft plan's results for this scenario are Appendix O, along with a more detailed discussion of the emerging technologies considered in this scenario.

The third "non-price" carbon reduction policy tested, **Retire Coal**, is a variation on the two **Maximum Carbon Reduction** scenarios. Under this scenario, only the region's existing coal generation is retired while existing gas generation remains available for deployment.

The fourth "non-price" carbon dioxide emission reduction policy option tested was the **Regional RPS at 35%** scenario. Under this scenario, the region's reliance on carbon dioxide-free generation was increased by assuming that the region would satisfy a region wide Renewable Portfolio Standard requiring 35 percent of the region's retail sales of electricity are met with such resources by 2030.

The Council also tested two other scenarios that combined both pricing and non-pricing strategies to assess their collective impact. The **Coal Retirement with the Social Cost of Carbon** scenario was designed to test whether the addition of carbon cost would alter the resources selected to replace retired coal plants. The **Coal Retirement with the Social Cost of Carbon & No New Gas** scenario was designed to assess the emissions reduction benefits and cost of restricting coal replacement resources to renewables.

In order to compare the cost of resource strategies that reflect both "carbon-pricing" and "non-carbon pricing" policy options for reducing carbon dioxide emissions it is useful to separate their cost into two components. The first is the direct cost of the resource strategy. That is, the actual the cost of building and operating a resource strategy that reduces carbon dioxide emissions. The second component is the revenue collected through the imposition of carbon taxes, through a cap and trade system or pricing carbon damage cost into resource development decisions. This second cost component, either in whole or in part, may or may not be paid directly by electricity consumers. For example, the "social cost of carbon" represents the estimated economic damage of carbon dioxide emissions worldwide. In contrast to the direct cost of a resource strategy which will directly affect the cost of electricity, these "damage costs" are borne by all of society, not just Northwest electricity consumers. In the discussion that follows, only the direct cost (i.e., costs net of carbon revenues) of resource strategies are reported.

Table 3 - 1 shows the average net present value system cost for the least cost resource strategy and average carbon dioxide emissions across all 800 futures for the year 2035 for the seven

scenarios and sensitivity studies conducted to specifically evaluate carbon dioxide emissions reductions policies (and economic risks) for the development of the Seventh Power Plan. [23] Scenarios are listed based on their average level of carbon dioxide emissions in 2035, which the highest emission scenario at the top of the table. Table 3- 1 also shows this same information for the **Existing Policy** and **Lower Conservation** scenarios which were not designed to reduce carbon emissions. As a point of comparison, the carbon dioxide emissions from the generation serving the Northwest loads averaged approximately 54 million metric tons per year from 2001 through 2014.

Table 3 - 1: Average System Costs Excluding Carbon Revenues and PNW Power System Carbon Dioxide Emissions by Scenario

Scenario	System Cost w/o Carbon Dioxide Revenues (billion 2012$)	2035 PNW Carbon Dioxide Emissions (MMT)
Lower Conservation	$ 97	41
Increased Market Reliance	$ 76	37
No Demand Response	$ 86	37
Existing Policy	$ 82	36
Regional RPS at 35%	$ 128	26
SCC - Mid-Range	$ 78	21
Retire Coal w/SCC_MidRange	$ 91	18
Max. CO2 Reduction - Exist. Tech.	$ 117	16
Retire Coal	$ 98	16
Retire Coal w/SCC_MidRange & No New Gas	$ 126	10

Table 3 - 1 shows the **Existing Policy** scenario which assumed no additional carbon dioxide emissions reductions policies beyond those in place prior to the issuance of the Environmental Protection Agency's Clean Air Act 111(b) and 111(d) regulations results in carbon dioxide emissions in 2035 of 36 million metric tons. The direct cost of this resource strategy is $82 billion (2012$). The **Regional RPS at 35%** scenario's least cost resource strategy reduces projected 2035 carbon dioxide emissions by about 10 million metric tons. However, this policy has a direct cost of $128 billion, or $46 billion above the **Existing Policy** scenario's resource strategy. Two scenarios, the **Retire Coal** and **Maximum Carbon Reduction - Existing Technology** scenarios produce equivalent carbon dioxide emissions in 2035 (16 MMTE), but the **Retire Coal** scenario has a $19 billion lower average system cost. The only difference between these two scenarios is that the **Retire Coal** scenario does not retire inefficient natural gas plants, whereas **the Maximum Carbon –**

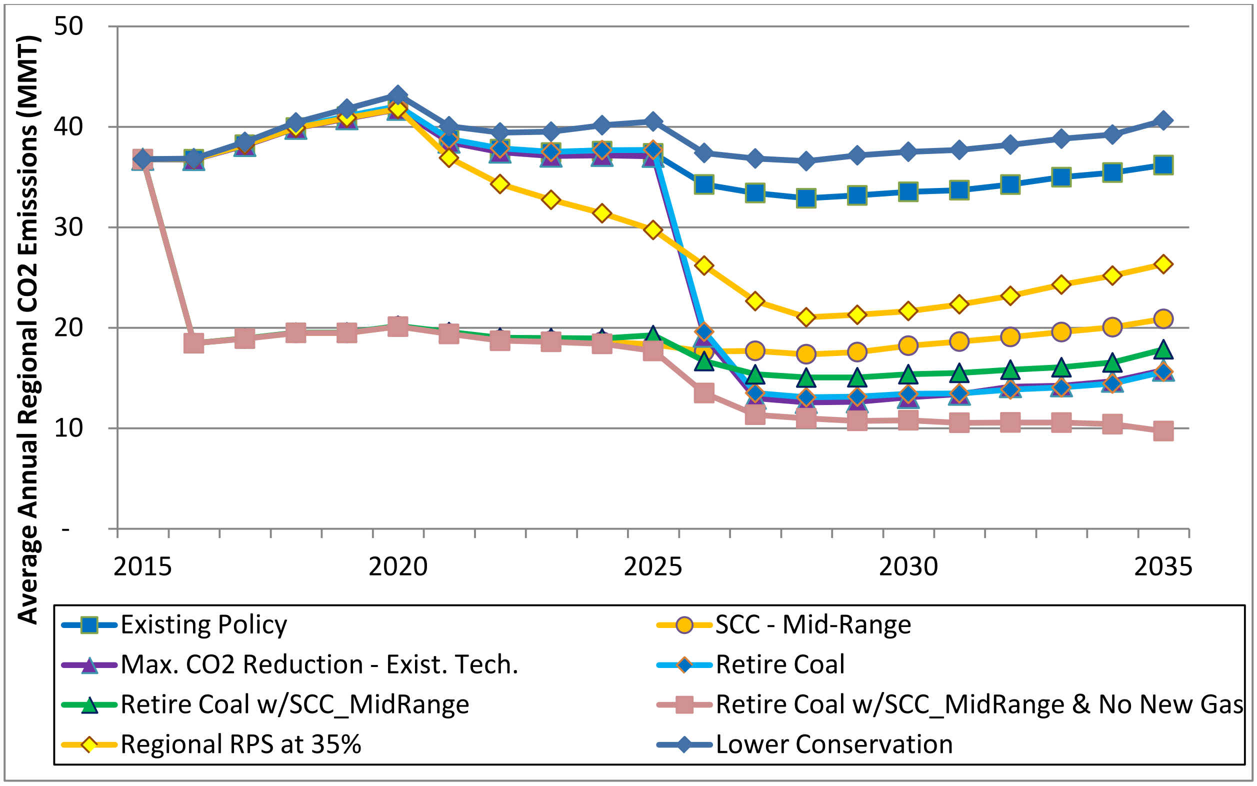
[23] The emissions forecast shown in Table 3-1 are slightly lower than anticipated actual regional emissions. This is because the Council's modeling assumes that all resources serving the region are economically dispatched as if operated by a single utility. In reality, both technical constraints and institutional barriers prohibit this optimized level of system integration from occurring. As a result, the most efficient thermal generator may not be used to serve load, even if it could have been dispatched to do so which understates the regional emissions.

Existing Technology scenario does. Thus, it appears that retaining existing natural gas plants, even relatively inefficient ones does not materially increase carbon dioxide emissions and avoids the cost of constructing new gas-fired replacement generation.

The average system cost for all of the carbon emission scenarios which impose a price on carbon emissions (**SCC-MidRange**, **Retire Coal w/SCC MidRange** and **Retire Coal w/SCC MidRange & No New Gas)** are affected by the interaction of the Northwest region with the rest of the western power market. For these scenarios it was assumed that the social cost of carbon was imposed throughout the west, not just in the region. As a result, the relative carbon dioxide content in the region compared to the rest of the western market plays an important role in determining whether the region imports or exports. For example, the **SCC MidRange** scenario, which reduces 2035 carbon dioxide emissions to 21 million metric tons or to about 15 million metric tons below that of the **Existing Policy** scenario has an average system cost that is $4 billion lower ($78 vs. $82 billion). This scenario's lower cost results from increased regional revenue from exports that reduce the cost of developing the scenario resource strategy. This scenario illustrates that the Northwest will likely have a competitive advantage if pricing policies are used throughout the western electricity market to reduce carbon dioxide emissions.

Comparing the results of these scenarios based on a single year's emissions can be misleading. Each of these policies alters the resource selection and regional power system operation over the course of the entire study period. Figure 3 - 16 shows the annual emissions level for each scenario. A review of Figure 3 - 16 reveals that the three scenarios that assume that the "mid-range" estimate of the social cost of carbon dioxide damage costs is imposed in 2016, immediately reduce carbon dioxide emissions and therefore have impacts throughout the entire twenty year period covered by the Seventh Power Plan. In contrast, the other three carbon dioxide reduction policies phase in over time, so there cumulative impacts are generally smaller.

Figure 3 - 16: Average Annual Carbon Dioxide Emissions by Carbon Reduction Policy Scenario



The **Regional RPS at 35%** scenarios gradually reduce emissions, while the **Retire Coal, Maximum Carbon Reduction – Existing Technology** and **Maximum Carbon Reduction - Emerging Technology** scenarios dramatically reduce emission as existing coal and inefficient gas plants are retired post-2025. The difference in timing results in large differences in the cumulative carbon dioxide emissions reductions for these policies. All scenarios show gradually increasing emissions beginning around 2028 as the amount of annual conservation development slows due to the completion of cost-effective and achievable retrofits. This lower level of conservation no longer offsets regional load growth, leading to the increased use of carbon dioxide emitting generation.

Table 3 - 2 shows cumulative emission reductions from 2016 through 2035 for each of the carbon dioxide reduction policy scenarios compared to the **Existing Policy** scenario. It also shows the average present value system cost per million metric ton of carbon dioxide reduction for these five carbon dioxide reduction policy options. Table 3-2 reveals that **SCC MidRange** scenario has negative cost per unit of carbon reduction. As discussed above, this lower present value system cost is a result of the increase in regional net revenues from electricity exports that occurs when carbon costs are imposed throughout the entire western electricity market. The cost per unit of carbon dioxide emission reduction for all the three scenarios that include imposing the social cost of carbon as one policy element are all lower as a consequence of this circumstance.

Table 3 - 2: Average Cumulative Emissions Reductions and Present Value Cost Excluding Carbon Revenues of Alternative Carbon Dioxide Emissions Reduction Policies Compared to Existing Policies - Scenario

CO2 Emissions - PNW System 2016 - 2035 (MMT)	Cumulative CO2 Emission Reduction Over Existing Policy - Scenario (MMT)	Incremental Present Value Average System Cost of Cumulative Emission Reduction Over Existing Policy - Scenario (2012$/MT)
SCC - Mid-Range	351	$ (11)
Existing Policy	-	-
Retire Coal w/SCC_MidRange	377	$ 23
Retire Coal	197	$ 78
Retire Coal w/SCC_MidRange & No New Gas	430	$ 100
Max. CO2 Reduction - Exist. Tech.	201	$ 170
Regional RPS at 35%	132	$ 349

The single policy option with the lowest cost per unit of carbon dioxide emission reduction shown in Table 3-2 is the **SCC-MidRange** scenario. This scenario reduces cumulative carbon dioxide emissions by 351 million metric tons between 2016 and 2035. The single policy option with the highest cost per ton of carbon dioxide reduction is the **Regional RPS at 35%** scenario. The high per unit cost of carbon dioxide emissions reduction from this scenario occurs because it does not result in the retirement or significantly reduce the use of existing coal plants. All of the other policy options tested either retire the region's existing coal plants, or dramatically reduce their dispatch as a result of the imposition of carbon pricing.

The next least expensive option combines two policies by adding a retire coal policy to the imposition of social cost of carbon policy, illustrated by the **Retire Coal w/SCC MidRange** scenario. This scenario reduces cumulative carbon dioxide emissions by another 26 million metric tons. Combining three policy options reduces emissions still further. This is illustrated by the **Retire Coal w/SCC-MidRange & No New Gas** scenario that restricts new resource development to renewable resources in addition to retiring coal plants and imposing the social cost of carbon. This scenario reduces cumulative carbon dioxide emissions by another 53 million metric tons at a cost of $100 per metric ton.

However, in order to judge the incremental costs and benefits of restricting new resource development to renewable resources it is useful to compare the difference in cumulative emissions and costs between the **Retire Coal w/SCC_MidRange** and the **Retire Coal w/SCC_MidRange & No New Gas** scenarios. From data in Tables 3-1 and 3-2 it can be determined that cumulative carbon dioxide emissions are reduced by 53 million metric tons and average system cost increase from $91 to $126 billion, or $35 billion. Thus, on an incremental basis the cost of these additional carbon dioxide emission reductions is $635 per metric ton. This illustrates the value of isolating the incremental impacts of each carbon reduction policy so that the most effective combinations can be identified.

It is important to note that in all scenarios than impose the social cost of carbon the coal plants serving the region dispatch infrequently following the imposition of carbon cost. This occurs because these plants are more expensive than existing natural gas generation once carbon cost are considered. As a result, such plants might be viewed by their owners as uneconomic to continue operation. If this is indeed the case, and these plants are retired, then the cost of replacement resources needed to meet the energy or capacity needs supplied by the retiring plants would add to the average present value system cost of this scenario. As a result, the actual cost of the **Social Cost of Carbon – MidRange** scenario would likely be higher and much closer to the **Retire Coal w/SCC-MidRange** scenario.

In the analysis discussed above, only the cost incurred during the planning period (i.e. 2016-2035) and the emissions reductions that occur during this same time frame are considered. Clearly, investments made to reduce carbon dioxide emissions will continue beyond 2035, as will their carbon dioxide emissions impacts. These “end-effects” could alter the perceived relative cost-efficiency of carbon dioxide reduction policy options shown in Table 3 - 2. For example, over a longer period of time the cumulative emissions reductions from the **Maximum Carbon Reduction – Existing Technology** scenario could exceed those from the **SCC-MidRange** scenario because by 2035 the **Maximum Carbon Reduction – Existing Technology** scenario results in 5 MMTE per year lower emissions. In this instance, if the difference in emissions rates for these two scenarios were to remain the same for an additional 30 years, then their cumulative emissions reductions over 50 years would be nearly identical. Since it is impossible to forecast these “end effects,” readers should consider the scenario modeling results shown in Table 3 - 2 as directional in nature, rather than precise forecast of either emissions reductions or the cost to achieve them.

The key findings from the Council’s assessment of the potential to reduce power system carbon dioxide emissions are:

- The retirement of all of the existing coal generation serving the region could reduce Northwest power system carbon dioxide emissions from a historical average of 54 million metric tons per year to about 16 million metric tons per year, or by nearly 70 percent. Achieving this level of carbon dioxide emission reduction is nearly $16 billion or nearly 20 percent above the cost of the least cost resource strategies that are anticipated to comply *at the regional* level with the newly established federal emissions limits.
- If all of the region’s existing coal plants are retired and replaced exclusively with renewable resources and all generation is dispatched to reflect a mid-range estimate of the social cost of carbon, regional power system carbon emissions could be reduced to 10 million metric tons per year by 2035, or 80 percent below historical levels. The cost of achieving this level of carbon emission reduction is $44 billion, or nearly 55 percent above the cost of the least cost resource strategies that are anticipated to comply *at the regional* level with the newly established federal emissions limits. The average cost of this scenario is significantly lowered by the expected increase in net power sales revenues from exports assuming a western or national power market imposition of a carbon cost.
- At present, it is not possible to entirely eliminate carbon dioxide emissions from the power system without the development and deployment of nuclear power and/or emerging technology for both energy efficiency and non-carbon dioxide emitting generation that require technological or cost breakthroughs.

- Deploying renewable resources to achieve maximum carbon reduction presents significant power system operational challenges, in particular by dramatically increasing the need for balancing and flexibility reserves.

- The most cost-effective carbon dioxide emissions reduction policies are those that result in the retirement or significantly reduce the use of existing coal plants. The single policy option for reducing carbon dioxide emissions with the lowest cost per unit of emission reduction imposes the equivalent of the federal government's mid-range estimate of the social cost of carbon throughout the entire Western electricity market. The single policy option for reducing carbon dioxide emissions with the highest cost per unit of emission reduction establishes a regional renewable portfolio standard at 35 percent. The high per unit cost of carbon dioxide emissions reduction from this policy occurs because it does not result in the retirement or significantly reduce the use of existing coal plants.

Federal Carbon Dioxide Emission Regulations

As the Seventh Power Plan was beginning, development the US Environmental Protection Agency (EPA) issued proposed rules that would limit the carbon dioxide emissions from new and existing power plants. Collectively, the proposed rules were referred to as the Clean Power Plan. In early August of 2015, after considering nearly four million public comments the EPA issued it final Clean Power Plan (CPP) rules. The "111(d) rule," referred to by the Section of the Clean Air Act under which EPA regulates carbon dioxide emissions for existing power plants, has a goal of reducing national power plant carbon dioxide emissions by 32 percent from 2005 levels by the year 2030. This is slightly more stringent than the draft rule which set an emission reduction target of 30 percent. [24] EPA also issued the final rule under the Clean Air Act section 111(b) for new power plants and the proposed federal plan and model rules that would combine the two emissions limits.

To ensure the 2030 emissions goals are met, the rule requires states begin reducing their emissions no later than 2022 which is the start of an eight year compliance period. During the compliance period, states need to achieve progressively increasing reductions in carbon dioxide emissions. The eight year interim compliance period is further broken down into three steps, 2022-2024, 2025-2027, and 2028-2029, each associated with its own interim goal.

Under the EPA's final rules, states may comply by reducing the average carbon dioxide emission rate (pounds of carbon dioxide/kilowatt-hour) emitted by all power generating facilities located in their state that are covered by the rule. In the alternative, states may also comply by limiting the total emissions (tons of carbon dioxide per year) from those plants. The former compliance option is referred as a "rate-based" path, while the latter compliance option is referred to as a "mass-based"

[24] U.S. Environmental Protection Agency, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," 80 Fed. Reg. 64,662 (October 23, 2015). A coalition of states, utilities, utility organizations and others challenged the rule applying to existing sources in the federal D.C. Circuit Court of Appeals. The U.S. Supreme Court stayed the effectiveness of the rule in an order issued February 9, 2016, pending not just review on the merits by the court of appeals but also the resolution of any petition for further review in the Supreme Court following whatever decision is issued by the court of appeals. The litigation is ongoing as the Council completed the Seventh Power Plan.

path. Under the "mass-based" compliance option EPA has set forth two alternative limits on total carbon dioxide emissions. The first, and lower limit, includes only emissions from generating facilities either operating or under construction as of January 8, 2014. The second, and higher limit, includes emissions from both existing and new generating facilities, effectively combining the 111(b) and 111(d) regulations.

The Council determined that a comparison of the carbon dioxide emissions from alternative resource strategies should be based on the emissions from both existing and new facilities covered by the EPA's regulations. This approach not only better represents the total carbon dioxide footprint of the power system, but it more fully captures the benefits of using energy efficiency as an option for compliance because it reduces the need for new generation. Table 3 - 3 shows the final rule's emission limits for the four Northwest states for the "mass-based" compliance path, including both existing and new generation.

Table 3 - 3: Pacific Northwest States Clean Power Plan Final Rule Carbon Dioxide Emissions Limits[25]

Mass Based Goal (Existing) and New Source Complement (Million Metric Tons)					
Period	Idaho	Montana	Oregon	Washington	PNW
Interim Period 2022-29	1.49	11.99	8.25	11.08	32.8
2022 to 2024	1.51	12.68	8.45	11.48	34.1
2025 to 2027	1.48	11.80	8.18	10.95	32.4
2028 to 2029	1.48	11.23	8.06	10.67	31.4
2030 and Beyond	1.49	10.85	8.00	10.49	30.8

EPA's regulations do not cover all of the power plants used to serve Northwest consumers. Most notably, the Jim Bridger coal plants located in Wyoming serve the region, but are not physically located within the regional boundaries defined under the Northwest Power Act.[26] In addition, there are many smaller, non-utility owned plants that serve Northwest consumers located in the region, but which are not covered by EPA's 111(b) and 111(d) regulations. Therefore, in order for the Council to compare EPA's carbon dioxide emissions limits to those specifically covered by the agency's regulations, it was necessary to model a sub-set of plants in the region.

[25] Note: EPA's emissions limits are stated in the regulation in "short tons" (2000 lbs). In Table 3-2 and throughout this document, carbon dioxide emissions are measured in "metric tons" (2204.6 lbs) or million metric ton equivalent (MMT).

[26] The Power Act defines the "Pacific Northwest" as Oregon, Washington, Idaho, the portion of Montana west of the Continental Divide, "and such portions of the States of Nevada, Utah, and Wyoming as are within the Columbia River drainage basin; and any contiguous areas, not in excess of seventy-five air miles from [those] area[s]… which are a part of the service area of a rural electric cooperative customer served by the Administrator on December 5, 1980, which has a distribution system from which it serves both within and without such region." (Northwest Power Act, §§ 3(14)(A) and (B).)

Under the Clean Air Act, each state is responsible for developing and implementing compliance plans with EPA's carbon dioxide emissions regulations. However, the Council's modeling of the Northwest Power system operation is not constrained by state boundaries. That is, generation located anywhere within the system is assumed to be dispatched when needed to serve consumer demands regardless of their location. For example, the Colstrip coal plants are located in Montana, but are dispatched to meet electricity demand in other Northwest states. Consequently, the Council's analysis of compliance with EPA's regulations can only be carried out at the regional level. While this is a limitation of the modeling, it does provide useful insight into what regional resource strategies can satisfy the Clean Power Plan's emission limits.

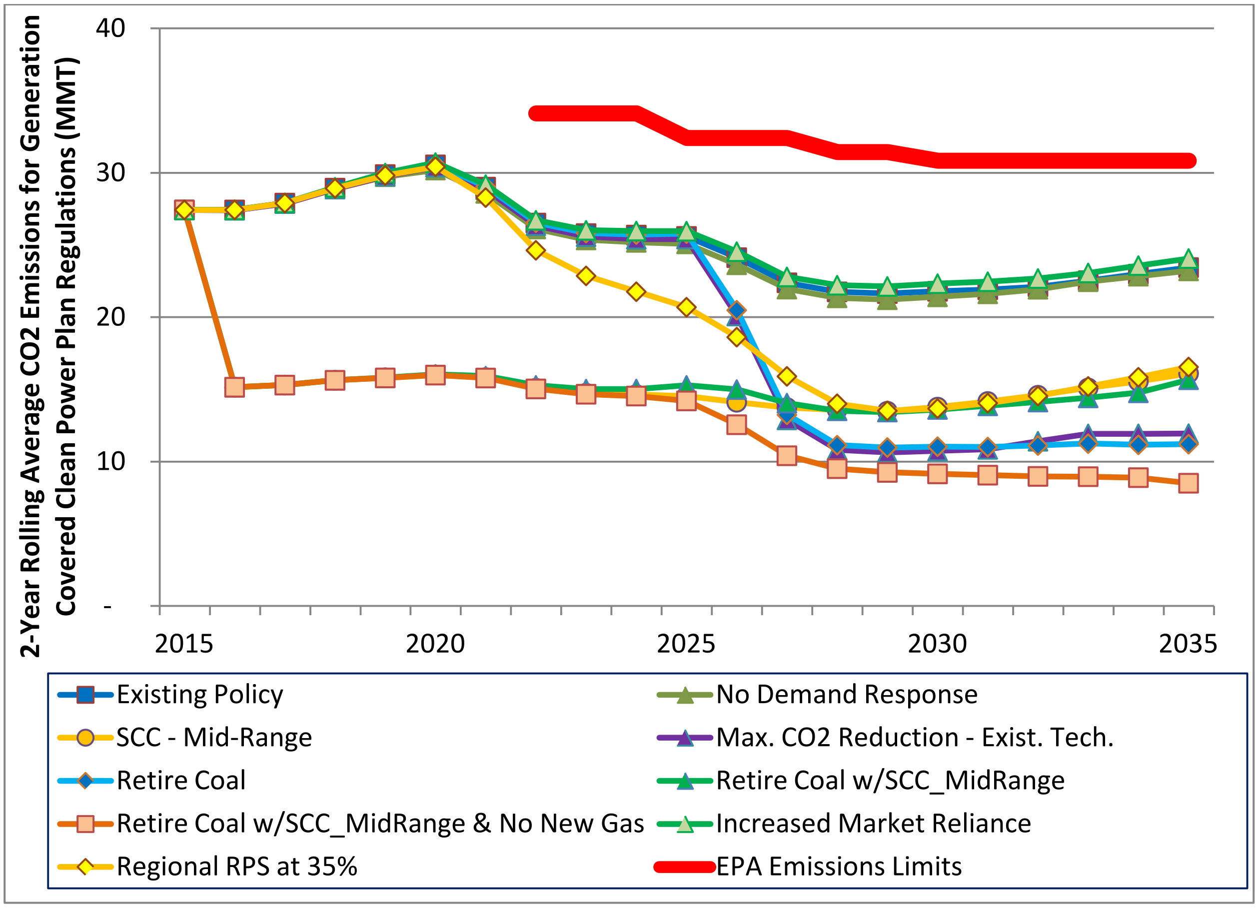
Figure 3 - 17 shows the annual average carbon dioxide emissions for the least cost resource strategy identified under each of the major scenarios and sensitivity studies evaluated during the development of the Seventh Power Plan. The interim and final EPA carbon dioxide emissions limits aggregated from the state level to the regional level is also shown in this figure (top heavy line). Figure 3 - 17 shows all of the scenarios evaluated result in average annual carbon dioxide emissions well below the EPA limits for the region.

One of the key findings from the Council's analysis is that *from a regional perspective* compliance with EPA's carbon dioxide emissions rule should be achievable without adoption of additional carbon dioxide reduction policies in the region. This is not to say that no additional action need occur.

State compliance plans for meeting the Clean Power Plan regulations have not been drafted. These will likely call for additional actions beyond those required to achieve compliance *at the regional level*, since not all states in the region are equivalently affected by the final 111(d) regulations. This is clearly the case with Montana, where EPA's regulations require the second largest percentage reduction in carbon dioxide emissions of any state.[27] Moreover, even at the regional level, all of the least cost resource strategies that have their emission levels depicted in Figure 3 - 17 call for the development of between 4,000 and 4,400 average megawatts of energy efficiency by 2035. All of these resource strategies also assume that the retiring Centralia, Boardman, and North Valmy coal plants are replaced with only those resources required to meet regional capacity and energy adequacy requirements. Utility development of new gas-fired generation to meet local needs for ancillary services, such as wind integration, or capacity requirements beyond the modest levels included under these scenarios would increase emissions. Finally, all of the carbon dioxide emissions from the least cost resource strategies depicted in Figure 3-17 also assume that Northwest electricity generation is dispatched first to meet regional adequacy standards for energy and capacity rather than to serve external markets.

[27] Montana, which must reduce its carbon emissions by 47%, is second only to South Dakota that must reduce its carbon dioxide emissions by 48%.

Figure 3 - 17: Average Annual Carbon Dioxide Emissions for Least Cost Resource Strategies by Scenario for Generation Covered by EPA Carbon Emissions Regulations Located Within Northwest States



RESOURCE STRATEGY COST AND REVENUE IMPACTS

The Council's Regional Portfolio Model (RPM) calculates the net present value cost to the region of each resource strategy it tests to identify those strategies that have both low cost and low economic risk. The RPM includes only the forward-going costs of the power system; that is, only those costs that can be affected by future conditions and resource decisions. Figure 3 - 18 shows the present value system cost for the ten scenarios evaluated for development of the final Seventh Power Plan.[28] Figure 3 - 18 shows the present value of power system costs both with and without assumed

[28] Chapter 15 provides this same information for both these scenarios and the other principal scenarios evaluated during development of the draft plan.

carbon dioxide emissions costs. That is, the scenarios that assumed some form of carbon dioxide price include not only the direct cost of building and operating the resource strategy, but also the costs of emitting carbon dioxide assumed in those scenarios. Therefore, in Figure 3 - 18 the present value system cost of the least cost resource strategies for only those scenarios that assume the social cost of carbon is imposed include carbon dioxide costs. The average system cost for the other scenarios are the same with or without considering carbon dioxide revenues.

Figure 3 - 18: Average Net Present Value System Cost for the Least Cost Resource Strategy by Scenario With and Without Carbon Revenues

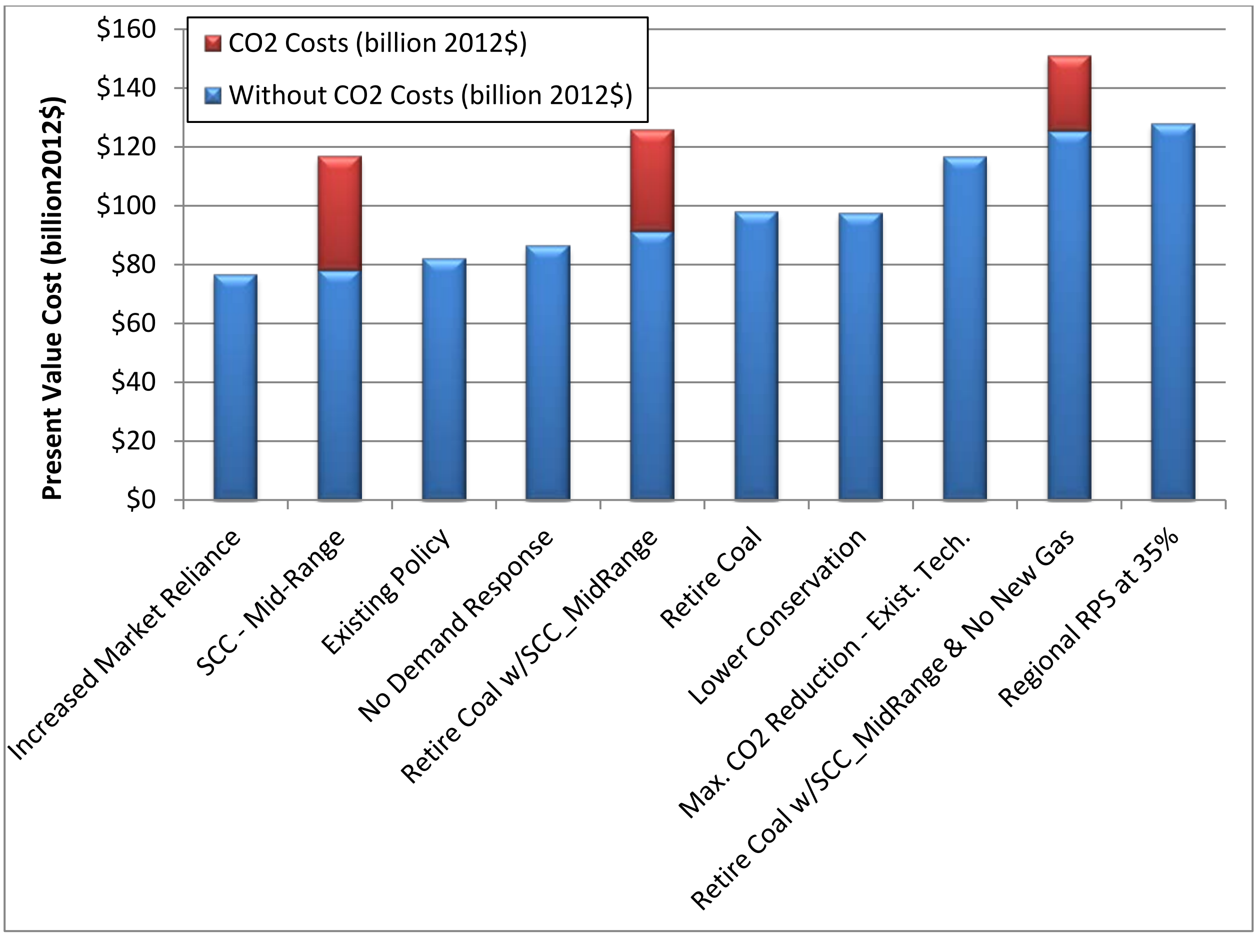


Table 3 - 4 shows average present value system cost, net of carbon revenues, for ten selected scenarios evaluated for the Seventh Power Plan. This table shows the difference in present value cost of each of these scenarios compared to the **Existing Policy** scenario. A review of Table 3-4 shows that the **Increased Market Reliance** and the **SCC MidRange** resource strategies both have a lower present value system cost than the **Existing Policy** resource strategy. The finding that the **Increased Market Reliance** resource strategy has a lower cost than the **Existing Policy** resource strategy supports the Council's recommendation that the Resource Adequacy Advisory Committee review its assumptions regarding the cost and risk of reliance on external market contracts to meet regional adequacy standards. As discussed previously, the lower present value system cost for the **SCC MidRange** resource strategy is a result of cost-offsets from increased revenue due to higher value regional exports when carbon pricing is assumed across the entire western electricity market.

Table 3-4 also shows that not developing demand responses resources, i.e., following the **No Demand Response** least cost resource strategy) would add $4 billion to the regional power system cost. Similarly, adopting a resource strategy that targets only conservation with cost below short run wholesale market prices (i.e. the **Lower Conservation** resource strategy) would increase regional power system cost by $16 billion compared to the **Existing Policy** resource strategy.

Six of the scenarios shown in Table 3-4 test different policy options for reducing carbon dioxide emissions. As a result, with the exception of the **SCC MidRange** scenario, they all have higher average system cost than the **Existing Policy** scenario which includes no new policies to reduce carbon emissions. The relative merits of these policy alternatives are discussed in the prior section of this Chapter.

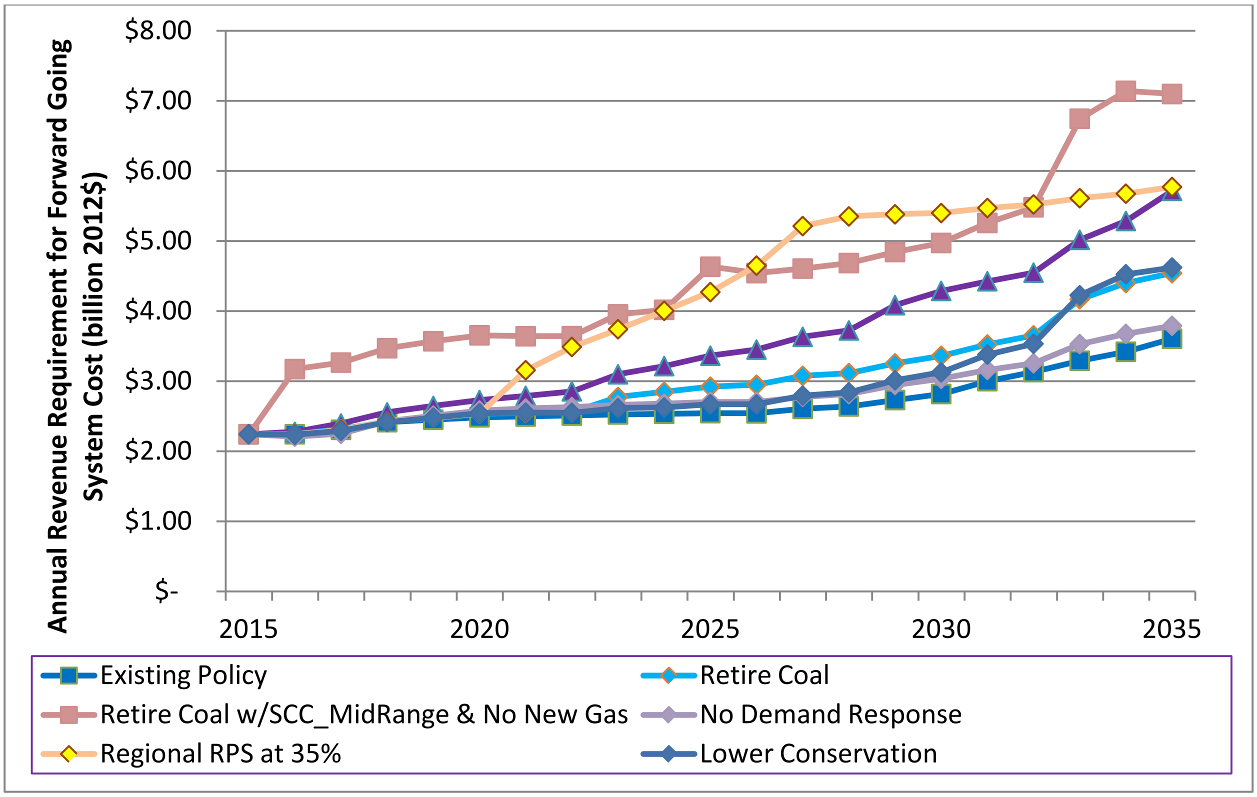
Table 3 - 4: Average Net Present Value System Cost without Carbon Dioxide Revenues and Incremental Cost Over Existing Policy Scenario

Scenario	Present Value System Cost of Resource Strategy, Excluding Carbon Revenues (billion 2012$)	Incremental Present Value System Cost Over Existing Policy Scenario Resource Strategy (billion 2012$)
Increased Market Reliance	$ 76	$ (5)
SCC - Mid-Range	$ 78	$ (4)
Existing Policy	$ 82	$ -
No Demand Response	$ 86	$ 4
Retire Coal w/SCC_MidRange	$ 91	$ 9
Retire Coal	$ 98	$ 16
Lower Conservation	$ 97	$ 16
Max. CO2 Reduction - Exist. Tech.	$ 117	$ 35
Retire Coal w/SCC_MidRange & No New Gas	$ 126	$ 44
Regional RPS at 35%	$ 128	$ 46

Reporting costs as net present values does not show patterns over time and may obscure differences among individual utilities. The latter is unavoidable in regional planning and the Council has noted throughout the plan that different utilities will be affected differently by alternative policies. It is possible, however, to display the temporal patterns of costs among scenarios. Four of the scenarios assume no carbon dioxide regulatory compliance cost or damage costs**: Existing Policy, Maximum Carbon Reduction - Existing Technology, Lower Conservation** and **Renewable Portfolio Standards at 35 Percent** so their forward going costs are identical with and without carbon dioxide cost. In order to compare the direct cost of the actual resource strategies resulting from carbon dioxide pricing policies with these four scenarios it is necessary to remove the carbon dioxide cost from those other scenarios. Figure 3 - 19 shows the power system cost over the forecast period for the least cost resource strategy, excluding carbon dioxide costs.

Forward-going costs include only the future operating costs of existing resources and the capital and operating costs of new resources. The 2016 value in Figure 3 - 19 includes mainly operating costs of the current power system, but not the capital costs of the existing generation, transmission, and distribution system since these remain unchanged by future resource decisions. The cost shown for the Retire Coal w/**SCC MidRange & No New Gas** scenario does not include the cost of carbon dioxide damage.

Figure 3 - 19: Annual Forward-Going Power System Costs, Excluding Carbon Dioxide Revenues

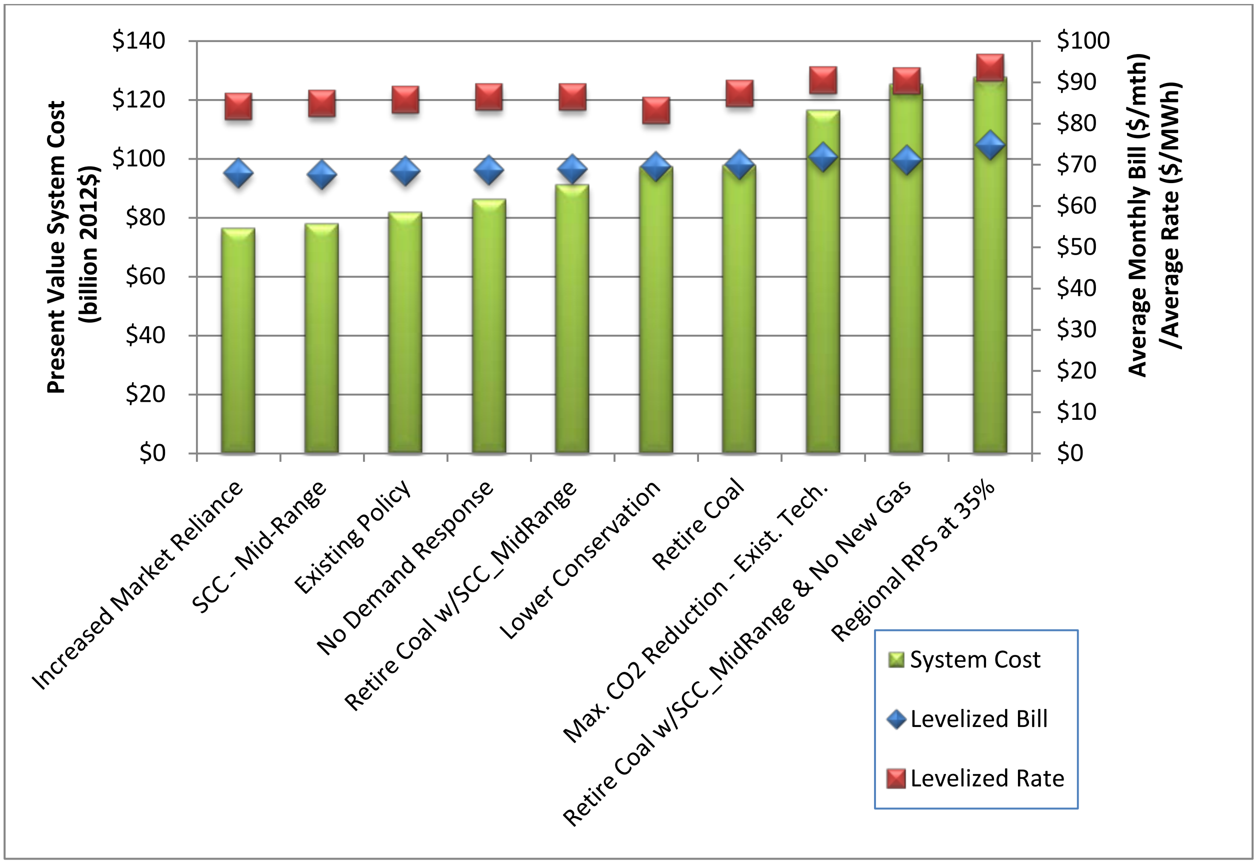


A review of Figure 3 - 19 shows the **Existing Policy** scenario has the lowest annual cost throughout the planning period. The **Lower Conservation** resource strategy shows similar annual system cost to the **Existing Policy** scenario, but begins to deviate above that scenario beginning around 2025. The **No Demand Response** scenario shows a similar pattern, with higher annual cost later in the planning period. All of the scenarios that are designed to reduce carbon dioxide emissions have higher annual cost than the Existing Policy scenario. In particular the **Retire Coal w/SCC-MidRange & No New Gas**, the **Regional RPS at 35%** and the **Maximum Carbon Reduction - Existing Technology** least cost resource strategies all exhibit significantly higher annual cost.

In the following section of this chapter these revenue requirements are translated into electric rates and typical residential customer monthly electricity bills. The addition of existing system costs makes these impacts on consumers appear smaller than looking only at forward-going costs. The rate and bill effects are further dampened by the fact that conservation costs are not all recovered through utility rates. In fact, it becomes difficult to graphically distinguish among the effects of some of the scenarios.

Figure 3 - 20 shows the effects of the different scenarios' average system costs translated into possible effects on electricity rates and residential consumer monthly electricity bills. The "rate" estimates shown in Figure 3 - 20 are average revenue requirement per megawatt-hour which include both monthly fixed charges and monthly energy consumption charges. The residential bills are typical monthly bills. In order to compare these scenarios over the period covered by the Seventh Power Plan, both the average revenue requirement per megawatt-hour and average monthly bills have been levelized over the twenty year planning period. Both are expressed in constant 2012 dollars.

Figure 3 - 20: System Costs, Rates, and Monthly Bills, Excluding Carbon Dioxide Revenues

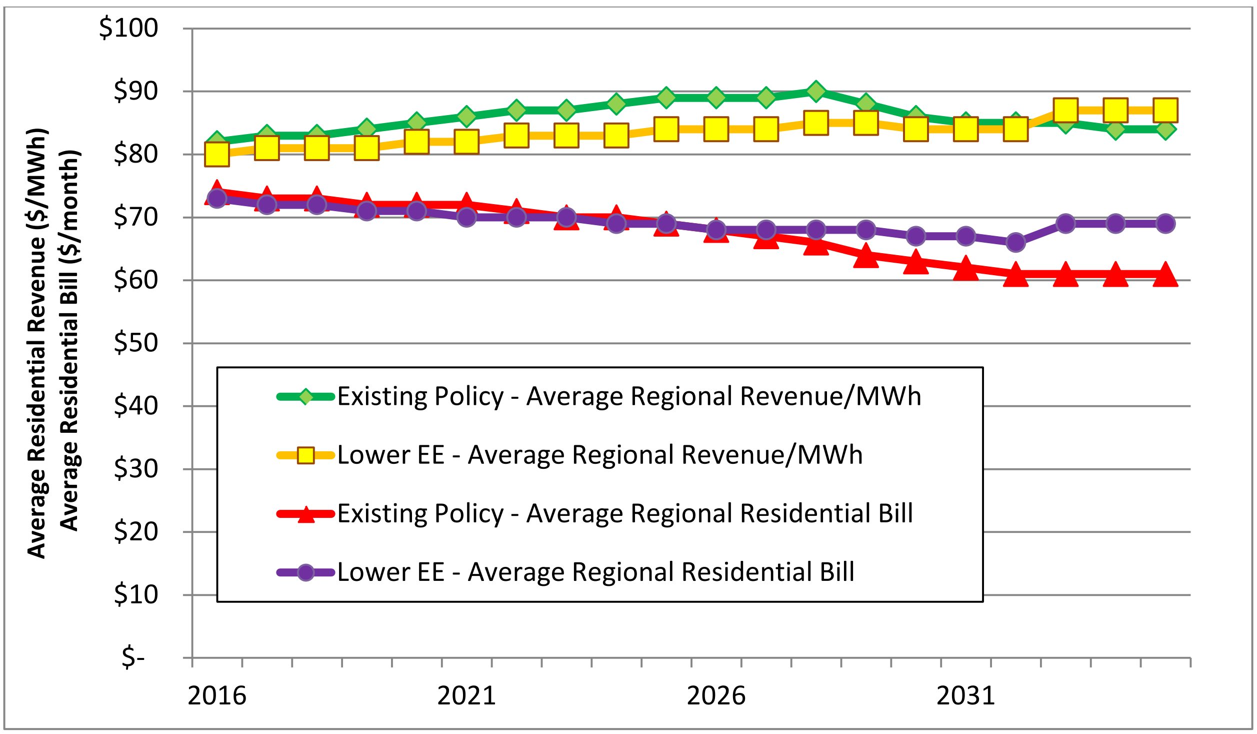


As can be seen in Figure 3 - 20, levelized rates and bills generally move in the same direction as the average net present value of power system cost reported in this plan. The only exception to this relationship is in the **Lower Conservation** scenario.

The **Lower Conservation** scenario has an average system cost of $97 billion, compared to the **Existing Policy** resource strategy's $82 billion. Even with a $16 billion higher average system cost the **Lower Conservation** resource strategy has a lower levelized average revenue requirement per megawatt-hour than the **Existing Policy** scenario ($83/MWh vs. 86/MWh). However, the, the average monthly bills for the two scenarios are nearly identical throughout this same period with the **Existing Policy** scenario having slightly lower monthly bill ($69/month vs. $70/month) than the **Lower Conservation** scenario.

However, viewed over time the **Lower Conservation** scenario's average monthly bill is higher by a several dollars per month than the **Existing Policy** scenario's average monthly bill. Figure 3 - 21 illustrates how system cost can increase with lower conservation, but rates decrease because costs are spread over a larger number of megawatt-hours sold without conservation. Figure 3 - 21 also illustrates how the greater efficiency improvements lower average electricity bills through time. As can be seen this figure, the average monthly bills for the **Lower Conservation** and **Existing Policy** scenarios are nearly equivalent through around 2030, then the **Existing Policy** scenario's bills are increasingly lower. This occurs despite the fact that the **Existing Policy** scenarios average revenue requirement per megawatt-hour is several dollars per megawatt-higher than the **Lower Conservation** scenario's.

Figure 3 - 21: Regional Average Revenue per Megawatt-Hour and Residential Electricity Bills With and Without Lower Conservation



CHAPTER 4: ACTION PLAN

Contents

INTRODUCTION

The action plan describes things that need to happen in order to implement the Council's Seventh Power Plan. It focuses on the next six years and the priorities in the plan. The Action Plan starts with activities that comprise the Regional Resource Strategy. The following three sections set forth actions that the Region, the Bonneville Power Administration and Council itself should undertake to support implementation of the Seventh Plan. The final section describes activities that the Council will engage in to maintain and enhance its analytical capabilities. In many cases, the action plan suggests the entities that have primary responsibility for implementation activities and a time frame for completion of the action.

RESOURCE STRATEGY

Energy efficiency is the first priority resource in the Northwest Power Act. The Council's analysis for the Seventh Plan affirmed that energy efficiency improvements provide the most cost-effective and least risky response to the region's growing electricity needs. Further, acquisition of cost-effective efficiency reduces the contribution of the power system to greenhouse gas emissions. While many new sources of carbon-free electricity are available, they are currently more expensive and provide little reliable peaking capacity. The acquisition of cost-effective efficiency will also buy time to develop cost-effective alternative sources of carbon-free generation. Over the past decade the region has successfully accomplished conservation, exceeding both the Fifth and Sixth Plan's goals. Nevertheless, achieving the level of conservation identified in the Seventh Plan will require continued aggressive actions by the region.

The second priority in the Seventh Plan's resource strategy is to develop the ability to deploy demand response resources to meet system capacity needs under critical water and weather conditions. In order to satisfy regional resource adequacy standards the region should develop significant demand response resources by 2021 to meet the need for additional peaking capacity. The Seventh Power Plan action plan recommends that a minimum of 600 MW of demand response resources would be cost-effective to develop under all future conditions tested across all scenarios which do not rely on increased firm capacity imports.

After energy efficiency and demand response, the increased use of natural gas generation is the third element in the Seventh Power Plan's resource strategy. Increasing the use of the region's existing natural gas generation offers the lowest cost option for reducing regional carbon emissions and replacing retiring coal generation. Moreover, it is clear that after efficiency and demand response, new natural gas-fired generation is the most cost-effective resource option for the region in the near-term.

At the regional level, the probability that new natural gas-fired generation will be needed to supply peaking capacity prior to 2021 is quite low. However, the Seventh Plan recognizes that meeting capacity needs and providing the flexibility reserves necessary to successfully integrate growing variable generation sources may require near-term investments in generation resources to provide reliable electricity supplies in specific utility balancing areas. In addition, individual utilities have varying degrees of access to electricity markets and varying resource needs. The Council's regional power plan is not necessarily a plan for every individual utility in the region, but is intended to provide guidance to the region on the types of resources that should be considered and their priority for development.

Combined development of improved efficiency, demand response, renewable generation as required by state renewable portfolio standards and the increased use of existing natural gas generation, will help delay investments in more expensive and carbon emitting forms of electricity generation until state and regional carbon dioxide emission reduction compliance plans are developed and implemented and alternative low-carbon energy technologies become cost-effective.

Resource Strategy Action Items

The Council recommends that the region pursue the following actions to implement the Seventh Plan's resource strategy:

RES-1 **Achieve the regional goal for cost-effective conservation resource acquisition.** [Utilities, Energy Trust of Oregon, Utility Regulators, Bonneville, NEEA and States] Conservation programs and budgets should be designed to achieve savings based on the schedule shown below. Cumulative accomplishments, starting with savings acquired in FY2016, should achieve a minimum conservation goal of 1400 aMW by 2021, 3000 aMW by 2026 and 4300 aMW of cost-effective conservation by 2035. The Council will monitor achievement of cost-effective savings annually to assess progress towards both the biennial milestones detailed below and longer-term goals. Expected savings in excess of Sixth Plan targets prior to 2016 have been taken into account in setting the goals below and do not count towards meeting these goals. Savings achieved in excess of the biennial milestones below should be considered part of the next biennial progress toward the conservation goals.

Conservation Energy Milestones by Fiscal Year in Average Megawatts

	FY16-17	FY18-19	FY20-21	FY22-23
Annual Energy	370	460	570	660
Cumulative Energy	370	830	1400	2060

RES-2 **Evaluate cost-effectiveness of measures using methodology outlined.** [RTF, Bonneville, Utility Regulators, NEEA, Utilities, Energy Trust of Oregon] To determine if a measure is cost-effective, from a total resource cost basis, and in order to ensure that the cost-effectiveness formulation incorporates the full capacity contribution of measures and risk avoidance, regional utilities should use the methodology described in Appendix G: Conservation Resources and Direct Application Renewables. This method assures that all the costs and benefits are captured, that the time-dependent shape of the savings are accounted for, and that the capacity contribution of the measures are fully taken into account. Based on the findings of the Seventh Power Plan, the Council recommends the RTF adopt this method and associated input values. Individual entities may have different input values than those provided in Appendix G. However, the Council recommends that their methodology should be consistent with Appendix G.

RES-3 **Develop and implement methods to identify system specific least-cost resources to maintain resource adequacy.** [Utilities, Energy Trust of Oregon, Utility Regulators, Bonneville, NEEA, and States] The Seventh Plan's analysis identified a potential need to add resources, including conservation and demand response, to maintain an adequate and reliable system. The Council's resource strategy includes guidance to Bonneville and the region's utilities on what resources would meet these needs at the least cost from a regional perspective. However, it is not possible in the Council's regional plan to specify exactly when additional resources will be needed or which resources and in what amounts best match the needs of individual entities. While the Council will continue to analyze these issues from a regional system perspective, the region's utilities and Bonneville should develop and implement methods to evaluate resource decisions to maintain resource adequacy. These methods should be consistent with the Council's Seventh Plan and with the Council's annual Resource Adequacy Assessment. To consider all potentially available resources including conservation and demand response these methods should:

- Include an assessment of whether additional conservation acquisitions, beyond the levels set forth in RES-1, would be the least-cost resource for meeting the additional Bonneville or utility resource needs,
- Include an assessment of whether demand response would be the least-cost resource for meeting the additional Bonneville or utility resource needs,
- Evaluate cost-effectiveness by comparing the cost of increasing conservation acquisition and demand response to the cost of resources that add to regional reliability, such as additional thermal generation resources, rather than to short-term market purchases (e.g. RES-2),
- Consider thermal generation resources especially when local transmission congestion or provision of ancillary services provide added benefits, and
- Assess the individual positions of Bonneville or the utility with regard to the contribution to individual and regional reliability.

The Bonneville Resource Program following the next Council Resource Adequacy Assessment (scheduled for 2016) should outline an approach and schedule to accomplish this action item. Utility integrated resource plans developed after the next Resource Adequacy Assessment should also include comparable approaches.

RES-4 **Expand regional demand response infrastructure.** [Utilities that dispatch resources, Utility Regulators, Bonneville and States] Utilities and Bonneville should begin to or continue to develop or contract for systems to enable rapid expansion of demand response programs targeting winter or summer peaks relative to their individual system needs as assessed in RES-3. Utilities and Bonneville should explore how current conservation programs can be leveraged to expand demand response infrastructure. Such contracts and/or systems should be capable of integrating demand response into utility dispatch and operations and should be tested to verify that they can provide reliable demand reductions These systems should be in place prior to the announced retirement date of existing coal generation facilities in the region and be maintained as a resource for deployment under low-water, high-load conditions or other times of system stress.

The Council's analysis indicates that a minimum of 600 MW of demand response resources would be cost-effective to develop under all future conditions tested across all scenarios which do not rely on increased firm capacity imports. Moreover, even if additional firm peak power imports during winter months are assumed to be available, developing a minimum of 600 MW of demand response resources is still cost-effective in over 70 percent of the futures tested. In the mid-term assessment the Council will determine if the region has made sufficient progress towards acquiring cost effective demand response or confirming import capability sufficient to provide the region with a minimum additional peaking capacity of 600 MW

RES-5 **Support regional market transformation for demand response.** [NEEA, Utilities that dispatch resources, Utility Regulators, Bonneville, and States] Regional market transformation efforts and techniques should be used to reduce the cost and expand the availability of products that exist on the customer-side of the meter that could serve as demand response resources. The region has a proven track record of working with manufacturers and engaging in standards and code processes to reduce the cost and increase the market penetration of energy efficient products. These same approaches should be applied to demand response. For example, including demand-response ready controls in regional market transformation initiatives for energy efficiency in consumer appliance and lighting controls could accelerate the ability to develop automated demand response resources employing those products. A systematic approach to market transformation should be well established two years in advance of the next power planning process.

RES-6 **Expand renewable generation technology options considered for Renewable Portfolio Standards (RPS) compliance.** [Utilities, Utility Regulators, and States] As utilities continue to comply with existing state Renewable Portfolio Standards they should assess the cost and generation potential for utility-scale solar photovoltaic and geothermal technologies when developing strategies to comply with existing state Renewable Portfolio Standards. Each utility should consider its own cost and resource need profile in such assessments. The Council will review utility Integrated Resource Plans and state compliance processes to track the types of renewable resources developed under state RPS.

RES-7 **Regional carbon emissions.** [Utilities, Bonneville, Utility Regulators, and States] The Council did not evaluate resource strategies for state level compliance with the Environmental Protection Agency's Clean Power Plan (Clean Air Act, Sections 111(b) and 111(d)) carbon dioxide emissions limits. However, analysis for the Seventh Plan found that compliance was highly probable *at the regional level* through the reductions in emissions from coal-plants that are already scheduled for retirement, by achieving the regional conservation goals set forth in RES-1, by satisfying existing state Renewable

Portfolio Standards and by re-dispatch of existing gas-fired generation. Should individual states or the region seek further emissions reductions, the least cost resource strategies identified by the Council rely on decreased use of existing coal generation and increased reliance on both existing and new natural gas generation, rather than increased use of renewable resources that do not reliably supply peaking capacity.

RES-8 **Adaptive Management.** [Council, Utilities, Bonneville, Utility Regulators, and States] In order to track Seventh Plan implementation and adapt as needed the Council, in cooperation with regional stakeholders, will provide:

- Annual Resource Adequacy Assessments
- Annual Conservation and Demand Response Progress Reports
- Mid-Term Assessment of Plan Implementation and Planning Assumptions

Regional Actions Supporting Plan Implementation

The Council recommends that the region pursue the following actions to implement the Seventh Plan:

REG-1 **Develop robust set of end-use load shapes with plan to update over time.** [Council, Bonneville, NEEA, Utilities, Energy Trust of Oregon] The capacity value of energy-efficiency measures is significant. Data on new and emergent loads, including stand-by loads, however, is lacking. Additionally, where no more recent data are available, many of the end-use load shapes used in the Seventh Plan were developed 30 years ago. The region needs to update these load shapes to better understand peak contributions. Completion of this action will result in a data set of hourly (8760 hours per year) load shapes for a wide variety of end-uses and building segments. A business case for this study was completed for the Regional Technical Forum in 2012. Improvements in technology and opportunities for out-of-region coordination should reduce the cost of updating load shapes as compared to the 2012 business case. An update of the business case, specific work plan for implementation, and funding secured to accomplish this study should be completed by the end of 2016. Priority should be to fill significant gaps in existing end-use load shape data.

REG-2 **Provide continued support for the Northwest Energy Efficiency Alliance (NEEA).** [Bonneville, Utilities, and Energy Trust of Oregon] Provide continued support for NEEA's 2015-2019 strategic and business plans. Consider additional support for NEEA to provide regional leadership on new opportunities where NEEA's core competencies, economies of scale and risk mitigation provide maximum value to the region. Identify and adopt new initiatives, and facilitate strategic planning efforts among partners to implement conservation opportunities identified in the Seventh Plan. Market transformation initiatives implemented by NEEA may need to be revised or expanded to encompass changing markets and the rapid progress in energy codes and standards. Specific action items in the Seventh Plan for which the Council recommends NEEA be the lead implementer include:

Activities within the existing scope of NEEA's 2015-2019 Strategic and Business Plans:

- REG-10. Develop strategies to coordinate energy-efficiency planning within region.
- MCS-4. Develop a regional work plan focusing on emerging technologies to help ensure adoption.
- REG-7. Conduct regional sector-specific stock assessments.
- MCS-7. Monitor and track code compliance in new buildings.
- REG-8. Understand the impact of codes and standards on load forecasting and regional conservation goals.

New activities not included in NEEA's 2015-2019 Strategic and Business Plans:

- REG-1. Develop robust set of end-use load shapes with plan to update over time.
- RES-5. Support regional market transformation for demand response.
- MCS-6. Develop and deploy best-practice guides for the design and operations of new and emerging industries, such as data centers.
- ANLYS-9. Conduct research to improve understanding of electric savings in water and wastewater facilities from reduction in water use.

  For any of these items that NEEA is not able to implement, Bonneville, the utilities, and Energy Trust should work with the Council to develop strategies to address them.

REG-3 **Collaborate on demand response data collection.** [Utilities, Bonneville and Utility Regulators] To assist with regional power planning, utilities should include the following information in their Integrated Resource Plans and Bonneville in its Resource Program:

- Data (date and amount) on the historic dispatch of demand response (DR)
- Future plans for DR acquisition, including an assessment of the system need (e.g., winter capacity, wind integration, etc.) that DR is anticipated to meet
- Assessment of DR potential within the utility's service territory

REG-4 **Collaborate on collection of regional operating reserve planning data.** [Utilities, Bonneville, and Utility Regulators] Utilities should include their planning assumptions for the provision of operating reserves in their Integrated Resource Plans and Bonneville in its Resource Program. These assumptions should emphasize reliability ahead of economic operations, that is, reasonable estimates for times of power system stress. The following should also be included :

- An estimate of the utility's or Bonneville's requirement for operating reserves
- Reasonable planning assumptions for the amount of the reserve requirement estimated to be held on hydropower generation and which projects should be assigned in power system models to provide these reserves
- Reasonable planning assumptions for the amount of the reserve requirement estimated to be held on thermal plants and which plants should be assigned in power system models to provide these reserves
- Reasonable planning assumptions for any third-party provision of reserves

REG-5 **Conduct regular conservation program impact evaluations to ensure that reported energy and capacity savings are reliable.** [Bonneville, RTF, Energy Trust of Oregon, Utilities, Utility Regulators] Implementation of cost-effective energy efficiency is a key element of all least-cost resources strategies where energy efficiency is the single largest system investment in new resources. As such, the region needs to assure the implementation of efficiency programs produces reliable, cost-effective energy and capacity savings. The Regional Technical Forum should maintain and update its program impact evaluation guidelines and standards to ensure the reliability of energy and capacity savings reported and to inform the adaptive management of energy savings programs going forward, leveraging national efforts in developing best practices. Bonneville, utilities, Energy Trust of Oregon, and regulators should assure effective evaluations of the energy and capacity impacts of programs occur on a regular basis. The Regional Technical Forum should track these evaluated savings in its regional conservation progress report.

REG-6 **Report on progress toward meeting Seventh Plan conservation objectives including the contribution of conservation to system peak capacity needs.** [RTF, Council, Bonneville, Utilities, Energy Trust of Oregon, and NEEA] As part of the Council's review of Seventh Plan implementation, the Regional Technical Forum should collect data annually from Bonneville, Utilities, Energy Trust of Oregon, and NEEA to report on progress towards meeting the plan's conservation goals and objectives. This Regional Conservation Progress Report should address whether and how the conservation technologies and practices identified in the plan are being developed for acquisition through local utility programs, coordinated regional programs, market transformation, adoption of codes and standards, code compliance efforts, and other mechanisms. The report should incorporate results of program impact evaluation and identify any acquisition gaps that need to be addressed. Given the importance of the capacity contribution of conservation identified in the Seventh Plan analysis, the report should also include estimates of the contribution of conservation to system peak capacity needs.

REG-7 **Conduct regional sector-specific stock assessments.** [NEEA] The stock assessments are a valuable resource for individual utilities and the region and should be updated regularly. Updated data should be available by early 2020, in time to inform the development of the Eighth Plan. Continue to enhance and improve the residential, commercial, and industrial assessments with regional review and input. Add an agricultural stock assessment that would improve understanding of opportunities in that sector, recognizing current data collection activities by Bonneville and difficulties in acquiring needed data. Currently, only the residential and commercial assessments are built into the NEEA 2015 through 2019 business plan, but there is significant value in collecting data for the industrial and agriculture sectors as well. Efforts in these sectors require coordination with stakeholders to establish the appropriate data collection methods. NEEA should define a schedule for designing and executing these assessments with a goal of having data available for all sectors by early 2020.

REG-8 **Reflect the impact of codes and standards on load forecast and their contribution to meeting regional conservation goals.** [NEEA, Utilities, Energy Trust of Oregon, Bonneville, National Labs] NEEA should track the savings impact of enacted codes and standards and collect the necessary data, such as saturation of appliances, number of units installed, and unit savings. With appropriate disaggregation, these savings impacts can then be included in utility load forecasts and may be claimed against savings goals. NEEA should leverage the work Bonneville has completed to quantify the impacts of federal standards adopted since the development of the Sixth Plan. NEEA should produce an annual report on the savings impact of standards and updated models to link savings and load forecast estimates.

REG-9 **Use whole-building consumption data to improve energy and demand savings acquisitions and estimates.** [Bonneville, Utilities, Energy Trust of Oregon, NEEA, Trade Allies, Evaluators, Regulators] Utilities should exploit the greater availability of interval data and analytic tools to improve estimates of both energy and demand savings and encourage facilities to undertake whole building improvements. Utilities and regulators should facilitate the sharing of whole building data (including billing data) with regional analysts, recognizing security and privacy concerns. These data will be useful in identifying savings potential from emerging technologies, new uses of electricity that contribute to load growth and standby or "idle mode" energy use. Utility program portfolios should incorporate programs that rely on a whole building approach to savings. A report on data analysis approaches and availability barriers should be completed by the end of 2017.

REG-10 **Develop strategies to coordinate energy-efficiency planning within region.** [NEEA, Bonneville, Energy Trust of Oregon, Utilities] Regional entities working together can more cost-efficiently capture conservation for many measures that have broad regional application and require coordination among implementing parties. NEEA recently facilitated the development of an initial regional strategy for commercial and industrial lighting, one of the largest sources of new efficiency potential in a very fast-changing market with a complex delivery infrastructure that crosses all utility boundaries. Similar facilitation efforts should be developed for other areas where regional cooperation among utilities, Bonneville, states, trade allies, and others is valuable. NEEA should initiate at least three such regional strategy efforts by the end of 2016.

REG-11 **Analyze regional interest in convening a forum to explore the benefits of alternative business models and rate designs to promote energy efficiency when confronted with stable or declining growth in regional electricity demand.** [Council, Bonneville, Utilities, Regulators, States, Stakeholders]. The Council's plan finds that the adoption of cost-effective energy efficiency and demand response resources will minimize long-term regional bills while ensuring reliable electric service and reduce environmental impact. Different perspectives have emerged regarding local near-term economic effects related to acquiring energy efficiency and demand response under stable or declining load growth. Regional efficiency leaders have called for a forum to explore the benefits of alternative utility business models and rate designs to put energy efficiency investments on the same plane as other utility resource investments.

Therefore, the Council should initiate a process to determine the interest in convening such a forum. If sufficient interest and participation warrant a forum, the conveners should propose the scope, participants, deliverables and timing of the forum. The Council should conclude the scoping process by the end of 2016.

Regional Actions Supporting Plan Implementation – Model Conservation Standards

The Council recommends that the region pursue the following actions to implement the Seventh Plan's Model Conservation Standards:

MCS-1 **Ensure all-cost effective measures are acquired.** [Bonneville, Utilities, Energy Trust of Oregon, States] In order to achieve all cost-effective conservation, all customer segments should participate in programs. The Northwest Power Act has required that the Bonneville Power Administration (BPA) distribute the benefits of its resource programs "equitably throughout the region."[1] Bonneville and the regional utilities should determine how to improve participation in cost-effective programs from any underserved segments. Although low-income customers are often an underserved segment, other hard-to-reach (HTR) segments may include: moderate income customers, customers in rural regions, small businesses owners, commercial tenants, multifamily tenants, manufactured home dwellers, and industrial customers. Ideally, the customers in the HTR segment should participate in similar proportion to non-HTR customers, assuming similar savings potential.

To accomplish this goal, Bonneville and the utilities in their overall data collection should include, to the extent it is readily available, demographic and business characteristic data that helps identify the existence of any HTR segments. Bonneville and the utilities should also coordinate with local and state agencies to leverage available data on various HTR segments. For example, community action programs will have information on low-income customers and program participation. The portion of participating customers in the assumed HTR segments should then be compared against the portion of customers within these segments in the utility's service area. This will determine which customer segments are indeed underserved. There may be other approaches to determining the HTR segments. For example, utilities may be able to review federal census track data against program participation.

Bonneville and the utilities should report to the Council on the proportion of participation from HTR segments and how these data were collected. The report should occur in 2017, and then annually thereafter. The strategies to improve participation by HTR segments should be considered in BPA's overall assessment and possible redesign of

[1] Northwest Power Act §6(k), 94 Stat. 2722

energy efficiency implementation as described in BPA-6. After the first report, and prior to the completion of the Council's mid-term assessment, Bonneville and the utilities should devise strategies to improve participation by customers in cost-effective conservation in any underserved HTR segments identified in the report.

Evaluating all HTR sectors is important. In evaluating the sub-sectors highlighted below, considerations should include where data are readily available:

- Small and Rural Utilities: One specific segment that has been shown to have special difficulties in implementing energy-efficiency programs is the small and rural utility segment. A study conducted by the RTF in 2012 identified technical support needed by these utilities and infrastructure delivery constraints.[2] A series of initiatives have been put in place to remedy some of the problems identified in that report and improve participation, but issues may remain that the assessment should investigate. For example, some utility customers of Bonneville may have limited staff and limited access to contractors to effectively use their Bonneville energy efficiency incentive. Strategies to improve participation should consider arrangements among utilities to share efficiency planning and implementation activities. Product availability and measure uptake may lag in smaller rural markets compared to larger markets. NEEA market transformation initiatives focused on those lagging markets should be considered as possible solutions along with assistance from Bonneville on education, program administration and measures directly tailored toward the small and rural utilities.

- Low-Income Households: Existing programs, such as the U.S. Department of Energy Low-Income Home Energy Assistance Program, have provided an infrastructure to increase penetration of energy-efficiency measures into the low-income segment. However, it is not known whether these programs and their current structure are sufficient. The assessment should determine whether the pace of low-income conservation improvements achieved, over the last five years, is sufficient to complete implementation of nearly all remaining cost-effective potential in the low-income segment by 2035. Strategies to improve participation and pace of acquisition should consider further coordination between utility, tribal, and Community Action Programs (CAP) identified by Bonneville's Low-Income Work Group. That work group should continue to seek improvements in program coordination and implementation as a joint effort between utilities, tribes, states and CAP agencies.

- Moderate-Income Households: The up-front cost required to purchase or install efficiency measures is often a significant barrier to moderate-income customers. Financial incentives from utilities, Bonneville, and Energy Trust of Oregon usually only

[2] Small and Rural Utility RTF Technical Support Needs Study. http://rtf.nwcouncil.org/subcommittees/smallutilities/RTF%20Small_Rural_01-19-12_FINAL.pdf

cover a portion of measure cost, thus potentially limiting the participation of these customers, who do not qualify for the high incentives offered in programs for low-income households. The assessment should investigate program participation rates among households above the low-income threshold and below median income levels and the reasons for any discrepancy relative to higher income households. The Energy Trust of Oregon has a well established program called Saving Within Reach that could provide helpful guidance on the potential establishment and operation of a moderate income program should a program be needed region-wide.

- Manufactured Homes: The manufactured home segment may face special challenges related to income, ownership, building codes, and some difficult-to-implement conservation measures specific to manufactured housing and their heating systems. The assessment should determine whether the adoption of measures in the manufactured home segment is on pace to complete implementation of nearly all remaining cost-effective potential over the next 20 years. Where expected shortfalls appear, specific barriers to implementation should be identified and solutions targeted at those barriers. While this market segment has been successfully targeted with a limited set of conservation measures (e.g. duct sealing), a more comprehensive approach that identifies and implements an entire suite of cost-effective measures during a single visit may be more cost-efficient.

MCS-2 **Develop program to assess and capture distribution efficiency savings.** [RTF, Bonneville, Utilities] Significant cost-effective savings can be achieved through voltage optimization measures, such as conservation voltage regulation. The relatively slow historical adoption of these measures has been due to a variety of barriers that may be addressed by programs or performance standards. By spring of 2017, Bonneville should develop a plan to determine potential savings, identify barriers, and develop program assistance or distribution system performance standards. The plan should outline resource needs sufficient to assess potential and begin programs for one-third of its utility customers and customer load by 2021 with the goal of implementing all cost-effective measures for 85 percent of its utility-customer load by 2035. Investor-owned utilities should do similar assessments and implement cost-effective efficiency improvements by 2035.

MCS-3 **Encourage utilities to actively participate in the processes to establish and improve the implementation of state efficiency codes and federal efficiency standards.** [State Regulators, Bonneville, Utilities] Without robust efficiency programs paving the way for new measures and practices, efficient building codes and standards could not achieve their current levels of efficiency. However, for codes to continue to improve, programs need flexibility in pursuing measures that may not currently be cost-effective, but demonstrate likely cost reductions. In addition, as building codes and federal standards begin to push the envelope of emerging efficiency practices, regulators should provide allowance for programs to offer measures and practices which are new, have limited market acceptance or availability, or are part of voluntary code provisions. Based on results of code compliance studies, Bonneville and the utilities should work with authorities having jurisdiction to encourage code compliance in any areas where it is lacking. This activity should be ongoing throughout the action plan period and should be reviewed after each new code adoption.

MCS-4 **Develop a regional work plan to provide adequate focus on emerging technologies to help ensure adoption.** [Bonneville, NEEA, Utilities, National Labs, Energy Trust of Oregon, Council, States] Nearly half of the potential energy savings identified in the Council's Seventh Power Plan are from emerging technologies or measures not in previous plans. The region has proven success at moving emerging technologies and design strategies into the marketplace and should continue to work toward this goal. This includes (1) tracking adoption of new measures in the Seventh Plan supply curves, (2) identifying actions to advance promising technologies and design strategies, (3) increasing adoption of existing technologies with low market shares, and (4) scanning for new technologies and practices. The Regional Emerging Technology Advisory Committee (RETAC) should develop a work plan to ensure success in these four areas and to track progress over the action plan period. The initial work plan should be developed by mid-2016 and updated every two years.

MCS-5 **Actively engage in federal and state standard development.** [Council, Bonneville, NEEA, Energy Trust of Oregon, Utilities, States] Regional presence in the standard setting process has provided immense value to the region and the country. NEEA, on behalf of the region's utilities, should lead the effort to continue and perhaps expand this engagement with the U.S. Department of Energy as well as provide data and recommendations. The Council should continue to represent the Northwest states' interest in these processes. The region's engagement should inform the standards and the test procedures. NEEA should also assist the states in the development of state-level standards for products not covered by the federal rules. This should be an ongoing activity with periodic assessment of resource requirements.

MCS-6 **Develop and deploy best-practice guides for the design and operations of emerging industries.** [NEEA, Bonneville, Utilities, Trade Allies, States] Emerging industries such as indoor agriculture and large data centers are rapidly increasing throughout the region. Many of these facilities have significant load that could be reduced with guidance on best-practice design and operational approaches. Development of the first generation of best-practice guides should be available by late-2016. NEEA should identify opportunities to deploy the best-practice guides to decision makers and design and operations professionals in the respective industries.

MCS-7 **Monitor and track code compliance in new buildings.** [NEEA, State code agencies, National Labs] Ensure new residential and commercial buildings (including major remodels) are built at or above code-required levels across the four Northwest states. NEEA should work with regional code stakeholders to develop and implement appropriate methods to directly measure levels of code compliance and associated energy savings. The compliance study should assess local jurisdiction code plan review and inspection practices. Site visits with local code jurisdictions, and the design and construction industry should be conducted to assess training, education, and other resource needs to assure high levels of code compliance. NEEA should explore whether there may be other regional entities (e.g. Pacific Northwest National Laboratory) with whom NEEA could collaborate and leverage its work. NEEA's work plan and budget should include sufficient resources for continuing compliance studies with the expectation of reports for all states and sectors by 2020. Ideally, the completion of these reports should be timed to inform future code updates.

Bonneville Actions Supporting Plan Implementation

The Council recommends that Bonneville pursue the following actions to maintain consistency with the Seventh Plan:

BPA-1 **Achieve Bonneville's share of the regional goal for cost-effective conservation resource acquisition.** [Bonneville] Bonneville should continue to meet its share of the Seventh Plan conservation goals working with its public utility customers, the Northwest Energy Efficiency Alliance, the Regional Technical Forum, the states, and the tribes. Bonneville should ensure that public utilities have the incentives, support, and flexibility to pursue sustained conservation acquisitions appropriate to their service areas in a cooperative manner, as set forth in detail in the conservation action plan items. Bonneville should offer flexible and workable programs to assist utilities in meeting the conservation goals, including a backstop role for Bonneville should utility programs fail to achieve these goals. Should public utility savings fall short of Bonneville's share of the regional conservation goal, the Council expects the agency to conduct an assessment of the problem and implement solutions. **(See Action Item RES-1 for specifics)**

BPA-2 **Update methods to identify least-cost resources needed to maintain regional adequacy. (See Action Item RES-3 for specifics)** [Bonneville]

BPA-3 **Continue efforts to establish demand response.** [Bonneville] Bonneville should continue its efforts to evaluate and enable the use of demand response as a resource to meet future resource needs. As modeled in the Seventh Power Plan, demand response resources are used to meet fall, winter and summer peak demands primarily under critical water and extreme weather conditions. Bonneville has also tested other potential applications of demand response resources, such as to help in the integration of variable resources like wind. The Council was not able to explicitly model the use of demand response resources to reduce the need for variable resource integration or other ancillary services during the development of the Seventh Power Plan. Applications of demand response may likely provide cost-effective options for providing such services. Therefore, Bonneville should continue to develop its ability to meet the need for other ancillary services, such as variable resource integration, with demand response, as one aspect of its evaluation.

This effort should identify and remove barriers to successful implementation of demand response and include:

- Establishing resource acquisition rules for demand response as an integrated part of assessing resource needs as detailed in RES-3
- Expanding the infrastructure for demand response as detailed in RES-4
- Identifying the amount and cost of demand response potential including potential in the Bonneville customer utilities service areas that could be made available for Bonneville resource needs
- Assessing barriers to the further development of demand response by Bonneville and implementing actions to overcome those barriers

Bonneville should include the resource acquisition rules, the potential assessment for demand response and the assessment of barriers to developing demand response in its Resource Program.

BPA-4 **Improve access to demand response data.** [Bonneville] Bonneville should create systems to add demand response dispatch data to its existing publicly available data on the Bonneville public website. **(See Action Item REG-3 for specifics)**

BPA-5 **Quantify the value of conservation in financial analysis and budget-setting forums.** [Bonneville] Bonneville should estimate both the cost and benefit (value) of its historic and forecast investments in energy efficiency with respect to its overall net revenue requirement for both power supply and transmission services. Data on both the costs and benefits should be publicly available in forums where agency budgets and investment allocation are discussed and decisions are made. The value of conservation is often missing from discussions setting budgets for conservation while the cost elements are always present. By quantifying the financial value of cost-effective conservation and the revenue requirement compared to no conservation, there would likely be greater buy-in from utility customers for the efficiency expenditures. Bonneville should work with the Council to develop a method to calculate estimated value of conservation (e.g., return on investment) and provide the estimate as part of its budgeting processes, Integrated Program Review, Capital Investment Review, and annual budget documents. Bonneville should have robust data to make this estimate before its next Integrated Program Review.

BPA-6 **Assess Bonneville's current energy efficiency implementation model and compare to other program implementation approaches.** [Bonneville] Bonneville's current efficiency program approach is based on a proportional funding model. Program offerings and incentives are designed to provide equal access to measures and program funding in proportion to Tier 1 load. This model, while effective in achieving funding equity among customer utilities, may limit the ability of Bonneville to focus its acquisition efforts on acquiring all cost-effective conservation in the region.

By the end of 2017, Bonneville should commission a study to assess alternative program design, funding allocation and incentive mechanisms and compare benefits and costs of implementing alternative models. Bonneville should develop the scope of the study in consultation with the Council and stakeholders. Alternative program approaches could include a focus on the value of the savings based on winter capacity needs, geographical needs, or localized capacity constraints. Additional approaches should explore different cost performance metrics such as lowest first year cost, lowest levelized cost, or highest benefit-to-cost ratio. The study should develop an example portfolio for each approach, assessing the resulting potential savings and costs to Bonneville and its customers. The study should, for each portfolio:

- Assess likelihood of achieving all cost-effective conservation;
- Address the technical, policy, and economic tradeoffs;
- Assess the incentives and disincentives to program participation;
- Assess administrative process efficiency;
- Assess changes in the value of cost-effective energy efficiency, revenue requirements and how the benefits flow to customers (see BPA-5);
- Assess effectiveness of achieving savings for large projects at end-use customers;
- Assess effectiveness of the bi-lateral transfer mechanisms in allowing utilities to exchange energy-efficiency funding to balance utility circumstances of power needs and conservation potential.

BPA-7 **Bonneville and the Council should develop a report that identifies barriers to conservation acquisition by Bonneville's customer utilities with recommended strategies to eliminate or minimize such barriers. [Bonneville, Council]** The report should identify economic, contractual, motivational, institutional, and political barriers to acquisition and implementation of conservation and demand response measures. Strategies to address barriers should be developed in consultation with customer utilities and other stakeholders. The report should be completed by the end of 2017.

BPA-8 **Bonneville should perform an analysis of its operating reserve requirements.** [Bonneville] Bonneville should conduct an analysis of the most cost-effective method of providing operating reserves that meet system reliability requirements at the lowest probable cost. Bonneville should report the input assumptions, methods of analysis and results of this analysis to the Council for use in the Council's planning process. The analysis should be included in each Bonneville Resource Program. (See Northwest Power Act, §4(e)(3)(E), 94 Stat. 2706.)

BPA-9 **Bonneville should continue to evaluate methods for reducing or mitigating regional generation oversupply conditions.** [Bonneville] Bonneville should work with its customers to create incentives that help mitigate generation oversupply conditions.

BPA-10 **Enhance Bonneville's load forecasting model**[Bonneville, Council] Council staff will work closely with Bonneville staff to implement the Council's long-term end-use forecasting model. The enhancement in end-use modeling capability will enable Bonneville to better reflect impacts of future codes and standards and more explicitly account for the impact of conservation acquisitions on forecast loads.

Council Actions Supporting Plan Implementation

COUN-1 **Form Demand Response Advisory Committee.** [Council] A major finding of the Seventh Plan is that the region would benefit from the development of demand response (DR) resources. To facilitate this, the Council should establish a Demand Response Advisory Committee to assist in the identification of strategies to overcome regional barriers to DR implementation and the quantification of DR potential. The scope of this committee's activities should be to facilitate the deployment of demand response resources in the region by serving as a forum for sharing program experience and data. This committee should be chartered by the Council by the end of FY2016. In drafting the charter, technologies that enable or function in a similar fashion to demand response should be considered, such as distributed standby generation, distributed energy storage, transactive energy, and other specific "smart grid" or "grid edge" technologies.

COUN-2 **Continue to co-host the Pacific Northwest Demand Response Project (PNDRP).** [Council] The Council should continue to coordinate with the Regulatory Assistance Project to host the Pacific Northwest Demand Response Project (PNDRP). PNDRP should be convened at least annually.

COUN-3 **Review the regional resource adequacy standard.** [Council, Resource Adequacy Advisory Committee, Bonneville, Pacific Northwest Utilities Conference Committee] The Council's current adequacy metric (loss of load probability) and threshold (maximum value of 5%) has been used since 2011 as a good indicator of potential future power supply limitations. However, the loss of load probability metric may not be the most appropriate for determining the adequacy reserve margin and the associated system capacity contribution for specific resources (see COUN-4 and COUN-5), both of which are critical components of the Regional Portfolio Model. The loss of load probability metric (as currently defined) is also not appropriate for estimating the effective load carrying capability of resources. The Council should review and, if necessary, amend its standard. Any change to the adequacy standard should be adopted by the Council in time to be used for the development of its next power plan.

COUN-4 **Review the Resource Adequacy Assessment Advisory Committee assumptions regarding availability of imports.** [Council, Resource Adequacy Advisory Committee, Bonneville, Pacific Northwest Utilities Conference Committee] The Council's current assumptions regarding the availability of imports from out-of-region sources and from in-region market resources should be reexamined. The sensitivity of total system cost to import availability has been demonstrated in the Regional Portfolio Model analysis. To minimize cost and avoid the risk of overbuilding, the maximum amount of reliable import should be considered. The Resource Adequacy Advisory Committee should reexamine all potential sources of imported energy and capacity and make its recommendations to the Council. Any changes to import assumptions should be agreed upon in time to be used for the development of the next power plan.

COUN-5 **Review the methodology used to calculate the adequacy reserve margins used in the Regional Portfolio Model.** [Council, Resource Adequacy Advisory Committee, System Analysis Advisory Committee, Bonneville, Pacific Northwest Utilities Conference Committee] Resource strategies developed using the Regional Portfolio Model are very sensitive to the adequacy reserve margin (ARM), calculated using output from the Council's adequacy model (GENESYS). The ARM is effectively a minimum build requirement that ensures that resource strategies selected by the Regional Portfolio Model will produce acceptably adequate power supplies. The underlying methodology and assumptions used to assess ARM values should be thoroughly reviewed by regional entities. Any changes to the ARM methodology should be agreed upon prior to the development of the next power plan.

COUN-6 **Review the methodology used to calculate the associated system capacity contribution values used in the Regional Portfolio Model.** [Council, Resource Adequacy Advisory Committee, System Analysis Advisory Committee, Bonneville, Pacific Northwest Utilities Conference Committee] Resource strategies developed using the Regional Portfolio Model are very sensitive to resource associated system capacity contribution values (ASCC), which are calculated using the Council's adequacy model (GENESYS). The ASCC provides the effective capacity value of resources when they are incorporated into a power supply with storage (e.g. the Northwest hydroelectric system). The methodology and assumptions used to assess ASCC values should be thoroughly reviewed by regional entities. Any changes to the ASCC methodology should be agreed upon prior to the development of the next power plan.

COUN-7 **Perform a regional analysis of operating reserve requirements.** [Council] The Council will use the Bonneville analysis of reserve requirements (See action item BPA-8) and work with other regional stakeholders to complete a regional analysis of the most cost-effective method of providing operating reserves that meet reliability requirements at the lowest probable cost. This analysis should be completed in time to include in the next power plan.

COUN-8 **Participate in and track WECC activities.** [Council] The Council should continue to represent the Northwest region in the planning activities at the Western Electric Coordinating Council (WECC), including participation on the Loads and Resources Subcommittee (LRS). The LRS develops WECC resource adequacy guidelines and assessments and acts as the interface with NERC in these areas and on NERC's development of standards in the resource adequacy area. The WECC and NERC activities provide the background within which the Council analyzes adequacy issues and approaches and develops its regional adequacy assessments.

COUN-9 **Monitor regional markets and marketing tools that impact the dispatch of the power system.** [Council] Since the Sixth Plan, the region has seen the advent of an energy imbalance market between PacifiCorp and the California ISO. There have also been efforts underway at the Northwest Power Pool to create products and services that improve the dispatch of the power system for balancing load and generation. Both of these efforts have resource implications for the region. The Council should monitor these efforts and any additional efforts that impact dispatch to assess whether its power system modeling should be altered.

COUN-10 **Reaffirm and update Section 6(c) policy.** [Council and Bonneville] The Council and Bonneville worked together in the 1980s to establish a policy on how to implement Section 6(c) of the Northwest Power Act, the provision specifying how Bonneville is to assess and decide whether to add a "major resource" to its system. The Section 6(c) policy includes a provision that requires Bonneville periodically to review and (if necessary) update the policy, with the help of the Council. Bonneville and the Council and Bonneville last reviewed and updated the policy in 1993, and have mutually agreed to defer review ever since. The Council and Bonneville should review, reaffirm or update the Section 6(c) policy within the next two years.

COUN-11 **Participate in efforts to update and model climate change data.** [Council, River Management Joint Operating Committee, System Analysis Advisory Committee, Resource Adequacy Advisory Committee] The Council should continue to work with regional entities that collect and process results from global climate analyses. This includes monitoring efforts overseen by the RMJOC to downscale global results for use in the Northwest. Information that is critical for use in Council planning models includes climate modified unregulated flows, their associated rule curves and projected monthly temperature changes. The Council will also continue to explore ways to incorporate climate induced impacts to hydroelectric generation and load into its Regional Portfolio Model. Results from the most recent Intergovernmental Panel on Climate Change Assessment Report are currently being downscaled for the Northwest but that work is not expected to be completed until early 2017. The results of that effort should be thoroughly vetted prior to the development of the next power plan.

COUN-12 **Improve estimates of deferred transmission and distribution amounts.** [Council, Pacific Northwest Utilities Conference Committee (PNUCC), Utilities, State Regulatory Commissions] The Council should work with PNUCC, utilities and state regulatory commissions to develop more robust methodology to estimate transmission and distribution deferral costs and benefits. These costs are used to account for the costs and benefits of delaying expansion of the transmission and/or distribution system. This process should be completed by mid 2017.

MAINTAINING AND ENHANCING COUNCIL'S ANALYTICAL CAPABILITY

The Council's power plan is extremely data and model intensive. Maintaining data on electricity demand, resource development, energy prices, and generating and efficiency resources is a significant effort. It is one that the Council's staff cannot do alone. Data collection for the regional power system and alternative resources available to meet demand is something best accomplished through regional cooperation. The action plan contains recommendations to maintain and improve planning data for the region.

Load Forecasting

ANLYS-1 **Improve industrial sales data**. [Council, NEEA, Utilities] The Council will work with BPA, NEEA, and utilities to improve industrial sector sales data by disaggregating those data by NAICS codes to improve forecasting and estimates of conservation potential. Currently, industrial sales are reported by utilities to FERC and EIA in an aggregate fashion. Reporting sales data at a more disaggregated, industry specific (e.g. lumber and wood products, food processing) level would improve the ability to forecast loads and conduct assessments of conservation potential. The Council in cooperation with Bonneville should develop a system to regularly collect and categorize data accounting for at least 80% of industrial loads. Confidentiality issues should be addressed and solved. This process and improved industrial data sets should be completed by 2018.

ANLYS-2 **Improve long-term load forecast for emerging markets**. [Council, Demand Forecasting Advisory Committee] The Council should enhance the Council's long-term end-use load forecasting model's capability to account for rooftop solar PV with electricity storage, data centers (large, small and embedded data centers), and indoor agricultural (cannabis) loads. The Council will work with utilities and advisory committee members to monitor and forecast loads for these fast growing markets.

ANLYS-3 **Explore development of an end-use conservation model.** [Council] Many conservation planners in the industry utilize an integrated end-use based conservation assessment model to closely tie savings to load forecasts. In addition, models may also be improved by including performance-based efficiency approaches. The Council will scope the development of a working model. Depending on findings/budget, the Council may contract out model development. Report on scope will be completed by 2017.

ANLYS-4 **Review and enhancement of peak load forecasting.** [Council, Demand Forecasting Advisory Committee, Resource Adequacy Advisory Committee] This task reviews and reconciles peak load forecasting methods used for long-term resource planning (RPM) and short-term Adequacy Assessment (Genesys) analysis. This task should be completed before the next Resource Adequacy Assessment.

ANLYS-5 Enhance modeling of electrification of transportation system. [Council, Demand Forecasting Advisory Committee, Bonneville, ODOE, Others] This task is intended to enhance the Council's assumptions and modeling of the potential impact that electrification of the Northwest transportation system could have on regional electricity demand and load shape.

Conservation

ANLYS-6 Establish a forum to share research activities and identify and fill research gaps. [Council, RTF, NEEA, Utilities, Energy Trust of Oregon, Bonneville, National Labs, States, Research Institutions] There is a variety of ad hoc conservation-related research initiatives ongoing in the region. Among these activities are research on reliability of energy and capacity savings, emerging technologies, end-use load shapes, regional stock assessments, product and equipment sales data, and non-energy impacts of efficiency measures. However, these activities lack the coordination that could improve usefulness, reduce duplication, provide better access to existing data, and identify significant research gaps. The Council should facilitate a research coordination forum to define research needs and differing objectives, identify key players and a coordinating body, identify gaps, and develop plans to prioritize gap filling. The forum should develop a roadmap and a work plan to identify tasks and implementers considering the existing research initiatives currently underway. The roadmap and work plan should be completed by mid-2018.

ANLYS-7 Reporting should include explicit information on what baseline is assumed. [Bonneville, Utilities, Energy Trust of Oregon, NEEA, RTF] As part of its annual Regional Conservation Progress (RCP) report, the RTF provides the Council an estimate of energy savings toward the current plan's conservation goals. To accurately determine this, the RTF and Council need to understand what baseline was assumed for the energy-efficiency measures. The progress against the plan's goals should be measured against the plan's baselines. If the baseline is not aligned with the plan, the RTF can (generally) adjust the savings accordingly as long as measure and baseline information are included in the utility's tracking system. Bonneville currently endeavors to make these adjustments through its momentum savings analysis. The RTF should provide a progress report by the end of 2018 with the goal that all savings provided for the RCP report include baseline information by 2020.

ANLYS-8 Develop guidelines on quantifying non-energy impacts. [RTF, States] Although difficult to quantify, non-energy impacts (both benefits and costs) due to efficiency improvements (such as water savings and health benefits due to reduction in wood smoke emissions[3]) may be significant and thus justify societal investment, regardless of

[3] See Chapters 12 and 19 for more information

whether the measures are cost-effective on energy benefits and costs alone. The Regional Technical Forum in cooperation with the RTF Policy Advisory Committee should develop guidelines consistent with the Regional Power Act[4] to consistently identify and quantify (where appropriate) significant impacts. These guidelines should inform prioritization of research on non-energy impacts, taking into consideration the resources needed to sufficiently quantify impacts. Where impacts are expected to be significant but cannot be reliably and consistently quantified, the RTF should work to develop model language to note their impact for consideration by decision makers. Specifically related to health benefits from wood smoke reduction, the RTF should include model language on residential space heating measures for which significant secondary health benefits exist, as these measures are updated. States should consider such impacts, whether quantified or described in model language, when setting cost-effectiveness limits for measures and programs, recognizing that it may not be appropriate for the utility system to pay for non-energy benefits that do not accrue to the power system.

ANLYS-9 **Conduct research to improve understanding of electric savings in water and wastewater facilities from reduction in water use.** [Council, RTF, Bonneville, Utilities, Energy Trust of Oregon, NEEA] As described in ANLYS-8, non-energy impacts can be significant and should be considered in prioritizing energy-efficiency measure deployment. Water conservation can save energy through reducing the embedded energy requirements for transporting and treating water as well as the non-energy benefit of using less water. However, the last comprehensive study of energy use for water/wastewater treatment was completed over ten years ago. This study should be updated to more accurately estimate potential energy savings from these systems. This action item calls for: conducting research to better understand savings opportunities for water-processing industries (water supply and wastewater). A new or updated analysis of water/wastewater baseline should be completed by 2018.

ANLYS-10 **Include reliability of capacity savings estimates in RTF guidelines.** [RTF] Given the Seventh Plan's finding on the importance of energy efficiency in meeting capacity resource requirements, the region needs better information on these capacity impacts. The RTF should update its guidelines to include savings reliability requirements for capacity. In doing so, the RTF will review the unit energy savings measures to determine whether existing approaches to estimating capacity impacts meet guideline requirements and identify any research needs to improve reliability of capacity estimates. The RTF should develop recommendation memos that address each measure and identify research needs for all measures by the end of 2017. Prioritization of this work will be included in the annual work plan discussions with the RTF's Policy Advisory Committee.

[4] Section 839a(4)(B) of the Northwest Power Act.

Generation

ANLYS-11 Planning coordination and information outreach. [Council] The Council will continue to participate in the development of Bonneville's Resource Program and in utility integrated resource planning efforts. In addition, the Council will periodically convene its planning advisory committees for purposes of sharing information, tools, and approaches to resource planning.

ANLYS-12 Re-develop the revenue requirements finance model – MicroFin. [Council, Bonneville, User Group] The Council, in coordination with Bonneville and a user group convened from interested parties of the Generating Resources Advisory Committee, should review and redevelop the revenue requirements finance model MicroFin, with a completed model in place by the Seventh Plan Mid-Term Assessment. The Council should develop a work plan to review the current version of MicroFin, identify technology needs in order to upgrade the model, and either perform the redevelopment in-house or outsource it via a request for proposals. The redevelopment should be completed by the Seventh Plan Mid-Term Assessment in order to have time to prepare the model for use in the development of the Eighth Plan. The Council should convene a user's group to help ensure the new model is user friendly and to help inspect the results.

MicroFin is the Council's primary financial tool for developing levelized costs and RPM inputs for new generating resources and it is in need of redevelopment. The model produces accurate and useful results, however it is based on a legacy system that no longer fits the current Excel environment and is cumbersome to work with. An upgrade will allow for easier enhancements to be made to the model and an improved user interface. The new model will ideally be accompanied by a user's guide that will ensure that it is easier to use as well as to share with the public.

ANLYS-13 Update generating resource datasets and models. [Council] The Council should review its various generating resources datasets, looking for opportunities to consolidate and streamline the data update process. This review and possible upgrade to a single system or dataset should be ongoing after the Seventh Plan, with completion in time for the Eighth Plan. The Council maintains and updates multiple sets of data on regional generating resources and projects, including:

- Project database – tracks existing and new projects in the region and their development and operating characteristics, generation data, technology and specifications, and various other data
- Renewable Portfolio Standard (RPS) Workbook – tracks generating projects and state RPS within WECC (with a focus on the Pacific Northwest) and forecasts future resource needs
- AURORA resource database
- GENESYS dataset

These datasets are important sources of information for many of the Council's models and analyses. While currently maintained separately, they share much of the same information and there is an opportunity to streamline both the updating of data and the data sharing. The value in a consolidated data source would be to ensure that all of the models are using the exact same data and values and it would also reduce staff time spent updating and maintaining multiple datasets.

ANLYS-14 Monitor and track progress on the emerging technologies that hold potential in the future Pacific Northwest power system. [Council, Generating Resources Advisory Committee] The Council should continue to monitor on an ongoing basis the emerging technologies identified in the Seventh Plan as potential resources of the future regional power system. There are several emerging technologies which could play an important role in the operation of the future power system, including:

- Distributed power with and without storage (Solar PV, CHP)
- Utility Scale Solar PV with battery storage
- Enhanced geothermal systems (EGS)
- Offshore wind
- Wave and tidal energy
- Small modular reactors (SMR)
- Energy Storage
    - Pumped storage with variable speed technology[5]
    - Battery storage
    - Other

The Council should track significant milestones in development, cost and technology trends, lifecycles, potential assessments, and early demonstration and commercial projects. Included in the analysis of the technologies is identifying any potential benefit the resource might provide during low water years. By monitoring these resources closely in between power plans, the Council will be prepared to analyze them and determine if they are viable resource alternatives in the Eighth Plan.

ANLYS-15 Scope and identify ocean energy technologies and potential in the region, determine cost-effectiveness, and develop a road map with specific actionable items the region could collaborate on should development be pursued. [Council, Generating Resource Advisory Committee] The Council should convene a subgroup of the Generating Resources Advisory Committee that includes regional utilities and other ocean energy stakeholders to a) scope out the emerging ocean energy technologies and identify the cost and realistic potential in the region, b) develop a set of regional priorities

[5] While pumped storage itself is not an emerging technology, its potential uses and benefits are changing and emerging to fit new generation challenges. It should be monitored along with the emerging technologies and assessed as a resource in the future power system.

and action items needed should ocean energy development be pursued, and c) foster better coordination of utility efforts and investments in ocean energy.

There are several ocean energy technologies that have significant technical potential in the Pacific Northwest, including wave energy, off-shore wind, and tidal. These technologies are still emerging and in various stages of the research and development phase. While there have been efforts within the region to pursue the research and development of ocean energy, improved coordination across utilities and other stakeholders could increase program success rate and spread both risks and benefits across the region. The Council can help to foster better coordination of utility efforts across the utility community in collaboration with developers and other stakeholders to determine if there is regional interest in the development of ocean energy and outline steps to explore it further.

ANLYS-16 **Research and develop a white paper on the value of energy storage to the future power system.** [Council, Generating Resources Advisory Committee] The Council should convene a subgroup of subject matter experts from its Generating Resources Advisory Committee to assist in the research and development of a Council white paper on the full value stream of energy storage and its role in the power system, including transmission, distribution, and generation. In addition, the white paper should investigate the existing need for frequency and voltage regulation and balancing reserves in the regional power system. The Council should author the white paper with help from industry experts, or lead a request for proposals and select a consultant to write the paper. The white paper should be completed in advance of the Eighth Plan.

One of the potential constraints to extensive storage development is the ability of the developer and/or investor to capture and aggregate the full value of the storage system's services in a non-organized market and transform interest and overall system need into revenue streams and project funding. Many of the benefits of large scale storage are the portfolio effects for an optimized regional system, not just solely to a specific power purchaser, utility or end-user, and therefore it can be difficult to raise funds and seek cost-recovery for storage projects if the purchaser is not directly benefiting from all of the services, or is paying for a service that benefits others who are not also contributing funds. The white paper should clearly identify the issues and barriers and provide useful information that would be beneficial to the region's decision makers, power planning entities and integrated resource planning processes.

ANLYS-17 **Track utility scale solar photovoltaic costs, performance and technology trends in the Pacific Northwest, and update cost estimates.** [Council, GRAC] The Council should continue to monitor on an ongoing basis the costs and performance and technology trends of solar PV in the Pacific Northwest and update the forecast of future cost estimates as necessary. This should be done on an ongoing basis and with the assistance of subject matter experts from the Generating Resources Advisory Committee.

Solar PV is a rapidly evolving technology, both in terms of cost and performance. The Seventh Plan required development of a forecast of future solar PV costs. With continued uncertainty over solar installation costs and performance, updates to estimated installation costs and forecasts are required to accurately reflect the real world market. Utility scale solar installations paired with large battery systems could add further value to solar and is another important trend to follow. Detailed production estimates for many locations across the Northwest would also be useful.

ANLYS-18 Track natural gas-fired technology costs and performance, and update as necessary, particularly around combined cycle combustion turbine (CCCT) and reciprocating engine technologies. [Council, Generating Resources Advisory Committee] The Council should continue to monitor natural gas-fired technology costs and performance and technology trends in the Pacific Northwest, specifically concerning CCCTs and reciprocating engines. This should be done on an ongoing basis and with the assistance of subject matter experts from the Generating Resources Advisory Committee.

Natural gas-fired generation, particularly CCCT and reciprocating engine technologies, continue to evolve in terms of cost and performance and may play an important role in the future power system.

ANLYS-19 Monitor new natural gas developments in the region and gauge the potential impact on the regional power system. [Council, Generating Resources Advisory Committee, Northwest Gas Association, Pacific Northwest Utilities Conference Committee] The Council should monitor and track on an ongoing basis new natural gas developments in the region (such as pipelines, storage, LNG export terminals) and determine the potential future impacts on the regional power system. PNUCC is following similar issues, which may offer an opportunity for collaboration.

New natural gas uses and system development in the region may impact future power generation. On-going issues to track and potentially analyze include:

- Potential pipeline constraints, particularly on the west-side
- LNG facility developments in Canada and the West Coast of the U.S.
- Shale production from Canada and the U.S. Rockies
- Methanol plant development
- Natural Gas Vehicle (NGV) transportation
- Track on-going research on methane emissions resulting from gas production and transportation, and potential policy impacts

ANLYS-20 Monitor current and proposed federal and state regulations regarding the impacts of generating resources on the environment in the Pacific Northwest and subsequent impacts to the regional power system. [Council, Generating Resources Advisory Committee] The Council should continue to monitor and track on an ongoing basis the current and proposed regulations regarding the environmental impacts of generating resources and the subsequent impacts on the regional power system in terms of cost and operation.

System Analysis

ANLYS-21 Review analytical methods. [Council, Bonneville] As is customary between power plans, the Council will undertake a comprehensive review of the analytic methods and models that are used to support the Council's decisions in the power plan. The goal of this review is to improve the Council's ability to analyze major changes in regional and Bonneville systems and make recommendations to ensure a low-cost, low-risk power system for the region. This review will focus on changing regional power system conditions such as capacity constraints, balancing and flexibility constraints, and transmission limitations to better address these issues in future power plans.

ANLYS-22 GENESYS Model Redevelopment. [Council, Resource Adequacy Advisory Committee, System Analysis Advisory Committee, Bonneville, Pacific Northwest Utilities Conference Committee] The GENESYS model has been used extensively by the Council, Bonneville and others to assess resource adequacy. It contains, as one of its modules, Bonneville's hydro regulation model (HYDROSIM). GENESYS has also been used to assess costs and impacts of alternative hydroelectric system operations (e.g. for fish and wildlife protection). It can be used to assess the effective load carrying capability of resources (e.g. wind and solar) and it can provide estimates of the impacts of potential climate change scenarios. The model, however, has components and file structures that are decades old. Because of the multiple uses of GENESYS and because it is a critical part of the Council's process to develop the power plan, it should be redeveloped to bring the software code up to current standards, to improve its data management and to add an intuitive graphical user interface (GUI). The use of an outside contractor is likely the best course of action but options will be reviewed by the Council, Bonneville and the System Analysis and Resource Adequacy Advisory Committees. Recommendations will be made to the Council to decide on an appropriate approach given the funding available. This redevelopment should be completed in time for the next power plan.

ANLYS-23 Enhance the GENESYS model to improve the simulation of hourly hydroelectric system operations. [Council, Resource Adequacy Advisory Committee, Bonneville, Pacific Northwest Utilities Conference Committee] The Council's GENESYS model simulates the operation of the hydroelectric system plant-by-plant for monthly time steps. For hourly time steps, however, it simulates hydroelectric dispatch in aggregate. To do that, an approximation method is used to assess the aggregate hydroelectric system's peaking capability. That method should be reviewed and enhanced to better simulate the hourly operation of the hydroelectric system. As a first step, the Resource Adequacy Advisory Committee should review real-time operations. In order to improve the simulation, it may be necessary to break up the aggregate hydroelectric system used for hourly simulations into two or three parts, reflecting the different conditions and operations on the Snake River and on the upper and lower Columbia River dams. This work may also require the use of an outside contractor. Any changes in the GENESYS model should be complete in time for the next power plan.

Transmission

ANLYS-24 **Coordinate with regional transmission planners.** [Council] ColumbiaGrid and Northern Tier Transmission Group (NTTG) both have regional responsibilities for transmission system planning. The Council will coordinate with these organizations to work towards consistent regional planning assumptions and track efforts that may have implications for the power plan.

ANLYS-25 **Transmission Expansion Planning Policy Committee (TEPPC).** [Council] One of the primary functions of TEPPC is to oversee and maintain public databases for transmission planning. The Council will work with this committee on coordinating the public data used in the Council's planning process with the data produced by this committee. To the extent possible the Council will use these data to inform assumptions for generation and load outside the region.

FISH AND WILDLIFE

F&W-1 **Investigate further the effects of new resource development, especially renewable resource development and associated transmission, on the environment in general and on wildlife in particular.** [Council, State Fish and Wildlife Agencies, Indian Tribes, State Energy and Energy Siting Agencies, Transmission Providers, Utilities, Bonneville] Some of the region's fish and wildlife agencies and Indian tribes have expressed significant concern about the cumulative impacts to wildlife and the environment from the development of the region's power system, other than the effects from hydroelectric projects themselves for which there is a robust protection and mitigation program. This concern increased in the wake of the recent spurt in development in the region of renewable and gas-fired generation and the associated transmission lines, and the possibility of further such development. What is not clear is whether the current mechanisms for analyzing and addressing these effects are indeed inadequate, and if so, what can or should be done about this situation. The Council staff will work with representatives of the state fish and wildlife agencies and Indian tribes along with the state energy and energy siting agencies, transmission providers, utilities, Bonneville, and others to gain a better understanding before the next power plan of the nature and extent of both the adverse effects and of the regulations and programs intended to address those effects.

CHAPTER 5: BONNEVILLE LOADS AND RESOURCES

Contents

List of Tables and Figures

Bonneville uses its load forecast and existing resources as a starting point to conduct a more detailed needs assessment through its Resource Program process. Due to a number of necessary adjustments made to the loads and resources used in this analysis the reader is advised not to make a direct comparison between the load and resource balance presented in this chapter with the load and resource balance presented in the BPA 2015 White Book or the PNUCC 2015 NRF report.

KEY FINDINGS

Currently, the federal power supply primarily consists of hydroelectric generation, with nearly 21,000 megawatts of nameplate capacity and about 12,000 megawatts of single-hour peaking capability (under critical hydro conditions in January). The federal system also includes 1,120 megawatts of nuclear capacity, 24 megawatts of cogeneration, and 744 megawatts of contract purchases, for a total of approximately 14,000 megawatts of single-hour peaking capability. However, some of the federal system's resources must be held in reserve for contingencies and load following. These requirements account for about 2,000 megawatts of capacity, which is subtracted from the federal system capability, to yield a net federal peaking capability of about 12,000 megawatts.

On the energy side, the hydroelectric system provides about 6,600 average megawatts of (critical period) firm energy. Accounting for the energy contributions from other generating resources yields a net firm energy generating capability for the federal system of about 8,000 average megawatts.

Bonneville's annual loads are forecast to grow from 8,050 average megawatts in 2016 to between 8,300 and 8,600 average megawatts in 2035. Bonneville's single-hour peak load is forecast to grow from about 13,000 megawatts in 2016 to between 14,000 and 15,500 megawatts by 2035, depending on future economic conditions. These forecasts are for frozen efficiency scenarios, meaning that no new energy efficiency savings are counted.

A simple deterministic comparison of federal resources and loads indicates that Bonneville is likely to experience energy and capacity shortfalls over the next twenty years. However, as described in more detail for the region in Chapter 11, this deterministic look ahead is not necessarily the best indicator of future resource needs. For example, this simple comparison of loads and resources includes only the lowest (critical period) hydroelectric capability for both energy and peak. And, while it does include firm contractual agreements for power exchanges between Bonneville and other entities, it excludes available non-firm spot market supplies from both within region and from out-of-region sources. It also does not include expected future energy-efficiency savings. So, whether Bonneville will actually face a shortfall depends on runoff conditions, spot market availability, and the success rate of implementing energy-efficiency measures. Bonneville understands this and, for its own resource needs assessment, uses a number of more sophisticated analytical methods to more precisely determine its future needs.

Unlike the data and analysis provided in Chapter 11 (for regional resource needs), the Bonneville calculations in this chapter explicitly include reserve requirements. Contingency reserves are resources that are only used during unexpected events and load following reserves are used to ensure that generation matches load every minute (balancing) and every hour (load following).

For regional analysis, balancing reserves are incorporated by reducing the amount of hydroelectric peaking capability devoted to serving firm load. The regional analysis does not subtract contingency or load following reserve requirements from resource capability. Instead, the GENESYS model assesses the amount of required contingency and load following reserve for each hour of the year and checks to see if sufficient supply is available to meet that requirement. If reserves cannot be met, GENESYS counts that as a shortfall, which contributes toward the assessment of adequacy. Reserves were left in the Bonneville calculations in this chapter because not doing so produces a capacity load-resource balance (Figure 5-3) that is misleading. The Council will reevaluate how it treats reserves for its future regional adequacy assessments.

INTRODUCTION

The Council analyzes the power system from a regional perspective, and prepares a "regional conservation and electric power plan." The Northwest Power Act also directs the Council to forecast the resource needs of the Bonneville Power Administration and identify resources available to meet those needs, setting forth in the power plan a "scheme for implementing conservation measures and developing [generating] resources" under the resource acquisition provisions of Section 6 of the Act in order "to reduce or meet the [Bonneville] Administrator's obligations." As part of this effort, the focus of this chapter is on analyzing Bonneville's loads and currently available resources. The resource strategy for future resource development for the region as a whole and for Bonneville in particular, is set forth in Chapter 3 and in the Action Plan in Chapter 4.

The Act instructs the Council, after developing a demand forecast of at least twenty years, to then develop a "forecast of power resources" that the Council estimates will be required to meet Bonneville's obligations, including the portion of those obligations that can be met by resources in each of the different priority categories identified in the Act. The Council's forecast of Bonneville resource needs is to "include regional reliability and reserve requirements." The forecast is also to take into account the effects of implementing the fish and wildlife program that the Council separately develops under the Act on the availability to Bonneville of the existing hydroelectric power system. And the forecast of Bonneville's resource needs is to include "the approximate amounts of power the Council recommends should be acquired by the [Bonneville] Administrator on a long-term basis and may include, to the extent practicable, an estimate of the types of resources from which such power should be acquired."

The Bonneville "obligations" referred to in the Act include both Bonneville's contractual power sales obligations, after taking into account planned savings from conservation measures, *and* Bonneville's fish and wildlife protection and mitigation obligations called for in the Council's Fish and Wildlife Program under the Act. A number of provisions in the Act then call for Bonneville to implement conservation measures and acquire other resources to meet or reduce these obligations "consistent" with the Council's power plan, with certain specified exceptions.

The purpose of this chapter is to quantify Bonneville's forecasted load and existing resources (including reserve and reliability requirements) in order to estimate its load-resource balance over the 20-year study horizon. Bonneville develops its own resource needs assessment using data in its annual White Book publication A detailed description of potential resource acquisitions can be found in Chapter 3 and specific Bonneville action items can be found in Chapter 4.

The distinction between the regional resource strategy and the Bonneville resource strategy is greater in the 21st century than anticipated by Congress when adopting the Northwest Power

Act in 1980. A premise underlying the development of the Act was that the Council's regional resource plan would be essentially the same as Bonneville's resource strategy. The expectation at the time was that the region's utilities would largely request that Bonneville serve their growing regional loads. Bonneville would then implement conservation measures and acquire generating resources consistent with the power plan as needed to reduce or meet those growing regional loads. The costs of new resources would be spread across the region in a rate melded with the lower costs of the existing federal base system, mostly hydroelectric power resources.

As discussed in detail in the Council's Fifth and Sixth Power Plans, this approach proved unworkable in its full extent by the first part of the new century, for a number of reasons. Bonneville, the region's utilities, and the Council spent a better part of a decade crafting a new paradigm, eventually enshrined in a Bonneville policy decision and implemented through new power sales contracts and a tiered-rate mechanism. The current understanding is that Bonneville will continue to serve a portion of the region's loads with the federal base system; will reduce any need or obligation to meet growing regional loads by implementing conservation and other measures that reduce energy and capacity needs and stretch the value of the base system; and will acquire additional generating resources to meet load growth brought to Bonneville only through arrangements and a tiered-rate structure that confines as much as possible the risk and costs of those new resources to the utilities seeking the service. The only other reason Bonneville may need to acquire resources is to maintain system stability and reliability, such as to balance variable generation resources on its system. The change in expectations for Bonneville's role in the regional power system is the reason for the distinction in the Council's recent power plans between the regional resource strategy and the resource acquisition activities specifically focused on Bonneville's needs.

BONNEVILLE'S LOAD/RESOURCE BALANCE

As part of the assessment of the region as a whole, the Act requires that the Council's Power Plan focus specifically on the obligations that might be placed on Bonneville over the 20-year period covered by the plan. The plan must include at a sufficient level of detail 1) a forecast of the load that might be placed on Bonneville, as well as other obligations that might affect its system generation, including implementation of fish and wildlife program measures; 2) identification of Bonneville's existing generating resources and planned energy-efficiency savings; 3) an assessment of any potential needs to meet or reduce possible future loads and obligations; and 4) an assessment of Bonneville's share of regional reserve and reliability requirements. Bonneville's generating resources are summarized in Chapter 9 and in Bonneville's 2015 White Book. Operating and planning reserves, including Bonneville's role in future reserve requirements, are discussed in Chapter 10. Regional potential for energy efficiency, generating resources and demand response are discussed in Chapters 12, 13, and 14, respectively.

In this chapter, Bonneville's loads and resources are combined to assess a load-resource balance over a 20-year planning period. The methodology used for Bonneville is identical to that described in Chapter 11 for the region, with the exception of the treatment of reserves. Also, as emphasized in Chapter 11, a load-resource balance assessment is only the first step in a more complex process to determine resource adequacy and resource strategies to meet identified needs. Bonneville uses its load forecast and existing resources as a starting point to conduct a more detailed needs assessment through its Resource Program process. The Council works closely with the Administrator to ensure consistency and validity of all data used in that process.

Bonneville's Resources

Currently, the federal power supply primarily consists of hydroelectric generation, with nearly 21,000 megawatts of nameplate capacity and about 12,000 megawatts of single-hour peaking capability (under critical hydro conditions in January). The federal system also includes 1,120 megawatts of nuclear capacity, 24 megawatts of cogeneration, and 744 megawatts of contract purchases, for a total of approximately 14,000 megawatts of single-hour peaking capability. However, some of the federal system's resources must be held in reserve for contingencies and load following. These requirements account for about 2,000 megawatts of capacity, which is subtracted from the federal system capability, to yield a net federal peaking capability of about 12,000 megawatts.

On the energy side, the hydroelectric system provides about 6,600 average megawatts of (critical period) firm energy. Accounting for the energy contributions from other generating resources yields a net firm energy generating capability for the federal system of about 8,000 average megawatts.

Tables 5 - 1 and 5 - 2 show Bonneville's annual energy and peaking capability (from the 2015 White Book) along with its reserve requirements and estimated transmission losses.

Table 5 - 1: 2015 White Book Federal System Resources
Annual Energy (Average Megawatts) under Critical Water

Resource Type/Year	2016	2021	2026	2035
Net Hydro	6,666	6,658	6,644	6,644
Other Resources	1,145	971*	1130	957*
Contract Purchases	387	507	562	173
Transmission Losses	(243)	(242)	(248)	(231)
Total Net Resources	7,955	7,895	8,089	7,543

* This reflects partial year operation of Columbia Generating Station due to refueling requirements

Table 5 - 2: 2015 White Book Federal System Resources
Single-hour Peaking Capability (Megawatts) under Critical Hydro

Resources/Year	2016	2021	2026	2035
Net Hydro	12,056	12,619	12,599	12,710
Other Resources	1,144	1,120	1,120	1,120
Contract Purchases	744	694	969	308
Reserves & Losses	(2109)	(2133)	(2122)	(2127)
Total Net Resources	11,835	12,300	12,293	12,011

Bonneville's Forecast Obligations

In order to forecast Bonneville's future obligations (e.g. long-term contract sales, sales to federal agencies) the Council used BPA's long-term firm load obligations for 2016 to 2035 as reported in the 2015 White Book. Forecast sales in 2016 were then adjusted for Bonneville's transmission losses (2.97 percent) to compute Bonneville's system energy load. Forecast of single-hour capacity needs were also extracted from the 2015 White Book. These single-hour load obligations were then adjusted to include Bonneville's transmission loss of 3.38 percent. These reported transmission loss factors were updated as part of BPA's recent rate case. The result of this calculation indicates that obligations will be about 8,000 average megawatts by 2016, depending on regional economic growth. By 2035 the energy load forecast will likely reach 8,300 average megawatts. Capacity requirements would increase from 12,700 megawatts to about 13,000 megawatts. Bonneville's estimate of its annual energy and single-hour winter peak loads, prior to any adjustment for losses or embedded conservation, is shown in Table 5-3. Embedded conservation refers to conservation that is captured in BPA load forecast. Because BPA load forecast uses econometric methodology, it includes impact of past conservation.

Table 5 - 3: 2015 White Book Forecast of Bonneville's Annual Energy and January Single-Hour Peak Capacity Loads

Year	2016	2021	2026	2035
Annual Energy – BPA total firm obligations (aMW)	8,050	8,086	8,082	8,310
January Single-Hour Peak Loads (MW)	12,720	12,769	12,623	12,962

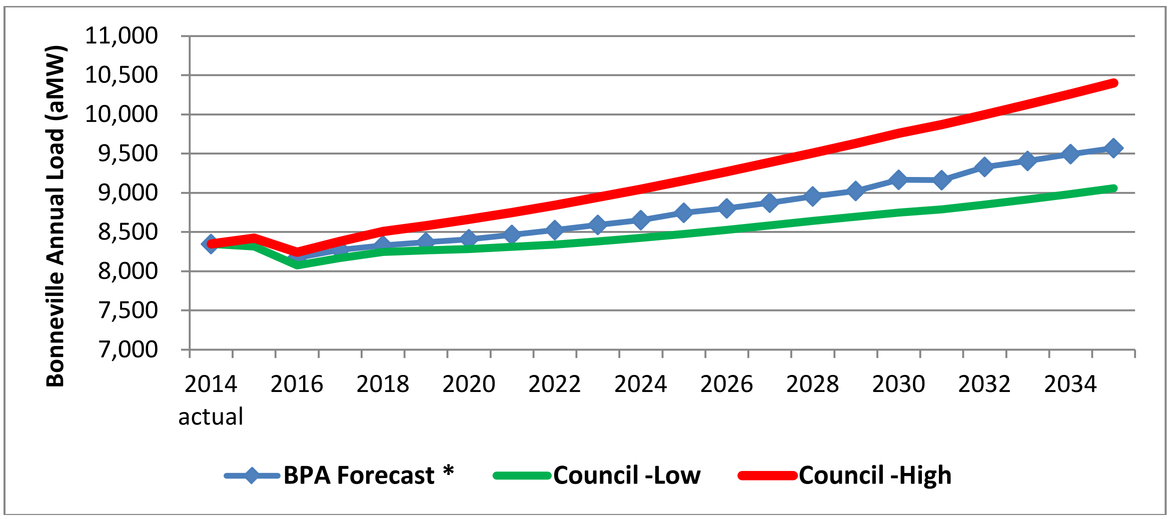
Bonneville's estimates of annual energy and peak loads shown in Table 5-3 include forecast levels of future conservation but do not include line losses. The Council's estimates of Bonneville's future obligations described above do not include prospective conservation, but do include line losses. Council analysis adds back in the losses shown in 2015 White Book for both energy and single hour January peak. The following section describes adjustments that were made so that Bonneville and Council forecasts of federal loads can be compared.

Comparison of the Council's Load Forecast and Bonneville's White Book Forecast for Obligations

Due to differences in forecasting methodologies, in order to compare the Council's forecast to Bonneville's forecast of federal obligations, three adjustments need to be made to the Bonneville forecast. These include; 1) an adjustment for line losses, 2) an adjustment for conservation embedded in the agency's load forecast, and 3) an adjustment for Direct Service Industry (DSI) loads. The Council uses a frozen efficiency load forecast when estimating its 20-year load and resource balance for the region. This approach allows for an explicit treatment of future conservation resources in the Council's planning models. Bonneville's load forecast methodology embeds the impact of future conservation savings implicitly, through use of econometric estimations. To compare Bonneville's obligations reported in the White Book with the Council's, an adjustment must be made to remove embedded conservation savings from Bonneville's forecast.

Bonneville estimates that incremental annual conservation savings embedded in their forecast is about 60 average megawatts. To compare the two forecasts, annual conservation savings embedded (implicitly accounted for in the econometric relationships) in Bonneville's forecast must be added back into that forecast as additional load. Then, since Bonneville accounts for transmission losses separately, those losses must also be added to the Bonneville forecast. Also, Bonneville obligation to DSIs has been reduced to 91 average megawatts, consistent with 2015 White Book. After making these three adjustments, the revised Bonneville 20-year load forecast is plotted in Figure 5 - 1 along with the Council's estimate of Bonneville's obligations. The drop in forecast of load in 2016 is due to Alcoa's announced idling of their smelting operations in the state of Washington.

Figure 5 - 1: Comparison of Council Frozen Efficiency Load Forecasts with Bonneville White Book Forecast, Adjusted for Losses and Embedded Conservation



*To make Bonneville and Council forecasts comparable, DSI loads of 225 aMW are excluded from BPA's obligation. BPA's most recent rate case data assumes DSI obligations of 91 aMW.

The year-by-year comparison of the Council's forecast of Bonneville's obligations and Bonneville's adjusted obligations is presented in Table 5 - 4. As evident in that figure, the forecasts are reasonably close.

Table 5 - 4: Comparison of Frozen Efficiency Load Forecasts

	2016	2017	2018	2019	2020
BPA Forecast*	8,170	8,273	8,330	8,369	8,409
Council's Low forecast for Bonneville	8,122	8,215	8,291	8,313	8,332
Council's High forecast for Bonneville	8,287	8,426	8,555	8,631	8,709

* Excludes DSI load of 225 aMW not part of BPA obligation. BPA rate case data puts DSI obligations at 91 aMW.

Figure 5 - 2 shows the Council's forecast range of Bonneville's annual energy loads and resources over the 20-year study horizon. Resources reported in the 2015 White Book, were adjusted for transmission losses (i.e. losses were subtracted from Bonneville's resource total). In this analysis, however, transmission losses are added to Bonneville's forecast of sales to get Bonneville's load at the generator busbar. This allows a more direct comparison of Bonneville's load forecast to the Council's forecast. So for this analysis, Bonneville's resources do not have transmission losses subtracted out. Table 5 - 5 shows the Bonneville load-resource balance for specific years.

Figure 5 - 2: Bonneville's Annual Energy Loads and Generating Capability

(Frozen Efficiency)

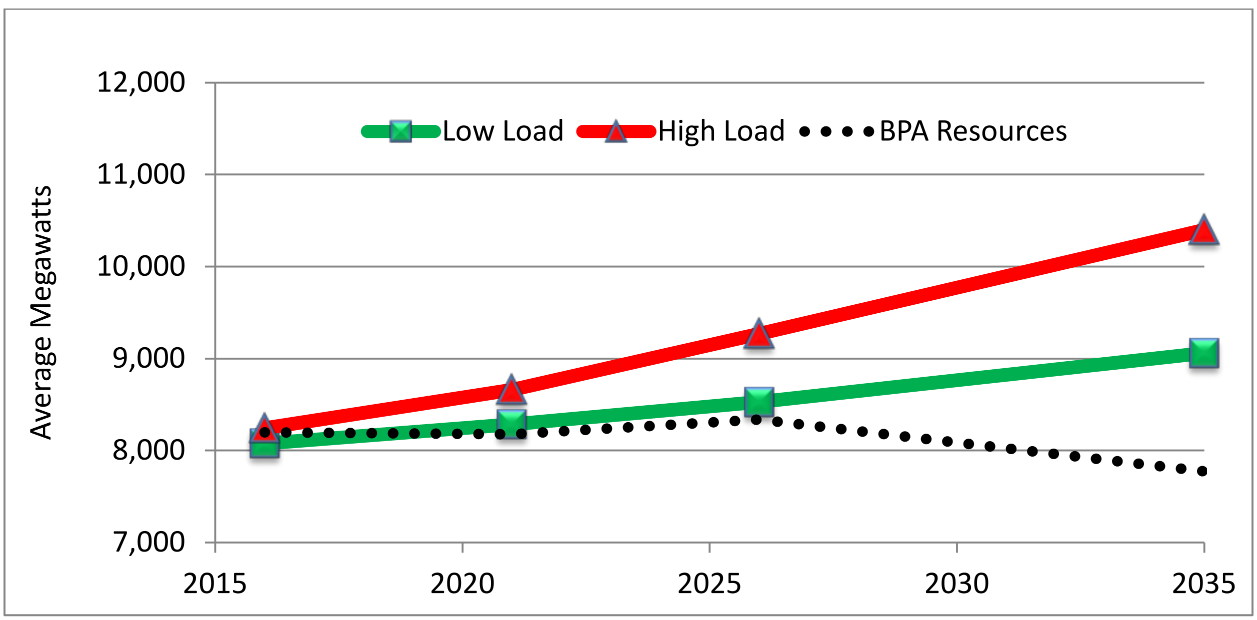


Table 5 - 5: Bonneville's Energy Load-Resource Balance (Frozen Efficiency)

Forecast	2016	2021	2026	2035
Low (aMW)	122	-108	-191	-1285
High (aMW)	-43	-485	-933	-2625

Comparison of Bonneville and Council's Peak Load Forecast

Bonneville's peak load is coincident with the region's peak load, which typically occurs during the winter. To compare BPA's single-hour load forecast with the Council's, the same approach was taken as used to compare the energy load forecasts. Bonneville's forecast of single-hour peak load presented in the 2015 White Book was adjusted for transmission losses (3.38 percent of single-hour peak load) and adjusted for the conservation savings on peak (using a two-to-one ratio for winter peak hour savings relative to energy savings). Then the adjusted single-hour peak load for 2016 was projected forward using the Council's annual growth rate to get the frozen efficiency peak-load forecast.

Table 5 - 6: Comparison of Frozen Efficiency Single Hour Winter Peak Forecasts

	2016	2017	2018	2019	2020
BPA Forecast – 2015 White Book	12,960	13,609	14,063	15,446	12,960
Council's Low forecast for Bonneville	12,363	12,471	12,558	12,571	12,579
Council's High forecast for Bonneville	12,706	12,883	13,046	13,133	13,222

The single-hour winter peak load for Bonneville is shown below in Figure 5 - 3 along with Bonneville's resource peaking capability over the same time span. Table 5 - 7 provides Bonneville's projected capacity load-resource balance. Bonneville's adjusted single-hour load forecast with frozen efficiency is in line with the Council's estimate for the high load growth frozen efficiency forecast. Note that these forecasts do not include any new conservation acquisition targets identified in this plan.

Figure 5 - 3: Bonneville's Winter Single-Hour Peak Load Forecast and Single-Hour Peaking Capability (Frozen Efficiency)

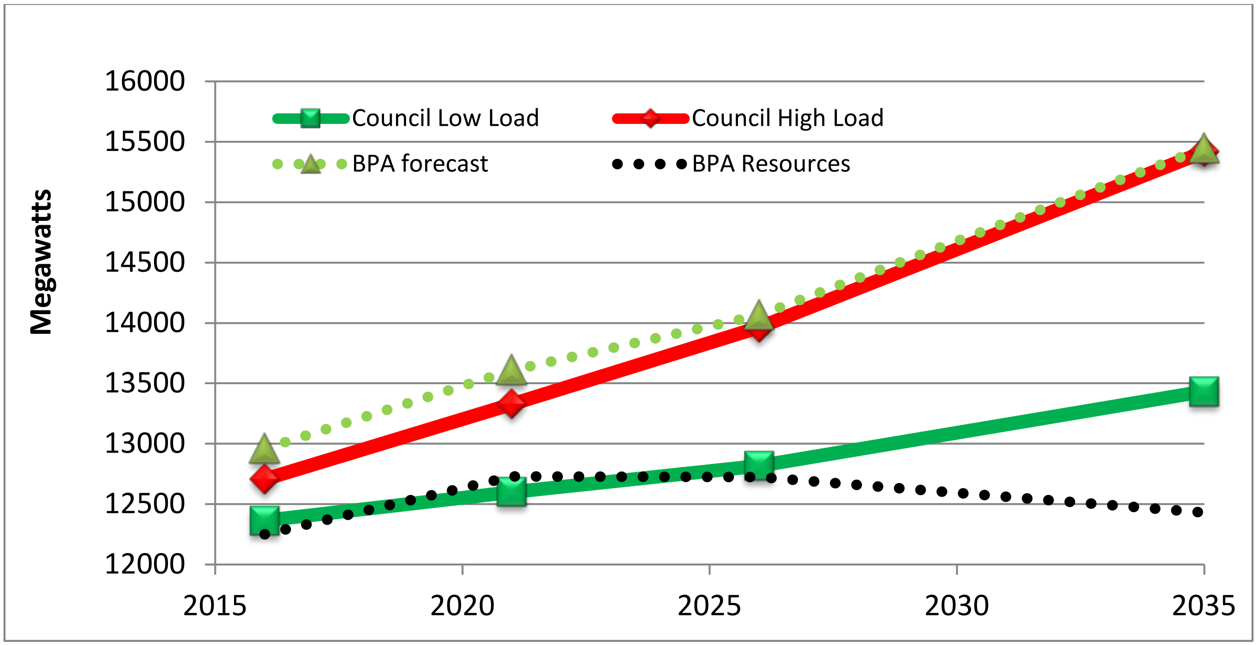


Table 5 - 7: Bonneville's Capacity Load-resource Balance (Frozen Efficiency)

Forecast	2016	2021	2026	2035
Low	-114	131	-94	-1002
High	-456	-597	-1240	-2986

BONNEVILLE RESOURCE ACQUISITION AND ACTIVITIES

Bonneville's Needs Assessment defines the timing and scale of the difference between forecasted federal loads and existing resources using multiple metrics. Bonneville will prepare a more precise and specific resource needs assessment based on forecasted federal loads and existing resources as described above. Bonneville then determines the specific timing and amount of new resources needed to meet its federal obligations through its Resource Program development process. Bonneville's Resource Program should be consistent with the Council's Seventh Power Plan taking into account its obligation to provide an adequate, reliable, and cost-effective power supply while maintaining its ability to implement the fish and wildlife measures identified in the Council's Fish and Wildlife. Specifically, Bonneville is expected to acquire its share of all cost-effective energy efficiency, evaluate and develop demand response resources, and examine the availability and cost of generating resources (if needed). In addition, Bonneville is expected to continue to explore ways to provide operating and balancing reserves in the most economic manner. A more detailed description of the Council's recommendations for the region and Bonneville's resource strategy can be found in Chapter 3 and specific Bonneville action items can be found in Chapter 4.

CHAPTER 6: NORTHWEST POWER ACT REQUIREMENTS FOR THE POWER PLAN

In the Northwest Power Act of 1980, Congress authorized the four states of the Columbia River Basin to form an interstate compact agency – the Council -- and directed the Council to prepare and periodically review a “regional conservation and electric power plan.” The Act specifies how the Council is to review the power plan; what the Council must do prior to the review of the power plan (engage the region in a separate process to develop or amend a program to “protect, mitigate and enhance” Columbia River fish and wildlife); what the Council must include in the power plan; what the ultimate purpose of the power plan is; and how the Bonneville Power Administration is to use the Council’s power plan to guide decisions to implement energy-conservation measures and acquire new generating resources.

The purposes of the Northwest Power Act that the power plan is intended to fulfill: Northwest Power Act, Section 2

The power planning effort must fulfill the purposes of the Act as established by Congress, including:

- to encourage conservation and efficiency in the use of electric power and the development of renewable resources within the Pacific Northwest;
- to assure the Pacific Northwest of an adequate, efficient, economical, and reliable power supply;
- to provide for the participation and consultation of the states, local governments, consumers, customers, users of the Columbia River system, federal and state fish and wildlife agencies, Indian tribes, and the public at large in the development of regional plans and programs for energy conservation and new generating resources; protecting, mitigating and enhancing fish and wildlife resources; facilitating the orderly planning of the region’s power system; and providing environmental quality; and
- to protect, mitigate, and enhance the fish and wildlife of the Columbia River and its tributaries, including related spawning grounds and habitat.

The purposes set forth in the Act were a direct response by Congress to the increasingly difficult resource issues the Pacific Northwest faced in the years leading up to the Act -- how best to develop an adequate, reliable, and economical power system for the region on the base of the region’s extensive hydroelectric system while simultaneously dealing with the decline in salmon and steelhead populations resulting from the development and operation of that system.

To carry out these purposes, the Act authorized the states of Washington, Oregon, Idaho, and Montana to establish the Council as an interstate compact agency and charged the Council with three primary responsibilities: 1) developing and periodically reviewing a “regional conservation and electric power plan”; 2) prior to each power plan, developing and periodically amending a “program to protect, mitigate and enhance fish and wildlife" affected by the Columbia River basin hydrosystem; and 3) developing both plan and program in a highly public manner with substantial public input.

The priorities, elements and development of the Council's regional conservation and electric power plan: Northwest Power Act, Sections 4(d) through 4(g)

Sections 4(d) through 4(g) of the Act describe the "regional conservation and electric power plan" that the Council is to adopt and then review every five years; the process the Council is to follow in developing and reviewing the plan; and the substantive elements of the plan.

Section 4(e) lists the substantive priorities, considerations, and elements that the power plan must contain and reflect. The plan must "give priority to resources which the Council determines to be cost-effective." Of the cost-effective resources available, the plan must give priority "first, to conservation; second, to renewable resources; third, to generating resources utilizing waste heat or generating resources of high fuel conversion efficiency; and fourth, to all other resources." Given the resource priorities established by Congress, the Council is responsible for developing a plan that "set[s] forth a general scheme for implementing conservation measures and developing resources… to reduce or meet the [Bonneville Power] Administrator's obligations." (See below on what those obligations are.) The Council must develop this resource scheme "with due consideration by the Council for (A) environmental quality, (B) compatibility with the existing regional power system, (C) protection, mitigation, and enhancement of fish and wildlife and related spawning grounds and habitat, including sufficient quantities and qualities of flows for successful migration, survival, and propagation of anadromous fish" and other criteria the Council may set forth in the plan.

The Act then details specific elements that must be included in the power plan in order to accomplish the priorities established by Congress in the Act. The Council is to include these elements "in such detail as the Council determines to be appropriate":

(A) an energy conservation program, including model conservation standards[1]

(B) recommendation for research and development

(C) a methodology for determining quantifiable environmental costs and benefits under section 3(4) of this Act[2]

[1] Conservation is defined in Section 3(3) of the Act. Detailed requirements for the model conservation standards are set forth described in Section 4(f) of the Act. For further discussion, *see* Chapters 12 and 17.

[2] Section 3(4) of the Act defines what it means for a conservation measure or generating resource to be "cost-effective". Cost-effectiveness, per the Act, is based on the "incremental system cost" of each measure or resource, and is to include all direct costs of that measure or resource over its effective life, including all direct and quantifiable environmental costs and benefits. Cost-effectiveness under the Act also requires the measure or resource must be forecast to be reliable and available when needed to meet or reduce demand. *See* Chapter 19 for the required "methodology for determining quantifiable environmental costs and benefits" and further discussion of that element of the Act and of the "due consideration" requirements on the Council in developing the plan's resource strategy. "Resource" is defined in Section 3(19).

(D) an electricity demand forecast of at least 20 years; a forecast of the power resources estimated by the Council to be required to meet the obligations of the Bonneville Power Administrator; and the portion of those obligations can be met by resources in the Act's priority categories. The power resource forecast shall also (i) include regional reliability and reserve requirements, (ii) take into account the effect, if any, of the requirements of the Council's fish and wildlife program on the availability of resources to Bonneville, and (iii) include the approximate amounts of power the Council recommends should be acquired by Bonneville and may include, to the extent practicable, an estimate of the types of resources from which such power should be acquired

(E) an analysis of electricity reserve and reliability requirements and cost-effective methods of providing reserves designed to insure adequate electric power at the lowest probable cost

(F) the fish and wildlife program promulgated prior to the power plan by the Council under Section 4(h) of the Act

(G) any surcharge recommendation relevant to implementation of the model conservation standards and a methodology for calculating the surcharge

Sections 4(d)(1) and (g) of the Act describe how the Council is to engage the region in developing the power plan, requiring the Council to engage the public extensively in review of the power plan issues and elements. The Act directs the Council (and Bonneville) to insure widespread public involvement in the formulation of the plan and regional power policies, as well as to maintain comprehensive programs to inform the public of major regional power issues and obtain the public's views on the plan and major regional power issues. The Council and Bonneville are also directed to secure advice and consultation from Bonneville's power sales customers and others. The Act also requires the Council and Bonneville, as the Council develops and Bonneville implements the power plan, to encourage the cooperation, participation, and assistance of appropriate federal and state agencies, local governments, and Indian tribes. The Council and Bonneville are also to recognize and not abridge the authorities of state and local governments, electric utility systems, and other non-federal entities responsible for the planning, supply, distribution, operation, and use of electric power and the operation of electricity generating facilities.

What this adds up to is that the Council engages the public and key regional stakeholders for more than two years in an extensive public effort to review the existing power plan and existing power system, gather information about priority issues relevant to the region's power system, develop a draft revised power plan, review the draft, and then finalize the updated power plan. The Council develops and discusses the substantive power plan issues in public at regularly scheduled monthly meetings of the Council's Power Committee and the full Council during the development of the plan and at additional Power Committee and Council meetings called solely for the purpose of discussing issues related to the power plan. All meetings are open to the public, with substantial public notice and participation. Documents relevant to the power plan are widely available to the public throughout this process. The same is true of the meetings and discussions of the Council's power plan advisory committees, which are groups of technical and policy experts assembled to assist the Council in, among other things, analyzing issues and analytical work prepared in anticipation of the power plan. All meeting agendas and presentations are made available to the public through the Council's website and in other ways.

Once the Council develops and releases a draft revised power plan, the Act requires that the Council hold public hearings on the proposed power plan in each of the four Northwest states. The Council also schedules consultations on the draft plan with key regional entities, many of them specifically called out in the Act for consultation. This includes Bonneville, the Bonneville customers, other state and federal agencies, the region's Indian tribes, and non-governmental organizations with an interest in the power plan. In releasing the draft power plan and taking and considering public comment, the Council largely follows the notice and comment procedures specified in the federal Administrative Procedures Act. This includes providing for wide public notice of the draft power plan (and major elements of the plan in formulation before the draft), as well as written and oral comments at not just the specially designated public hearings on the draft plan, but also at the Council's regularly-scheduled meetings and through informal consultations throughout the two-year period both leading up to the release of the draft plan and then following its release.

The Council's power plan guides Bonneville's new resource acquisition decisions: Northwest Power Act, Sections 4(d)(2) and 6(a) through 6(c)

In adopting the Northwest Power Act, Congress envisioned that Bonneville, the federal power marketing agency selling at wholesale the electrical power produced by the Federal Columbia River Power System, would also be a major engine for adding new resources to the region's power system as needed. Sections 6(a)(2)(A) and (B) of the Act thus authorize and obligate Bonneville to acquire "sufficient resources" to meet the agency's contractual power sales obligations and to assist the agency in meeting the requirements in section 4(h) that Bonneville protect, mitigate and enhance fish and wildlife in a manner consistent with the Council's fish and wildlife program.

Sections 4(d)(2) and 6(a), 6(b), and 6(c) then tie Bonneville's acquisition of new resources for these purposes directly to the Council's power plan by requiring that Bonneville's resource acquisitions, with certain narrow exceptions, be consistent with the Council's power plan. This assures the states and the region, through the Council, have a significant role in guiding Bonneville's resource acquisitions.

Aspects of the Seventh Power Plan and its resource strategy particularly focused on Bonneville are found in Chapter 7 (including the "Bonneville needs" portion of the regional demand forecast); in the provisions of the Resource Strategy and Action Plan chapters particularly focused on Bonneville (Chapters 3 and 4), and in the "Bonneville's Loads and Resources" chapter that pulls together the disparate elements of the plan into a Bonneville-focused discussion (Chapter 5).

Given the Administrator's obligation to acquire resources consistent with the Council's plan, the Council's regional power plan has obvious effects and influences on power supply decisions made by others in the region. The Act does not impose on other entities the same legal obligations toward the Council's plan as the statute requires of Bonneville, but the fact that Bonneville is the primary wholesale provider and marketer of electric power in the Pacific Northwest necessarily results in the plan affecting the resource decisions of Bonneville's customers as well as investor-owned utilities that purchase power from Bonneville and who may also own and market their own generation. The power plan is also examined by state energy offices as well as regulators responsible for overseeing the activities of various participants in the region's energy industry. Such entities do not owe any legal obligation towards the Council's plan. But they and others recognize that Bonneville does have obligations, and they recognize as well that the Council is the only entity tasked with taking a region-wide perspective to long-range power planning. The result, not surprisingly, is that the Council's power plan has an impact on power planners and regulators that goes beyond the resource acquisition activities of Bonneville. The State of Washington has gone one step further, in that Washington's Energy Independence Act (known as I-937) ties conservation planning in Washington to the Council's methodology for conservation planning. This is a matter of state law, not of the Northwest Power Act. See Chapter 12 for further discussion of the Energy Independence Act's requirements and their relationship to the Council's power plan.

The relationship of the Council's fish and wildlife program to the Council's power plan: Northwest Power Act, Sections 4(e)(3)(F), 4(h)

The last important piece of the statutory background is the first in order of Council action. In Section 4(h) Congress directed the Council, "prior to the development or review of the [power] plan, or any major revision thereto" to adopt a program intended to protect, mitigate, and enhance the fish and wildlife adversely affected by the hydroelectric facilities in the Columbia River Basin. In contrast to the power plan provisions of the Act, developing or amending the fish and wildlife program is highly circumscribed.

A fish and wildlife program amendment process must begin by the Council requesting in writing recommendations from the region's state and federal fish and wildlife agencies and Indian tribes for "measures … to protect, mitigate, and enhance fish and wildlife, including related spawning grounds and habitat, affected by the development and operation of any hydroelectric project on the Columbia River and its tributaries" and "objectives for the development and operation of such projects on the Columbia River and its tributaries in a manner designed to protect, mitigate, and enhance fish and wildlife." These recommendations become the raw material from which the Council builds the resulting program measures and objectives. The Council must engage with the fish and wildlife agencies and tribes, the federal agencies operating and regulating the Columbia hydroelectric facilities, Bonneville, Bonneville's utility customers, and the general public to shape the recommendations into program measures, with narrow criteria for rejecting recommendations and while satisfying a set of strict substantive criteria along the way. These include a number of standards that further tie the Council's fish and wildlife program decision making to the recommendations, expertise, and activities of the fish and wildlife agencies and tribes, as well as requirements to use the best available scientific knowledge in the choice of program measures to select the least-cost measures among those that meet the same sound biological objectives. The program the Council adopts must also continue to assure that the region has an adequate, efficient, economical, and reliable power supply.

After the Council adopts its fish and wildlife program, Bonneville has an obligation under Section 4(h)(10)(A) to use its fund and its authorities to protect, mitigate, and enhance fish and wildlife "in a manner consistent with" the Council's fish and wildlife program and power plan and the purposes of the Act. Bonneville and the other federal agencies operating, managing, or regulating Columbia River hydroelectric facilities have a separate obligation under Section 4(h)(11) to exercise their responsibilities taking into account the Council's fish and wildlife program at each stage of relevant decision making processes "to the fullest extent practicable."

Per Section 4(e), the Council's fish and wildlife program also becomes part of the Council's subsequent power plan. Bonneville has an obligation under Sections 4(d) and 6 of the Act to acquire sufficient resources consistent with the Council's power plan to not only meet load but to assist in meeting the fish and wildlife protection and mitigation requirements that emerge from the Council's fish and wildlife program. See Chapter 20 for a further discussion of the integration of the fish and wildlife program – and especially the program's measures for system operations – into the power plan analysis and the plan's resource strategy.

CHAPTER 7: ELECTRICITY DEMAND FORECAST

Contents

List of Figures and Tables

Throughout this chapter the demand forecast is presented as a range. This is done to reinforce the fact that the future is uncertain. The Council's planning process does not use a single deterministic future to drive the analysis. Rather, the stochastic variation introduced in the Regional Portfolio Model tests a wide range of future uncertainties in load, fuel prices etc.

The forecast for the Bonneville Power Administration's load and resource obligations is presented in Chapter 5.

KEY FINDINGS

Pacific Northwest consumers used 19,400 average megawatts or 170 million megawatt-hours of electricity in 2013. Without development of conservation beyond that projected to result from changes in retail electricity prices, the Council forecasts regional electricity demand will grow between 20,600 and 23,600 average megawatts by 2035.[1] Regional demand is expected to increase by 1,800 to 4,400 average megawatts from 2015 to 2035 with an annual increase of 90 to 220 average megawatts per year. This translates to a growth rate of 0.5 to 1.0 percent per year. The regional peak load for power, which typically occurs in winter, is forecast to grow from 30,000 to 31,000 megawatts in 2015 to 31,600 to 35,600 megawatts by 2035. This equates to an average annual growth rate of 0.4 to 0.8 percent. Cost-effective efficiency improvements identified in this Seventh Power Plan are anticipated to meet most if not all of this projected growth under most future conditions.

The slow pace of growth in electricity demand is unprecedented. Lower forecast growth in demand is due to projected significant improvements in federal appliance standards and to a much lesser extent, the growth in distributed generation at customer sites (e.g. rooftop solar photovoltaics [PV]). After accounting for the impact of new cost-effective conservation that should be developed over the 20-year period covered by the Seventh Plan, the need for additional generation is forecast to be quite small compared to historical experience. While annual electricity demand is forecast to grow slowly, summer-peak demand continues to grow and may equal winter-peak demand near the end of this 20-year plan.

Unlike most of the rest of the nation, the Northwest has historically been a winter-peaking power system. However, largely due to the increased use of air conditioning, the difference between winter- and summer-peak loads is forecast to shrink over time. Assuming normal weather conditions, winter-peak demand in the Seventh Power Plan is projected to grow from 30,000 to 31,000 megawatts in 2015 to around 31,600 to 35,600 megawatts by 2035. Summer-peak demand is forecast to grow faster than winter peak. Summer peak is forecast to grow from 27,000 to 28,000 megawatts in 2015 to 30,600 to 33,600 megawatts by 2035. The average annual growth rate for winter-peak demand is forecast to be 0.4 to 0.8 percent per year while the annual growth rate for summer-peak demand is forecast to grow at a slightly faster pace of 0.7 to 1.0 percent per year. As a result, by 2035 the gap between summer-peak load and winter-peak load will have narrowed considerably from about 3,000 megawatts to between 1,000 to 2000 megawatts.

[1] Throughout this chapter the amount of electricity used by consumers is referred to as either electricity ***demand*** or ***sales.*** Electricity ***load*** refers to the amount of electricity produced at generation facilities and includes transmission and distribution system losses.

INTRODUCTION

Background

It has been nearly 33 years since the Council adopted its first power plan in 1983. Since then, the region's energy environment has undergone many changes. In the decade prior to the passage of the Northwest Power Act, total regional electricity demand was growing 3.5 percent per year. Demand growth, excluding the direct service industries or DSIs (i.e., the aluminum and chemical companies directly served by Bonneville), grew at an annual rate of 4.3 percent. In 1970, regional demand was about 11,000 average megawatts and during that decade demand grew by nearly 4,700 average megawatts. As shown in Figure 7 - 1, during the 1980's, the pace of demand growth slowed significantly. Nevertheless, electricity demand continued to grow at about 1.5 percent per year, totaling about 2,300 average megawatts over the decade. In the 1990's another 2,000 average megawatts was added to the regional demand, resulting in a growth rate of 1.1 percent annually in the last decade of the 20th century. However, since 2000, regional electricity demand has actually declined. As a result of the West Coast energy crisis of 2000-2001 and the recession of 2001-2002, regional demand decreased by 3,700 average megawatts between 2000 and 2001. A significant factor for reduction in demand was the closure of many of the industrial plants (i.e., the Direct Service Industries) served by the Bonneville Power Administration. Regional demand for electricity in the Northwest has still not returned to the level experienced in 2000 prior to the West Coast energy crisis. As can be seen in Figure 7 - 1, 2014 regional electricity demand (i.e. sales) were still below the sales in 2000.

Figure 7 - 1: Total and Non-DSI Regional Electricity Sales (aMW)

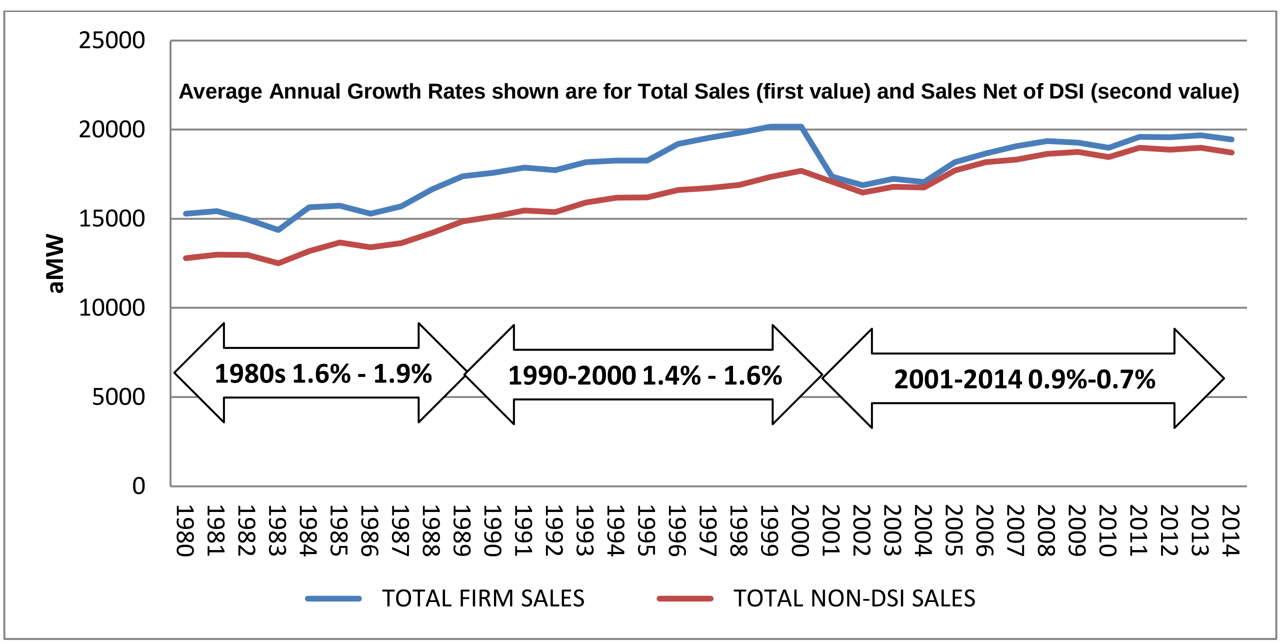
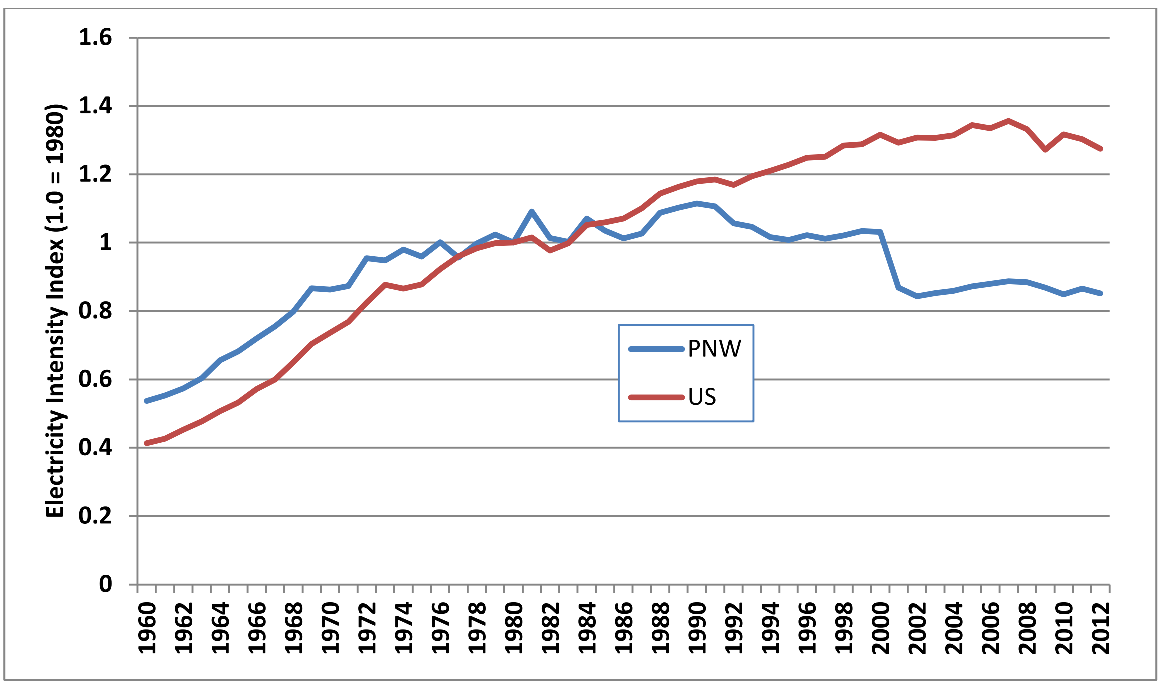


Table 7 - 1: Average Annual Growth of Total and Non-DSI Regional Electricity Sales

Annual Growth	Total Sales	Non DSI
1970-1979	4.1%	5.2%
1980-1989	1.5%	1.7%
1990-1999	1.1%	1.5%
2000-2007	-0.8%	0.5%
2007-2014	0.3%	0.3%

The dramatic decrease in electricity demand over roughly the last four decades shown in Table 7 - 1 was not due to a slowdown in economic growth in the region. The region added more population and more jobs between 1980 and 2000 than it did between 1960 and 1980. The decrease in demand was the result of a move to less electricity-intensive activities and improvements in energy efficiency. As shown in Figure 7 - 2, in the Pacific Northwest, electric intensity in terms of use per capita increased between 1980 and 1990, but has been declining since 1990. This shift reflects industry changes in the region (e.g., the significant drop in electricity intensity per capita between 2000 and 2001 was due to the closure of many of the DSIs), increasing electricity prices, decreases in the market share of electric space and water heating and regional and national conservation efforts.

Figure 7 - 2: Trends in Electricity Intensity Per Capita 1960-2012 (index to 1980)



SEVENTH POWER PLAN DEMAND FORECAST

The Pacific Northwest consumed 19,400 average megawatts or 172 million megawatt-hours of electricity in 2013. Without the development of conservation beyond that projected to result from changes in retail electricity prices, the Council forecasts regional electricity demand to grow to 20,600 to 23,600 average megawatts by 2035. After accounting for distribution and transmission system losses, regional loads, measured at the generation site, are expected to increase by 2,200 to 4,800 average megawatts between years 2015 and 2035. This translates to an average increase of 90 to 220 average megawatts per year or a growth rate of 0.5 to 1.0 percent per year. The regional peak load for power, which typically occurs in winter, is forecast to grow from 30,000 to 31,000 megawatts in 2015 to around 31,600- 35,600 megawatts by 2035. This equates to an average annual growth rate of 0.4 to 0.8 percent.

Unlike most of the rest of the nation, the Northwest has historically been a winter-peaking power system. However, largely due to the increased use of air conditioning, the difference between winter- and summer-peak loads is forecast to shrink over time. Assuming normal weather conditions, winter-peak demand is projected to grow from 30,000 to 31,000 megawatts in 2015 to 31,600 to 35,600 megawatts by 2035. Summer-peak demand is forecast to grow faster than winter peak demand. Summer peak demand is forecast from 27,000 to 28,000 megawatts in 2015, to 30,600 to 33,600 megawatts by 2035. The average annual growth rate for winter-peak demand is forecast to grow at 0.4 to 0.8 percent per year while the annual growth rate for summer-peak demand is forecast to grow at a slightly faster pace of 0.7 to 1.0 percent per year. As a result, by 2035 the gap between summer-peak load and winter-peak load will have narrowed considerably from about 3,000 megawatts to 1,000 - 2000 megawatts.

Demand Forecast Range

Forecasting future electricity demand is difficult because there is considerable uncertainty surrounding economic growth and demographic variables (e.g. net migration), natural gas prices and other factors that significantly affect electricity demand. To evaluate the effect of these economic and fuel-price uncertainties in the Seventh Power Plan, the Council developed a range of demand forecasts. The Seventh Power Plan's low to high range is based on IHS-Global Insight's Q3 2014 range of national forecasts. IHS-Global Insight is a well-known national consulting company. To forecast electricity demand under each scenario, the Council used the economic assumptions from the IHS-Global Insight's forecast. Economic variables presented in Appendix B, show the range of values for key economic assumptions used for each scenario modeled. The resulting range for the most significant economic drivers of growth in electricity demand is shown in Table 7 - 2.

Table 7 - 2: Forecast Range for Key Economic Drivers of Growth in Demand

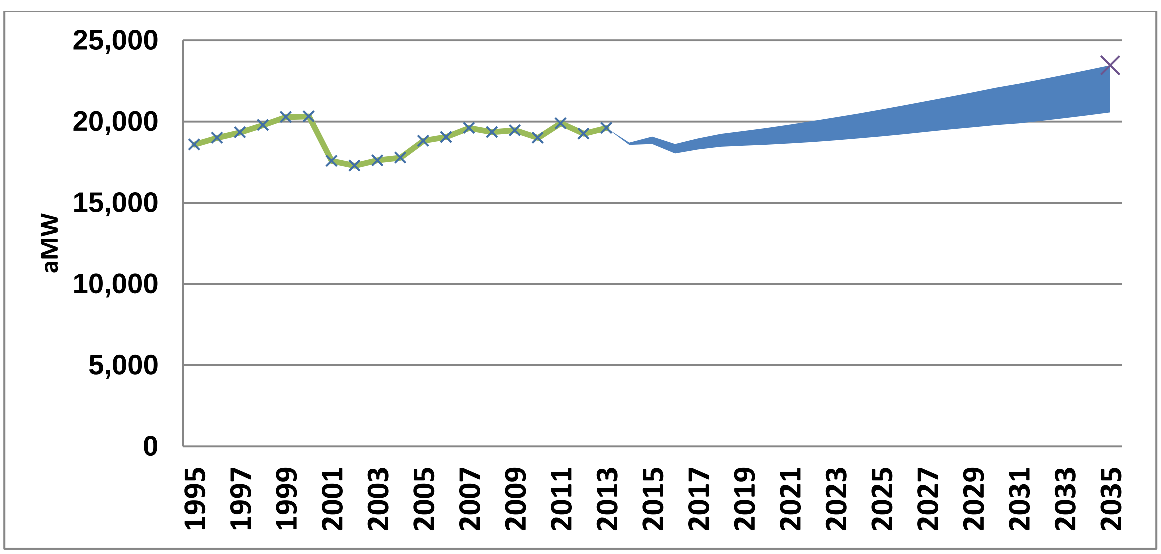
Average Annual Growth Rates over next 20 years

	Medium case	High case	Low case
Residential units	1.18%	2.0%	0.08%
Commercial floor space	1.11%	2.1%	0.67%
Industrial output ($2012)	1.56%	2.4%	0.95%
Agricultural output ($2012)	0.81%	2.0%	0.26%

Two alternative economic scenarios were developed for the Seventh Power Plan. The most likely range of economic growth is 0.6 to 1.1 percent per year. The low scenario growth rate of 0.6 percent per year reflects a prolonged recovery from the recession, and the high scenario growth rate of 1.1 percent per year reflects a more robust recovery and future growth.

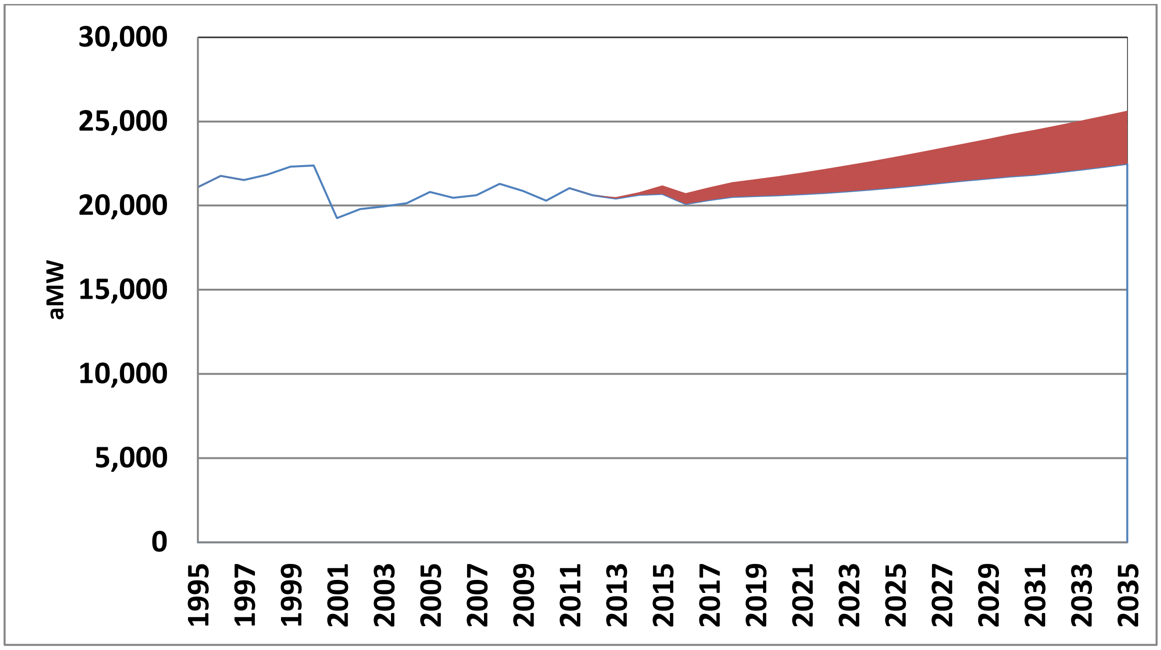
Figure 7 - 3 shows the Seventh Power Plan's electricity demand forecast range through 2035 and historical regional electricity demand since 1995. Under the low forecast, regional demand for electricity by 2030 returns to the level of regional demand prior to the West Coast energy crisis in 2000. Under the high forecast, electricity demand increases much more quickly, so that in 2020 demand is roughly equivalent to regional demand in 2000. Figure 7 - 4 shows this same information, but includes line-losses. In all of its resource planning work, Council uses loads at the point of generation; this is to properly compare options on supply and demand side (efficiency or demand response).

Figure 7 - 3: Historical and Seventh Power Plan Electricity Demand (sales) Forecast Range (aMW)*



* Demand (sales) figures include electricity use by consumers and exclude transmission and distribution losses. Load figures are measured at the point of generation (busbar).

Figure 7 - 4: Historical and Seventh Northwest Power Plan Load Forecast (aMW) Including Line-Losses



Sector Level Load Forecast

The Seventh Power Plan forecasts loads to grow at an average annual rate of 0.6 to 1.1 percent during the 2015 through 2035 period. Table 7 - 3 shows the actual 2012 regional electricity loads and forecast future loads for selected years, as well as the corresponding annual growth rates. These load forecasts do not include any new conservation initiatives. Note that changes in sector level loads are shown as a range, reflecting the uncertainty inherent in forecasts. Average Annual Growth Rate (AAGR) is shown in the last column.

Table 7 - 3: Load Forecast By Sector (aMW)

Sector	2012	2015	2020	2035	Average Annual Growth Rate 2015-2035
Residential	8,313	8,339 – 8,375	8,100 – 8,400	8,100 – 9,300	-0.2% - 0.5%
Commercial	6,377	6,700 – 6,900	6,900 – 7,200	8,000 – 8,600	0% - 1.1%
Industrial	5,618	5,350 – 5,650	5,400 – 5,900	6,100 – 7,200	0.7% - 1.2%
Transportation	8	26 - 31	67-147	162 - 623	10% to 16%
Street lighting	348	351	354	361	0.1%

From 2015 to 2035, the residential sector electricity load is forecast to grow between negative 0.2 to positive 0.5 percent per year. On average this translates to an annual reduction in residential sector loads of about 14 average megawatts to an annual increase of about 50 average megawatts each year. Modest growth in the residential sector reflects substantial reductions in load due to federal standards, increased on-site solar PV generation, as well as slower growth in home electronics.

Commercial sector electricity loads are forecast to grow by 0.9 to 1.1 percent per year between 2015 and 2035. This translates to a commercial sector load increase from 6,700-6,900 average megawatts in 2015 to 8,000-8,600 average megawatts by 2035. The slower commercial sector load growth, compared to the Sixth Power Plan is due to the presence of federal standards, slower growth in new floor space, and greater efficiency in lighting technology, primarily from using solid state lighting (i.e., LEDs). On average, this sector adds 64 to 85 average megawatts per year to regional electricity loads.

Industrial sector loads are forecast to grow 0.7 to 1.3 percent annually. Industrial loads are forecast to grow from 5350-5650 average megawatts in 2015 to 6100-7200 average megawatts by 2035. This translates to 35-77 average megawatts per year. Industrial loads in the Northwest have been slow to return to levels experienced before the West Coast energy crisis. The resource-based industries (e.g. pulp and paper) are being replaced with high-tech industries. For example, one segment of the industrial sector that has experienced significant growth is that of custom data centers. Although these businesses do not manufacture a tangible product, they are typically classified as industrial customers because of the amount of electricity they use. The Council's estimates show that there are currently 350 to 450 average megawatts of connected load for these businesses. Loads from these data centers are forecast to increase to between 400 and 900 megawatts by 2035.

In the Seventh Power Plan, the direct service industry's (DSI) load was changed from the draft to final version of the Plan. In November 2015, Alcoa announced temporary closure of their smelting operations in the state of Washington. The DSI load which was assumed to be around 700-800 average megawatts for the forecast period post-2018 was lowered by about 400 aMW for the final plan. Although the portion of Alcoa's Wenatchee aluminum smelter that is served from non-Bonneville sources is not technically a DSI (it is not served by Bonneville), that load is included in the DSI category in the Seventh Power Plan to permit comparison with prior plans.

The transportation sector's electricity load is expected to grow substantially as the number of plug-in electric (all electric or hybrid electric) vehicles increases. The Council's Seventh Power Plan projects loads in this sector to increase from 8 average megawatts in 2015 to 160-620 average megawatts by 2035.

Future Trends for Plug-in Hybrid or All-Electric Vehicles

Concern for the environment and volatile gasoline prices have created great interest in electric vehicles (EVs), both all-electric and plug-in hybrids. The most recent data from the Environmental Protection Agency (EPA) show that annual sales increased from about 350 vehicles in December 2010 to sales of over 22,600 vehicles as of July 2015. This is significant given the financial crisis the U.S. auto industry went through during the recession. The number of EV branded vehicles increased from 2 in 2010 to 23 in 2014. Cumulatively, from 2010 through February of 2015, over 300,000 EVs were sold nationwide.

Average load from EVs is projected to increase from the current estimated 10 average megawatts in 2014 to between 160 and 650 average megawatts by 2035. Based on the currently observed hourly pattern of charging, most of the charging happens at night during off-peak (post-midnight) hours. Therefore, the impact of EV charging on off-peak loads is significantly higher than on-peak loads. Off-peak demand is forecast to be in the range of 250 to 1200 megawatts, while peak period demand for EV charging is forecast to be between 7 and 32 megawatts. Additional details/analysis on electric vehicles can be found in Appendix E.

Distributed Solar Photovoltaics

Distributed solar or “rooftop solar” using photovoltaic (PV) panels is a relatively new entry into the energy market in the Northwest. Deep declines in PV module prices, availability of third-party financing and other financial incentives have resulted in significant increases in the installation of these distributed generators during the past five years. The Council estimates that by 2015 there will be over 110 megawatts of Alternating Current (AC) nameplate capacity installed in the region, generating the equivalent of about 17 to 18 average megawatts of energy and providing about 18 megawatts of summer peak load reduction.[2] In the Seventh Power Plan, the Council has incorporated the impact of market-driven rooftop solar power generation into its long-term forecast model. Therefore, the load forecasts shown for each sector are net of the on-site generation from solar PV. The contribution to system average and system peak from solar PV installs is estimated taking into account coincident factors of mapped solar generation and system load.

To forecast market share for electricity generated from distributed solar systems, the Council developed an estimate of the relationship between the relative cost of system installs versus the retail cost of electricity. This relationship between inter-fuel competition between electricity and distributed solar PV was then used to forecast the future market share of distributed solar systems. The Council forecast of distributed solar PV adoption assumes a 53% reduction in cost between 2012 and 2030.[3] By 2035, the Council forecasts that 500 to 1,400 megawatts of solar PV systems will be installed in the region. On an annual basis, the energy generated from these distributed PV systems is forecast to reduce regional loads by 80 to 220 average megawatts. In addition, these distributed solar PV systems also reduce winter and summer peak loads. Summer peak impacts from distributed solar PV are forecast to be lower by as much as 600 megawatts by 2035.

To calculate the impact that distributed solar PV generation would have on system average and system peak loads, the Council used hourly solar PV generation profiles for 16 locations in the Northwest available from the National Renewable Energy Laboratory’s (NREL) *PV Watts* program. A more detailed discussion of rooftop solar PV generation appears in Appendix E- Demand Forecast, and the companion technical workbook showing year by year assumptions.

[2] For a more detailed discussion of sector-level sales and loads please see Appendix E.
[3] Appendix H contains additional discussion of the forecast decline in PV module costs.

A companion spreadsheet for Seventh Power Plan demand forecast data is available at the following link: http://www.nwcouncil.org/energy/powerplan/7/technical
(Regional and state level details on economic drivers, fuel prices, demand and load forecast)

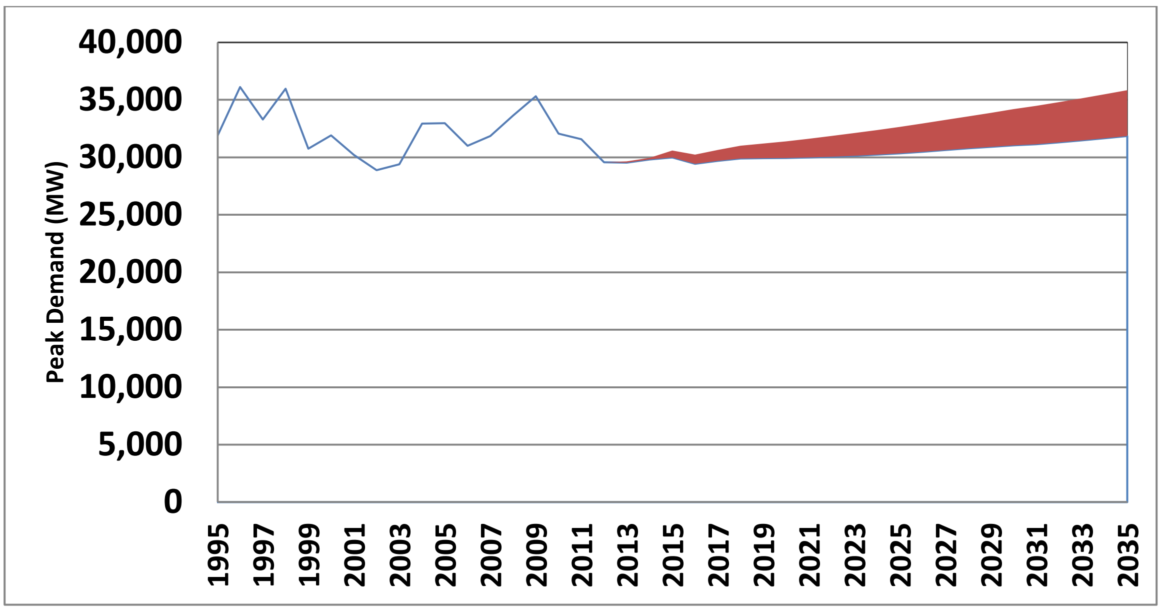
PEAK LOAD FORECAST

Peak Load

The regional peak load for power, which has historically occurred in winter, is expected to grow at an average annual growth rate of 0.3 to 0.8 percent from 30,000 to 31,000 megawatts in 2015 to 31,900-35,800 megawatts by 2035. Assuming historical normal temperatures, the region is expected to remain a winter-peaking system, although summer peaks are expected to grow faster than winter peaks, significantly narrowing the gap between summer-peak load and winter-peak load. By the end of the forecast period the difference between summer and winter peak is forecast to range from 1,000 to 2,000 megawatts. Summer peaks are projected to grow from 27,000 to 28,000 megawatts in 2015 to 30,500 to 33,800 megawatts in 2035.

The forecast for regional peak load assumes normal weather conditions. There are no assumptions regarding temperature changes incorporated in the Seventh Power Plan's load forecast. Climate change sensitivity analysis, discussed in Appendix M, projects that there could be an additional 4,000 megawatts of summer peak load added by 2035 due to climate change. Figure 7 - 5 shows estimated actual peak load for 1995-2012, as well as the forecasted peak load range for 2013-2035.

Figure 7 - 5: Historical and Forecast Regional Winter Peak Load (MW)



Alternative Load Forecast Concepts

Three different but related load forecasts are produced for use in the Council's resource planning process. The first of these forecasts is called a "price-effect" demand forecast, which is the forecast that has been presented up to this point. The price-effect forecast is the official demand forecast required by the Northwest Power Act.

The price-effect demand forecast reflects customers' choices in response to electricity and fuel prices and technology costs, without any new conservation resources. However, expected savings from existing and approved codes and standards are incorporated in the price-effect forecast, consequently reducing the forecast and removing the potential from the new conservation supply curves.

To eliminate double-counting the conservation potential, the load-forecasting model produces another long-term forecast, labeled Frozen-Efficiency forecast.

Frozen-Efficiency (FE) demand forecast, assumes that the efficiency level is fixed or frozen at the base year of the plan (in the case of the 7th Plan, base year is 2015). For example, if a new refrigerator in 2015 uses 300 kilowatt hours of electricity per year, in the FE forecast this level of consumption is held constant over the planning horizon. However, if there is a known federal standard that takes effect at a future point in time (e.g., 2022), which is expected to lower the electricity consumption of a new refrigerator to 250 kilowatt hours per year then post-2022 a new refrigerator's consumption is reduced to this new lower level in the FE demand forecast. In this way, the difference in consumption, 50 kilowatt hours, is treated as a reduction in demand rather than considered as a future conservation potential. This forecast approach attempts to eliminate the double-counting of conservation savings, since estimates of remaining conservation potential use the same baseline consumption as the demand forecast. That is, the frozen technical-efficiency levels are the conservation supply model's starting point. Frozen-efficiency load forecasts are inputs to the Regional Portfolio Model for use in resource strategy analysis.

Once the Council adopts a resource strategy for the Seventh Plan including regional conservation goals, a third demand forecast is produced. This forecast, referred to as the **Sales Forecast** is the Frozen Efficiency forecast net of cost-effective conservation and demand response resource savings contained in the plan's resource strategy. The level of demand response called for in the plan, which has the impact of lowering peak loads is shown in table 7-5.**.** The Sales Forecast represents the expected sales of electricity after all cost-effective conservation has been achieved[4]. It incorporates the effects of electricity prices and the cost-effective conservation resources that are selected by the Regional Portfolio Model. The sales forecast captures both price-effects and potential "take-back" effects (increased use in response to the lower electricity bills as efficiency increases). It should be pointed out that although the label for this forecast is "sales," it is presented at both the consumer's meter and at the generator site by including transmission and distribution system losses.

The difference between the Price-Effect and Frozen-Efficiency forecasts is relatively small. The Frozen-Efficiency forecast is typically slightly higher than the Price-Effect forecast. For the Seventh Power Plan the two forecasts differ by 60 to 600 average megawatts by 2035 depending on the underlying economic growth scenario. The following table and graphs present a comparison of these forecasts.

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[4] The "sales" forecast, as well as price-effect and frozen efficiency, can be measured at a consumer or generator site (which would include transmission and distribution losses). Demand is measured at the customer site while load is measured at the generator site.

Table 7 - 4: Range of Alternative Load Forecasts (as measured at the point of generation)

	Forecast	Scenario	2016	2021	2026	2031	2035	AAGR 2016-2035
Energy (aMW)	Price-effect	Low	20,100	20,680	21,205	21,829	22,482	0.56%
Energy (aMW)	Price-effect	High	20,743	21,960	23,157	24,498	25,638	1.06%
Energy (aMW)	FE	Low	20,097	20,682	21,219	21,866	22,542	0.58%
Energy (aMW)	FE	High	20,752	22,031	23,341	24,858	26,185	1.17%
Energy (aMW)	Sales	Low	19,242	18,857	17,775	17,427	17,921	-0.36%
Energy (aMW)	Sales	High	19,891	20,157	19,737	20,116	21,220	0.32%
Winter Peak (MW)	Price-effect	Low	29,438	29,990	30,482	31,139	31,854	0.40%
Winter Peak (MW)	Price-effect	High	30,237	31,617	32,946	34,481	35,843	0.85%
Winter Peak (MW)	FE	Low	29,436	30,000	30,518	31,221	31,983	0.42%
Winter Peak (MW)	FE	High	30,252	31,734	33,246	35,057	36,708	0.97%
Winter Peak (MW)	Sales	Low	28,815	27,152	24,980	23,782	23,847	-0.94%
Winter Peak (MW)	Sales	High	29,608	27,781	26,322	25,433	26,065	-0.64%
Summer Peak (MW)	Price-effect	Low	26,484	27,285	28,179	29,311	30,494	0.71%
Summer Peak (MW)	Price-effect	High	27,364	28,846	30,384	32,187	33,805	1.06%
Summer Peak (MW)	FE	Low	26,478	27,278	28,188	29,346	30,553	0.72%
Summer Peak (MW)	FE	High	27,382	28,980	30,737	32,876	34,849	1.21%
Summer Peak (MW)	Sales	Low	25,805	24,781	23,839	23,957	24,579	-0.24%
Summer Peak (MW)	Sales	High	26,676	25,458	26,661	25,502	26,678	0.00%

Impact of Demand Response on System Peak

Up to this point in our discussions of alternative load forecasts we have focused on the impact of energy efficiency programs on loads. The Seventh Power Plan also calls on regional utilities to acquire demand response resources, which can be called upon during peak periods. Forecasted summer and winter peak loads under the "Sales" scenario are expected to be reduced by the target amount of demand response shown in the table below.

Table 7 - 5: Range of Demand Response Resource Expected to be used (MW)

	Forecast	Scenario	2016	2021	2026	2031	2035
Winter	Sales	Low	501	906	906	940	1347
Winter	Sales	High	1002	1852	1947	2440	3036
Summer	Sales	Low	468	827	827	860	1282
Summer	Sales	High	468	1728	1838	2380	2932

Figure 7 - 6: Price-Effects Forecast Range– Energy

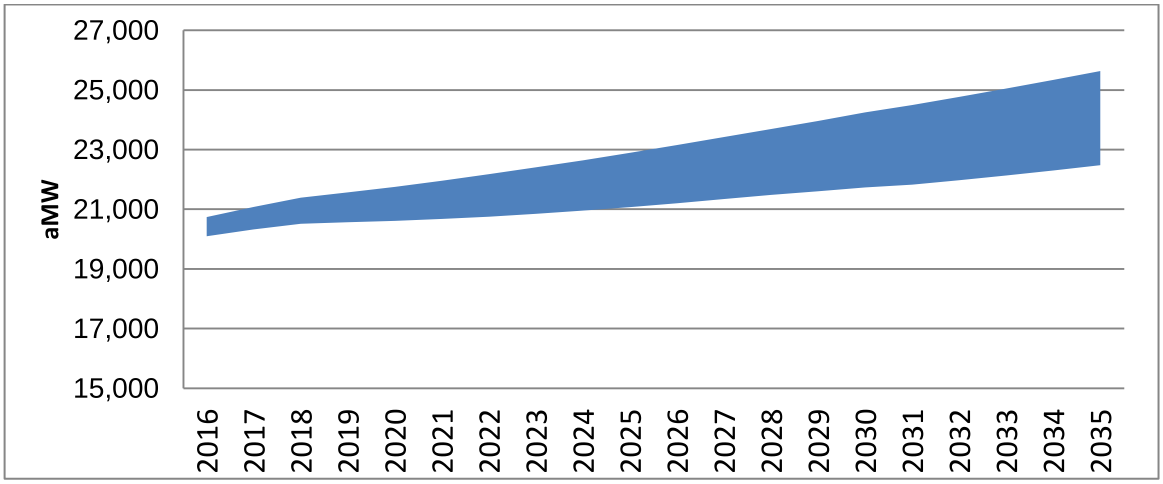


Figure 7 - 7: Frozen- Efficiency Forecast Range– Energy

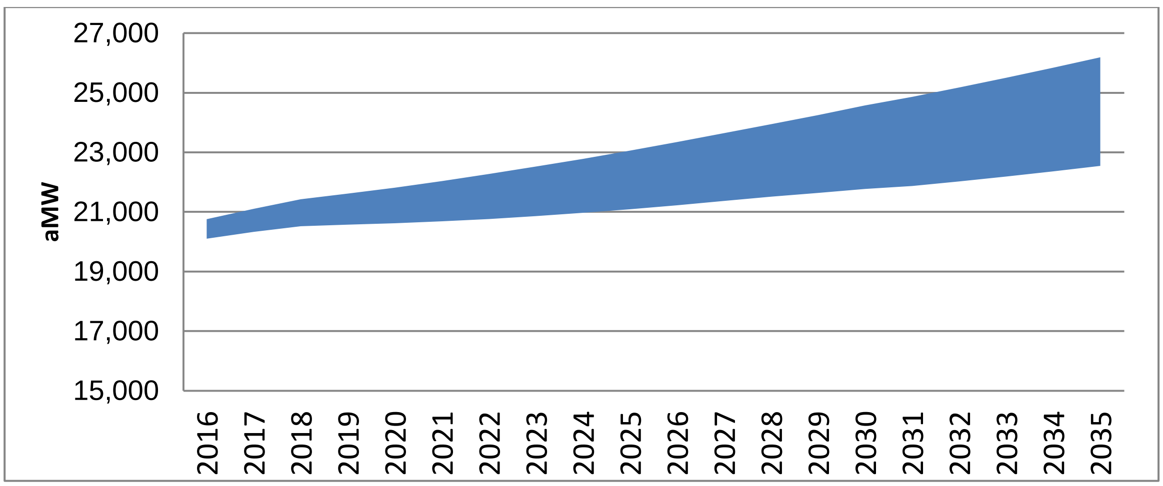


Figure 7 - 8: Sales (Net Load After Conservation) Forecast Range – Energy

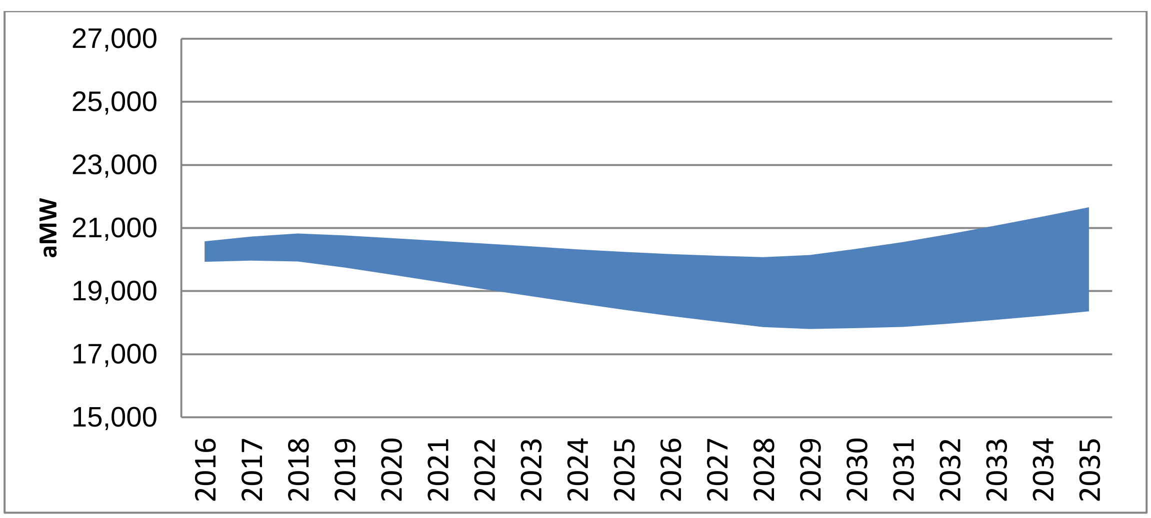


Figure 7 - 9: Price-Effects Forecast Range - Winter Peak

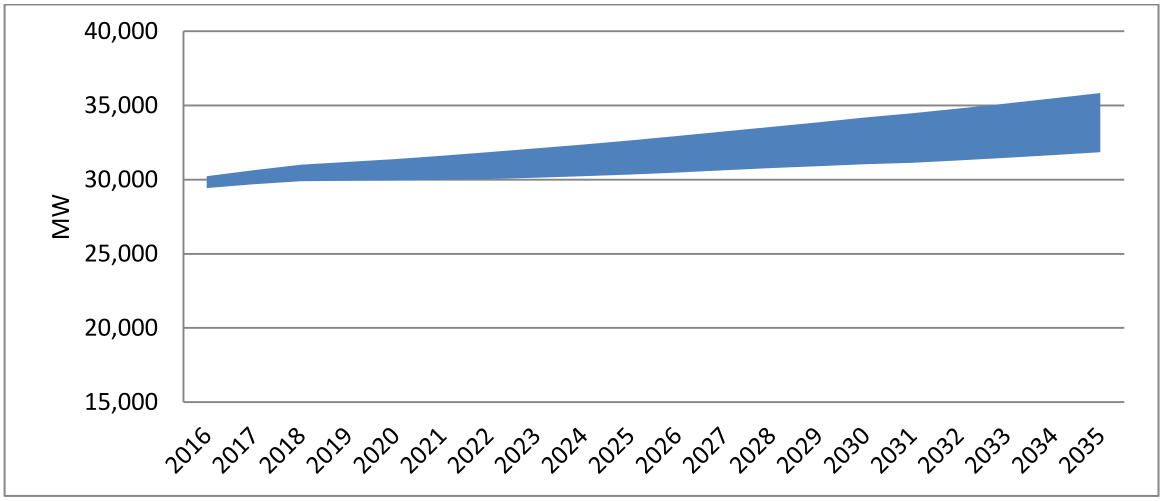


Figure 7 - 10: Frozen- Efficiency Forecast Range – Winter Peak

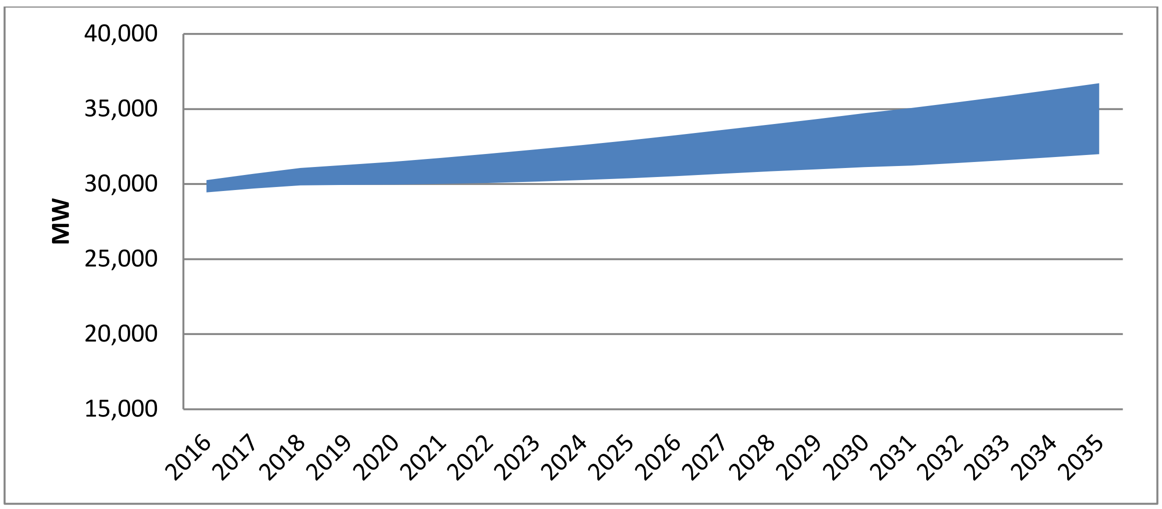


Figure 7 - 11: Sales (Net Load After Conservation and DR) Forecast Range – Winter Peak

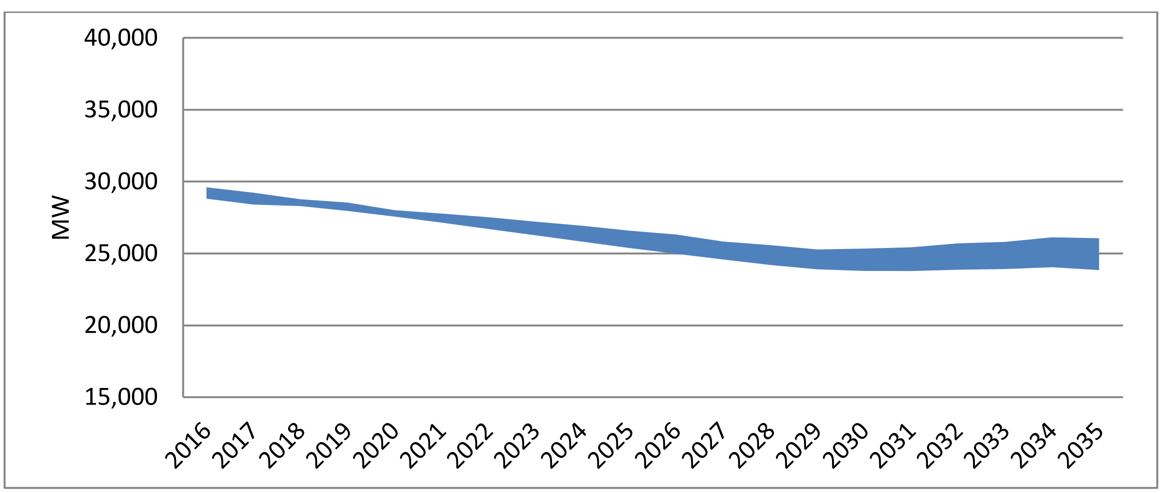


Figure 7 - 12: Price-Effects Forecast Range – Summer Peak MW

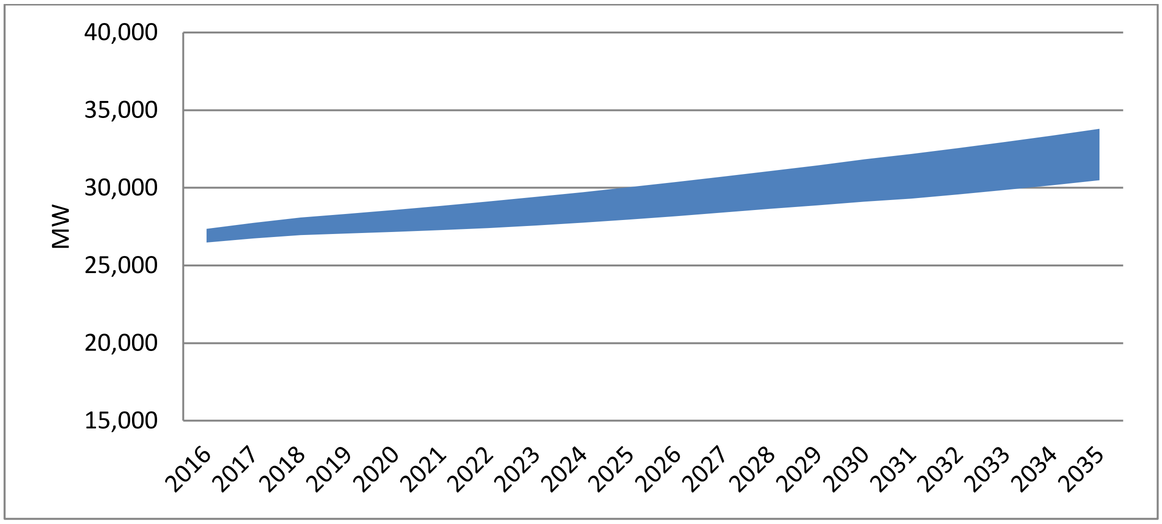


Figure 7 - 13: Frozen- Efficiency Forecast Range – Summer Peak

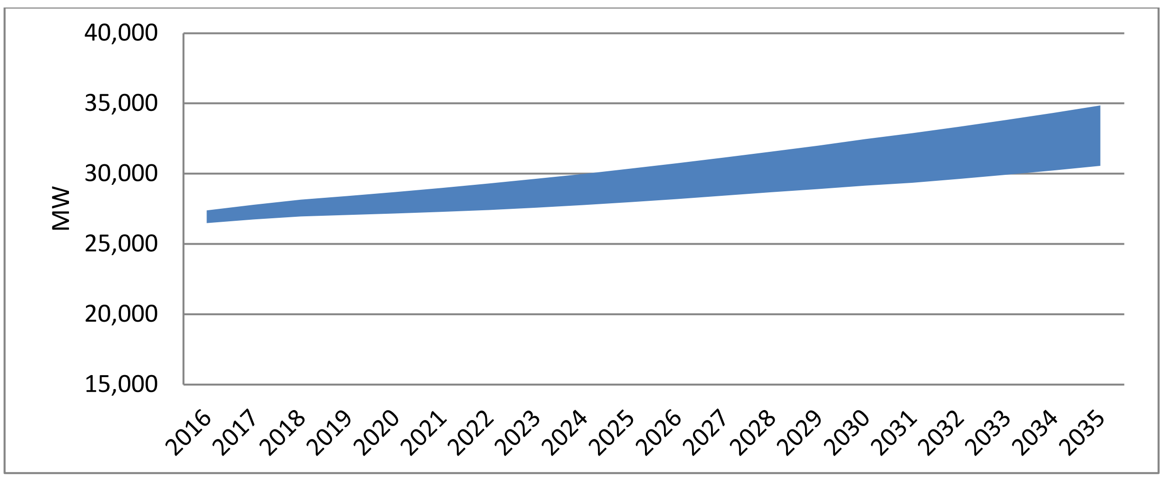
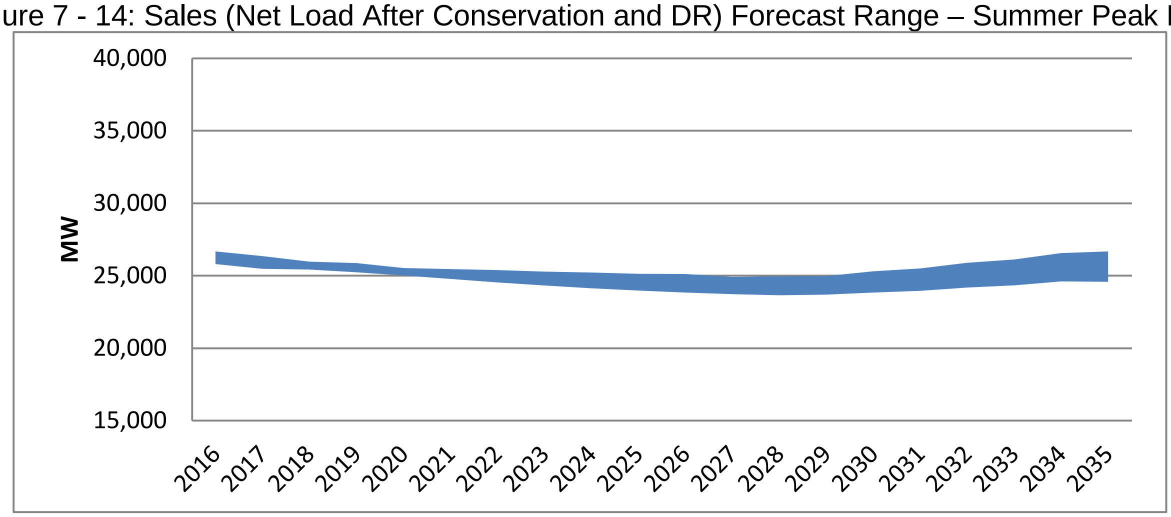


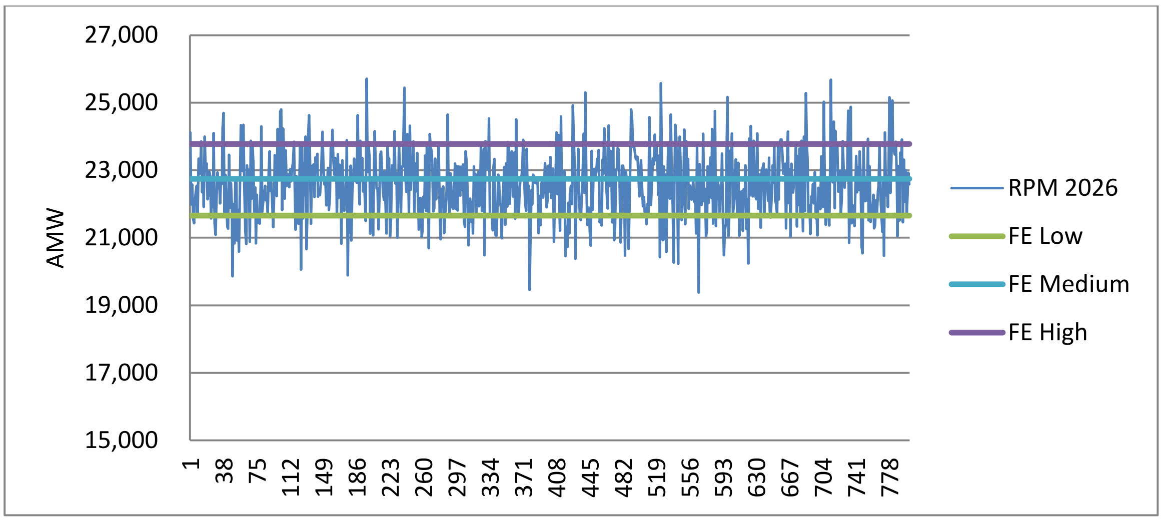
Figure 7 - 14: Sales (Net Load After Conservation and DR) Forecast Range – Summer Peak MW



Regional Portfolio Model (RPM) Loads

While the Council develops three types of long-term forecasts, the quarterly Frozen-Efficiency load forecast is the forecast used in the RPM for developing alternative future load-growth paths. The RPM takes the Frozen-Efficiency load forecast and introduces short-term excursions that simulate such events as business and energy commodity price cycles and load variations that could be caused by weather events. Figure 7 - 15 shows the 800 future load paths evaluated in the RPM for a year 2026. As can be observed, in some futures RPM loads are above the Frozen Efficiency forecast range for 2026 and in some futures RPM loads are below the Frozen Efficiency forecast range.

Figure 7 - 15: RPM Comparison of 800 future load paths and range of loads from Frozen Efficiency Load Forecast for 2026



A more refined method for estimating single-hour peak values was created to provide the RPM with expected hourly peak for each quarter. This methodology consists of using the average quarterly weather-normalized energy from the long-term model and the hourly temperature sensitive load multiplier from the Council's short-term model and running a Monte Carlo simulation on the loads under the weather conditions of the past 86 years (1929-2013) to create an expected hourly load for each quarter. The process used to convert the Frozen Efficiency forecast to the specific 800 futures used in the RPM is discussed in more detail in Chapter 15 and in Appendix L.

Direct Use of Natural Gas

As part of developing the Seventh Power Plan, the Council evaluated whether or not a direct intervention in the markets where natural gas is thermodynamically or economically more efficient, would be necessary. In Appendix N of this plan, the Council presents findings on the economics of direct use of natural gas to displace electrical residential space and/or water heating. The Council performed an updated analysis (discussed in Appendix N) that focused on one of the eight market segments identified in the Council's 2012 assessment as providing both consumers and the region with economic benefits through conversion from electricity to natural gas.

The updated analysis estimates the share of single family homes with electric water heating and natural gas space heating that would find economic benefits by conversion to natural gas water heating when their existing water heater requires replacement. Two estimates were made. The first, which is comparable to the Council's 2012 analysis, assumes that in all cases the most economical (i.e. lowest life-cycle cost) water heating fuel type would be selected. The second case, assumes that consumers would not always select the lowest cost option due to other "non-economic" barriers to conversion. This case found that fewer, but still a significant share, of households would alter their existing water heating fuel. Moreover, based on historical fuel selection trends, it appears that natural gas continues to gain space and water heating market share while electricity's share of these end uses continues to decrease. The Council's analysis concluded that market mechanisms are operating efficiently and that no market intervention is needed. Further details on the Seventh Power Plan Direct Use of Natural Gas can be found in Appendix N.

CHAPTER 8: ELECTRICITY AND FUEL PRICE FORECASTS

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List of Figures and Tables

KEY FINDINGS

Prices for wholesale electricity at the Mid-Columbia trading hub remain relatively low, reflecting the abundance of low-variable cost generation from hydropower and wind, as well as continued low natural gas fuel prices. The average wholesale electricity price in 2014 was around $30 per megawatt-hour, and in 2015 had dipped to around $23 per megawatt-hour. By 2035, prices are forecast to range from $25 to $67 per megawatt-hour in 2012 dollars. The upper and lower bounds for the forecast wholesale electricity price were set by the associated high and low natural gas price forecast. Although the dominant generating resource in the region is hydropower, natural gas fired plants are often the marginal generating unit for any given hour. Therefore, natural gas prices exert a strong influence on the wholesale electricity price, making the natural gas price forecast a key input. The region depends on externally-sourced gas supplies from Western Canada and the U.S. Rocky Mountain region.

Prices for natural gas have dropped significantly since reaching a high in 2008, and are expected to remain relatively low moving forward. Historically, natural gas prices have been volatile and so a range of forecasts was developed to capture most potential futures. The low range for prices starts at $2.64 per million British Thermal Units (mmBtu) at Henry Hub in 2015, and increases in real dollar terms to $3.60 per mmBtu by 2035. This low range case represents a future with slow economic growth, low gas demand, and robust supplies. The high range of the forecast climbs to $10 per mmBtu by 2035, which represents a future with high economic growth, high demand for natural gas, and a limited gas supply. It should be noted that the higher price range for natural gas implicitly incorporates potential regulatory compliance costs for reducing methane emissions.

The Regional Portfolio Model (RPM) uses both natural gas and wholesale electricity prices as the basis for creating 800 futures. Each future has a unique series of natural gas and electricity prices through the 20-year planning period. These price series include excursions below and above the price ranges shown here for both electricity and natural gas to reflect the volatility and uncertainty in future commodity prices. See Chapter 15 and Appendix L for discussions of how these natural gas and wholesale electricity price forecasts are translated into the 800 futures used in the RPM.

WHOLESALE ELECTRICITY PRICES

The Council periodically updates a 20-year forecast of electric power prices, representing the future price of electricity traded on the wholesale spot market at the Mid-Columbia trading hub. The current forecast is an input to the Regional Portfolio Model (RPM). It provides the benchmark quarterly power price under average fuel price, hydropower generation, and demand conditions. A more complete description of the development of the electricity price forecast and results is provided in Appendix B.

The forecast used for the Seventh Power Plan is an update to the Council's 2013 forecast.[1] There was little change in prices from the previous forecast cycle. A few key findings from the current forecast cycle include:

- Wholesale electricity prices at the Mid-Columbia trading hub remain relatively low, reflecting low-variable cost of ample hydropower and wind generation in the region, continued low price of natural gas, and slow demand growth.
- Natural gas prices exert a strong influence on electricity prices, both in the forecast and historically. As a result, the forecast span of electricity prices was based on high and low gas price forecasts.

The Council uses the AURORAxmp Electricity Market Model, as provided by EPIS Inc. to develop the wholesale electricity price forecast. This is an hourly dispatch model which calculates an electricity price based on the variable cost of the marginal generating unit. The key price drivers include:

- Load at generation – electricity demand net of energy efficiency and inclusive of line loss[2]
- Fuel prices delivered to generation
- Existing and new generation capabilities and costs
- Renewable Portfolio Standards driving resource builds
- Greenhouse gas emission policies

There are two steps in the modeling process that produces the forecast. First, a congruent set of assumptions and inputs are established and a long-term resource optimization model run is performed. This run determines the mix of generation resources that are available over the planning horizon, and may include new resource builds for capacity and energy, as well as retirements. A second run is then performed to determine the hourly dispatch using those resources, producing an hourly price for each pricing zone. Low-variable cost resources such as hydropower and wind are dispatched first, followed by efficient or otherwise low-cost thermal resources such as gas or coal. As load increases, less efficient and/or more expensive resources are dispatched.

In the Council's configuration of the model, electricity prices are calculated for 16 zones which comprise the entire Western Electricity Coordinating Council (WECC) area. The Northwest region is broken into three zones:

1. PNWW – Western Oregon and Washington
2. PNWE – Eastern Oregon and Washington, along with Northern Idaho and Western Montana
3. Southern Idaho

The PNWE zone serves as a proxy for the Mid-Columbia trading hub.

[1] http://www.nwcouncil.org/media/6829307/wholesaleelectricity.pdf

[2] The Council adjusts retail sales (and energy savings) to load at the generator by adjusting for transmission and distribution system losses. For the Seventh Power Plan, transmission system losses were assumed to be 2.3 percent and distribution system losses were assumed to be 4.7 percent.

Generating plants that physically sit outside the Northwest but serve load within the region are counted as in-region resources. Average hydropower and wind generating conditions are used for each year of the 20 year planning horizon. Forecasts for load, fuel prices, and Renewable Portfolio Standards (RPS) are input to the model. Renewable resource development associated with RPS requirements tends to dampen wholesale electricity prices because their low operating costs are not dependent on fuel purchases.

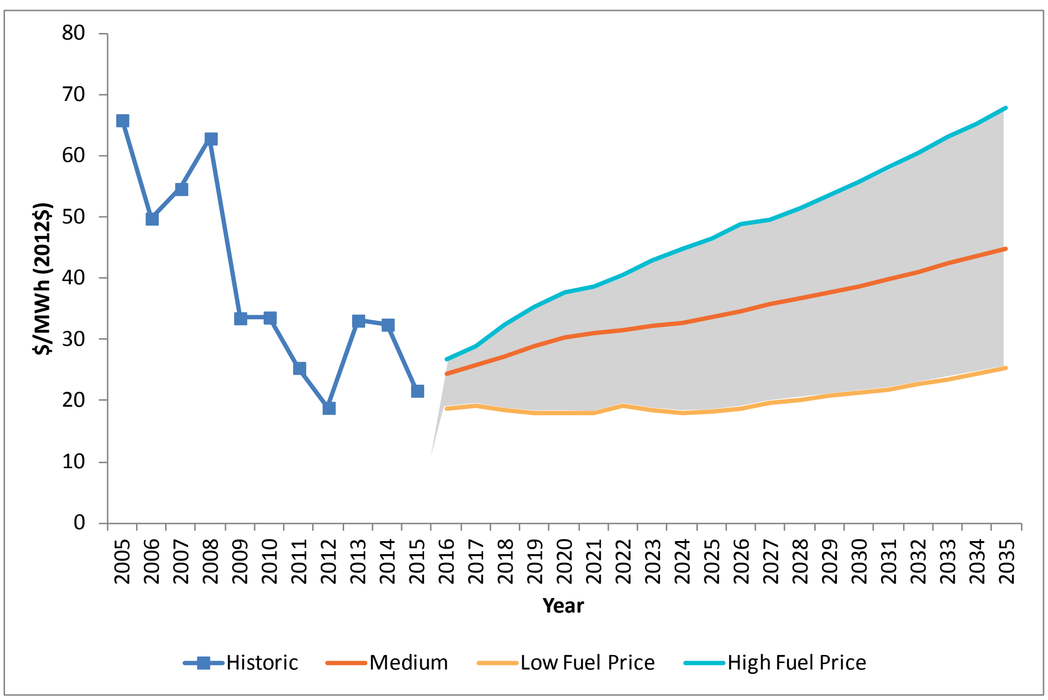
Pricing policies associated with carbon dioxide (CO_2) emissions can influence wholesale electricity prices. In this forecast cycle, the British Columbia carbon tax, initiated in 2008, was included, as was an estimate of the CO_2 prices ($ per ton CO_2) associated with California's Cap and Trade program. These policies have the effect of increasing the dispatch cost for CO_2-emitting resources within British Columbia and California and for electricity imported to those regions.

Five primary forecast cases were defined for this forecast cycle and run through the AURORAxmp pricing model:

1. Medium - medium forecasts for electricity demand and fuel price
2. High Demand - high electricity demand forecast
3. Low Demand - low electricity demand forecast
4. High Fuel - high fuel-price forecast (primarily natural gas)
5. Low Fuel - low fuel-price forecast (primarily natural gas)

The forecast results are summarized in Figure 8 - 1, along with recent historic pricing at the Mid-Columbia hub. The upper and lower bounds which define the range of electricity prices over the planning horizon are set by the high and low fuel-price forecast cases.

Figure 8 - 1: Historic and Forecast Annual Wholesale Electricity Price at Mid-C



The input assumptions for demand growth and fuel price, along with electric price results are summarized in Table 8 - 1.

Table 8 - 1: Electricity Price Forecast Assumptions and Results[1]

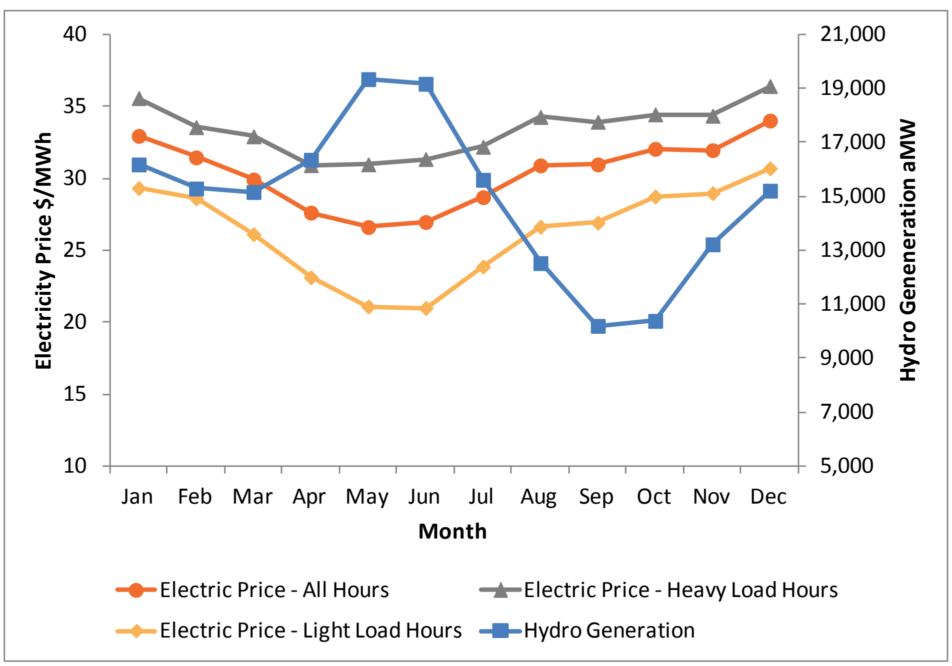
Forecast Case	Average Annual Demand Growth %	Levelized Natural Gas Price ($/mmBtu)	Levelized Electricity Price at Mid C ($/MWh)
Medium	0.38	3.87	33.34
High Demand	1.05	3.87	34.18
Low Demand	0.23	3.87	31.73
High Fuel	0.38	5.80	44.77
Low Fuel	0.38	2.21	19.65

[1]Note

- Time horizon 2016 – 2035
- Demand compiled from 3-zone region that comprises the Northwest and is net of conservation (Sixth Plan level)
- All costs in 2012 dollars
- 4 percent discount rate applied to levelized costs

Electricity prices exhibit a seasonal pattern, reflecting the Northwest's unique demand and generation characteristics. Figure 8 - 2 shows monthly price results for the medium forecast case for a single year (2020), along with the monthly hydropower generation in the region. The chart illustrates the typical seasonal price pattern at the Mid-Columbia trading hub: high prices in the winter when demand for heating is high, and low prices in the late spring/early summer due to low demand, abundant hydro run-off, and strong wind generation. Load can be divided into two time periods. Heavy load hours are defined as the morning through evening hours when demand is highest, while light load hours include the later night time and early morning hours.

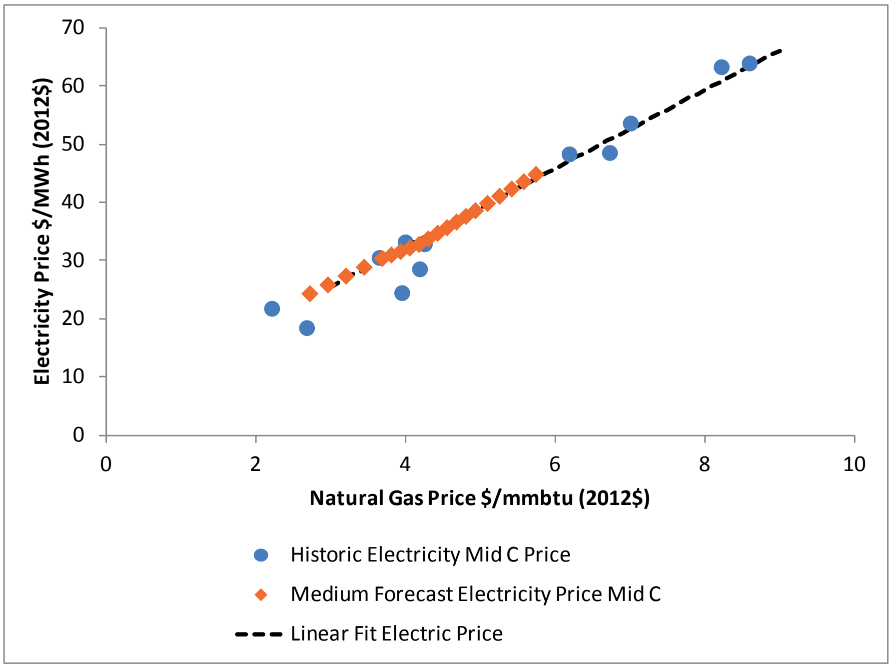
Figure 8 - 2: Monthly Electricity Prices and Hydro Generation in year 2020



In addition to hydropower, there are four other primary sources of power in the Northwest: coal, natural gas, nuclear, and wind. For a typical year, hydropower generation supplies around 60 percent of the region's overall generation. This low-variable cost source of power, along with wind generation and energy efficiency has kept wholesale electricity prices low. Though hydropower is the dominant source of generation in the region, the price of natural gas strongly influences the electricity price. This is because natural-gas fired power plants are often the marginal generating unit which set prices, so the variable cost of fuel for these power plants influences the electricity price. The region depends on external sources for natural gas, with approximately 75 percent coming from the Western Canadian Sedimentary Basin and the rest from the U.S. Rocky Mountain region.

Figure 8 - 3 shows the relationship between the wholesale electricity price and the natural gas price. The annual natural gas price is shown on the x-axis, and the related annual electricity price is on the y-axis. The relationship holds in historic conditions as well as forecast conditions.

Figure 8 - 3: Relationship of Electricity Price to Natural Gas Price

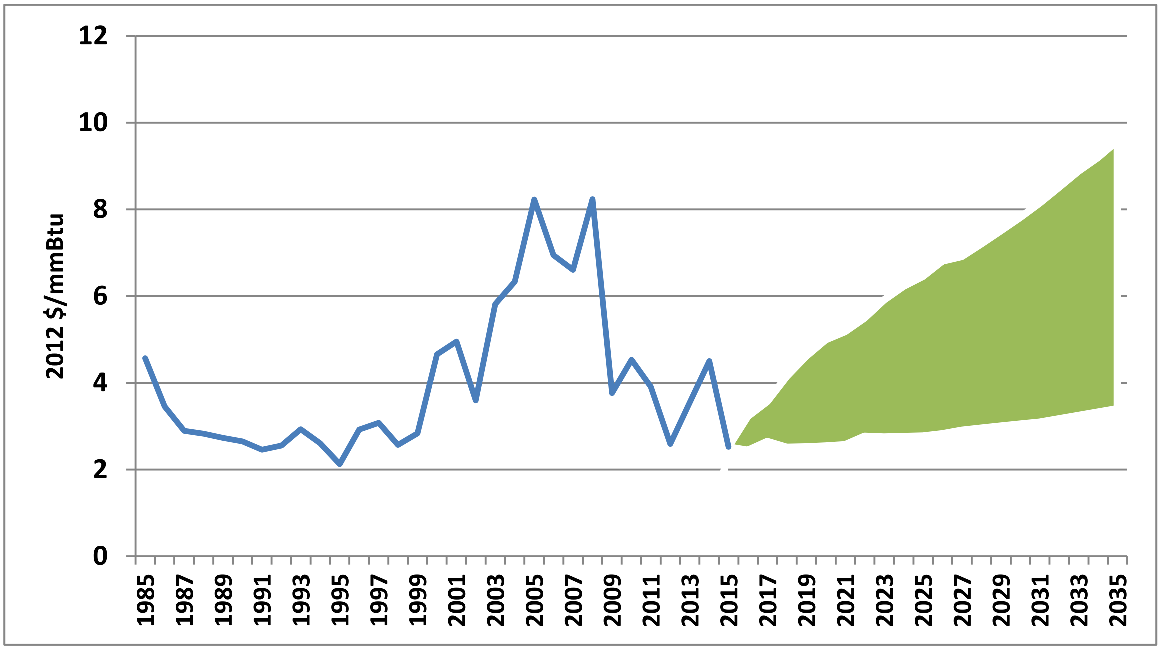


As a result of this linear relationship, the bound for the wholesale electricity price forecast was defined by the high and low fuel-price forecasts. Future bounds with new gas prices could be defined by the linear fit relating electricity price to natural gas price.

Other Fuel Price Forecasts - U.S. Natural Gas Commodity Prices

Natural gas prices are a key fuel price input in determining future electricity prices. Factors determining the future price of natural gas are supply and demand for natural gas. The regional price for natural gas is influenced by the national markets in the United States and Canada. The history of natural gas prices reflects changing supply and demand conditions. Figure 8 - 4 shows the range of U.S. wellhead natural gas price forecasts proposed for the Seventh Power Plan. As shown in the graph, natural gas prices nearly doubled between 2000 and 2008. Since the high in 2008, prices have continued to decline.

Figure 8 - 4: U.S. Wellhead Natural Gas Price Forecast Range 2012$/mmBtu



The low forecast shows prices that range from $ 2.45 per mmBtu in 2016 to $3.40 per mmBtu by 2035 under ample supplies and slow recovery in demand. The high forecast shows prices that range from $3.23 per mmBtu in 2016 to $9.58 per mmBtu in 2035 (in constant 2012$). These prices represent the range of current expectations as expressed by the Council's Natural Gas Advisory Committee. Please note that during the resource planning analysis, the RPM model includes short-term excursions below and above the price range shown here.

The high and low forecasts are intended to be extreme future price variations from today's relatively consistent market. The high case prices increase to nearly $10 per mmBtu by 2035. The Council's forecasts assume that more rapid world economic growth will lead to higher energy prices, even though short-term effects of a rapid price increase can adversely influence the economy. For long-term trend analysis, the stress on prices from an increased need to expand energy supplies is considered the dominant relationship. The high natural gas price scenario assumes rapid world economic growth. This scenario might be consistent with very high oil prices, high environmental concerns that limit use of coal, limited development of world liquefied natural gas (LNG) capacity, and slower improvements in drilling and exploration technology, combined with the high cost of other commodities and labor necessary for natural gas development. It is a world in which there are limited alternative sources of energy and opportunities for demand reductions.

The low case assumes slow world economic growth which reduces the pressure on energy supplies. It is a future in which world supplies of natural gas are made available through aggressive development of LNG capacity, favorable nonconventional supplies (an example of non-conventional natural gas source would be natural gas produced through fracking of source rock) and the technologies to develop them, and low world oil prices providing an alternative to natural gas use. The low case would also be consistent with a scenario of more rapid development of renewable electric generating technologies, thus reducing demand for natural gas. In this case, the normal increases in natural gas use in response to lower prices would be limited by aggressive carbon-control policies. It is a world with substantial progress in efficiency and renewable technologies, combined with more stable conditions in the Middle East and other oil and natural gas producing areas.

In reality, prices may at various times in the future resemble any in the forecast range. Such cycles in natural gas prices, as well as shorter-term volatility, are captured in the Council's Regional Portfolio Model. For a more detailed year-by-year forecast of natural gas, oil, and coal prices, please see Appendix C and the companion workbook from the Council's website.

In December 2015, the Council updated its July 2014 forecast of natural gas prices. For updated values please see the 7th plan technical workbook:

Companion Spreadsheet for 7th Plan with Demand Forecast Data including - Regional and state level details on economic drivers, fuel prices, demand and load forecast - available from following link: http://www.nwcouncil.org/energy/powerplan/7/technical

CHAPTER 9: EXISTING RESOURCES AND RETIREMENTS

Contents

List of Figures and Tables

KEY FINDINGS

Over the course of the Council's three and a half decades of existence, the Northwest power supply has seen some dramatic changes. The Council was created, in part, because of a fear in the late 1970s that regional demand for electricity would quickly outgain the power supply's capability. That did not turn out to be the case and the Council's first power plan was developed to address a short-term generating surplus instead of the perceived deficit.

During the late 1980s and into the 1990s, the electric industry was convinced that the "market" would incentivize capital development of generating resources. This also did not turn out to be the case and very little generating capability was added during the 1990s. By 2001, due to the failure of the California market and the second driest year on record in the Northwest, the region faced a severe energy crisis. It survived but only by securing very expensive temporary generating capability and, most dramatically, paying to curtail service to aluminum smelters – all of which lead to significantly increased electricity rates.

The years between 2001 and 2005 saw increased activity in resource development and by the Council's Sixth Power Plan, the region was more or less again in a load-resource balance. This short history of the region's power supply illustrates the difficulties planners have in forecasting future needs and subsequently developing proper strategies to cover potential changes in those future needs.

Today the hydroelectric system remains the cornerstone of the Northwest's power supply, providing about two-thirds of the region's energy, on average. Over the last five years, a larger share of its generating capability has been allocated to providing within-hour balancing reserves, thereby reducing what can be deployed to meet firm load. This is a direct result of the high rate of wind resource development in the region since 2010.

One of the Council's key accomplishments over the last 35 years has been its support for the implementation of nearly 5,800 average megawatts of energy efficiency – equivalent to over 15 percent of the region's firm energy generating capability. Over the past five years, the region has achieved just over 1,500 average megawatts of energy efficiency savings, exceeding the Sixth Power Plan's five year goal of 1,200 average megawatts from 2010 to 2014.

As mentioned above, the region has seen a very rapid development of wind generation, with roughly 8,700 megawatts of wind capacity built over the last ten years – including about 2,000 megawatts installed in 2012 alone. This development was prompted in large part by renewable portfolio standards adopted in three of the four Northwest states (Washington, Montana, Oregon). In Idaho, the Public Utilities Regulatory Policy Act (PURPA) has also played a major role in wind development. It appears, however, that the rapid development of wind seen over the past ten years is likely to slow down over the next five-to-ten year period.

Over the past five years, about 520 megawatts of new gas-fired generating capability was added, with another 440 megawatts or so expected to be completed by 2017. During the same period, TransAlta's Big Hanaford combined-cycle gas-fired power plant and the Elwha and Condit small hydroelectric power plants were all retired. PPL Montana announced the permanent retirement of its J.E. Corette coal plant scheduled for late 2015. In 2020, Portland General Electric plans to cease coal-fired generation at Boardman and TransAlta will retire one of its units of its Centralia coal plant in 2020 and the second unit in 2025. NV Energy has announced the retirement of the North Valmy coal plant, which is co-owned by Idaho Power Company, scheduled for 2025.

Political pressure to decrease generation from carbon-producing resources has prompted development of more carbon-free resources and efficiency measures. One of the challenges for the Council's plan is to identify strategies to maintain an adequate, efficient, economic, and reliable power supply in a future with increasing shares of variable resources and smaller more widely distributed sources of energy supply.

THE PACIFIC NORTHWEST POWER SUPPLY

Existing Generating Resources

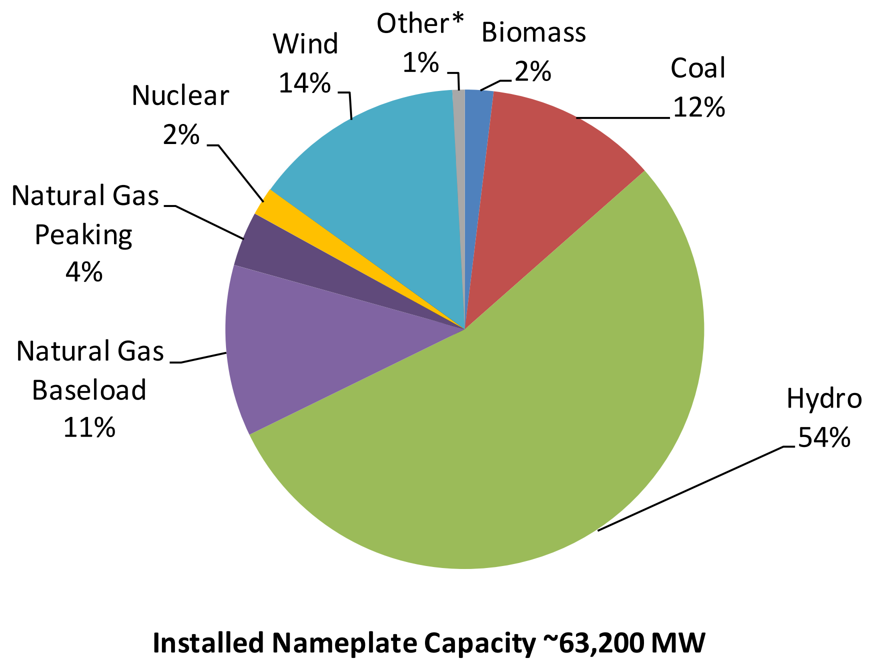
The 2016 regional power supply is still dominated by the hydroelectric system, although its share of total generating capability has decreased since 1980, mostly due to the addition of a significant amount of non-hydroelectric resources. However, during that same period, hydroelectric generating capability has also been reduced because of increasing operating constraints to benefit fish and wildlife and because more of its capability has been allocated toward providing balancing reserves to cover the growing number of wind turbines.

Figure 9 - 1 shows the breakdown of the region's existing generating resources by type, as a percentage of total installed nameplate capacity. Second to hydroelectric capacity, which contributes 54 percent of the total, gas-fired resources provide about 15 percent of the total, with peaking units contributing about 4 percent and base-loaded units making up the other 11 percent. Wind generation is the next largest capacity component with 14 percent of the 63,200 megawatt total. Coal generation comes next providing 12 percent of the total installed nameplate capacity.

Unfortunately, characterizing each resource type's contribution based on nameplate capacity can be misleading because nameplate capacity is not always a good indicator of useable capacity. In particular, for both hydroelectric and wind resources, nameplate capacity is not an accurate indicator of peaking capability. For example, only five percent of Northwest wind resource nameplate capacity is assumed when analyzing plans to meet future peaking needs. Thus, on a firm capacity basis, wind only provides about one percent of the total system firm peaking capability.[1] Hydroelectric peaking capability is also much smaller than its nameplate capacity. This is because most hydroelectric facilities in the region have limited storage behind their reservoirs. Moreover, the peaking capability of the hydroelectric system depends on the duration of the peak event – the longer the duration, the smaller the peaking capability. For example, the region's hydroelectric system's nameplate capacity is about 33,000 megawatts but it can only produce about 26,000 megawatts of sustained peak over a two-hour period. Its four-hour peaking capability drops to about 24,000 megawatts and over ten hours, it can only provide about 19,000 megawatts of firm capacity.

[1] Firm peaking capability refers to an amount of generating capacity (in megawatts) that can be dispatched with a high level of confidence during peak demand hours.

Figure 9 - 1: Pacific Northwest Electricity Power Supply – Installed Nameplate Capacity



Located in Power Act Region or contracted to PNW loads; WECC; In-service, under construction, standby or idle
Includes PacifiCorp WY wind plants
*Other - Geothermal, Petroleum, Solar

A better assessment of how much each resource contributes to meet Northwest loads is to compare each resource's energy generating capability with that of the entire power supply. Figure 9 - 2 shows the breakdown by resource for average energy generating capability.

In 1983 the hydroelectric system made up 78 percent of the region's firm energy generating capability (12,350 average megawatts of hydroelectric compared to 3,563 average megawatts of thermal).[2] Today the hydroelectric system's share of the regional total is much smaller. Compared to 78 percent in 1983, hydroelectric generation now makes up about 40 percent of the total system firm energy generating capability (11,600 average megawatts of hydroelectric to about 18,500 average megawatts of thermal, wind, and solar). But firm hydroelectric generation is based on the driest period on record (critical hydro) due to its low storage-to-runoff-volume ratio[3] and other factors.

[2] The First Northwest Conservation and Electric Power Plan, 1983, Chapter 6
[3] The U.S. portion of reservoirs in the Columbia River Basin can only store about 15 percent of the annual average river volume runoff.

Figure 9 - 2 shows average hydroelectric generation, which makes up about 47 percent of the total power supply's energy generating capability.

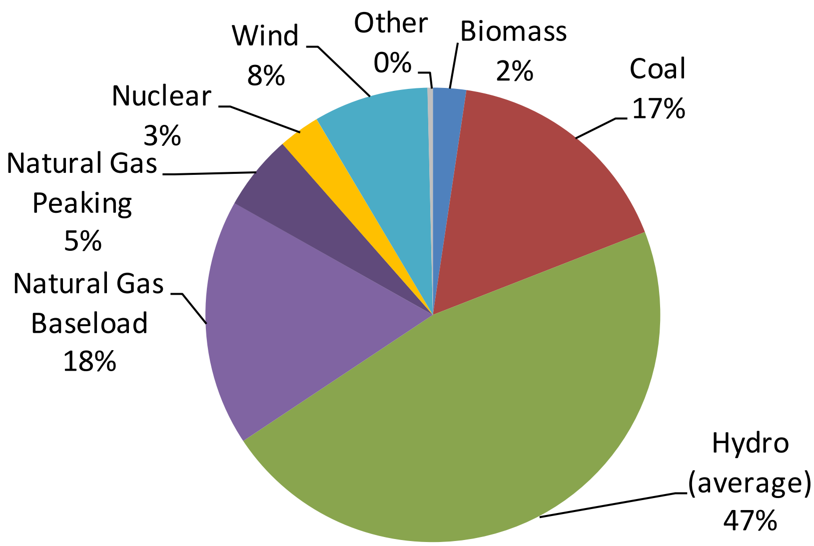
Following hydroelectric generation, the second largest source of energy generating capability is natural gas-fired generation, which provides about 23 percent of the total (with combined-cycle turbines at 18 percent and simple-cycle turbines and reciprocating engines at 5 percent). Large central station coal plants, located in Montana, Wyoming, and Nevada, represent the region's third largest energy resource comprising about 17 percent of the total. As described below, coal's share of the total will diminish over the next decade through announced retirements.

In contrast to the decline in coal generating capability, the past decade has seen a very rapid development of wind generation. Wind now comprises about 8 percent of the region's electricity supply. This development was prompted by renewable portfolio standards adopted in three of the four Northwest states. It appears, however, that the rapid development of wind is likely to slow down over the next five year period due to the expiration of incentives and low load growth.

The region has a single operating nuclear plant, Columbia Generating Station, which contributes about 3 percent to the energy supply. The existing regional power supply and its capabilities are described in detail in the Council's Generating Resources Database.[4]

[4] The Council's Generating Resource Database can be found at this link: www.nwcouncil.org/energy/powersupply

Figure 9 - 2: Pacific Northwest Electricity Power Supply – Energy Generating Capability



Northwest Generating Capability ~34,750 aMW

Located in Power Act Region or contracted to PNW loads; WECC; In-service, under construction, standby or idle
Includes PacifiCorp WY wind plants
*Other - Geothermal, Petroleum, Solar

Additions and Retirements

Over the past two decades, large thermal resources such as coal and nuclear plants became less desirable to acquire. In part, this was due to their large size, longer development lead times, and other factors such as cost and environmental considerations. Smaller, shorter lead time resources, such as gas-fired turbines, wind, and to some extent solar, which can be scheduled to better match load growth, are now the principal generating technologies considered for resource development. Since the adoption of the Sixth Power Plan in 2010, the region's power system has seen the addition of a variety of resources – although dominated by wind and natural gas – and limited retirements. Figures 9-3 and 9-4 show the energy and capacity additions and retirements over the past decade. Some of the highlights include:

- **Wind power.** Over the past decade, the region has seen significant wind power development. In 2012, the region installed around 2,000 megawatts nameplate capacity – the highest annual acquisition of wind capacity in the region to date. The following year, in part due to the expiration and uncertainty of the future of the Production Tax Credit, there was no major development of new wind resources. In all, roughly 8,700 megawatts of wind capacity has been built in the region since the early 2000s.

- **Natural Gas.** With low natural gas prices and the need for additional flexibility and integration of variable energy resources, the region has seen the addition of a few gas-fired plants. Two of the larger plants are the 300 megawatt Langley Gulch combined cycle power plant installed by Idaho Power in 2012, and the 220 megawatt reciprocating engine gas plant installed by Portland General Electric at the end of 2014.

- **Energy Efficiency.** The region has continued to exceed the Council's power plan annual energy efficiency targets since 2005. From 2010 through 2014, the region achieved 1,500 average megawatts of energy efficiency savings, exceeding the Sixth Plan's 1,200 average-megawatt goal for 2010-2014.

- **Small biomass.** Several small biomass plants have popped up around the region, such as anaerobic digesters on dairy farms and landfill gas power plants on municipal waste projects. While not huge power producers, these small plants often fit into the natural operation cycle and can generate electricity to meet on-site loads or to sell. As renewable resources, these projects qualify as eligible resources to meet many state renewable portfolio standard goals.

- **Hydroelectric power.** The region has been undergoing upgrades to many of its existing hydroelectric turbines resulting in increased efficiency (greater energy output) and adding turbines and new equipment resulting in increased capacity. New small hydropower projects have also been assessed for feasibility in the Pacific Northwest. Snohomish PUD developed its 7.5 megawatt nameplate capacity Youngs Creek project in 2011.

- **Retirements.** Very few plants have been retired over the past five years. Some of the notable retirements include: TransAlta's Big Hanaford combined cycle power plant and Elwha and Condit small hydroelectric dams.

- **Announced retirements**. There have been several announcements of upcoming retirements of coal plants in the region over the next decade. Portland General Electric announced that it will cease coal-fired generation at Boardman in 2020, TransAlta will retire Unit 1 and 2 of its Centralia coal plant in 2020 and 2025, respectively, and PPL Montana announced the permanent retirement of J.E. Corette in late 2015. NV Energy has announced the retirement of the North Valmy coal plant in Nevada, scheduled for 2025. Idaho Power Company co-owns the North Valmy plant.

- **Hydroelectric system operational changes.** The operational flexibility and generating capability of the Columbia River Basin hydroelectric system has been reduced since 1980 primarily due to efforts to better protect fish and wildlife. Over the past thirty years, the pattern of reservoir storage and release has shifted some winter river flow back into the spring and summer periods during the juvenile salmon migration period. In addition, minimum reservoir elevations have been modified to provide better habitat and food supplies for resident fish. The results of these changes have reduced the hydroelectric system's firm generating capability by about ten percent or by about 1,100 average megawatts. Since about 1995, the hydroelectric system's peaking capability devoted to meeting firm load has dropped by about 5,000 megawatts. This is due, in part, to the high development of wind resources and the correspondingly greater allocation of hydroelectric system capability toward providing within-hour balancing needs.[5]

[5] For more information on balancing needs see Chapter 16.

Figure 9 - 3: Generating Additions and Retirements (Installed Capacity)

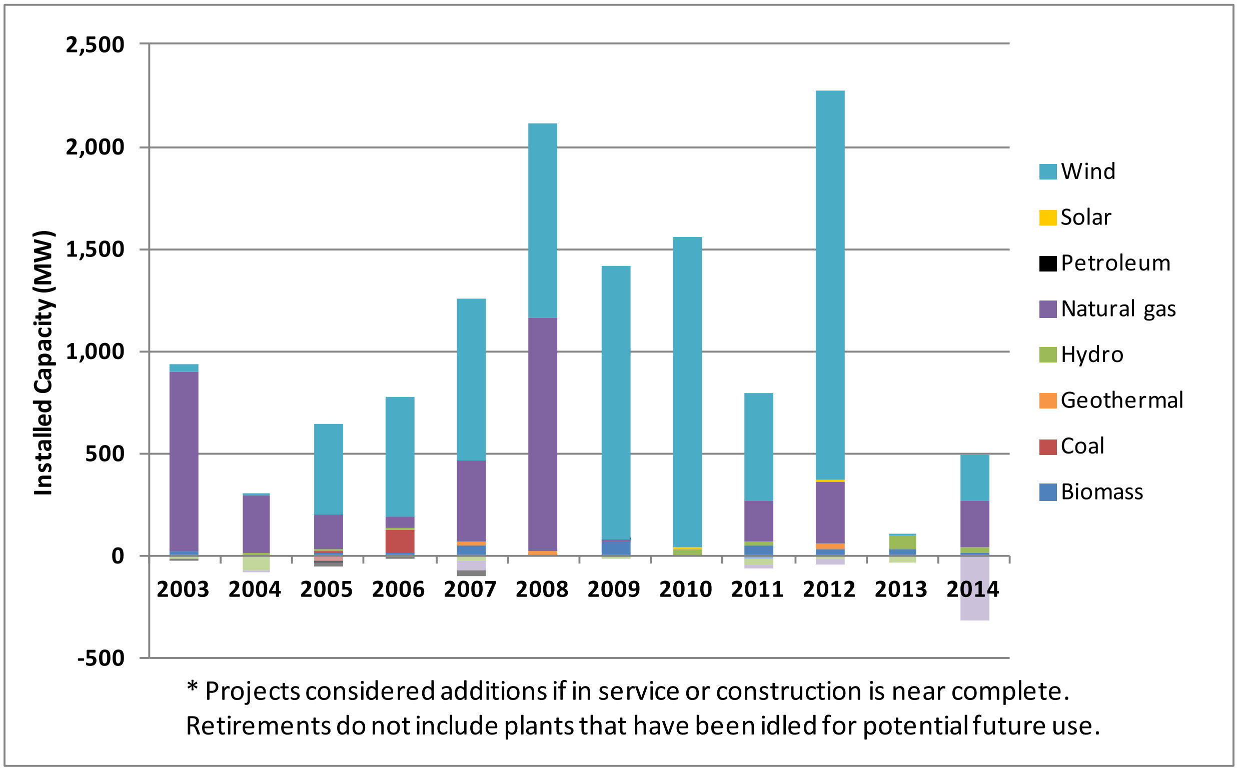
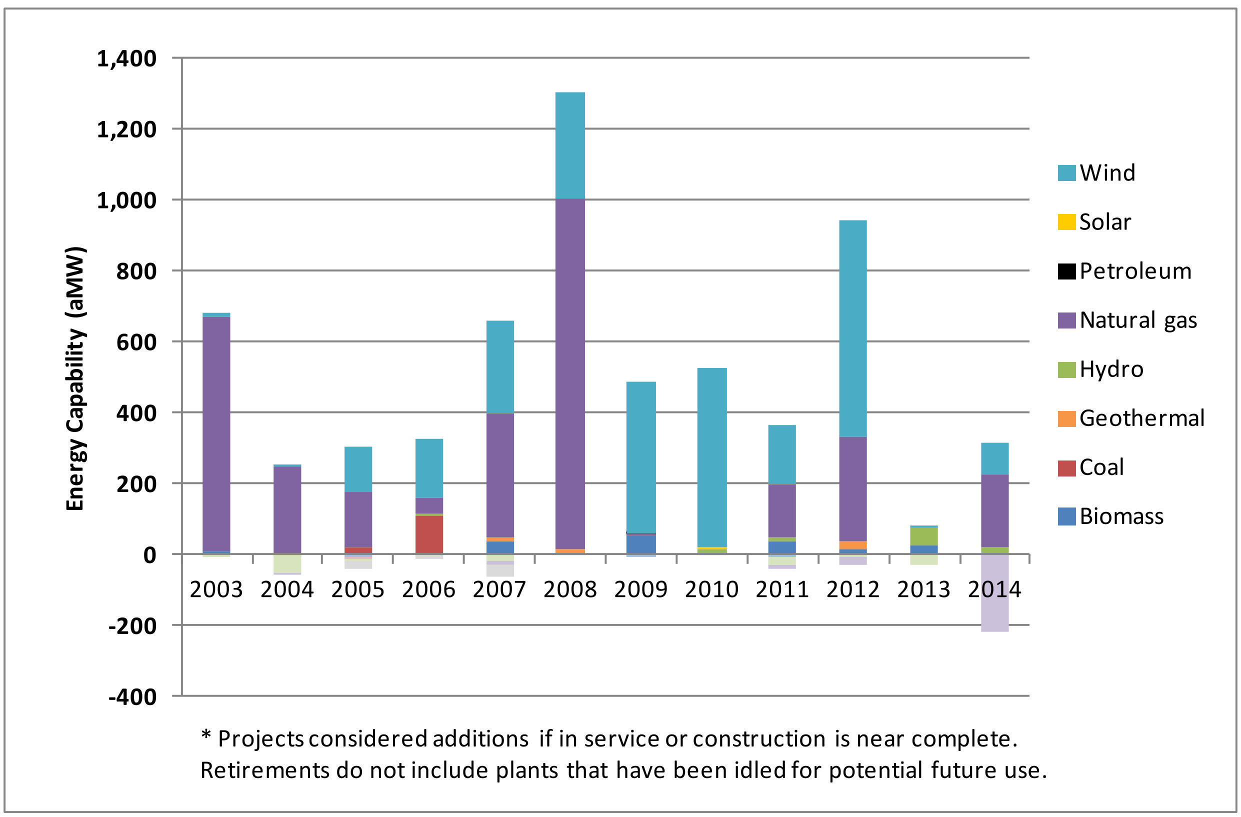


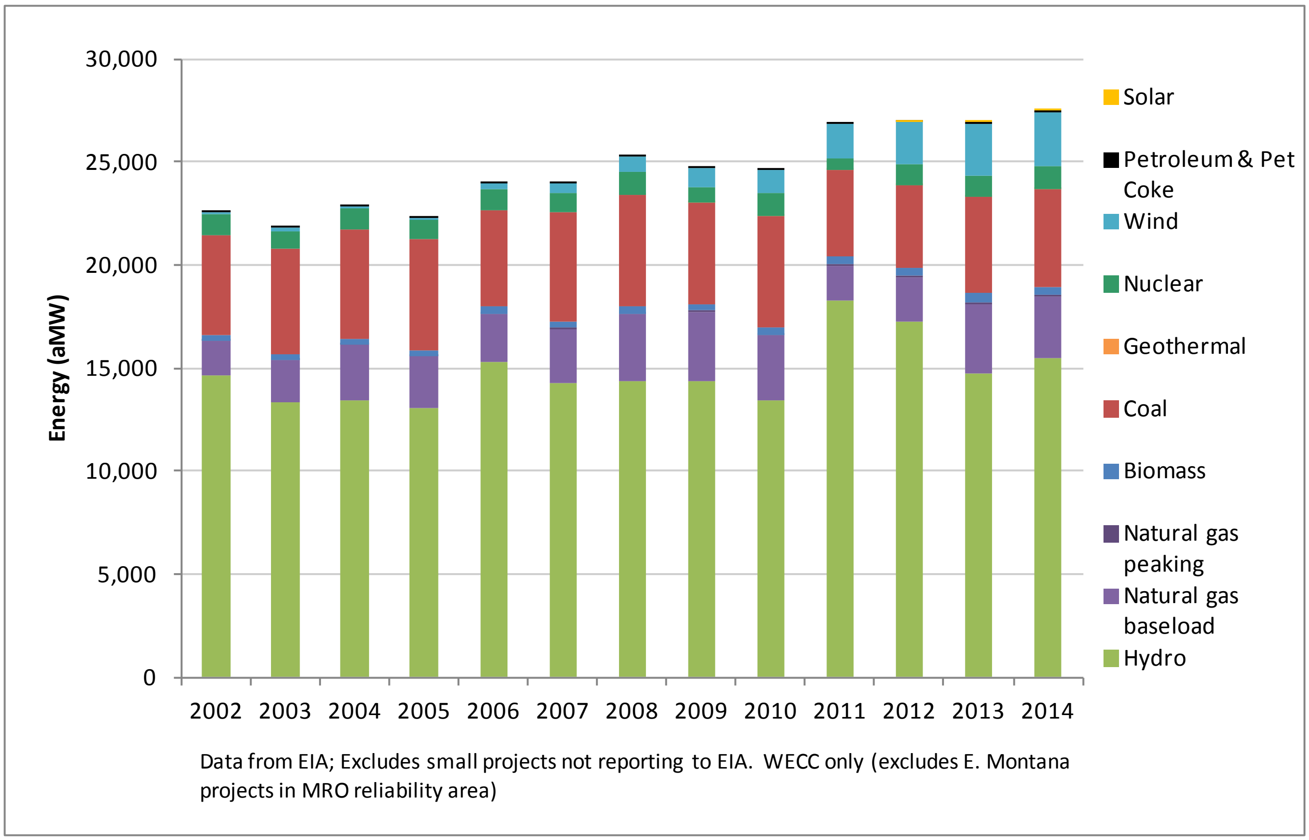
Figure 9 - 4: Generating Additions and Retirements (Energy Capability)



Historical Generation

The Pacific Northwest power system is dominated by its significant hydropower generation. Figure 9 - 5 below shows the historical annual energy production since 2002 by resource type. As illustrated in the figure, while remaining the dominant resource, annual hydroelectric generation varies significantly depending on weather conditions and snowpack. Generation from natural gas power plants is directly correlated to hydroelectric generation; in good water years, less power is dispatched from gas-fired plants and in poor water years, more power is dispatched. Generation from wind resources has made increasing contributions over the past decade.

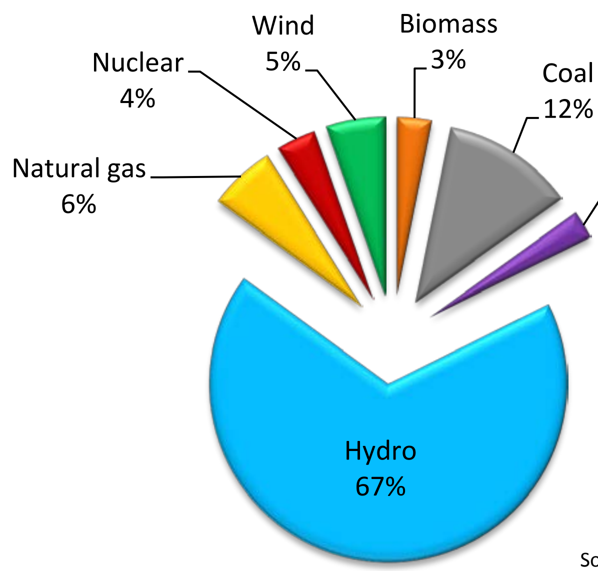
Figure 9 - 5: Historical Energy Production in the NW since 2002



Expected Resource Dispatch

Through this point in the chapter, the makeup of the region's power supply and how it has been dispatched over the last decade has been discussed. It is also of interest to project how the system might be used in future years. Figures 9 - 6 through 9 - 8 illustrate how various resource types would be dispatched, on average, for the 2017 operating year. The Council's 2014 resource adequacy assessment indicated that the region's power system was expected to continue to provide an adequate supply through 2020 (assuming that energy efficiency measures were acquired as targeted in the Sixth Power Plan). Figure 9 - 6 shows the expected dispatch of all regional resources. On average, the hydroelectric system provides about two-thirds of the energy needs for the region. Coal and natural gas combined provide about 18 percent of the region's electricity and the Columbia Generating Station (nuclear) provides about four percent of the total generation. Renewable resources, namely wind and biomass, contribute about eight percent. The remaining energy, about three percent, is imported from out of region or is produced by in-region merchant generators.

Figure 9 - 6: Expected Annual Energy Dispatch for the Northwest Power Supply in 2017



Type	Average MW
Firm Hydro	11,800
Add'l Hydro in Avg Yr	4,275
Coal	2,835
Natural Gas	1,436
Wind	1,260
Nuclear	849
Biomass	750
IPP + Imports*	614
Total	**23,819**

Source: Council's 2017 Adequacy Assessment.
* IPP = NW independent power producers
Imports = Short-term purchases from the SW

Figure 9 - 7 shows the expected resource dispatch for the federal system. The bulk of federal generation, nearly 90 percent, comes from the federal hydroelectric system. Figure 9 - 8 shows the expected resource dispatch for the non-federal portion of the region's power supply. The non-federal power supply is almost equally split between hydroelectric generation and non-hydroelectric generation. It should be noted that the actual generation production in any future year is dependent on the Columbia River Basin runoff volume –as was illustrated for historical generation in Figure 9 - 5.

Figure 9 - 7: Expected Annual Energy Dispatch for the Federal Power Supply in 2017

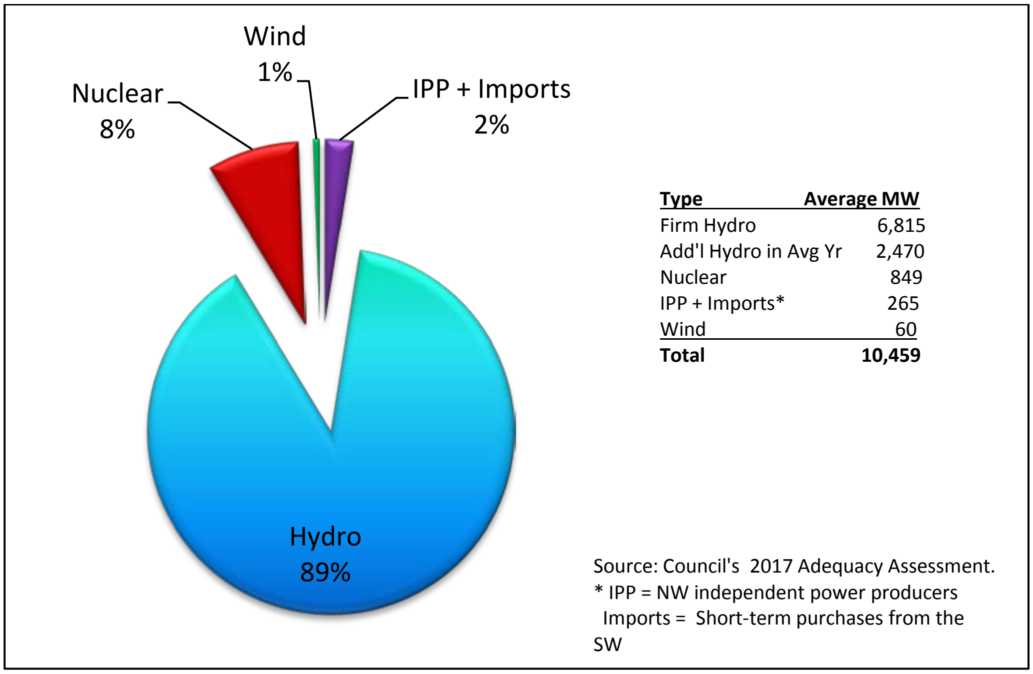
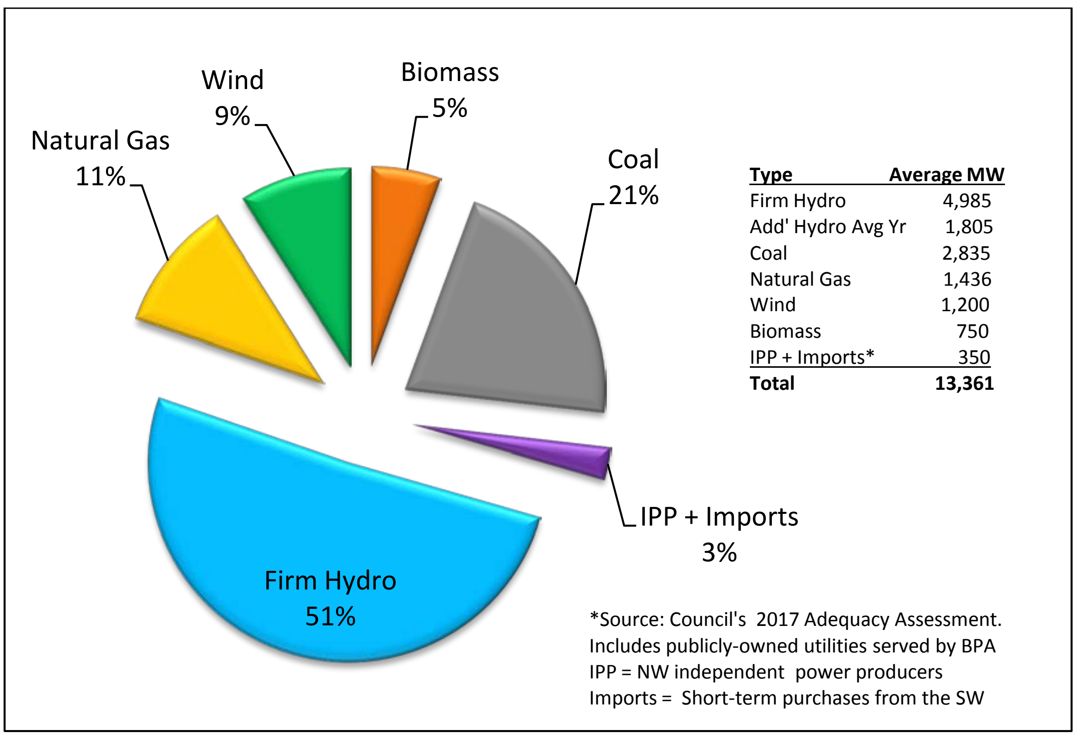


Figure 9 - 8: Annual Energy Dispatch of Non-Federal Generation in 2017



EXISTING GENERATING RESOURCES

The following section details the Pacific Northwest's existing resource base – how it was developed, what its drivers were, and in what quantity. In addition, the environmental effects and regulatory compliance requirements are noted for each resource – for more detail on these see Appendix I, which also contains a discussion of the environmental effects and issues associated with the development of the transmission system. See also Chapter 19, which describes the requirements for how the Council considers information on environmental effects with regard to the existing power supply, including the cost estimates related to compliance with environmental regulations, in crafting the power plan's new resource strategy.

The Hydroelectric System

The Columbia River originates in the Rocky Mountains in Canada, is joined by several major tributaries, including the Snake River, and extends a total of 1,243 miles to the Pacific Ocean. River flows are dominated by the basin's snow pack, which accumulates in the mountains during winter and then melts to produce runoff during spring and summer. The annual average runoff volume, as measured at The Dalles Dam, is 134 million acre-feet but it can range from a low of 78 million acre-feet to a high of 193 million acre-feet.

The Columbia River and its associated tributaries comprise one of the principal economic and environmental resources in the Pacific Northwest. Some 255 Federal and non-Federal dams have been constructed in the basin, making it one of the most highly developed basins in the world. Federal agencies have built 14 major multi-purpose projects on the Columbia and its tributaries, of which four are large storage reservoirs.[6] The total active storage capacity of all the reservoirs in the Columbia River (U.S. and Canada) is about 56 million acre-feet. This represents about 42 percent of the average annual volume runoff as measured at The Dalles. The four large Federal reservoirs have a storage capacity of just over 15 million acre-feet. Total active U.S. storage is a little over 35 million acre-feet, which includes about two million acre-feet of non-treaty storage at the Mica project in Canada. This represents about 63 percent of the basin's total active storage capability. In practice, however, some of the region's active storage is unavailable due to seasonal minimum elevation constraints implemented for various purposes, including fish and wildlife protection.

The low storage-capacity to runoff-volume ratio means that the reservoir system has limited capability to shape river flows to best match seasonal electricity loads. The Pacific Northwest has historically been a winter-peaking region, yet river flows are highest in late spring when electricity load is generally the lowest. Because of this, the region has based its resource acquisition planning on critical hydro conditions, that is, the historical water year[7] with the lowest runoff volume over the winter-peak demand period. Under those conditions, the hydroelectric system produces about

[6] These are the Grand Coulee, Libby, Hungry Horse, and Dworshak dams.
[7] The water year or hydrologic year is normally defined by the USGS from the beginning of October through the end of September and denoted by the calendar year of the final nine months. The water year of the Columbia River system, however, is modeled from the beginning of September (beginning of operation for reservoir refill) through the end of August.

11,600 average megawatts[8] of energy. On average, over all runoff conditions, it produces nearly 16,300 average megawatts of energy, and in the wettest years it can produce about 19,000 average megawatts. For perspective, the 2016 annual average regional load is expected to be in the range of 20,000 to 21,000 average megawatts.

The current U.S. portion of the Columbia River Basin's hydroelectric system has a nameplate capacity of about 33,000 megawatts. Because of limited storage, however, the hydroelectric system cannot sustain that much power production for very long. Again using the critical hydro criterion, analyses show that the hydroelectric system could sustain about 26,000 megawatts over a two-hour period, 24,000 megawatts over a four-hour period and 19,000 megawatts over a ten-hour period. These assessed capacity values are used for resource planning in the same way that the critical-year energy capability (11,600 average megawatts) is used. The assessed capacity values devoted to meeting firm load include the effects (a reduction) of carrying regional within-hour balancing reserves.

The Power Act requires that the Council's power plan and Bonneville's resource acquisition program assure that the region has sufficient generating resources on hand to serve energy load and to accommodate system operations to benefit fish and wildlife. The Act requires the Council to update its fish and wildlife program before revising the power plan, and the amended fish and wildlife program then becomes a part of the power plan. The plan sets forth "a general scheme for implementing conservation measures and developing resources" with "due consideration" for, among other things, "protection, mitigation, and enhancement of fish and wildlife and related spawning grounds and habitat, including sufficient quantities and qualities of flows for successful migration, survival and propagation of anadromous fish."[9] For further detail on these portions of the Act and how the Council is developing the Seventh Power Plan consistent with these requirements, see Chapters 19 and 20.

Since 1980, prior to the implementation of the Council's Fish and Wildlife Program, the hydroelectric system's firm energy generating capability has decreased by about 1,100 average megawatts, which represents almost 10 percent of its current capability. The hydroelectric system's peaking capability devoted to meeting firm load has decreased by over 5,000 megawatts since 1999.[10]

These impacts would definitely affect the adequacy, efficiency, economy, and reliability of the power system if they had been implemented over a short time. However, this has not been the case. Since 1980, the region has periodically amended fish and wildlife related hydroelectric system operations and, in each case, the power system has had time to adapt to these incremental changes. The Council's current assessment[11] indicates that the regional power supply can reliably provide actions specified to benefit fish and wildlife (and absorb the cost of those actions) while maintaining an

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[8] Source: 2014 White Book, Bonneville

[9] Northwest Power Act, Sections 4(e)(2), (3)(F), 4(h)(2)

[10] This decrease is not solely due to fish and wildlife constraints. It also includes operations to carry within-hour balancing reserves. This value is assumed to be consistent with a 10-hour peaking duration. It is not clear how much the peaking capability has declined since 1980 because that year's version of Bonneville's White Book was not found.

[11] See http://www.nwcouncil.org/energy/resource/Adequacy%20Assessment%20Final.doc.

adequate, efficient, economic, and reliable energy supply. See Chapter 20 for more information on the Council's Fish and Wildlife Program.

Coal-fired Power Plants

Following the development of the Columbia River hydroelectric system, coal and nuclear power were viewed as the most economical new sources of electricity. Between 1968 and 1986, 14 coal-fired power units at six sites were brought into service by Northwest utilities – Boardman (Oregon), Centralia (Washington), Colstrip (Montana), J.E. Corette (Montana), Jim Bridger (Wyoming), and North Valmy (Nevada). These large plants can serve about 7,300 megawatts of nameplate capacity, of which about 5,000 megawatts are currently dedicated to Northwest loads. In addition, there are several smaller coal plants in the region that total approximately 200 megawatts in nameplate capacity. Sufficient supplies of low-cost, low-sulfur coal are available from the Powder River Basin (eastern Montana and Wyoming), East Kootenay fields (Southeastern British Columbia), Green River Basin (Southwestern Wyoming), Uinta Basin (northeastern Utah and northwestern Colorado), and extensive deposits in Alberta.

Efforts to reduce carbon dioxide production have resulted in a series of state and Federal environmental regulations requiring modifications and improvements to existing coal-fired power plants. As a result of the incremental cost required to bring the coal plants into compliance with these known and proposed regulations, owners must weigh the economics of continued operation versus early retirement.

In the Pacific Northwest, several coal plants are scheduled for retirement during the Seventh Power Plan's 20-year power planning period. J.E. Corette is scheduled to retire in 2015, Portland General Electric is scheduled to cease coal-fired operation at Boardman in 2020, and Centralia's units one and two will be retired in 2020 and 2025, respectively. The North Valmy coal plant in Nevada, co-owned by Idaho Power, is scheduled to be retired by 2025.

Environmental effects of coal generation span a wide range, from the combustion of fuel to the disposal of waste. The mining of coal itself also produces greenhouse gas emissions, namely methane. Since coal is contaminated by heavy metals, radionuclides, and rare elements, these materials are released into the atmosphere as pollutants during the coal combustion process.[12] In addition, the intake and discharge of the cooling water (which may be contaminated by waste and metals during the cooling process) can affect nearby ecosystems and aquatic life. The disposal of waste from the coal combustion process requires a significant amount of land and, depending on the waste disposal structure, can pollute surface water.

As mentioned previously, there are many existing and proposed federal rulemakings intended to reduce and mitigate environmental impacts of coal generation. While many of the Pacific Northwest coal plants may already be in compliance with some or all of these regulations, it is important to note the rulemakings and the capital and operating costs to comply with them. Many of the rulemakings

[12] See the Third Power Plan, page 721 of Vol II, for a table of heavy metals released from a typical 500 MW coal plant in the PNW.

fall under the Environmental Protection Agency's Clean Air Act and Clean Water Act. The National Ambient Air Quality Standards (NAAQS), Regional Haze rule, Mercury and Air Toxics Standard (MATS), Coal Combustion Residuals rule (CCR), cooling water intake structures rules, effluent guidelines for steam electric power generation, and carbon pollution standards all affect regional coal plants.

See Appendix I for further detail on the environmental effects in the Pacific Northwest associated with the generation of electricity using coal, as well as the existing and proposed regulations to address those effects. That appendix also contains a detailed breakdown of the estimated compliance costs for each coal plant in the region.

Nuclear Power Plants

Coinciding with the development of the region's large coal-fired power plants in the 1980s, regional utilities initiated construction of ten nuclear power plants. Only two, Trojan, in Oregon, and the Columbia Generating Station (CGS) (originally known as Washington Public Power Supply System Nuclear Project number 2 or WNP-2), in Washington, were eventually completed.[13] Two partially completed plants, WNP-1 and WNP-3, were preserved for many years for completion, but they have since been terminated.

Trojan was permanently shut down in 1993, when it was concluded that the cost of a needed steam generator replacement would result in production costs barely competitive with the cost of power from new resources, and was subsequently demolished in 2006. CGS, now the only nuclear power plant in the region, has been upgraded from its original peak capacity and now has an installed nameplate capacity of 1,190 megawatts. In 2012, the Nuclear Regulatory Commission granted a 20-year renewal to CGS's 40-year operating license, now set to expire in 2043. The economics of continued operation of CGS have been questioned by some parties in the region, but this question is outside the scope of the Seventh Power Plan development.

Environmental effects of nuclear generation are focused primarily on water use and spent fuel disposal; the generation of nuclear energy does not lead to the emission of greenhouse gases. Nuclear power plants use a large amount of water for steam production and cooling, which potentially affect nearby ecosystems and aquatic life. In the case of CGS, its withdrawal from the Columbia River represents a small fraction of the overall river flow and would have to increase by six times to trigger EPA's minimum threshold for industrial water intake regulations.[14] Nuclear power is generated through the fission (splitting of atoms) of uranium and the spent fuel is therefore radioactive waste. This waste must be disposed of in long-term storage in an environmentally safe way, often in steel-lined concrete canisters above or below ground.

Existing and proposed federal rulemakings intended to reduce and/or mitigate the environmental impact of nuclear generation are: a series of Fukushima upgrades (ordered by the NRC in response

[13] Trojan was completed in 1976 and CGS in 1984. The Hanford Generating Project operated on steam from the N-reactor, a Hanford Production Reactor, until 1988, when it was shut down upon termination of plutonium production operations at Hanford.

[14] https://www.energy-northwest.com/ourenergyprojects/Columbia/Pages/Environmental-Impact.aspx

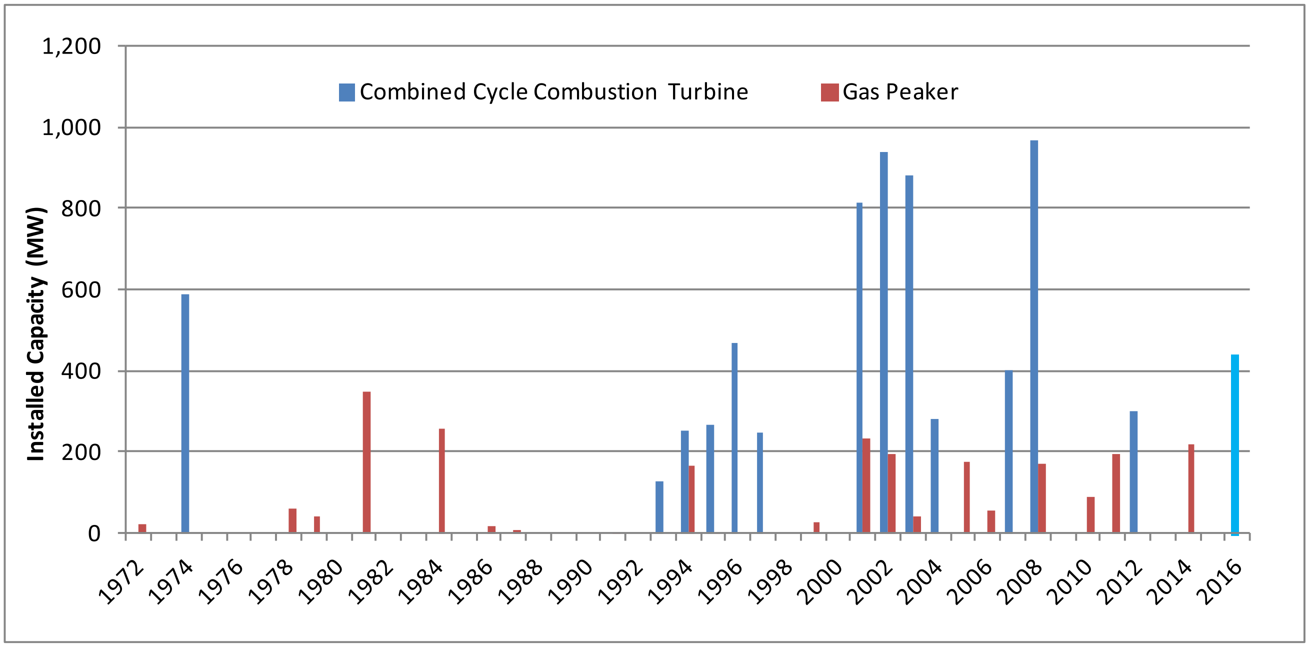
to the Tohoku earthquake in Japan and subsequent Fukushima nuclear plant accident), Containment Protection and Release Reduction rulemakings (CPRR), cooling water intake structure rules, and effluent guidelines. For detailed information on the environmental effects of nuclear generation, on the existing and proposed regulations addressing those effects, and estimates on the costs of compliance, see Appendix I.

Natural Gas-Fired Power Plants

Low natural gas prices and improving combustion turbine technology have made gas-fired combined-cycle power plants a low cost alternative for base load power generation in the Pacific Northwest. Most of these projects consist of one or two combined-cycle combustion turbine units, and many serve modest cogeneration loads. The recent increase in the development of gas peaking plants (simple cycle and reciprocating engine) in the Pacific Northwest and elsewhere can be attributed in part to the need for additional flexibility and efficiency in the power system to supplement and integrate variable energy resources such as wind and solar. Base load gas-fired plants provide about 6,900 megawatts of nameplate capacity and gas-fired peaking plants provide 2,200 megawatts of nameplate capacity in the region.

The first combined cycle power plant developed in the region was Portland General Electric's 600 megawatt Beaver plant in 1974. A few gas peaking plants, primarily frame simple cycle combustion turbines, were constructed in the early 1980's, but it wasn't until the early 1990's that natural gas power plant development picked up. At that time General Electric released its F-class frame unit, a machine with increased reliability and efficiency, and combined with low gas prices, the region saw a shift in development from coal to gas plants. A second wave of gas plant development by independent power producers came in response to the west coast energy crisis in the early 2000's. More recently, plants have been developed in response to power needs identified by investor-owned utilities in their integrated resource planning. Namely, Idaho Power constructed the 300 MW Langley Gulch combined cycle plant in 2012 and Portland General Electric constructed the 220 MW Port Westward II reciprocating engine plant at the end of 2014. Portland General Electric's 440 MW Carty combined cycle combustion plant is scheduled to come online in 2016. Figure 9 - 9 below shows the history of natural gas plant development since the 1970's.

Figure 9 - 9: History of Gas-Fired Plant Development since 1972



Environmental effects of natural gas generation are primarily greenhouse gas emissions from combustion and water use. Natural gas is the cleanest burning of the fossil fuels, with about half of the carbon dioxide emissions of coal and about two-thirds that of distillate fuel oil. In addition to carbon dioxide, nitrogen oxide and volatile organic compounds are also released.

When taking into account the full life cycle of natural gas, beyond simply the combustion of fuel into energy, there are environmental effects from the release or leakage of methane (also known as fugitive emissions) during the extraction, processing, transportation and storage of natural gas. In addition, drilling for natural gas and the construction of pipeline infrastructure have an adverse effect on the land and wildlife.

Existing and proposed federal rulemakings intended to reduce and/or mitigate the environmental impact of natural gas are National Ambient Air Quality Standards (NAAQS), cooling water intake structure rules, effluent guidelines, and potential carbon pollution standards. In addition, the EPA issued proposed rules in August 2015 (published in the Federal Register in September 2015) for reducing methane emissions from new and modified oil and gas facilities by 40 to 45 percent in the next decade. While the quantity of methane released from natural gas extraction and transport is less than the amount of carbon dioxide released, methane as a greenhouse gas is 34 times more potent than carbon dioxide over a 100-year period. For detailed information on the environmental effects, environmental regulations, and estimates of the cost of compliance, *see* Appendix I. Chapter 13 also includes a summary description of these effects and related information, including more sharply focused environmental compliance costs, with regard to the possible development of new gas-fired resources in the region.

Industrial Cogeneration

Cogeneration, or combined heat and power (CHP), plants produce both electricity and thermal or mechanical energy for industrial processes, space conditioning, or hot water. In the Pacific Northwest, there are different types of industrial cogeneration, namely biomass and natural gas plants. Industrial cogeneration in the forest products industry has long been a component of Pacific Northwest electric power generation. These plants include chemical recovery boilers in the pulp and paper industry, and power boilers fired by wood residues, fuel oil, and gas in both the pulp and paper and lumber and wood products sectors. Gas-fired combustion turbines have also been installed as industrial cogeneration units, oftentimes with the waste heat (steam) being used for secondary heating purposes.

Because of mill closures in recent years, and because many industrial cogeneration plants do not sell power offsite or generate power only when fuel costs are favorable, a precise inventory of operating industrial cogeneration plants is difficult to obtain. For these purposes, the known plants have been included in the generating capacity of the primary resource, for example biomass and natural gas. For a detailed breakdown by plant, see the Council's generating projects database.[15]

Environmental effects of cogeneration are the same as those for natural gas and biomass. See Appendix I for details.

Renewable Resources

While wind power has become the dominant renewable resource in the region, biomass has had a regional presence for decades, and geothermal and solar photovoltaic development is on the rise. Emerging resources like offshore wind power and wave/tidal energy are still nascent in the region (more information can be found in Chapter 13).

Evolving Policies and Incentives for Renewable Resources

Many federal and state policies have been established over the past several decades to promote development of renewable resources. In fact, the Pacific Northwest Electric Power Planning and Conservation Act, which created the Council, states in section 839b(e)(1) "the plan shall, as provided in this paragraph, give priority to resources which the Council determines to be cost-effective. Priority shall be given: first, to conservation; second, to renewable resources."

The adoption of the federal Production Tax Credit (PTC) and Business Energy Investment Tax Credit (ITC) has significantly contributed to the rapid development of renewable generation. Both incentives expired and renewed several times in the past decade, limiting their effectiveness in recent years due to last minute, retroactive, renewals. In late 2014, the PTC was renewed through the calendar year 2014, but very few projects nationally were able to take advantage of it. In

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[15] Council's generating projects database can be found on the Power Supply webpage of the Council's website - http://www.nwcouncil.org/energy/powersupply/

December 2015, both the PTC and ITC were amended once more as part of the Consolidated Appropriations Act.

The PTC is a production-based corporate income tax credit in which the owner of a qualifying project receives an incentive based on the amount that the project generates (per kilowatt hour) and sells, for the first ten years of operation. The incentive begins to phase down (a percentage reduction in the credit amount) for wind facilities beginning construction after 2016 and expires after 2019, and expires at the end of 2016 for all other eligible technologies. In contrast to the PTC, the ITC is a front-loaded incentive based on the initial capital expenditures of the project. The ITC is a 30 percent federal tax credit for solar systems on residential and commercial properties that remains in effect through 2019, at which point it phases down to 10 percent in 2022 for the foreseeable future.[16] Developers of wind projects are able to claim the ITC in lieu of the PTC, however the credit is phased down from 30% in 2016 to zero in 2020.

The adoption of state renewable portfolio standards (RPS) in Washington, Oregon, and Montana in the mid-2000s has also led to a significant increase in renewable resource development over the past decade. While Idaho does not have an RPS, its Idaho Energy Plan encourages the development of cost-effective local renewable resources, further contributing to the renewable boom of recent years. See Appendix I for a more detailed discussion of state RPS.

In Oregon, the Business Energy Tax Credit (BETC), which "is a nonrefundable credit against personal and corporate income taxes based on the 'certified cost' of certain investments in energy conservation, recycling, renewable energy resources, or reduced use of polluting transportation fuels," expired on July 1, 2014. Originally enacted in 1979, the BETC was an effort to encourage alternative energy development.

Wind

The first utility-scale wind projects in the region came online in 1998. With the adoption of the state renewable portfolio standards (RPS), wind development ramped up significantly, peaking in 2012 with 2,000 megawatts of installed capacity in the region. Uncertainty over the repeated expiration and renewal of the Production Tax Credit (PTC) has led to bursts and lulls in wind development. As an alternative to the PTC, wind developers were also able to take advantage of the Investment Tax Credit (ITC). The effect of both RPS and PTC/ITC drivers can be seen in Figure 9 - 10 below. In total, there is about 8,700 megawatts of wind power nameplate capacity installed in the region, including the PacifiCorp wind projects located in Wyoming.[17] Currently, about one-third of this wind power capacity is under long-term power purchase contracts with out-of-region parties. Figure 9 - 11 shows the cumulative wind capacity developed in the region by load serving entity, based on known

[16] The ITC can also be used at 30% for fuel cells and small wind (less than 100kW), and 10% for specific geothermal systems, microturbines, and combined heat and power projects – both credits expiring at the end of 2016. Geothermal electric maintains a 10% credit indefinitely. See the Database of State Incentives for Renewables and Efficiency (DSIRE) for more information - http://www.dsireusa.org/.

[17] The Council includes PacifiCorp Wyoming wind projects in its regional total because they are eligible to meet some renewable portfolio standard requirements in Oregon and Washington.

power purchase agreements. As states are on track to meet their near-term RPS goals, the pace of wind power development has slowed in recent years.

The diversity of the region's wind resource has been a topic of discussion, as the majority of the Pacific Northwest wind power is located in the Columbia River Gorge and along the Snake River in Idaho. In fact, as of the end of 2014, over half (4,782 megawatts[18]) of the installed wind capacity in the region was located within the Bonneville Power Administration balancing authority. On occasion, this has led to periods where wind power has been curtailed within a balancing authority when there has been an excess of wind and hydropower on the system. Central Montana is an excellent wind resource area that due primarily to transmission limitations remains mostly undeveloped to date – see Chapter 13 for development opportunities through transmission expansion.

Environmental effects of wind power generation are primarily limited to land use and wildlife interference, because there are no greenhouse gas emissions related to the generation of power itself. Project siting and licensing mitigates much of the land and wildlife impacts due to the requirement of environmental impact statements (EIS). While wind farms use a significant amount of land in total area, on average 85 acres per megawatt,[19] much of that land is either undisturbed by the development or multi-purposed. Wildlife interference occurs in two ways: direct mortality due to collisions with the wind turbines and indirect impacts to wildlife due to the loss of habitat in which the wind project resides. The primary wildlife impacted by wind projects in the Pacific Northwest are songbirds, migratory birds, raptors, and bats.

The Bald Eagle and Golden Eagle Protection Act (BGEPA) and Migratory Bird Treaty Act (MBTA) make it a violation of federal laws to kill, or "take," an array of bird species and therefore these laws impose regulations restricting the take of certain avian species. For more information, see Appendix I as well as Chapter 13 for a discussion of wind resource from the perspective of potential new resource additions to the Pacific Northwest's power system.

[18] http://transmission.bpa.gov/business/operations/wind/WIND_InstalledCapacity_PLOT.pdf
[19] http://www.aweo.org/windarea.html; http://www.nrel.gov/docs/fy09osti/45834.pdf

Figure 9 - 10: Wind Capacity Development in the Pacific NW since 1998 (Nameplate)

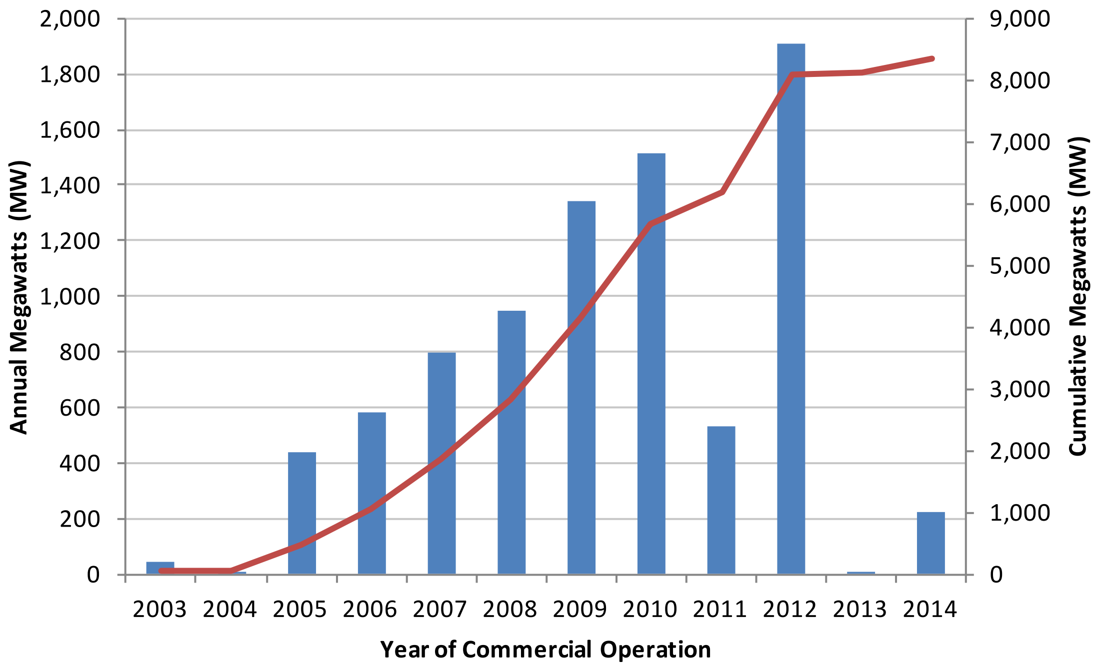
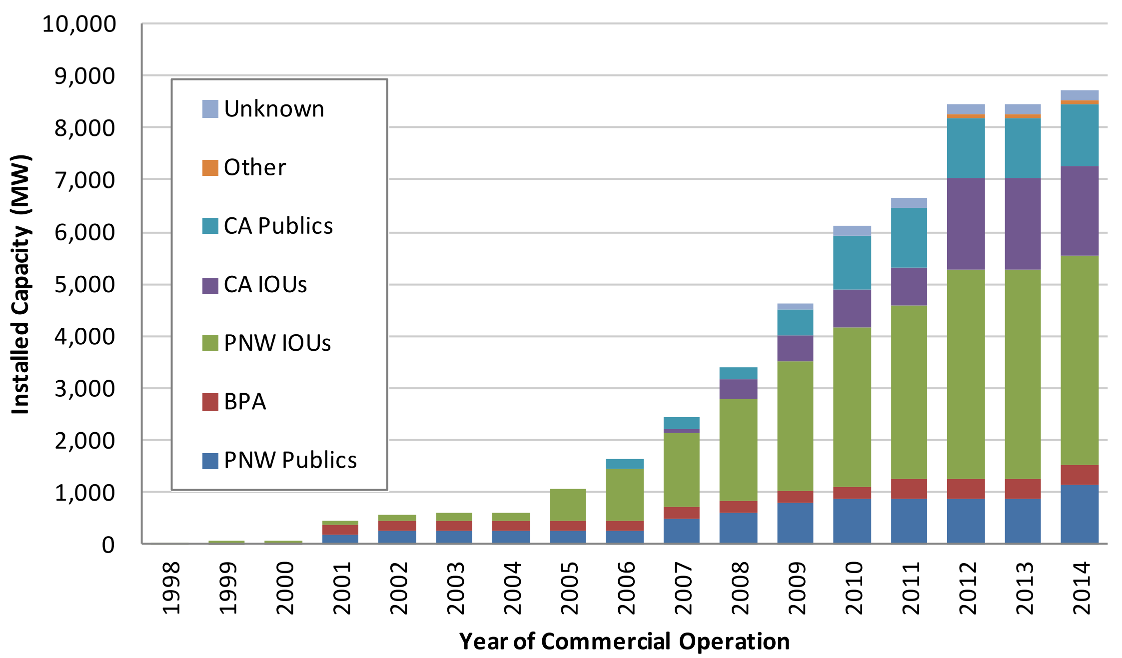


Figure 9 - 11: Wind Capacity by Load Serving Entity (Nameplate)



Located in Pacific Northwest, including PacifiCorp WY projects and NorthWestern MT projects; based on publically available information and power purchase agreements

Solar

In addition to being an eligible resource to meet state RPS, solar photovoltaic (PV) development has been driven by its rapidly decreasing capital costs and the federal and state incentives, namely the Investment Tax Credit (ITC).

Over the past decade, utility-scale solar PV power plants have been developed in growing quantities in the lucrative solar resource areas of the desert southwest. As module and inverter technologies have improved, costs have come down significantly and the Pacific Northwest is beginning to see development of its own. Outback Solar, in Lake County, Oregon, is currently the largest PV project in service in the region at five megawatts AC nameplate capacity. Several projects ranging from 10 megawatts to 80 megawatts, totaling 320 megawatts in Southern Idaho and Eastern Oregon are in development and projected to come online by the end of 2016.

Distributed solar PV energy, often constructed on residential and commercial rooftops with energy consumed directly by the end-user, has been a growing contribution to demand-side resources. State and utility incentives have contributed to the increasing presence of distributed PV in the Northwest, along with social and economic drivers. The Council estimates that by the end of 2015 roof-top solar will contribute about 21 average megawatts of energy and reduce system peak loads by about 56 megawatts.[20]

There are no concentrating solar power (CSP) projects in service or planned for the Pacific Northwest at this time. This type of solar resource has a higher cost per kilowatt than PV, although it has the potential of being a firm resource alternative with the addition of thermal storage.

Environmental effects of solar PV generation are mainly limited to land use and interference with wildlife. Energy production from solar PV plants does not contribute to the release of greenhouse gases. Much of the land and wildlife effects are mitigated during the siting and licensing of power plants. The few CSP projects in service in the desert Southwest and California have encountered issues with high avian and bat mortality directly related to the solar flux produced from the mirrors. For additional detailed information, see Appendix I and Chapter 13.

Biomass

Biomass includes a variety of fuels, including pulp and paper, woody residues (forest, logging, and mill residues), landfill gas, municipal solid waste, animal waste, and wastewater treatment plant digester gas.

There is about 1,000 megawatts of installed biomass nameplate capacity in the Pacific Northwest. In recent years, there have been several small (on average three megawatts) animal waste and landfill gas plants developed on existing dairy farms and landfill operations. With the economic recession in the late 2000’s, several of the region’s paper and textile plants have shut down, reducing the supply of pulping liquor for pulp and paper biomass plants.

[20] See Appendix E for more information on roof-top solar development.

Environmental effects of biomass generation include land use, water, and air quality. Biomass generation uses similar technology to coal and natural gas and therefore is subject to emissions arising from the production process; however, in general biomass emits fewer pollutants than its fossil fuel counterparts. The primary air emissions caused by biomass combustion include nitrogen oxides, sulfur dioxide, carbon monoxide, mercury, lead, volatile organic compounds, particulate matter, carbon dioxide, and dioxins.[21] Biomass generation can be considered a carbon dioxide reducing resource only if re-plantation of the spent fuel occurs (e.g. woody residues). Most existing biomass projects in the region are fueled by already spent resources rather than resources grown for the purpose of energy production, for example animal waste, woody residues, and municipal garbage, and therefore the impact to land and water use to supply the fuel is minimal as it already exists. Depending on the type of technology and fuel used in the power production, there are greenhouse gas emissions and water quality issues associated with biomass. Cooling water can affect nearby land and water sources, depending on where/how it is used. If a closed-loop system is utilized by the power plant, there are fewer impacts to nearby water sources than a once-through or open loop cooling system. *See* Appendix I for further detail on environmental effects and associated environmental regulations and compliance actions.

Geothermal

While there is significant geothermal resource in the Pacific Northwest, especially Southern Oregon and Idaho, there have only been a few projects developed to-date. Most recently, U.S. Geothermal's Neal Hot Springs – a 28.5 megawatt plant in Oregon – came online, bringing the total conventional geothermal installed nameplate capacity in the Pacific Northwest to 40 megawatts. A small geothermal power plant (three megawatts), Paisley Geothermal, is currently under construction in Southern Oregon by Surprise Valley Electric Coop. Demonstration projects for enhanced (engineered) geothermal systems are being developed at Newberry Crater, Oregon. Enhanced geothermal resources have a large potential to be a viable, base loaded energy alternative in the long-run if successful.

Environmental effects of geothermal generation are land and wildlife disturbances, air and water quantity and quality. Much like wind and solar, prospective geothermal power plants must undergo extensive environmental impact reviews that mitigate many land and wildlife impacts. While geothermal plants can take up to several hundreds of acres of land during development, much of that land can be reclaimed and repurposed once construction is complete. Air and water effects depend largely on the type of technology and open/closed loop cycle utilized by the power plant. There are few emissions from binary, closed-loop geothermal power plants as the water and air vapors are re-injected into the production cycle. Open-loop cycle plants emit primarily carbon dioxide and some methane, although it is at an amount that is equivalent to 30 percent of a conventional coal plant. *See* Appendix I for further details.

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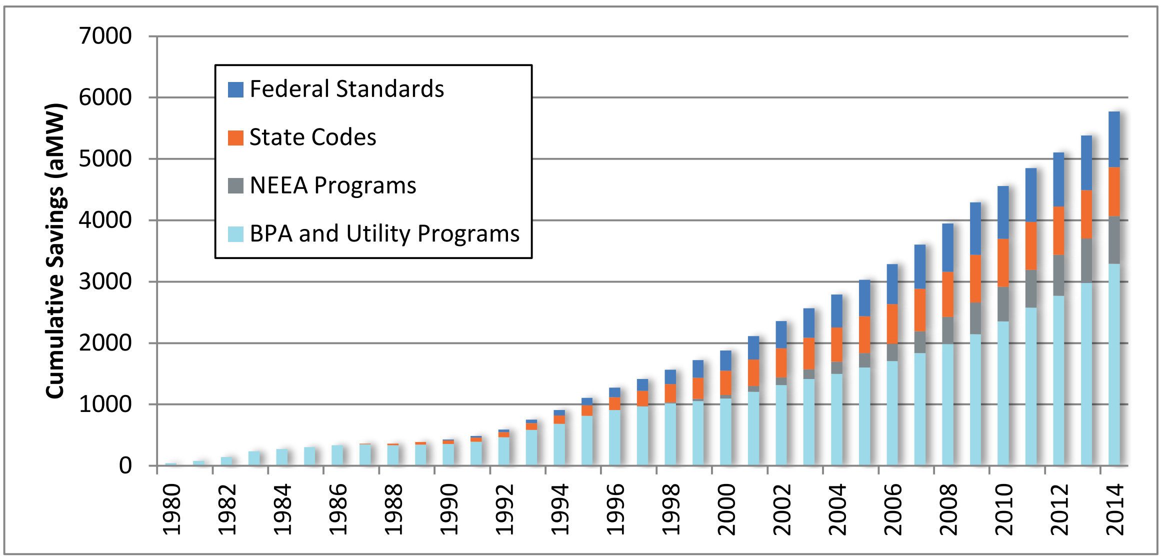
[21] http://teeic.indianaffairs.gov/er/biomass/impact/op/index.htm.

CONSERVATION

Conservation is the first-priority electric power resource in the Northwest Power Act, where it is defined as "any reduction in electric power consumption as a result of increases in the efficiency of energy use, production, or distribution." Since the passage of the Act in 1980, the region—through utility programs, market transformation efforts, and federal and state codes—has achieved nearly 5,800 average megawatts of energy savings.[22] Figure 9 - 12 shows cumulative conservation achievements since 1980. Note this figure does not include market-induced savings that have occurred outside the programs.[23] These achievements are equivalent to the annual firm output of the six largest hydroelectric projects in the region.

Figure 9 - 12: Cumulative Regional Savings Since 1980



Since 1980, conservation has met 57 percent of the region's load growth and has become the second largest resource for the region behind hydroelectric power. This level of conservation is equivalent to nearly 50 billion kilowatt-hours, with a retail value to consumers of over $3.73 billion. These accomplishments have required perseverance, commitment, fresh thinking, and hard work.

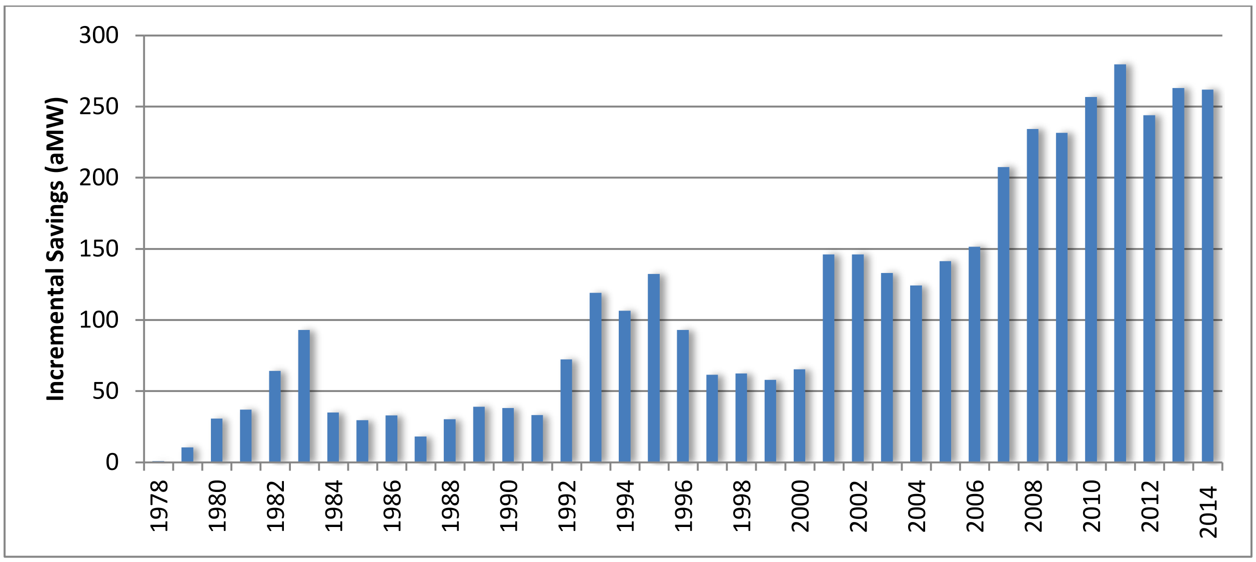
The amount of conservation over the years has varied. Figure 9 - 13 below shows the incremental savings for energy-efficiency programs—including Bonneville, utility, and Northwest Energy Efficiency Alliance programs—between 1978 and 2014. In the late 1970s and early 1980s, the region was in need of electricity, and conservation efforts were accelerated. In the early to middle 1980s, the region was in a period of surplus capacity, and conservation efforts were slowed. In the

[22] Findings are from the Regional Technical Forum's 2014 Regional Conservation Progress Report.
[23] See http://www.bpa.gov/EE/Utility/research-archive/Pages/Momentum%20Savings.aspx for more information.

early 1990s, there was again a need for resources, and the region responded once again by increasing conservation efforts. In the mid-1990s, conservation is again being slowed, as utilities see an uncertain future, and inexpensive energy is abundant in the West Coast market. All of that changed again with the west coast energy crisis in the early 2000s when programs once again increased their conservation efforts.

Significant investment in conservation as a resource continued through the Sixth Power Plan. Between 2010 and 2014, the region captured approximately 1,500 average megawatts of conservation. The vast majority of savings came from lighting projects and other significant contributors included residential and commercial lighting and HVAC projects, residential consumer electronics, and whole building projects across sectors. The total program investment during this period was over $2.5 billion.[24]

Figure 9 - 13: Incremental Savings from Bonneville, Utility, and NEEA Programs*



*Excluding codes and standards.

[24] Regional Technical Forum 2014 Regional Conservation Progress Report.

DEMAND RESPONSE

Demand response, as a means to reduce peak demand, has been used only sporadically throughout the region. Customer participation and utility needs change from year to year. Table 9 - 1 is a snapshot of some of the region's recent demand response programs, by seasonal availability, as reported in utility Integrated Resource Plans (IRPs). The results in Table 9 - 1 do not include current and recent pilot programs.

Table 9 - 1: Demand Response in the Pacific Northwest

System Operator	Program Types	Demand Response in MW (Winter/Summer)	Source
Idaho Power	Flex Peak, Irrigation, Air-Conditioning	0/390	Idaho Power 2015 Draft IRP
PacifiCorp	Irrigation, Curtailable Load Tariff*	149/319	PacifiCorp 2015 IRP
Portland General Electric	Time-Of-Use Pricing, Curtailable Load Tariff	28/0	Portland General Electric 2013 IRP
Bonneville Power Administration	Curtailable Load Tariff, Load Aggregator	60/30**	Discussion with BPA***

*The 149 MW Curtailable Tariff provides benefit for PacifiCorp's Idaho and Utah customers, so some of this might be credited to out-of region loads.

**The values listed in the table are the bottom of a range available, 60-145 MW in the winter and 30-100 MW in the summer. These values are dependent on the contract renewal which is based on projected system need. These values were current as of the draft Seventh Power Plan; however due to changes to BPA load, the existing DR estimates are in flux.

***On 7/8/2015, Council Staff discussed existing DR resources with John Wellschlager and Frank Brown from Bonneville.

In the last few years, demand response demonstration pilot programs have been implemented broadly throughout the region by Bonneville and by public and investor-owned utilities. Demand response can not only be used to decrease loads during peak hours but can also be used to increase load during light load hours when wind generation is unexpectedly high. These pilot programs, which are discussed more in Chapter 14, include exploration of demand response as a tool to provide balancing services for variable energy resources.

Demand response programs might also be able to defer new transmission or distribution investments, facilitate energy storage in flexible end-use loads, and provide dispatchable voltage control. These pilot programs have been conducted in the residential, agricultural, commercial and industrial sectors.

CHAPTER 10: OPERATING AND PLANNING RESERVES

Contents

List of Figures and Tables

KEY FINDINGS

The Northwest Power Act defines reserves as "the electric power needed to avert particular planning or operating shortages for the benefit of firm power customers of the Administrator… (A) from resources or (B) from rights to interrupt, curtail, or otherwise withdraw, as provided by specific contract provisions, portions of the electric power supplied to customers." To protect against planning shortages, the Council has developed an Adequacy Reserve Margin (ARM) that serves as a resource acquisition threshold for future energy and capacity needs. To protect against operating shortages, the Council includes contingency reserve requirements and within-hour balancing reserve requirements in its resource simulation and planning models.

The adequacy reserve margin specifies the amount of "extra"[1] resource needed, above the forecast weather-normalized load, to cover future uncertainties, such as temperature variations and resource outages. A separate ARM is calculated for energy needs and for capacity needs. The ARM is defined as the difference between total rate-based resource capability and weather-normalized load, divided by load, for a power supply that just meets the Council's adequacy standard.[2] Thus, in theory, future power supplies that meet the ARM thresholds should comply with the Council's adequacy standard.

Contingency reserves refer to actions that can be taken to maintain system balance during the unplanned loss of a large generator or transmission line. The Northwest Power Pool sets these reserve requirements for the Northwest to 3 percent of load plus 3 percent of generation or to the magnitude of the single largest system component failure, whichever is larger.[3] At least half of these reserves must be supplied by unloaded generators that are synchronized with the power supply (i.e. spinning reserves).

Within-hour balancing reserves are provided by resources with sufficiently fast ramp rates to meet the second-to-second and minute-to-minute variations between load and generation left over after scheduled operations. Because of the rapid and sizeable development of wind generation in the Northwest, balancing reserve requirements have grown substantially. Since the region's hydroelectric system carries the bulk of these reserves, its ability to serve on-peak demands has diminished over time. Regional balancing reserves include recently updated values for the Bonneville Power Administration, which are 900 megawatts for both incremental and decremental reserves in all months except April, May and June, when they are 400 and 300 megawatts, respectively. The rest of the region's balancing authorities hold the remaining reserve requirements of approximately 2,300 megawatts of incremental and 2,500 megawatts of decremental reserves. These estimates should be viewed as conservative, that is, they are the levels of reserve needed to be held during very low water conditions and during extreme temperatures.[4]

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[1] When including only rate-based resources and critical-period hydro in the ARM calculation, it is possible that the planning target turns out to be negative, that is, the power supply can be deficit and still be adequate.
[2] The Council deems a power supply to be adequate if its loss of load probability is no more than 5 percent.
[3] Northwest Power Pool, http://www.nwpp.org/our-resources/NWPP-Reserve-Sharing-Group
[4] See Chapter 16 and Appendix K for a more complete discussion of the derivation and use of these estimates.

BACKGROUND

The fundamental objective of power system operations is to continuously match supply of energy from electric generators to customers' load at all times. This involves proper planning to ensure that the power supply has sufficient energy, capacity and balancing capability to cover the monthly, daily, hourly and moment-to-moment variations in load and generation. Until recently, load serving entities in the Northwest focused more on energy needs because of the large capacity of the region's hydroelectric system. In other words, the system had sufficient machine capability to cover hourly peaks (capacity) and short-term variations in load (balancing) but did not have enough storage behind reservoirs to generate at high levels for extended periods of time (energy).

In more recent years, changes in the seasonal shape of Northwest load, increasing constraints placed on the operation of the hydroelectric system, and rapidly increasing amounts of variable generation resources (i.e., wind) have made system capacity and balancing needs higher priorities.

In this chapter, details are provided for the types of ancillary services and reserves that the power system must provide in order to continuously match generation to load. The term "ancillary services" usually refers to operations that a power supply manager takes to keep the system stable and reliable. These services include actions to maintain proper frequency and voltage across the entire system. They also include generator operations (i.e. ramp up and ramp down) to match the variability in load and, in today's world, to offset the variability of wind (and other variable generating supplies). The power system must also have sufficient surplus generating capability (or load management operations) to offset the loss of a major system component.

This chapter focuses on two aspects of ancillary services that are critical in the development of the Seventh Power Plan, namely operating reserves and planning reserves. Those terms are defined more clearly below. Chapter 16 and Appendix K of provide a more detailed discussion of how the region assesses its need for operating and planning reserves and how it can best provide for that need.

ANCILLARY SERVICES

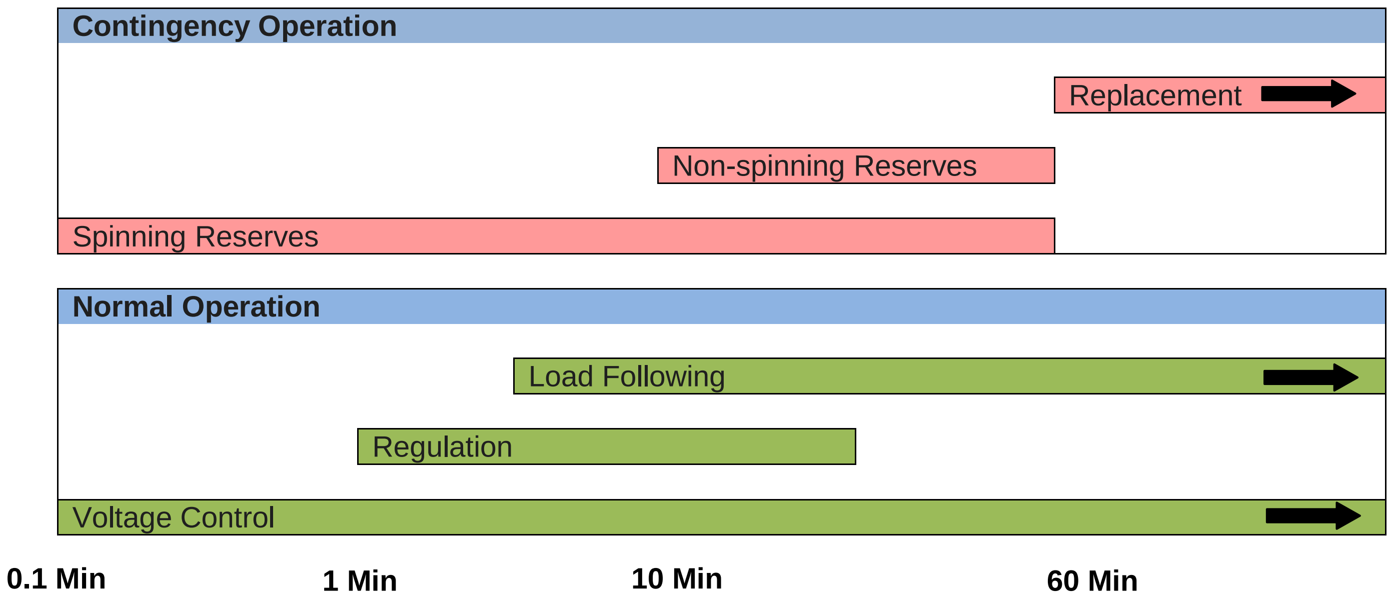
Ancillary services related to electric power are actions taken by system operators to ensure that energy is delivered in a reliable manner without diminished quality. The United States Federal Energy Regulatory Commission (FERC) defines ancillary services as "those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system." In general, ancillary services provide for:

- Frequency and voltage control
- Load following capability
- Outage protection

Frequency and voltage control maintain the stability and security of the transmission system and provide a consistent delivery of electricity (e.g. no brownouts). Load following capabilities are actions taken to insure that variations in load are matched exactly by generation at all times, ranging from seconds to minutes, hours, days and weeks. Outage protection operations are actions taken to instantly replace the loss of a generator or bulk transmission line. Table 10-1 provides a more detailed summary of ancillary services.

In general, ancillary services can be broken down into actions that can be taken during normal operations and those needed during emergency situations. Figure 10 - 1 below illustrates the types of actions that are typically taken during normal and emergency conditions and when those actions are commonly taken.

Figure 10 - 1: Response Time for Ancillary Services*



* Adapted from Kirby, Brendan, “Ancillary Services: Technical and Commercial Insights,” July 2007, page 8, Prepared for WÄRTSILÄ (a Finnish corporation which manufactures and services power sources and other equipment in the marine and energy markets).

Table 10 - 1: Summary of Key Ancillary Services*

Service	Service Description		
	Response Speed	*Duration*	*Cycle Time*
Normal Conditions			
Regulating Reserve	Online resources, on automatic generation control, that can respond rapidly to system-operator requests for up and down movements; used to track the minute-to-minute fluctuations in system load and to correct for unintended fluctuations in generator output to comply with Control Performance Standards (CPSs) 1 and 2 of the North American Electric Reliability Council (NERC 2006)		
	~1 min	*Minutes*	*Minutes*
Load Following or Fast Energy Markets	Similar to regulation but slower. Bridges between the regulation service and the hourly energy markets.		
	~10 minutes	*10 min to hours*	*10 min to hours*
Contingency Conditions			
Spinning Reserve	Online generation, synchronized to the grid, that can increase output immediately in response to a major generator or transmission outage and can reach full output within 10 min to comply with NERC's Disturbance Control Standard (DCS)		
	Seconds to <10 min	*10 to 120 min*	*Hours to Days*
Non-Spinning Reserve	Same as spinning reserve, but need not respond immediately; resources can be offline but still must be capable of reaching full output within the required 10 min		
	<10 min	*10 to 120 min*	*Hours to Days*
Replacement or Supplemental Reserve	Same as supplemental reserve, but with a 30-60 min response time; used to restore spinning and non-spinning reserves to their pre-contingency status		
	<30 min	*2 hours*	*Hours to Days*
Other Services			
Voltage Control	The injection or absorption of reactive power to maintain transmission-system voltages within required ranges		
	Seconds	*Seconds*	*Continuous*
Black Start	Generation, in the correct location, that is able to start itself without support from the grid and which has sufficient real and reactive capability and control to be useful in energizing pieces of the transmission system and starting additional generators.		
	Minutes	*Hours*	*Months to Years*

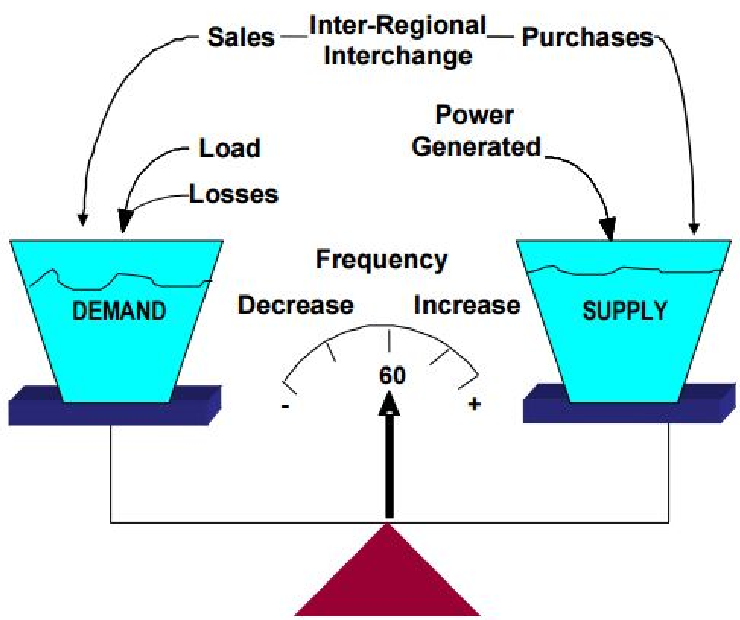
* Kirby, Brendan, "Ancillary Services: Technical and Commercial Insights," July 2007, page 9, Prepared for WÄRTSILÄ (a Finnish corporation which manufactures and services power sources and other equipment in the marine and energy markets).

Frequency and Voltage Control

The normal frequency of alternating current in the United States is 60 cycles per second. The normal voltage for residential and commercial use is 120 volts. While the frequency of electric current stays the same across all phases of the power system, from generation through end use, the voltage varies. Historically, electric power has been generated at large generating facilities and is then transported to users via high voltage transmission lines. The bulk electricity transmission grid often runs at 500,000 volts and is then transformed to lower voltage lines (230,000 and lower) before reaching the local distribution system that delivers the final power to users at 120 volts.

Frequency control refers to the capability of ensuring that grid frequency stays within a specific range of 60 cycles per second. Frequency will increase or decrease when mismatches between electricity generation and load occur. It decreases when load exceeds generation and increases when generation exceeds load. Large frequency deviations result in equipment damage and potential power system failure.

Figure 10 - 2: Illustration of Frequency Control*



*Source: “BALANCING AND FREQUENCY CONTROL,” A Technical Document Prepared by the NERC Resources Subcommittee, January 26, 2011, page 7.

Balancing authorities are electrical subareas within the region that are the responsible entities to maintain load-interchange-generation balance and support interconnection frequency in real time. Each balancing authority must balance its own load and resources and keep track of imports and exports, all while its own load and variable resource generation is continuously changing. Balancing authorities use a variety of techniques to balance their own generation and load and to keep the frequency of the system stable. Further, they are responsible for minimizing fluctuations in frequency between balancing authorities as power flows from one area to another.

Between balancing authorities, frequency is controlled by maintaining a stable net interchange with neighboring areas. The basic test of success for this is called the Area Control Error (ACE). ACE is a measurement, calculated every four seconds, based on the imbalance between load and generation within a balancing area, taking into account previously planned imports and exports and the frequency of the interconnection. The North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) reliability standards govern the amount of allowable deviation of the balancing authority's ACE over various intervals, although the basic premise is that ACE should be approximately zero. The ACE is maintained through a combination of automatic and operator actions. The automatic part is done through a computer-controlled system called Automatic Generation Control (AGC), which monitors the frequency of the system and correspondingly adjusts participating generators' output (within seconds) to bring the frequency back in line.

Voltage control refers to ensuring that the system voltage, for every phase of electricity delivery, is kept within a specific range of its targeted value. High voltage variations can destroy equipment by breaking down insulation. Periods of low voltage can make motors stall and overheat equipment. In extreme cases, a voltage loss can cause a blackout when a local drop in voltage cascades throughout a region.

In technical terms, voltage is controlled by injecting or absorbing *reactive power* by means of *synchronous or static* compensation. Every alternating-current (AC) power system has both real and reactive power. In an AC system, current varies (at 60 cycles per second in North America) as does the voltage. When the current and voltage oscillations get out of phase, the voltage can drag behind or race ahead of the current (i.e. get out of phase). This effectively lowers or increases the net voltage of the system. To compensate for this, electrical components that provide reactive power, such as capacitors, are added to the system.

In its planning process, the Council assumes that frequency and voltage control actions will be provided by the appropriate parties and, therefore, does not include these actions in its simulation and planning models.

Load Following Capabilities

Reserves to cover load following activities have two major purposes; 1) to cover unexpected variation in loads due to temperature or other factors and 2) to cover unexpected changes in generation from variable resources (i.e. wind).

Regulation and Scheduling

Regulation is the use of on-line generation equipped with Automatic Generation Control (AGC) which can change output quickly (megawatts per minute) to track the moment-to-moment fluctuations in customer loads and to correct for unintended fluctuations in generation. Regulation helps to maintain interconnection frequency, manage differences between actual and scheduled power flows between balancing areas, and match generation to load within a balancing area. Load following is the use of on-line generation, storage, or load equipment to track the intra- and inter-hour changes in customer loads.

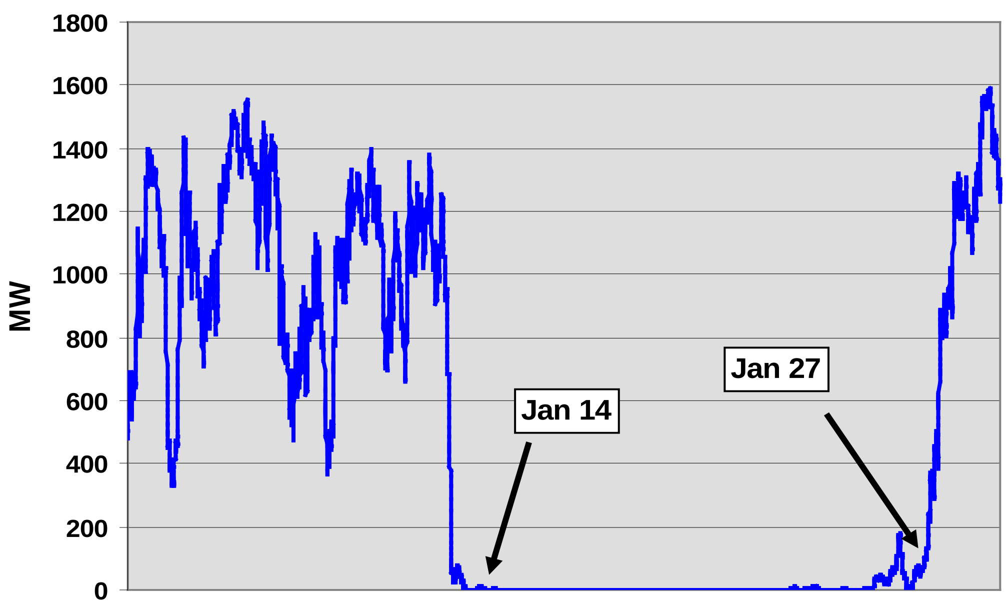
Scheduling is the before-the-fact assignment of generation and transmission resources to meet anticipated loads. Scheduling can encompass different time periods: a week ahead (e.g., a utility will schedule its units on Thursday for each hour of the following week), a day ahead, and before each hour. Scheduling of generation occurs for flows out of a balancing area, flows into a balancing area, and flows through a balancing area.

The Council does not include any regulation or scheduling operations in its planning process because they are not relevant to developing long-term resource acquisition strategies.

Balancing Reserves

Balancing reserves are provided by resources with sufficiently fast ramp rates to meet the second-to-second and minute-to-minute variations between load and generation left over after providing regulation and scheduled operations. Before the sharply increasing development of wind generation, balancing reserves were maintained mostly to cover short-term variations in load. After the development of wind, these reserves also covered short-term variance in the expected variable energy resource generation. Balancing reserves not only provide additional generating capability when loads unexpectedly increase (or wind/solar unexpectedly decrease) but also provide the ability to cut back generation when load suddenly drops or when wind/solar generation unexpectedly increases. Figure 10 - 3 below illustrates the variation in wind generation. In this particular case, wind stopped generating for almost a two-week period.

Figure 10 - 3: Bonneville Wind Generation (January 5 to 29, 2009)



Balancing reserves that provide additional capability are referred to as incremental (INC) reserves. Those that back off generation (or add more load) are referred to as decremental (DEC) reserves. The shortest time step in the Council's resource adequacy model (GENESYS) is one hour. Therefore, it cannot assess the need for or the sufficiency of balancing reserves. That need must be determined by other means.[5] In its final analyses, the Council includes an estimate for regional INC and DEC requirements, which include the recently updated Bonneville Power Administration requirements. More detail regarding the assessment and cost-effective implementation of these reserves is provided in Chapter 16 and in Appendix K.

In the Council's model, balancing reserves are assumed to be provided by both the hydroelectric system and thermal resources. This has the effect of reducing the amount of regional hydroelectric and thermal resource peaking capability that can be used to meet firm demand. It also results in an increase in the hydroelectric system's minimum off-peak period generation.

Example of Load Following Operations

An example of basic load following operations is described below, based on five-minute interval data from the Bonneville Power Administration balancing area for January of 2008. This was taken from Chapter 12 of the Council's Sixth Power Plan and provides a good example of load following operations.

Figure 10 - 4 illustrates a typical weekly load pattern, with a sharp daily up ramp in the morning as people get up, turn on electric heat, turn on lights, take showers, and as businesses begin the day. It also shows the Bonneville balancing area wind generation from the same period, highlighting the irregular pattern typical of wind generation. The data from this week will be used in several subsequent graphs, focusing on shorter time intervals to illustrate particular issues.

Focusing on a single day, January 7, 2008, Figure 10 - 5 highlights a single operating hour, from 6:00 a.m. to 7:00 a.m.

[5] Assessing the need for within-hour balancing reserves requires an analysis of sub-hourly (preferably minute to minute) resource dispatch and load. Balancing reserves carried by the hydroelectric system are incorporated as constraints in the Council's TRAPEZOIDAL model, which assesses hydroelectric peaking capability.

Figure 10 - 4: Bonneville Load and Wind Patterns (January 1 to 7, 2008)

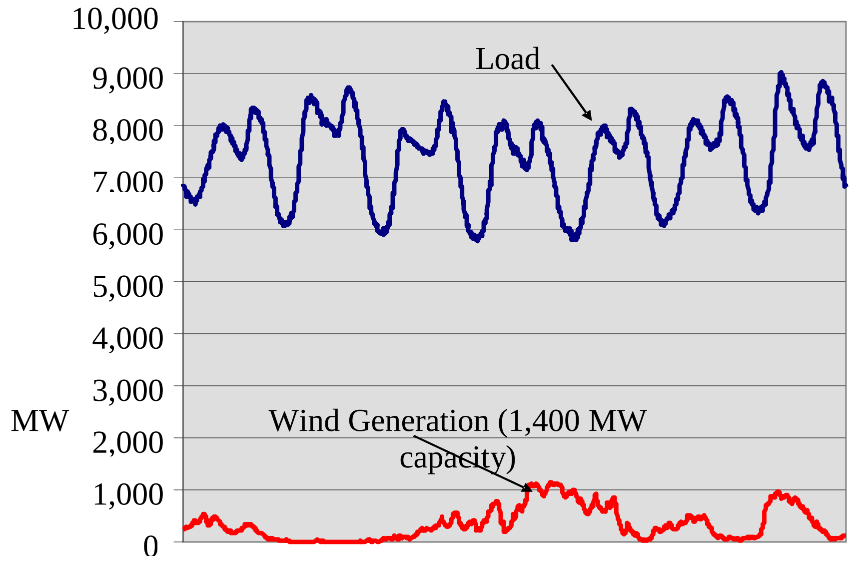
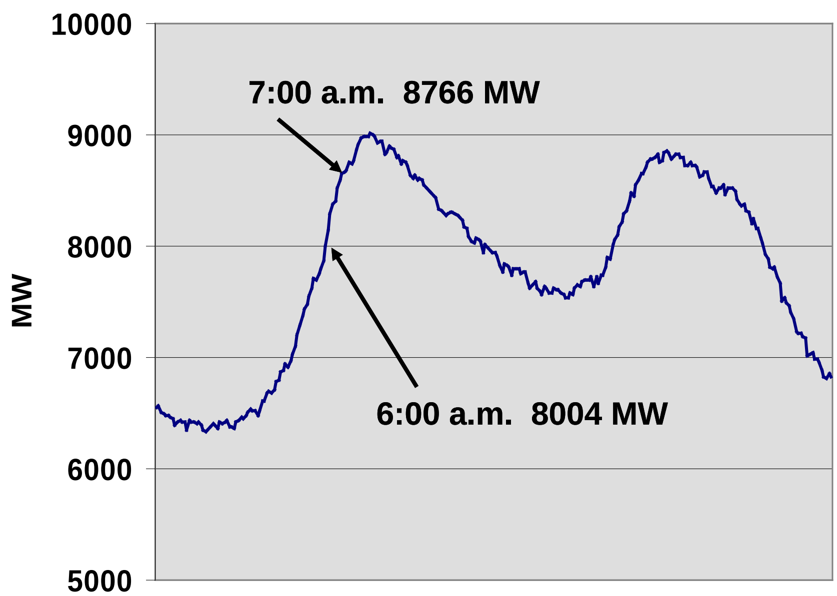


Figure 10 - 5: Daily Load Curve - Bonneville January 7, 2008 Midnight to Midnight

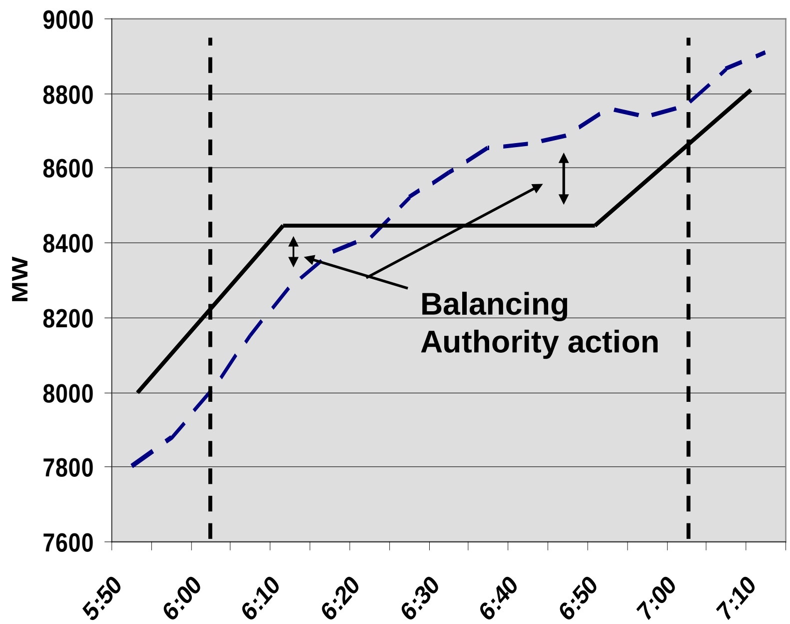


A balancing authority has to deal with a load ramp of, for example, 762 megawatts over the course of an hour, using the generation under its control in its own balancing area. At the same time, it must deal with any imports or exports that have their own time pattern for adjustment. Scheduling between balancing authorities in WECC is generally done in one-hour increments, with the schedules ramping in across the hour, from 10 minutes before the hour to 10 minutes after the hour.

Figure 10 - 6 focuses on the 6:00 a.m. to 7:00 a.m. load from the previous graph, while adding a hypothetical net schedule of generation to meet the average hourly load by any of its providers, including purchases from and sales to the market. The balancing authority must address the differences (both positive and negative) between the total scheduled generation and the net load in the balancing area by operating the generation under its control either up or down to match the load instantaneously, and to manage its ACE to acceptable levels. The graph points to the differences between scheduled generation and actual load that requires balancing authority action.

There are NERC and WECC reliability standards that govern how balancing authority action can be taken. In addition to contingency reserves, which must be available in case of a sudden forced outage, the standards require regulation reserves, which is generation connected to the balancing authority's AGC system. The standards do not require any specific megawatt or percentage level of regulation reserves. Rather, they require that the balancing authority hold a sufficient amount so that its ACE can be controlled within the required limits. How the balancing authority meets the requirements highlighted in Figure 10 - 6 involves some discretion.

Figure 10 - 6: Example Hourly Scheduling*



*Solid line shows scheduled generation and dashed line shows actual load.

Most balancing authorities prefer to break the requirement into two parts: one meeting the pure regulation requirement, allowing AGC generation to respond every four seconds; the other adjusting generation output over a longer period, typically 10 minutes. The pure regulation requirement is illustrated by Figure 10 - 7, which shows a hypothetical, random pattern at four-second intervals (which is the kind of pattern the load actually exhibits) on top of a five-minute trend. This is the load that the generation on AGC actually follows. Figure 10 - 8 illustrates one pattern of breaking that requirement up, separating the regulation requirement for generation on AGC from the remaining requirement, usually called load-following or balancing.[6]

Figure 10 - 7: Example Load at Four-Second Intervals Over Five Minutes

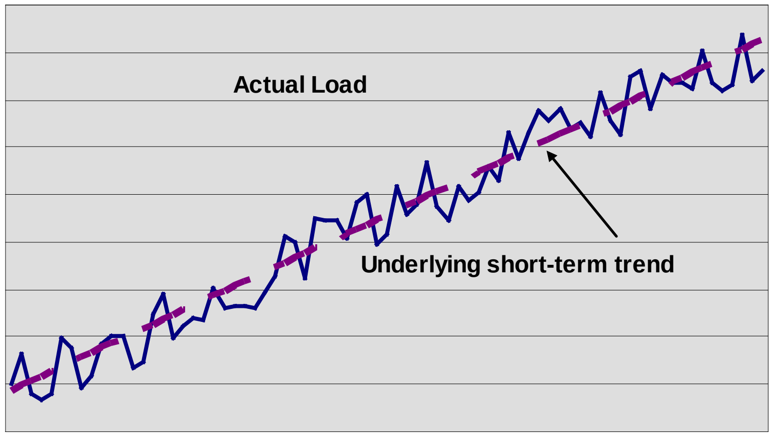
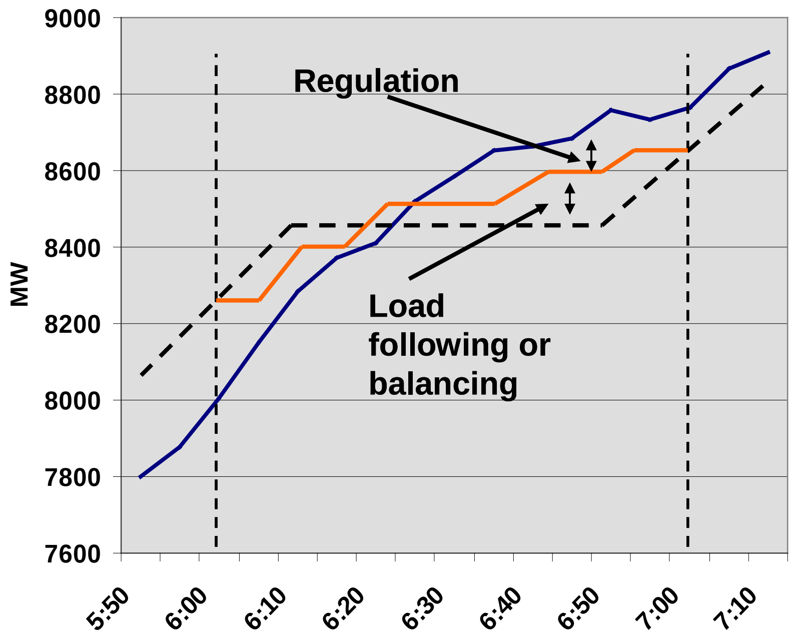


Figure 10 - 8: Illustration of Hourly Scheduling with Load Following*



*Dashed line shows scheduled generation, solid blue line shows actual load and orange line in between separates the AGC regulation from load following actions.

[6] When the only remaining requirement is the variation in load, load-following is the most common term. When the requirement includes the effect of variable generation, like wind, the term balancing is often used instead.

Balancing authorities plan for regulation and balancing services before the need for them arises. They ensure that enough scheduled generation is on AGC to provide moment-to-moment regulation services. They also plan to operate some generators at levels lower than they otherwise would in order to have the ability to increase generation and provide incremental load-following. Conversely, they may also need to operate some generators at levels higher than they otherwise would in order to have the ability to decrease generation and provide decremental load following.

The Council only includes within-hour balancing reserves in its long-term planning process. These are reserves that allow the power system to match generation to load (both up and down) during sub-hourly periods. In particular, these reserves cover the variation in sub-hourly loads and in wind and solar generation. The Council's final analyses use an estimate for the regional within-hour balancing reserves, which include the recently updated Bonneville Power Administration balancing area requirements. Chapter 16 and Appendix K describe how the Council is planning to assess the regional need for balancing reserves and how to best provide for them.

Outage Protection

FERC defines operating reserves (in Order No. 888) as "extra generation available to serve load in case there is an unplanned event such as loss of generation." The term "operating reserves," however, is not a standard term but generally means an amount of surplus generating capability that can be dispatched immediately or in a very short time in the event of a system failure. These reserves, more commonly referred to as contingency reserves, are required to include both spinning and standing (non-spinning) reserves.

The Council and other power industry entities define operating reserves in a more general way, to include not only contingency reserves but also reserves to cover load following operations, that is, the ability to cover unexpected variations (up or down) in load and in generation from variable energy resources (i.e. wind, solar, run-of-river hydro). A discussion of load following reserves was presented above. Contingency reserves are typically used for short-term and lower magnitude outage protection. Utilities also have measures to cover more severe outages and system blackouts.

Contingency Reserves

Contingency reserves refer to actions that can be taken to maintain system balance during the unplanned loss of a large generator or transmission line. Contingency reserves in the Northwest are set by the Northwest Power Pool (NWPP), a reserve-sharing subarea within the Western Electricity Coordinating Council (WECC), which itself is a subgroup of the North American Electric Reliability Corporation (NERC). The NWPP requires utilities to carry contingency reserves equal to 3 percent of load plus 3 percent of generation or equal to the magnitude of the single largest system component failure, whichever is larger.[7] At least half of these reserves must be supplied by spinning reserves and the rest can be provided by standing reserves.

[7] http://www.nwpp.org/our-resources/NWPP-Reserve-Sharing-Group

Spinning reserves are provided by an unloaded or partially-loaded generation source, which is synchronized to the power system and is instantly ready to serve additional load. Standing reserves are provided by generation not connected to the system but capable of serving load within a short period of time (10 minutes). In practice, many utilities lower costs by sharing reserves.

Contingency reserves can also be provided via agreements with customers to cut back a portion of their load under certain conditions. Load that can be cut automatically or in a very short time can be used as a spinning reserve. Load that takes longer to switch off provides standing reserves. Chapter 14 on demand response describes the Council's assessment of the regional potential for deploying such customer agreements to provide peaking capacity reserves.

The Council's hourly resource simulation model (GENESYS) keeps track of any hour in which contingency reserves cannot be maintained. Currently, a failure to maintain contingency reserves is treated as a curtailment. Fortunately, given the large capacity of the hydroelectric system, it is very rare to see a failure to maintain contingency reserves.

Black Start Measures

Black start measures provide sufficient generating capability to restart the power system or an islanded region of a power system in the event of a major blackout. The Council's power plan does not include an assessment of sufficiency for regional (aggregate) black start generation. Typically, individual utilities have their own strategies for providing backup generation (and other actions) to offset system failures. When the situation gets worse and more than one utility is involved, the Northwest Power Pool assesses the situation and generally initiates a conference call among affected balancing authorities.

Nonetheless, it is important for planners to understand the need for black start capability. Brendan Kirby summarizes the characteristics of black start generators in his 2007 report entitled "Ancillary Services: Technical and Commercial Insights,"

> *"Black start generators must be capable of starting themselves quickly without an external electricity source. They must have sufficient real and reactive power capability to be able to energize transmission lines and restart other generators. They must have sufficient ramping and control capability to remain stable as real and reactive loads change. Typically black start generators are at least tens of MW in capacity. They must also have relatively low minimum load capability and a broad operating range. They must be appropriately located in the power system to be useful in restarting other generators and in re-synchronizing the interconnection. They must be both able to control frequency and voltage and also be tolerant of off-nominal frequency and voltage. System frequency and voltage can fluctuate dramatically, especially in the early stages of system restoration. They must also have good communications with the system operations control center to facilitate a coordinated restart. Some regions require an on-site fuel supply."*

The Council assumes that individual utilities and load-serving entities will develop their own black start measures. These measures are not relevant to developing a long-term resource acquisition strategy.

PLANNING RESERVES

The Planning Reserve Margin (PRM) is the amount of capacity expressed in terms of percent above the expected weather-normalized load that a system has to carry to meet the reliability requirement. Usually coupled with probabilistic analyses, PRMs have been an industry standard used for decades as a target for future resource acquisition. The PRM is generally defined as the difference in deliverable generation and weather-normalized load, divided by load. Deliverable resources include existing resources, resources that are expected to be completed and operational and net firm transactions. Based on experience, for bulk power systems that are not energy-constrained, the planning reserve margin is the difference between available capacity and peak load, normalized by peak load, in units of percent. For example, a 20 percent planning reserve margin would imply that planned single-hour capacity should exceed expected load by 20 percent. Building a power supply that meets the PRM requirement is expected to maintain reliable operation while meeting unforeseen increases in future load (e.g. extreme weather) and unexpected outages of existing capacity. Further, from a planning perspective, planning reserve margin trends indicate whether capacity additions are keeping up with load growth.

Planning reserve margins are generally capacity-only based metrics. Therefore, PRMs do not provide an accurate assessment of performance in energy or fuel limited systems (e.g., hydroelectric capacity with limited storage). That is why the Council developed the Adequacy Reserve Margin (ARM) metric, which establishes minimum reserves needed for both future capacity and energy needs. In other words, the Council develops an adequacy reserve margin for energy needs and a separate adequacy reserve margin for capacity needs.

The ARM is defined as the difference between total rate-based resource capability and weather-normalized load, divided by the load, for a power supply that just meets the Council's adequacy standard. Thus, in theory, future power supplies that meet the ARM minimum thresholds should comply with the Council's adequacy standard of a loss-of-load probability not greater than 5 percent. The ARMs are used in the Council's Regional Portfolio Model to ensure that resulting resource acquisitions comply with the Council's adequacy standard while simultaneously accounting for the energy/fuel limitations of some resources and the associated available capacity to the system. More detail on how the ARMs are used to develop the Council's resource strategy is provided in chapters 11 and 15.

CHAPTER 11: SYSTEM NEEDS ASSESSMENT

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KEY FINDINGS

Comparing forecasted load to existing resource capability for the 2035 operating year indicates that the annual energy supply will be 1,000 average megawatts surplus under the low load forecast but 2,600 average megawatts deficit under the high forecast. The projections for capacity needs are more pessimistic. By 2035, the winter peaking capability is projected to be 1,275 megawatts short of expected peak load for the low load forecast and over 6,000 megawatts short for the high forecast.

However, this deterministic comparison of loads and resources is not an accurate assessment of resource needs because it does not take into account the effects of future uncertainties and the availability of market supplies. A better way to assess resource needs is to determine how much additional energy and capacity are required to ensure that the power supply satisfies the Council's adequacy standard of a 5-percent loss-of-load probability (LOLP).

Using a more sophisticated probabilistic method shows a relatively small energy need of 55 to 800 average megawatts by 2035 – much lower than the needs calculated using the deterministic approach. This is because the deterministic approach does not account for the substantial amount of in-region and out-of-region market supplies and it assumes critical water conditions – a very low likelihood event. The region's capacity needs in 2035, however, are much greater than those calculated using a deterministic approach. They range from about 4,300 megawatts under the low forecast to about 10,600 megawatts under the high forecast. This is because the deterministic approach does not capture combinations of water conditions, temperature, wind generation and forced outages that produce very large gaps between available resources and demand.

It is important to highlight that acquiring resources based strictly on a deterministic approach will lead to an over built system with respect to energy needs and to an under built system with respect to capacity needs.

In the near term, the power supply remains adequate until 2021, when the Boardman and Centralia 1 coal plants are expected to retire, but this assumes that the region will continue to implement cost-effective energy efficiency measures. If energy efficiency targets are not achieved, or if loads grow unexpectedly fast or if market supplies drop sharply, the region could face an inadequate supply much sooner.

One of the key enhancements to the analysis in this power plan is the improved linkage between the Council's adequacy model (GENESYS) and the Regional Portfolio Model (RPM). Using GENESYS, the Council's 5-percent adequacy standard is converted into Adequacy Reserve Margins (ARMs), which are fed into the RPM as minimum build requirements to maintain adequacy.

Another key enhancement in the linkage between the GENESYS and RPM models is the use of the associated system capacity contribution (ASCC) for all new resources in the RPM. The ASCC represents the effective capacity of a resource when it is added to the existing system. Because, unlike GENESYS, the RPM does not model the dynamic interaction between the hydroelectric system and non-hydro resources, the benefits of storage are not accurately captured. In many cases, this interaction results in an effective system capacity that is greater than the resource's nameplate capacity.

Implementing the ARM and ASCC parameters into the RPM is a way of ensuring that resulting resource strategies will produce adequate power supplies and more realistically reflect the interaction of new resources with the existing power system. To test this, projected power supplies for the 2026 and 2035 operating years from various RPM futures were tested for adequacy using the GENESYS model. However, because of the wide range of future uncertainties modeled in the RPM and because of unit size and other limitations, it is unrealistic to expect that every year's loss-of-load probability will be exactly 5 percent (the Council's standard). A specific year's power supply extracted from an RPM analysis is deemed to be acceptably adequate if its LOLP ranges between 2 and 5 percent. Supplies with zero LOLP values are over built and those with LOLP values greater than 5 percent are under built (inadequate). Adequacy tests show that LOLP values for futures with medium to high load growth fall within the acceptable range. For futures with low load growth, LOLP values tended to be near zero, meaning that those supplies are over built – likely because the RPM is acquiring resources (energy efficiency and demand response) for economic reasons and not for adequacy.

REGIONAL LOAD-RESOURCE BALANCE

A quick way to estimate the need for future resources is to compare existing regional generating capability to projected future load. This type of calculation is often referred to as a load-resource balance[1] and is usually made for both energy and capacity needs. Energy needs refer to having sufficient generating capability and fuel (water for the hydroelectric system) to match the annual average load, in units of megawatt-hours (or average megawatts). Capacity needs refer to having sufficient machine capability to match the highest load hour in the year, in units of megawatts. Using this approach, the implied target for resource acquisition is to have sufficient energy and capacity generating capability to serve the expected annual average load and the year's highest peak load, with a little extra to cover unexpected resource outages and extreme temperature fluctuations.
For the energy load-resource balance, weather-normalized annual average load is used. Only existing rate-based resources and those that are expected to be operational in the year in question are counted. For each thermal resource, the annual generating capability is equal to its single-hour winter capacity (not always the same as the nameplate capacity) adjusted by its average forced outage rate and its average down time for maintenance. Wind energy generation is assumed to be 30 percent of its nameplate capacity. Hydroelectric generation is based on the critical water year (1937) and includes all reservoir operating constraints for fish survival as detailed in the Council's current Fish and Wildlife Program. Only the savings from current energy efficiency programs and their effect on future loads are included. No load reductions from future energy efficiency programs are counted. This type of load forecast is commonly referred to as a "frozen efficiency" forecast. Market resources, such as in-region Independent Power Producer (IPP) plants and imports from out-of-region suppliers are also not included in this calculation.

Figure 11 - 1 below illustrates the forecast annual average energy load for both low and high-growth economic futures. This figure also shows the existing resource annual energy generating capability.

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[1] Load-resource balances are also estimated and published in both the PNUCC NRF and the BPA White Book.

Between 2015 and 2020 the region is expected to add 440 megawatts of new capacity from the Carty gas-fired plant and 220 megawatts of capacity from the Port Westward 2 project. In 2021, the Boardman (530 megawatt) and Centralia 1 (670 megawatt) coal plants are scheduled to be retired. By 2026 both the Centralia 2 (670 megawatts) and North Valmy (260 megawatts) coal plants are also expected to be retired. Centralia 2 and 290 megawatts of Centralia 1 are IPP resources, thus their retirements will not appear in Figure 11 - 1. Table 11 - 1 provides the corresponding load-resource energy balances for the specific years examined.

Figure 11 - 1: Annual Average Energy – Frozen Efficiency Load vs. Generating Capability

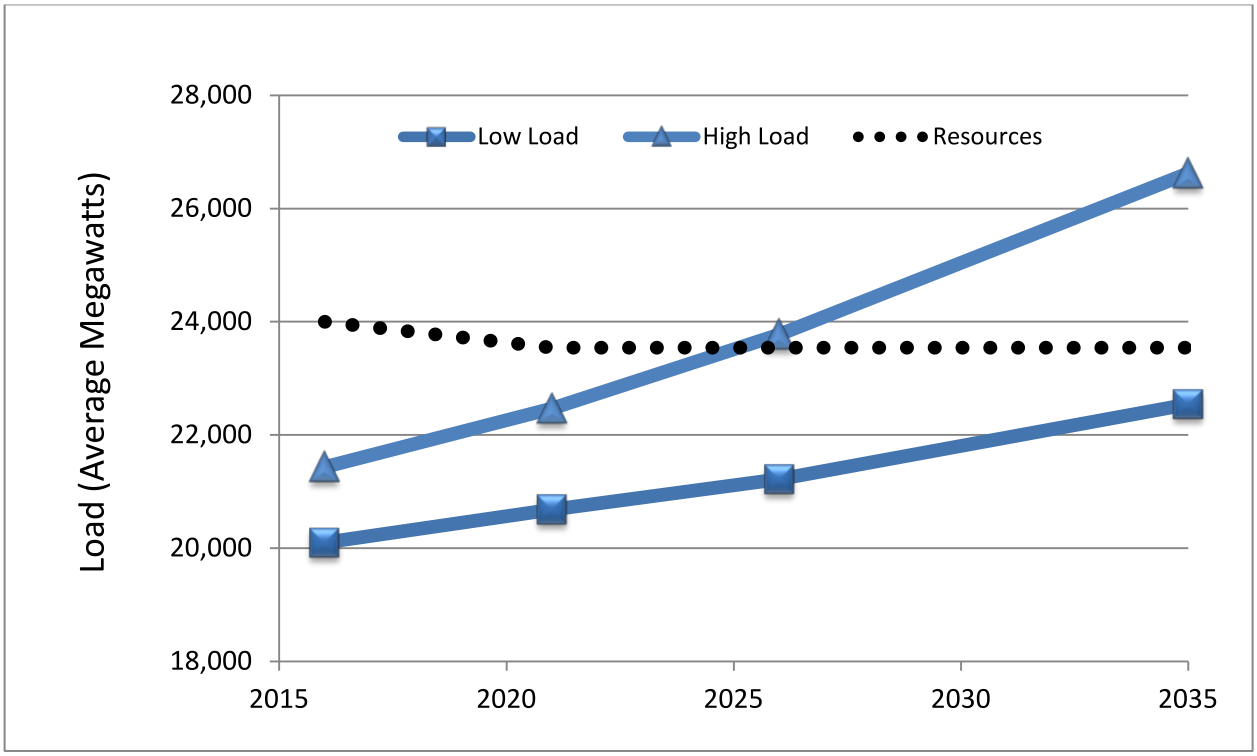

Table 11 - 1: Energy Load-resource Balance

Forecast	2016	2021	2026	2035
Low	3,903	2,859	2,322	999
High	3,248	1,510	200	-2,644

For the capacity load-resource balance, the load is the expected quarterly single-hour peak load. That value is determined by extracting the highest single-hour load for every quarter from each of the 80 different temperature profiles modeled (based on 1929-2008 historical temperatures) and then averaging those 80 peak-hour loads for each quarter. Thermal resource capacity is adjusted by the average forced-outage rate. For hydroelectric capacity, the 2.5 percentile[2] 10-hour sustained peak capability for each quarter is used. This is the maximum amount of generation that the hydroelectric system can sustain over a 10-hour period using water conditions that represent the lowest 2.5 percent for the quarter across the 80-year record. That is, there is a 97.5 percent probability that hydroelectric system capacity will be greater than this.

The single-hour peak load is used because the Council's long-term load forecasting model, which provides the loads for the RPM, does not forecast a sustained-peak load. On the resource side, the 10-hour sustained hydroelectric capacity is used because using a single-hour value greatly overestimates the capability of the hydroelectric system. Because of the relatively low storage-to-river-flow-volume ratio (about 0.16) the hydroelectric system cannot sustain the single-hour peak generation for even a two-hour period. Using the 10-hour sustained capacity with the single-hour peak load leads to a conservative assessment for the load-resource balance. Using these two parameters to define the adequacy reserve margins (as will be discussed later in this chapter) is perfectly acceptable, as long as the same parameters are used when adequacy is tested.

Figure 11 - 2 below illustrates the forecast winter peak-hour capacity load for both low and high economic futures. This figure also shows the amount of existing resource generating capacity. Table 11 - 2 provides the corresponding capacity load-resource balances for the specific years examined.

[2] The 2.5 percentile 10-hour sustained peak represents a minimum hydroelectric system peaking capability that can be achieved 97.5 percent of the time. In other words, in only 2.5 percent of the time is this peaking capability not achievable.

Figure 11 - 2: Winter Peak – Frozen Efficiency Load vs. Peaking Capacity

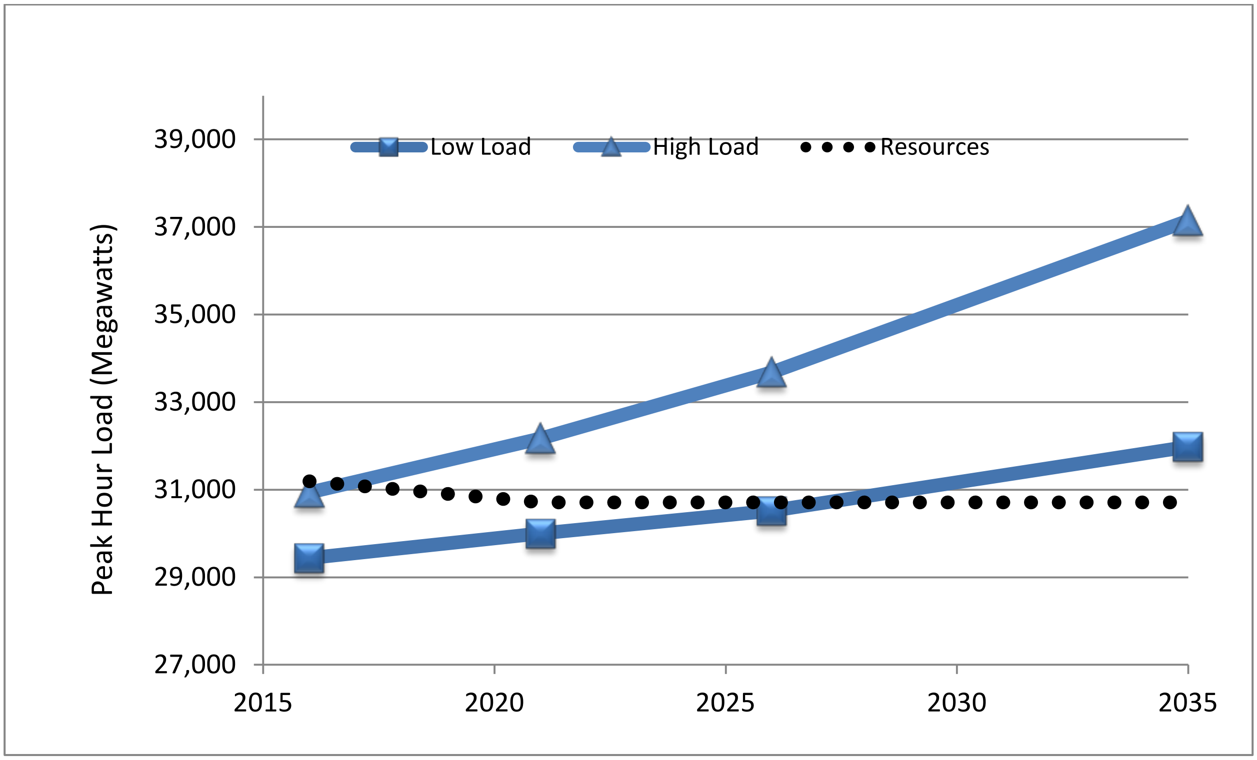

Table 11 - 2: Capacity Load-resource Balance

Forecast	2016	2021	2026	2035
Low	1,759	708	190	-1,275
High	943	-1,026	-2,538	-6,000

ENERGY AND CAPACITY NEEDS

The simple load-resource balance calculations done above provide a general idea of future resource needs. However, more accurate and appropriate methods have been developed to better assess future needs. The load-resource balance planning approach originated when the region was essentially isolated from the rest of the Western system by limited transmission. However, even after the North-South interties were built, this method continued to be used in regional load and resources summary publications.[3]

Planners generally knew, however, that a better method of assessing resource need was necessary. The reasons are twofold. First, in almost all years, hydroelectric generation will exceed production under critical-water conditions, which are used to calculate the load-resource balance. Second, Southwest markets (California, Arizona and New Mexico) should always have surplus energy and capacity to export in winter, when Northwest loads have historically been highest. Thus, planning for new resources in the Northwest based on the conservative load-resource balance criterion does not necessarily produce the least cost and least risk resource strategy and, in fact, can lead to overbuilding.

In addition, the Northwest power system has become more complex, with greater non-power constraints placed on the operation of the hydroelectric system, increased development of variable and distributed resources, and the growth of a west-wide electricity market. The Council recognized this need, and in its Fifth Power Plan recommended developing a resource adequacy standard to better assess future resource needs. Supporting this decision was federal legislation, passed in 2005, requiring an Electric Reliability Organization to develop a standard method of assessing the adequacy of the North American bulk power supply. That role is filled by the North American Electric Reliability Corporation (NERC).

Changes in the Bonneville Power Administration's role as a power provider mean that load-serving entities will bear more of the cost for their own load growth, making regional coordination to ensure adequacy especially important. Bonneville still bears the overall responsibility as the balancing authority for most of the region's public utilities.

The Council created the Northwest Resource Adequacy Advisory Committee to aid in developing a standard, and to annually assess the adequacy of the power supply. The committee, which is open to the public, includes utility planners, state utility commission staff, and other interested parties. In December of 2011, the Council adopted the advisory committee's recommendations for a northwest regional resource adequacy standard.

The Council's Adequacy Standard

The Council's overarching goal for its adequacy standard is to *"establish a resource adequacy framework for the Pacific Northwest to provide a clear, consistent, and unambiguous means of answering the question of whether the region has adequate deliverable resources to meet its load reliably and to develop an effective implementation framework."*

This standard has been designed to assess whether the region has sufficient resources to meet growing demand for electricity in future years. This is important, because it takes time – usually years – to acquire or construct the necessary infrastructure for an adequate electricity supply.

[3] The Bonneville Power Administration White Book and the PNUCC Northwest Regional Forecast of Loads and Resources.

Power supply adequacy is assessed five years into the future, assuming rate-based generating resources and a specified level of reliance on imported and within-region market supply. Resources include existing plants and planned resources that are sited and licensed and are expected to be operational during the year being assessed. Load assumptions are based on the Council's Short-term Load Model's medium forecast and are adjusted to include the expected conservation savings from the Council's latest power plan.

The adequacy of the Northwest's power supply is assessed as the likelihood of the occurrence of a supply shortfall by using probabilistic simulation methods. This approach differs from historical deterministic methods, which simply tally expected resource capability and expected regional load (i.e. load-resource balance approach). Probabilistic methods are commonly used around the country and the world because they offer a better assessment of adequacy by taking future uncertainties into account.

The metric used to assess the adequacy of the Northwest's power supply is the loss-of-load probability (LOLP). The LOLP is measured by performing a chronological hourly simulation of the power system's operation over a large set of variant conditions[4]. More specifically, the operation is simulated hourly over many different combinations of water supply, temperature (load variation), wind generation and resource forced outages. Any hour in which load cannot be served is recorded as a shortfall.

The resulting simulated shortfalls (periods when resources fail to meet load) are screened against the aggregate peaking and energy capability of standby resources. Standby resources are generating resources and demand-side management actions, contractually available to Northwest utilities, which can be accessed quickly, if needed, during periods of stress. These resources are intended to be used infrequently and are generally not modeled explicitly.

Shortfalls that exceed the aggregate capability of standby resources are considered curtailment events.[5] LOLP is assessed by dividing the number of simulations (years) with at least one curtailment event by the total number of simulations. In other words, it is the likelihood that a future year will experience a shortfall sometime during the year.

The power supply is deemed adequate if its LOLP, five years into the future, is 5 percent or less. This means that the likelihood of at least one shortfall event occurring sometime during that year must be 5 percent or less.

The GENESYS Model

The Council's GENESYS model is primarily used to assess resource adequacy. It is a Monte Carlo computer program that simulates the operation of the Northwest power system. It performs an economic dispatch of resources to serve regional load on an hourly basis. It assumes that all

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[4] This type of simulation is often referred to as a Monte-Carlo analysis.

[5] It should be noted that these simulated curtailment events do not necessarily translate into real curtailments because utilities often have other, more extreme, actions that they can take. However, for assessing adequacy, the threshold is set at the capability of standby resources.

available resources will be used to serve firm load. Those resources include merchant generation within the region and limited imports from out of region.

The model splits the Northwest region into eastern and western zones to capture the possible effects of cross-Cascade transmission limits. East-west transmission capacity is a function of line loading. The Southwest-to-Northwest intertie capacity is limited to 3,400 megawatts based on historical capacity assessments (but due to market inefficiencies and other potential constraints, peak-hour imports are limited to 2,500 megawatts during winter months only). Outages on the cross-Cascade and inter-regional transmission lines are not modeled.

The important stochastic variables (future uncertainties) that are modeled are river flows, temperatures (as they affect electricity loads), wind generation and forced outages on thermal generating units. The model typically runs thousands of simulations for a single fiscal year, choosing future uncertainties at random.

Non-hydro resources and contractual commitments for imports and exports are part of the GENESYS input database, as are forecasted electricity prices.

GENESYS dispatches all available regional resources and imported energy from out-of-region suppliers in order to serve firm loads in each zone. In the event that resources are not sufficient to meet firm loads, the model will draft the hydroelectric system below the “firm drafting rights” rule curve elevations. This “borrowed” hydro energy is used for short periods of time during cold snaps and heat waves or because of the loss of a major generator. Once the emergency has passed, reservoir levels are restored by running regional non-hydro resources or by importing out-of-region energy.

The model keeps track of periods when firm loads cannot be met or when required contingency reserves cannot be maintained. The LOLP is simply the percentage of simulations that result in a shortfall divided by the total number of simulations. The output also provides the frequency and magnitude of curtailments, along with other adequacy metrics.

GENESYS does not currently model long-term load uncertainty (unrelated to temperature variations in load) nor does it incorporate any mechanism to add new resources should load grow more rapidly than expected. It performs its calculations for a known system configuration and a known long-term load forecast. In order to assess the adequacy of the system over different long-term load scenarios, the model must be rerun using new load and resource additions.

The probabilistic assessment of adequacy in GENESYS provides much more useful information to decision-makers than a simple deterministic (static) comparison between resources and load. Besides the expected values for hydroelectric generation and dispatched hours for thermal resources, the model also provides the distribution (or range) of operations for each resource. It also highlights situations when the power supply is not able to meet all of its obligations. These situations are informative because they identify the conditions under which the power supply is inadequate. The frequency, duration, and magnitude of these curtailment events are recorded so that the overall probability of not being able to fully serve load is calculated.

It should be noted that in determining the LOLP, an assumption is made in GENESYS that all available resources will be dispatched in economic order to “keep the lights on,” regardless of cost.

Assumptions

Table 11 - 3 below summarizes assumptions used to assess the adequacy of the region's power supply. In general, they define what resources and loads are counted. As can be seen in the table, an adequacy assessment considers all sources of generation and demand control that are reasonably likely to be available.

Power supply adequacy is very sensitive to the following key assumptions:

Reserves – a certain amount of resource (or load management control) is set aside to cover unexpected changes in load and in variable resource generation. The purpose of operating reserves is to ensure that load is matched exactly with generation at all times. Chapter 10 summarizes reserves and ancillary services that the power system provides. Chapter 16 and Appendix K provide more detail regarding how reserve needs are assessed and how they can be best provided.

Merchant supplies – the Council assumes that all Independent Power Producer (IPP) capability will be available for regional use during winter months. During summer, however, when California experiences its peak loads, only 1,000 megawatts of IPP capability are assumed to be available for regional needs. This amount comes from an estimate of the amount of IPP generation that does not have direct transmission to California markets.

Imports – based on a report by Energy GPS[6], California's surplus capability should exceed the South-to-North intertie transfer capability in most months. Thus, the key assumption related to imports is the availability of the transmission interties. Based on historical assessments of South-to-North transfer capability, the Council has set the intertie limit to 3,400 megawatts (this was the recommendation of the Resource Adequacy Advisory Committee). Historical data show that availability of the transmission intertie should be 3,400 megawatts or greater 95 percent of the time. However, because of market inefficiencies and other physical or operational constraints, the advisory committee suggested limiting peak-hour imports to 2,500 megawatts during winter and to zero for summer.

Standby resources – these include small generating resources (too small to model), demand-side measures not already accounted for in the load forecast, pumped storage (at Banks Lake) and other miscellaneous measures.

Borrowed hydro – this represents hydroelectric generation derived from drafting certain reservoirs below their drafting-rights rule curve elevations for short periods of time. The drafting rights elevations are determined through a complicated analysis (based on the Pacific Northwest Coordination Agreement) that optimizes hydroelectric generation for the regional load shape during critical year (river flow) conditions. This analysis effectively determines the hydroelectric system's firm energy load carrying capability, which is contractually available to all participants in every year. Drafting below the drafting-rights elevations is done as a practical matter all the time for short periods of time, such as over a few hours or a few days. The critical factor with borrowed hydro is that it must be replaced as soon as possible so that the end-of-month elevation is not affected. The amount of borrowed hydro assumed for this analysis was derived by estimating how much the

[6] Belden, Tim and Turkheimer, Joel, "Southwest Import Capacity," EnergyGPS, March 3, 2014, http://www.nwcouncil.org/media/7149574/southwest_import_capacity_20140611.pdf

system could be drafted below the drafting-rights elevations without affecting the April and June reservoir refill requirements in the Council's current Fish and Wildlife Program.

Table 11 - 3: Assumptions for Resource Adequacy/Needs Assessment

Element	Assumption
New thermal resources	Must be sited and licensed
New wind and solar	Must be sited and licensed
Existing demand response	In load forecast
New demand response	In standby resources
Standby resources energy limit	40,800 MW-hours
Standby resources capacity	623 MW winter / 833 MW summer
EE for adequacy assessment	Council Sixth Power Plan targets[7]
EE for needs assessment	No new EE (i.e. use frozen efficiency load forecast)
Energy efficiency shape	Same as load but will match RPM shape in future analyses
In-Region market (IPP)	3,000 MW winter / 1,000 MW summer
On-peak imports	2,500 MW winter / 0 MW summer
Off-peak purchase-ahead imports	3,000 MW
South-to-North intertie limit	3,400 MW
Balancing reserves	Region-wide INC/DEC requirements, which include BPA's 400 MW INC/300 MW DEC April, May and June 900 MW INC and DEC all other months
Borrowed hydro	1,000 MW-periods

Adequacy Assessment vs. System Needs

The Council's adequacy assessment is used as a check on resource development. It assesses whether the regional power supply has sufficient resources to limit the LOLP to no more than 5 percent, assuming only existing resources and the targeted level of energy efficiency savings.

[7] Future energy efficiency savings are estimated by the Council's Short-Term Load Forecasting Model. This is an econometric model that projects future savings based on past trends. The projected savings are very close to the target values derived in the Council's 6th power plan.

The Council's needs assessment differs from an adequacy assessment in that it does not include targeted energy efficiency savings and it generally spans a longer time period (20 years). The needs assessment determines the expected magnitude of energy and capacity shortfalls during key years of the study horizon, which for the Seventh Power Plan are 2021, 2026 and 2035. This provides a general gauge of the magnitude of energy and capacity needs without explicitly trying to develop a resource mix to fill those needs. That task is left for the Council's Regional Portfolio Model.

Figures 11 - 3 and 11 - 4 below are similar to Figures 11 - 1 and 11 - 2 but additionally show the load uncertainty range used in the Regional Portfolio Model. These figures illustrate the differences in load forecasts used for adequacy assessments (two individual dots) and resource needs assessment (solid lines) and system expansion (dashed lines). The loads used for adequacy assessments are generally between the low and high range of forecasted loads because they are not designed to take into account the full range of future loads examined in the needs assessment and in the RPM analyses. The frozen efficiency load forecasts assume no new energy efficiency savings but do include the effects of anticipated savings from efficiency standards that are expected to be implemented and are weather normalized. The RPM range of loads across the 20-year study horizon is wider than the Council's frozen efficiency load forecast because the RPM incorporates a wider range of uncertainty surrounding future economic conditions.

It should be noted that even though the most recent adequacy assessment[8] concluded that the 2020 power supply is expected to be adequate, there remains a significant likelihood that it may not be, depending on how loads turn out and how the availability of imports changes.

[8] The Council's latest resource adequacy assessment can be found at http://www.nwcouncil.org/media/7149624/2020_21-adequacy-assessment-final-050615.pdf

Figure 11 - 3: Annual Energy Loads and Resources

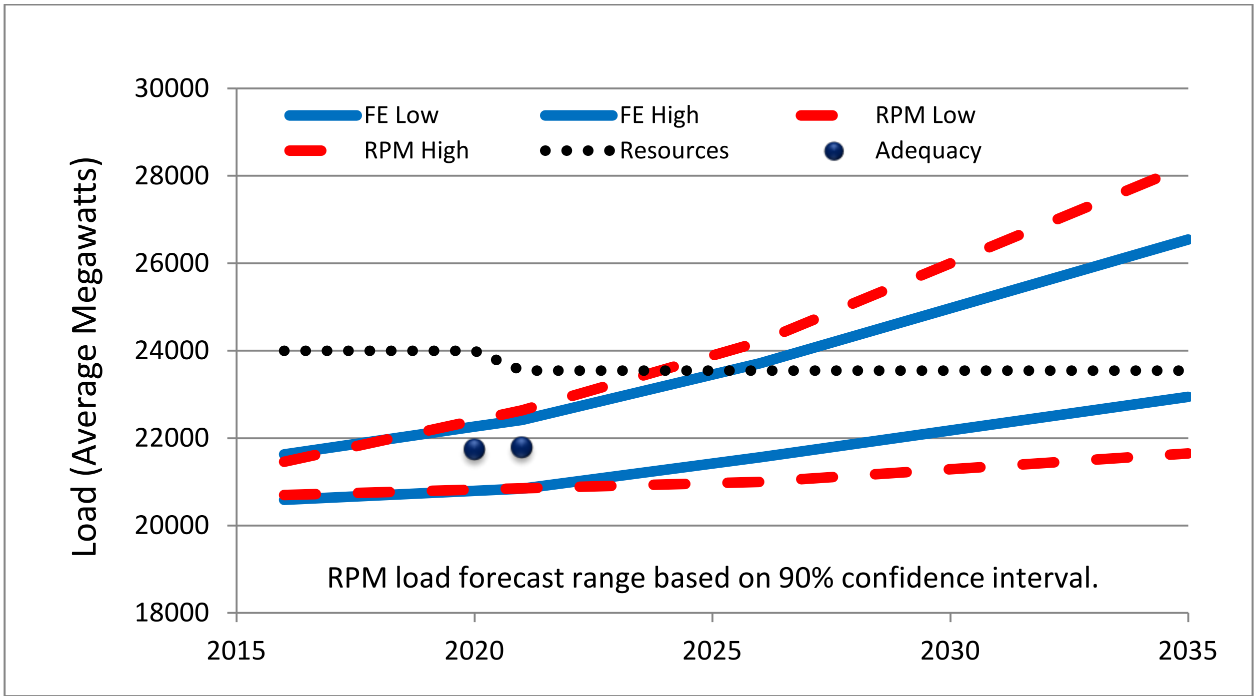
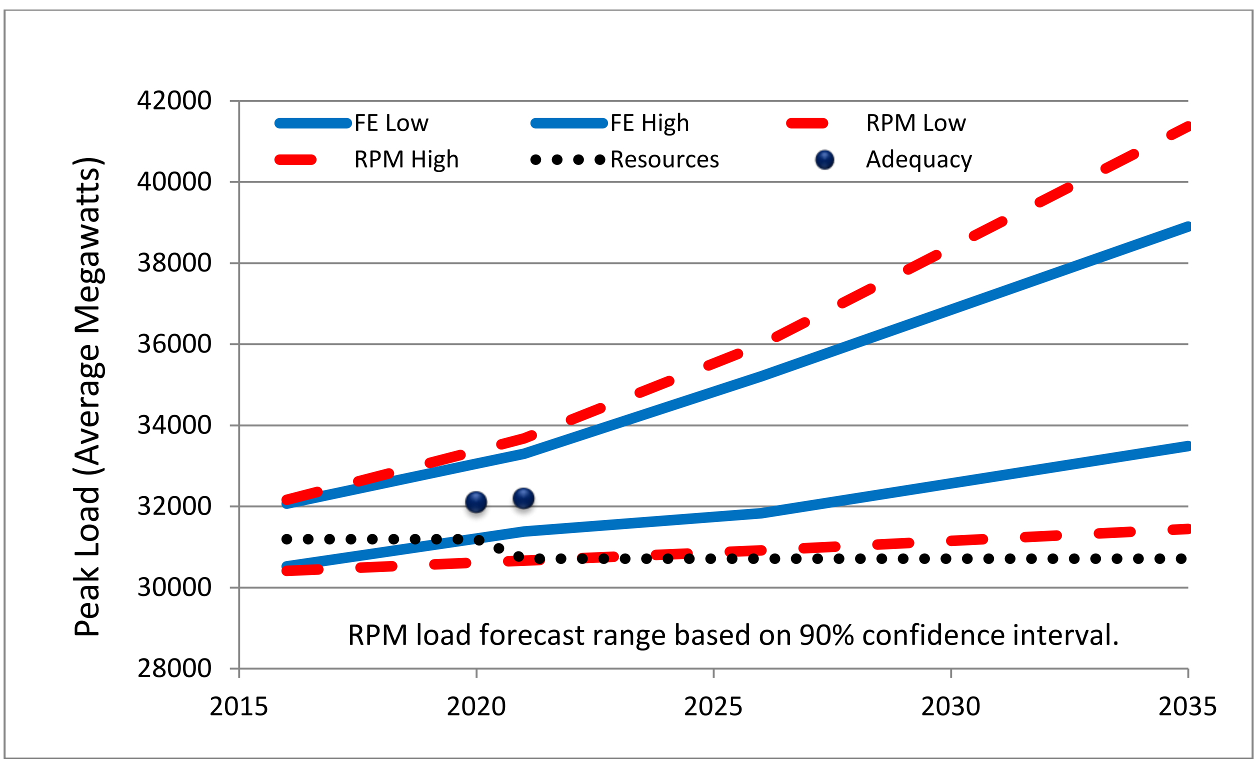


Figure 11 - 4: Winter Peak Loads and Resources



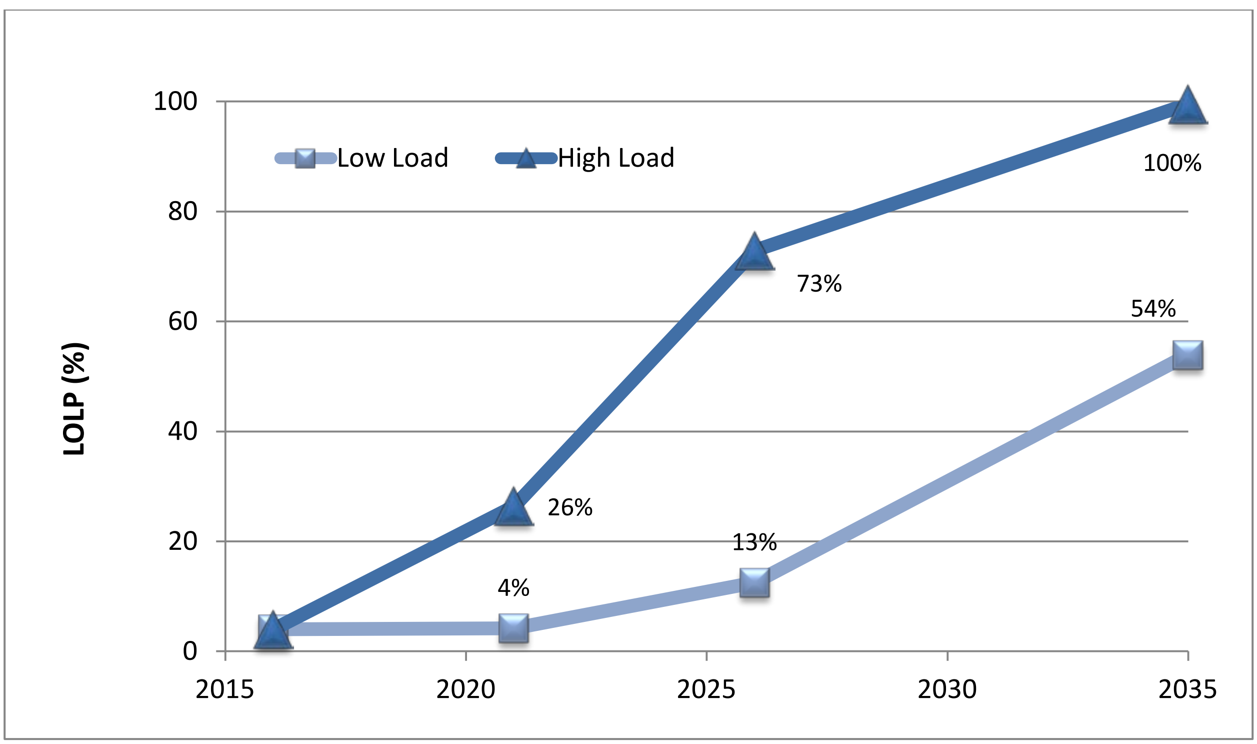
Projected Resource Shortfalls through 2035

The Council's resource needs assessment examines the loss-of-load probability for both the low and high load growth scenarios for 2021, 2026 and 2035. Those years are significant because they represent times with key resource retirements. The Boardman and Centralia 1 coal plants are scheduled to retire at the end of 2020. The second unit at Centralia and the North Valmy coal plants are expected to retire at the end of 2025. And, of course, 2035 is the end of the study horizon for the Council's Seventh Power Plan.

As illustrated in Figure 11 - 5, in every case except the 2021 low-load-growth scenario, the LOLP is greater than 5 percent (the Council's adequacy threshold). The LOLP grows to staggeringly high values over time because these analyses do not include any new generating resource additions or energy efficiency savings. In the extreme case, for 2035 under a high load growth scenario, there were very few simulations that did not have some kind of shortfall (the LOLP was just under 100 percent). This should not be a surprise since these studies, in effect, tell us what would happen if no resource actions were taken over the next 20 years.

But these results alone are not sufficient to inform resource planning. Based on these analyses, both the energy and capacity needed to get every point in Figure 11 - 5 down to a 5 percent LOLP can be determined. This information, in a slightly modified form is fed to the Regional Portfolio Model to ensure that the resulting resource strategy will provide an adequate supply.

Figure 11 - 5: Loss-of-Load Probability for the Needs Assessment (no new resources)



Resource Adequacy vs. Seventh Power Plan

The Council's latest resource adequacy assessment for the 2020 and 2021 operating years was released in May of 2015. Results indicate that the regional power supply is expected to remain adequate through 2020, assuming that the region continues to acquire the targeted Sixth Power Plan energy efficiency savings. In 2021, however, with the retirement of the Boardman and Centralia-1 coal plants[9] (1,330 megawatts of combined nameplate capacity), the report shows that the likelihood of a shortfall rises to a little over 8 percent, which is above the Council's 5-percent standard. Adding 1,150 megawatts of gas-fired generation would bring the 2021 loss-of-load probability back down to the 5-percent limit.

However, any comparison of the results of the Council's annual adequacy assessments with results from the multitude of scenarios examined while developing a power plan should be done with extreme caution. The adequacy assessment is intended to be a single-year spot check to indicate whether resource development is on track to maintain adequacy. Power plan analyses examine the operation and cost of thousands of different resource plans over a 20-year horizon, with many more future uncertainties than are accounted for in the adequacy assessment. However, in spite of these difficulties, certain specific years, with specific conditions can be compared so long as the differences in the purpose of these two analyses are understood.

One of the major differences between these two approaches is that power plan analyses use the Council's frozen efficiency load forecasts, which do not include any new energy efficiency measures but do incorporate the effects of standards and codes. In contrast, the loads forecast used to assess resource adequacy come from the Council's short-term model, which does include trends for future energy efficiency but does not account for standards and codes. Also, the frozen efficiency loads are weather normalized whereas loads used for the adequacy assessment are temperature dependent.

On the resource side of the equation, for the Seventh Power Plan the Council has amended the hydroelectric system capability to reflect a greater allocation of that resource to carry regional within-hour balancing reserves. This reduces hydroelectric system peaking capability to serve firm on-peak loads by about 1,000 megawatts[10] compared to the capability used for the May 2015 adequacy assessment, which only assumed the Bonneville Power Administration's balancing reserves.

The 2021 resource adequacy assessment loss-of-load probability was reported as about 8 percent and included about 1,700 average megawatts of expected new energy efficiency. The 2021 power plan frozen efficiency loss-of-load probability is on the order of 15 percent (for the medium load forecast) and includes no new energy efficiency but does incorporate savings from standards and

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[9] Boardman and Centralia 1 coal plants are scheduled to retire in December of 2020. However, because the Council's operating year runs from October 2020 through September 2021, these two plants would be available for use during the first three months of the 2021 operating year. For this scenario, the LOLP is 7.6 percent. The Council must take into account the long term effects of these retirements and, therefore, uses the more generic study that has both plants out for the entire operating year.

[10] Actual reduction in peaking capability depends on a number of different parameters and can fluctuate from near zero in some periods to over 1,000 megawatts in others.

codes. It also assumed the reduced hydroelectric system capability, adjusted to reflect regional balancing reserves.

To get the 2021 resource adequacy assessment LOLP down to the 5-percent standard, 1,150 megawatts of gas-fired generation were added to the expected 1,700 average megawatts of new energy efficiency savings. To get the 2021 power plan LOLP down to the 5-percent standard, the Council's Regional Portfolio Model shows an average addition of 2,380 average megawatts of new energy efficiency and about 1,300 megawatts of demand response, which for modeling purposes is equivalent to the addition of about 1,100 megawatts of gas-fired generation. Thus, in spite of the vastly different assumptions between these two cases, the overall conclusions are very similar. In both cases, the 2021 power supply would be inadequate under medium loads with no new resources or energy efficiency savings.

Assessing System Needs

The results described in the load-resource balance section above take a deterministic approach to assessing future resource gaps by simply comparing the expected low and high growth scenarios with expected resource availability and firm hydroelectric generation. To make this accounting a bit more useful, planners generally add a reserve margin to the load forecast, to account for various future uncertainties. The implied target for resource acquisition using this method is to exactly match resource capability with load plus reserves. However, this target does not guarantee that the resulting resource mix will be adequate, that is, that its loss-of-load probability will be 5 percent (or less).

A more precise and sophisticated approach to assessing resource needs is to calculate the LOLP for various years along the study horizon for both the low and high load forecasts, as was illustrated in the previous section. Then by examining the resulting record of potential shortfalls, the amount of peaking need (capacity) and annual generation need (energy) can be calculated.

For energy needs, the total amount of annual energy curtailment is tallied for every simulation. Every combination of water condition (80) and temperature profile (77) was examined, making the total number of simulations 6,160. Assuming the likelihood of each simulation to be the same, the resulting curtailment records are sorted from highest to lowest. Figure 11 - 6 shows the resulting curve, with annual energy curtailment on the vertical axis and probability of occurrence on the horizontal axis. The highest point on that curve represents the annual curtailment under the worst conditions across all simulated futures. The likelihood of that occurring is one in 6,160 – a very small percentage. The point at which the curve hits zero is close to the LOLP for this case.[11] A line drawn vertically up from the 5-percent mark on the horizontal axis crosses the curve at about 27 average megawatts on the vertical axis. This means that if we were to add 27 average megawatts of energy to the power system, the entire curve would shift down and cross zero at the 5 percent mark – yielding close to a 5 percent LOLP.

[11] These curtailment values have not been adjusted for standby resource offsets.

Figure 11 - 7 provides an example for capacity needs. Each point on that curve represents the highest single-hour curtailment for each simulation. Again there are 6,160 simulations. Using the same method as above, that figure shows that adding 6,000 megawatts of capacity would drop the curve so that it crosses zero at the 5 percent mark. So, for our simple example, it would take 6,000 megawatts of capacity combined with only 27 average megawatts of energy to get us close to a 5 percent LOLP.

Of the 6,000 megawatts of capacity that would be added to this system, some of that additional capacity would only be used about 40 hours per year. This describes a system that is capacity short. By providing the RPM with specific and separate energy and capacity needs, it can pick and choose from a variety of resources (each of which has defined energy and capacity components) to determine the most cost-effective solution to best fill the capacity and energy needs, while minimizing the likelihood of overbuilding.

Results of this analysis indicate that the region's power supply is capacity short and energy long – a similar conclusion drawn from the load-resource balance calculations. By 2035, under the low-load-growth forecast, the region will need only about 50 average megawatts of energy but about 4,300 megawatts of capacity to maintain a 5 percent LOLP. Under the high-load-growth forecast, the region will need about 800 average megawatts of energy and about 10,600 megawatts of capacity.

Figures 11 - 8 and 11 - 9 show the actual model output duration curves[12] for energy and peak curtailment for the years examined in this analysis. Tables 11 - 4 and 11 - 5 summarize the energy and capacity needs.

[12] These figures show the curtailment duration curves from the GENESYS analysis prior to being adjusted for standby resources.

Figure 11 - 6: Annual Energy Curtailment Duration Curve

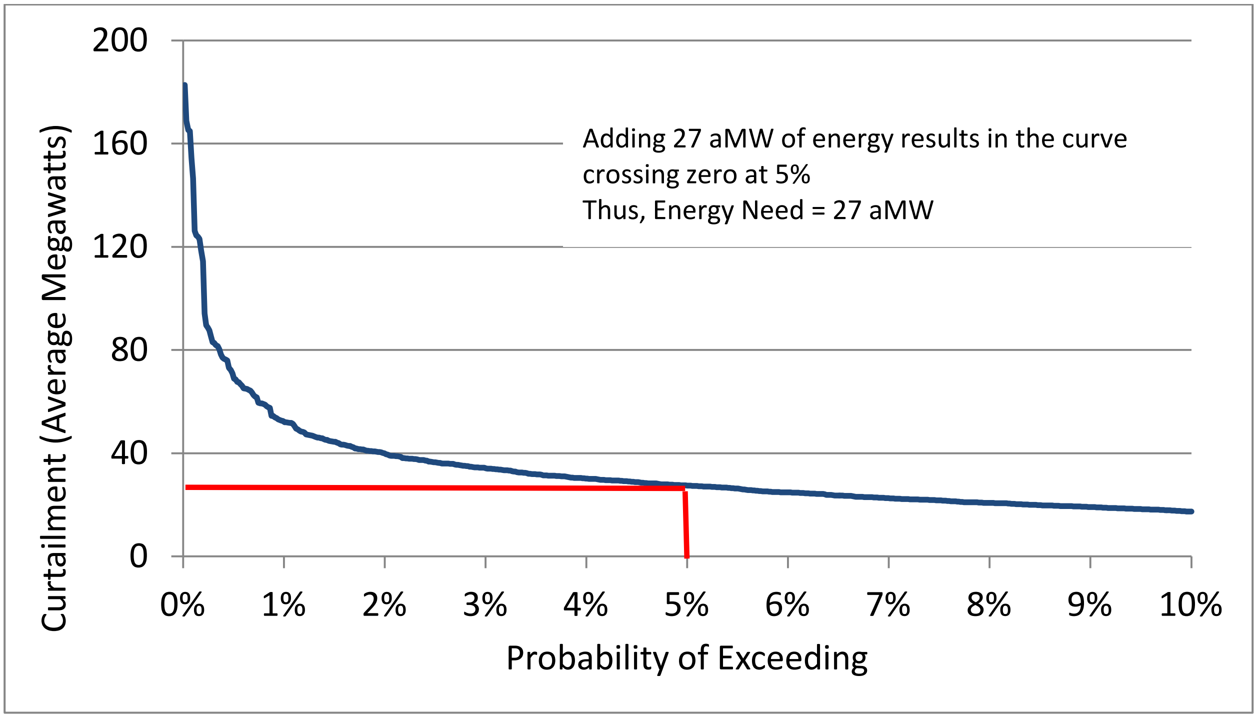


Figure 11 - 7: Peak-Hour Curtailment Duration Curve

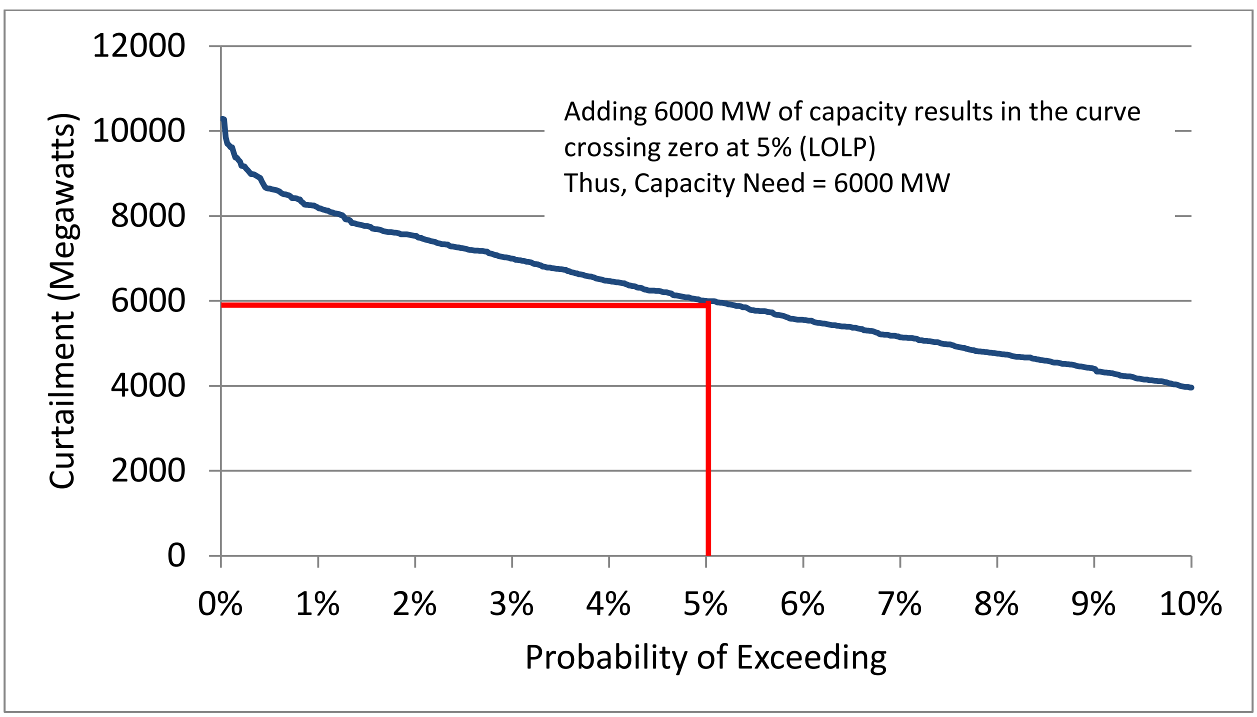


Figure 11 - 8: Annual Energy Curtailment Duration Curve

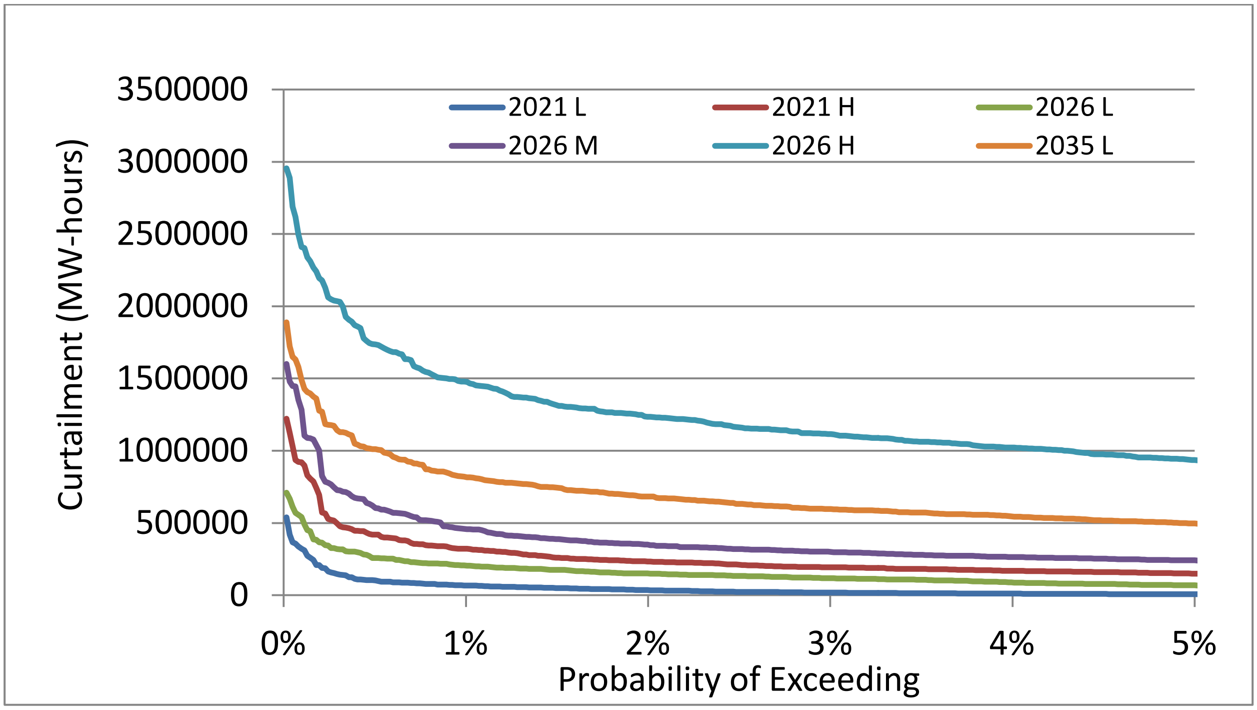


Figure 11 - 9: Peak-Hour Curtailment Duration Curve

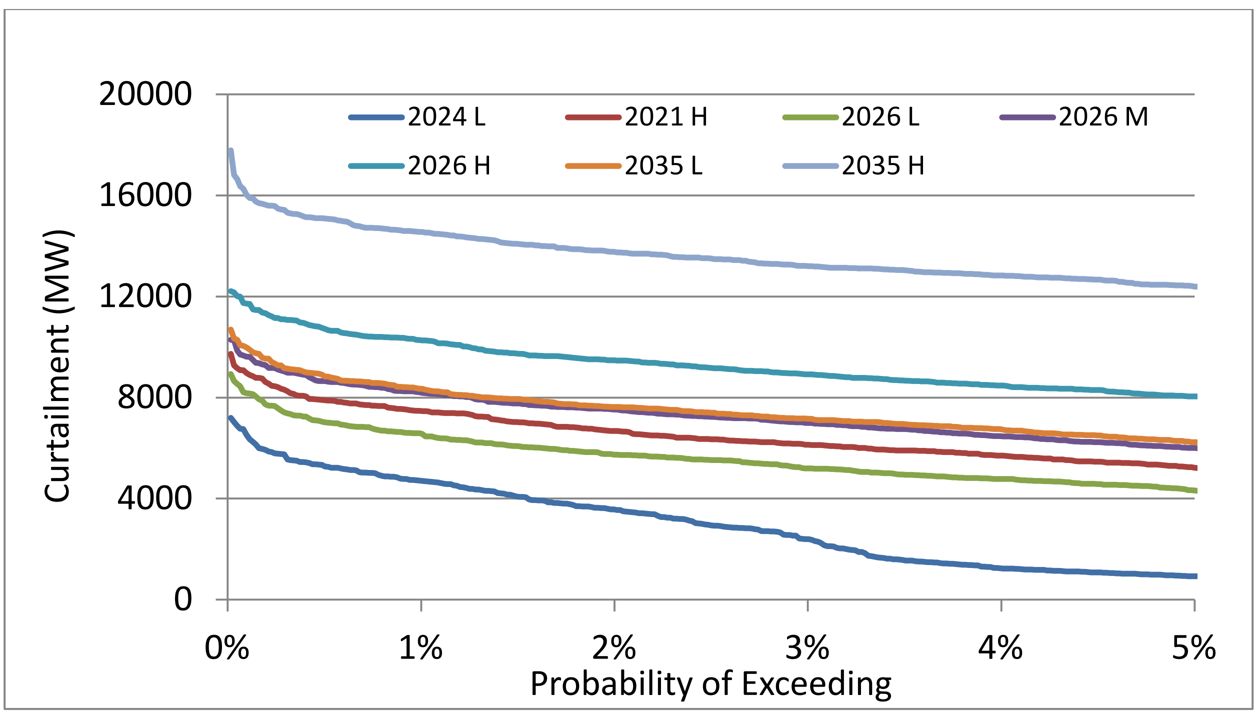


Table 11 - 4: Energy Needs (average megawatts)

Load Forecast	2021	2026	2035
Low	0	5	55
High	15	105	800

Table 11 - 5: Capacity Needs (megawatts)

Load Forecast	2021	2026	2035
Low	0	1,945	4,315
High	3,010	5,850	10,570

INCORPORATING ADEQUACY INTO THE PLAN

The resource needs assessment is valuable because it gives planners an indication of the range of potential energy and capacity needs the region may need over the next 20 years. Of course, the Council's resource strategy, which is developed with the aid of the Regional Portfolio Model, is a much more robust and adaptable plan that covers a wider range of future uncertainties. To better ensure that the RPM will produce a resource strategy that does not violate the Council's 5 percent LOLP adequacy standard and also does not significantly overbuild, the energy and capacity needs identified in the GENESYS model are converted into adequacy reserve margins, which are used in the RPM as minimum resource build requirements.

Adequacy Reserve Margin

The Adequacy Reserve Margin (ARM) is a factor that permits the adequacy standard as tested in the GENESYS model, to be incorporated in the Regional Portfolio Model's resource development logic. In simple terms, is the amount of additional capacity and energy, relative to expected load, required to maintain an adequate power supply. It is similar to the planning reserve margin that utilities often use for long-term resource planning, except that the ARM is based on a probabilistic calculation of potential curtailments under uncertain future conditions. The ARM is measured in units of percent and is defined as the difference between the generating capability of rate-based resources and expected load divided by the load, for a system that just meets the Council's adequacy standard.

Table 11 - 6 provides the details of the ARM calculation for both energy and capacity for the 2026 medium load forecast case. Resources are aggregated by similar types. The line item for thermal

resources, for both energy and capacity ARM calculations, includes whatever additional amount of capacity and energy is needed for the power supply to comply with the Council's adequacy standard. ARMs are calculated for each season (quarter) of the year except for spring, when they are assumed to be zero due to the generally surplus conditions. The ARMs are listed beginning with the fourth quarter (October through December) because both the GENESYS model and the RPM work on an operating year basis, which begins in October. ARM values are affected by resource mix and by load shape, which means that different ARM values could be assessed for every year of the study horizon and for every load path assumed (low, medium and high). However, it has not been demonstrated that this level of detail is warranted. For the final RPM analyses, the Council chose to use the mid-study-horizon ARM values (2026), averaged over the three basic load forecasts. Table 11 - 7 provides the ARM values used in the final RPM analyses.

Table 11 - 6: Example of an ARM Calculation (2026 Medium Case)

Capacity – Adequacy Reserve Margin				
Resource Type	**ARMc Calculation**	**Q4**	**Q1**	**Q3**
Thermal	Winter Capacity * (1 – FOR)	15344	16013	15251
Wind	5% of Nameplate[13]	227	227	227
Hydro	P2.5% 10-hour Sustained Peak	16715	17790	15404
Firm contracts	1-Hour Peak	-225	-167	-631
Total Resource		**32060**	**33863**	**30250**
Load	1-Hour Expected Peak	32494	33521	28142
L/R Balance	Resource – Load	-434	342	2109
ARMc	**(Resource – Load)/Load**	**-1.3%**	**1.0%**	**7.5%**

Energy – Adequacy Reserve Margin				
Resource Type	**ARMe Calculation**	**Q4**	**Q1**	**Q3**
Thermal	Winter Capacity*(1 – FOR)*(1 – Maint)	10992	10990	11012
Wind	30% of Nameplate	1360	1360	1360
Hydro	Critical Year Hydro (FELCC)	11827	10642	10569
Firm contracts	Period Average	-325	-200	-802
Total Resource		**23853**	**22790**	**22138**
Load	Period Average (weather normalized)	23319	23536	22262
L/R Balance	Resource – Load	534	-745	-124
ARMe	**(Resource – Load)/Load**	**2.3%**	**-3.2%**	**-0.6%**

[13] The ARM calculation is based on the existing power supply. The peaking contribution for existing wind resources is assumed to be 5 percent, which is the same assumption used in the RPM. The associated system capacity contribution values for wind, which are not 5 percent, only apply to new wind resources.

The ARMs shown in Table 11 - 7 range from negative to positive values. Negative ARM values can be interpreted to mean that the load-resource balance in that quarter can be deficit (based on how resources are counted) and still provide an adequate supply. Positive values mean that surplus resources are needed to maintain adequacy. These values should not be confused with planning reserve margins, which are always positive. And, while ARM values may not be intuitive, the decisive observation is that they work, that is, when used in the RPM, resulting resource acquisitions are neither under built nor over built.

Part of the reason that ARM values are not intuitive is because they do not account for the nearly 3,000 megawatts of in-region IPP capability or the 2,500 megawatts of winter import capability. They also do not include the effects of using borrowed hydroelectric generation. The ARMs for both energy and capacity are fed into the RPM model as minimum build requirements for adequacy. In other words, as the RPM steps through the study horizon years, it will build sufficient resources to ensure that the minimum ARM requirements for both energy and capacity are met. Resulting resource mixes have proven to be adequate.

Table 11 - 7: 2026 Average Energy and Capacity ARM Values used in the RPM

2026	Q4	Q1	Q3
Capacity	-0.51%	0.65%	7.52%
Energy	1.97%	-3.09%	-0.37%

Associated System Capacity Contribution

As discussed earlier in this chapter, the Council has developed a new method to better assess the specific energy and capacity needs for inadequate future power supplies. The new method uses the projected likelihood and magnitude of future curtailments, simulated by the Council's GENESYS model, to calculate how much new capacity and new energy is required to keep future power supplies adequate.

In past plans, the Council estimated future <u>energy</u> needs[14] by determining how much of a load reduction (in percent) was required to satisfy the Council's adequacy standard and, for <u>capacity</u> needs, how much new generating resource (combined-cycle combustion turbine capability) was needed to do the same. However, load reductions and new generating resource additions both provide different amounts of energy and capacity components. So, while these analyses are useful in assessing the general magnitude of inadequacy, they do not provide a precise estimate of the specific amount of energy <u>and</u> capacity needed to bring the power supply into adequacy compliance. The Council's new method provides specific amounts of capacity and energy needed for adequacy.

[14] This is not to be confused with developing a resource acquisition strategy. It is simply an estimate of potential future needs, which is useful when evaluating various resource strategies.

And, as was discussed earlier, these values are used to calculate the adequacy reserve margins used by the Regional Portfolio Model.

It was discovered, however, that using the ARMs as the adequacy thresholds in the RPM led to overbuilt supplies. This is because the RPM does not explicitly model the effects of hydro-thermal interactions (or more specifically the effects of system storage). As an example, suppose that the capacity need for a particular scenario is 5,850 megawatts (the amount of additional capacity needed to get to a 5-percent LOLP assessed by using the Council's new method). A simple solution is to add 5,850 megawatts of combined cycle combustion turbine capability to the mix. However, when that study is analyzed, the resulting LOLP is zero, meaning that the supply is overbuilt. This occurs because the added turbine capacity provides more energy generating capability than is needed for adequacy. This additional combustion turbine energy is sometimes dispatched instead of hydroelectric generation, which can be saved to be used during hours when the need is greater. The additional energy component of the combustion turbine gives it a greater effective system capacity than its nameplate value. This effect occurs for all resources that can interact with system storage.

In the example above, a separate GENESYS analysis indicated that only 4,400 megawatts of new turbine capacity was needed to bring the LOLP down to the 5 percent standard. Thus, 4,400 megawatts of new combined-cycle turbine capacity provides the equivalent of 5,850 megawatts of effective system capacity (a ratio of about 1.3). To compensate for the lack of a dynamic hydroelectric algorithm in the RPM, capacity contributions for all new resources are adjusted to account for their effective system capacity. This multiplier referred to as the Associated System Capacity Contribution (ASCC) can be greater than one or less than one. For example, the ASCC for a gas-fired turbine is 1.28 for winter months whereas the ASCC for wind during the same period is only 0.03 (3 percent). When the RPM assesses whether the power supply meets the Council's adequacy standard (i.e. meets the minimum ARM build requirement), it uses the ASCC values for all new resources. Adding the ASCC multipliers has shown that resulting resource acquisitions out of various RPM futures neither over nor under builds for adequacy. Table 11 - 8 shows the current ASCC values for new resources used in the RPM.[15]

[15] It should be noted, that like the ARM values, ASCC values are factors that enhance the communication between the GENESYS and RPM models. As such, while the ASCC convey a sense of each resource's contribution to system peak, they are not equivalent to Firm Energy Load Carrying Capability (FELCC) and Effective Load Carrying Capability (ELCC) that are sometimes used estimate intermittent resource contribution to firm energy and dependable capacity respectively.

Table 11 - 8: ASCC Values

Resource	Q1	Q2	Q3	Q4
Solar PV	0.26	0.81	0.81	0.42
Energy Efficiency	1.24	1.01	1.14	1.16
Wind	0.03	0.11	0.11	0.08
Gas-Fired Turbine	1.28	1.00	1.02	1.20
Geothermal	1.28	1.00	1.02	1.20

Confirming that the RPM Produces Adequate Supplies

Ensuring that the Council's long-term resource strategy will lead to adequate supplies is a separate issue from assessing the adequacy of the existing power system. This section describes how those analyses differ and how the Council's resource adequacy standard is incorporated into its planning models to ensure the adequacy of future power supplies.

The Northwest resource adequacy standard is based on a probabilistic metric defined by the Council that indicates whether existing resource capability is sufficient to meet firm loads through the next five years. That assessment takes into account only existing resources, targeted energy efficiency savings and new resources that are expected to be completed and operational during that time period. If a deficiency is identified, then specific actions are initiated. Those actions include reporting the problem, validating load and resource data and identifying potential solutions. This process is intended to be an early-warning for the region that indicates whether the capability of the existing power system sufficiently keeps up with load.

Although similar, an adequacy assessment for a resource strategy differs in significant ways. First, a resource strategy spans a much longer time period, namely 20 years. Second, a strategy implies that resource development will be dynamic, in other words, resource development depends on what future conditions are encountered. The adequacy of a single resource plan (i.e. the resource construction dates for a specific future) can be assessed, but that is not the same as assessing the adequacy of the strategy itself.

To ensure that the power plan's resource strategy will provide an adequate supply, adequacy reserve margins have been added to the portfolio model as minimum resource acquisition limits. In other words, if the model's economic resource acquisition does not measure up to the energy or capacity ARM thresholds; new resources will be added until ARM conditions are satisfied. When checking to see if the capacity ARM is satisfied, the associated system capacity contributions for all new resources are used.

In order to test that the ARM requirement produces an adequate supply, the LOLP for specific years, out of specific futures from the RPM analysis can be assessed. The test is considered successful if the LOLP is close to the Council's 5 percent standard. In practice, however, due to the "lumpiness" of resource size and due to lead-time considerations and uncertainty in load, a test would be considered successful if the resulting LOLP falls within a range of about 2 to 5 percent. These tests have been done for various load forecasts over various time periods and the results show that for cases when the loads are equal to or greater than the medium forecast, resulting LOLP values tend to fall between the 2 and 5 percent acceptable margin. For low load cases, resulting LOLP values are commonly close to zero because in these cases the RPM builds for economy and not for adequacy.

ARM vs. Planning Reserve Margin

As previously mentioned, the ARM is very similar to the more common planning reserve margin (PRM) used by most utilities for long-term resource planning. The PRM defines the amount of surplus capacity needed (above expected peak-hour load) to cover variations in loads and resources due to uncertain future conditions. Theoretically, building sufficient resources to meet the PRM should provide an adequate supply.

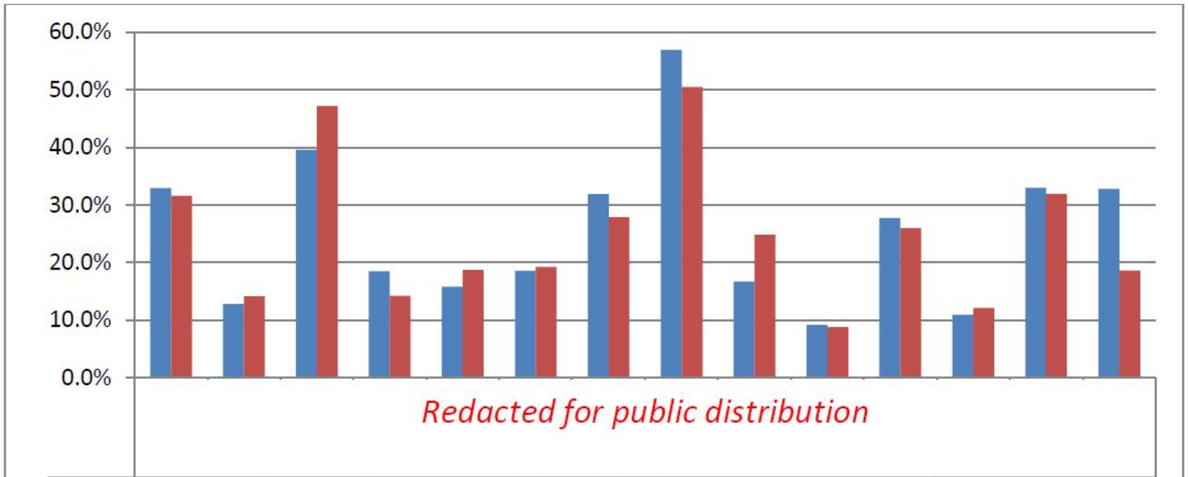
In practice the PRM has generally been developed using a "building block" approach. That is, additional reserves are added to the operating reserve to cover extreme temperatures and other future uncertainties.

For example, the Northwest Power Pool starts with an operating reserve of 7 to 8 percent (to cover contingencies and regulation). It then adds another 3 to 10 percent to cover prolonged resource outages. To that, it adds 1 to 10 percent to cover variations in weather, economics, general growth and new plant delays. The final planning reserve margin ranges from 11 to 28 percent for all future years.

The Western Electric Coordinating Council (WECC) also has used a building block approach to developing its PRM. The WECC begins with a 6 percent contingency reserve and adds to that 5 percent for regulation, 4 percent for additional outages and 3 percent for temperature variation. Their final PRM is 18 percent.

Figure 11 - 10 illustrates other planning reserve margins for various areas around the United States. The PRMs range from a low of about 12 percent to a high of over 50 percent. It is difficult to compare PRMs across utilities, however, because different utilities face different future uncertainties. To make matters more difficult, some areas do not even account for all future uncertainties when they calculate their PRMs. It should be noted that in recent years, a number of utilities in different areas in the country have begun to use probabilistic methods, similar to the Council's, to develop planning reserve margins.

Figure 11 - 10: Example of Planning Reserve Margins from around the United States



2011	32.9%	12.9%	39.6%	18.5%	15.8%	18.6%	31.9%	56.9%	16.7%	9.2%	27.7%	10.9%	32.9%	32.8%
2014	31.6%	14.2%	47.2%	14.2%	18.7%	19.2%	27.9%	50.5%	24.9%	8.8%	26.0%	12.2%	31.9%	18.7%

CHAPTER 12: CONSERVATION RESOURCES

Contents

List of Figures and Tables

For most of this chapter the Council presents results using the medium range of the forecast. In the section entitled "Total - All Sectors", the Council includes the entire range of uncertainty regarding the drivers. This is done to reinforce the fact that the future is uncertain. The Council's planning process does not use a single deterministic future to drive the analysis. The stochastic variation introduced in the Regional Portfolio Model tests a wide range of future uncertainties in load, fuel prices, etc.

KEY FINDINGS

The Northwest Power Act defines conservation as reduced electric power consumption as a result of improved efficiency in energy use. This means that less electricity is needed to provide the same level of services. Conservation resources are measures that ensure that new and existing residential buildings, household appliances, internal and external lighting systems, new and existing commercial buildings, commercial-sector appliances, commercial infrastructure such as street lighting and sewage treatment, and industrial and irrigation processes are energy efficient. These efficiencies, when cost-effective, reduce operating costs by cutting back on the operation of the least-efficient existing power plants; ultimately reducing the need to build new power plants and expand transmission and distribution systems. Conservation also includes measures to reduce electrical losses in the region's generation, transmission, and distribution systems where the measures result in a reduction in electrical power consumption.

The Council's assessment of conservation resources includes six major updates since the Sixth Power Plan:

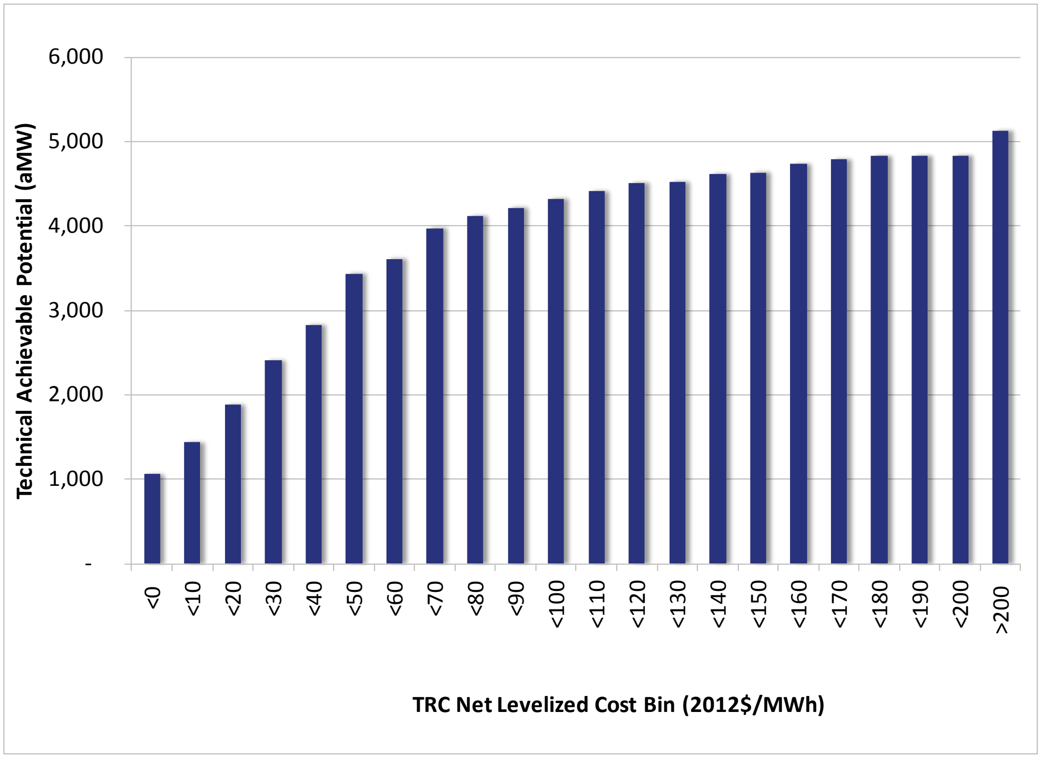
1. Accounting for utility conservation programs and other savings since 2010, including removal of measures that have saturated the market (e.g. LED TVs).
2. Adjusting both the load forecast[1] and the conservation assessment to reflect improvements in federal and state standards for lighting, appliances, and other equipment.
3. Adding potential savings from new technologies and practices that have matured to commercial readiness since the development of the Sixth Power Plan's estimates.
4. Updating estimates of energy equipment saturation, gas and electric fuel shares, and other key building characteristics from the residential, commercial, and industrial stock assessments.
5. Updating forecasts of the number of new homes, businesses, and farms.
6. Updating costs to be in 2012 constant dollars.

The Council identified around 5,100 average megawatts[2] of technically achievable conservation potential in the medium demand forecast by the end of the forecast period. Not all of the conservation potential identified is cost-effective to develop in all future scenarios; nor is all of it immediately available. The Council uses its regional portfolio model (RPM) to identify the amount of conservation that can be economically developed. The results presented in this chapter serve as an input to the RPM, which tested varying amounts and pace of conservation development against other resource options across a wide range of future conditions. The results of the RPM analysis are presented in Chapter 15.

[1] See Chapter 7 for details on the load forecast
[2] All savings values are at busbar.

The total technical achievable potential in 2035 by total resource cost (TRC) net levelized cost[3] bin is shown in Figure 12 - 1. Around 4,300 average megawatts of conservation are available at costs less than $100 per megawatt-hour (2012$). Another 800 average megawatts are available at costs above $100 per megawatt-hour.

Figure 12 - 1: Technical Achievable Conservation Potential in 2035 by Levelized Cost



The achievable savings break down by sector as follows:

- Over 2,300 average megawatts of conservation are technically achievable in the residential sector. Most of the savings come from improvements in water-heating efficiency, lighting efficiency, and heating, ventilating, and air-conditioning (HVAC) efficiency.

- Nearly 1,900 average megawatts of potential savings are available in the commercial sector. Nearly two-thirds of these potential savings are in lighting systems. New technologies like solid-state lighting (LEDs) and improved lighting fixtures and controls offer added potential savings in both outdoor and indoor lighting. Savings in ventilation, server rooms, and other ‘plug loads’[4] account for much of the remainder.

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[3] TRC net levelized cost includes all quantifiable costs and benefits directly attributable to the conservation measures such as changes in consumption of other-fuels, operations and maintenance expenses, non-electric costs or benefits such as water savings, and environmental costs and benefits. Further discussion is in the Methodology section.

[4] Plug loads are those from equipment that is plugged into a wall outlet; e.g. computers, copiers, monitors and other peripherals.

- Potential savings in the industrial sector are estimated to be around 580 average megawatts by the end of the forecast period. The industrial assessment found that effective business management practices could significantly increase savings from equipment and system optimization measures.

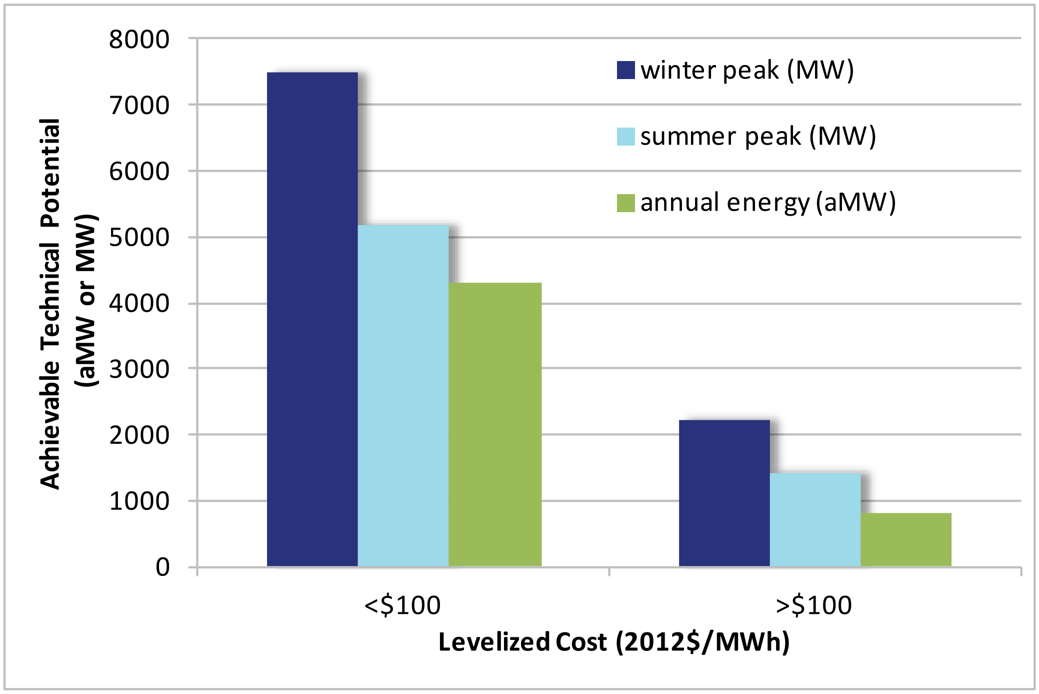
- Approximately 130 average megawatts of conservation are available in the agriculture sector through irrigation system efficiency improvements, improved water management practices, and more efficient dairy milk processing.

- Finally, potential savings from improved efficiency in utility distribution systems are estimated to be over 200 average megawatts by the end of the forecast period.

In addition to providing energy benefits, conservation measures also provide capacity benefits. Using best-available load shapes by measure category, the Council estimates the 5,100 average megawatts of energy translates to 9,700 megawatts of capacity savings during the regional peak winter hour (6pm on a weekday in December, January, and February) and 6,600 megawatts of capacity savings during the regional peak summer hour (6pm on a weekday in July and August).[5] The peak and energy impacts by total resource cost (TRC) net levelized cost bins of below and above $100 per megawatt-hour are provided in Figure 12 - 2. TRC net levelized cost includes all quantifiable costs and benefits directly attributable to conservation measures such as changes in consumption of other-fuels, operations and maintenance expenses, non-electric costs or benefits such as water savings, and environmental costs and benefits and is described further in Appendix G.

[5] The peak impacts presented in this Chapter do not include the Associated System Capacity Contribution (ASCC). For more information on the ASCC, see Chapter 11.

Figure 12 - 2: Peak and Energy Impacts by Levelized Cost Bundle for 2035



The availability of energy efficiency over time is another key aspect of this resource assessment. Many resources (such as new water heaters) only become available at the point of equipment turnover or new construction. Other resources (such as insulation upgrades), while technically available immediately, will only be achieved over time due to infrastructure and resource constraints. To account for this, the Council applied ramping assumptions to estimate the proliferation of each conservation measure over time. The maximum potential by cost bin is provided for each year in Figure 12 - 3 and Figure 12 - 4. Figure 12 - 3 illustrates the availability for the Council's entire 20-year plan horizon and Figure 12 - 4 for the first six-year period only.

Figure 12 - 3: Maximum Cumulative Availability of Conservation Resources Over 20-year Plan Period

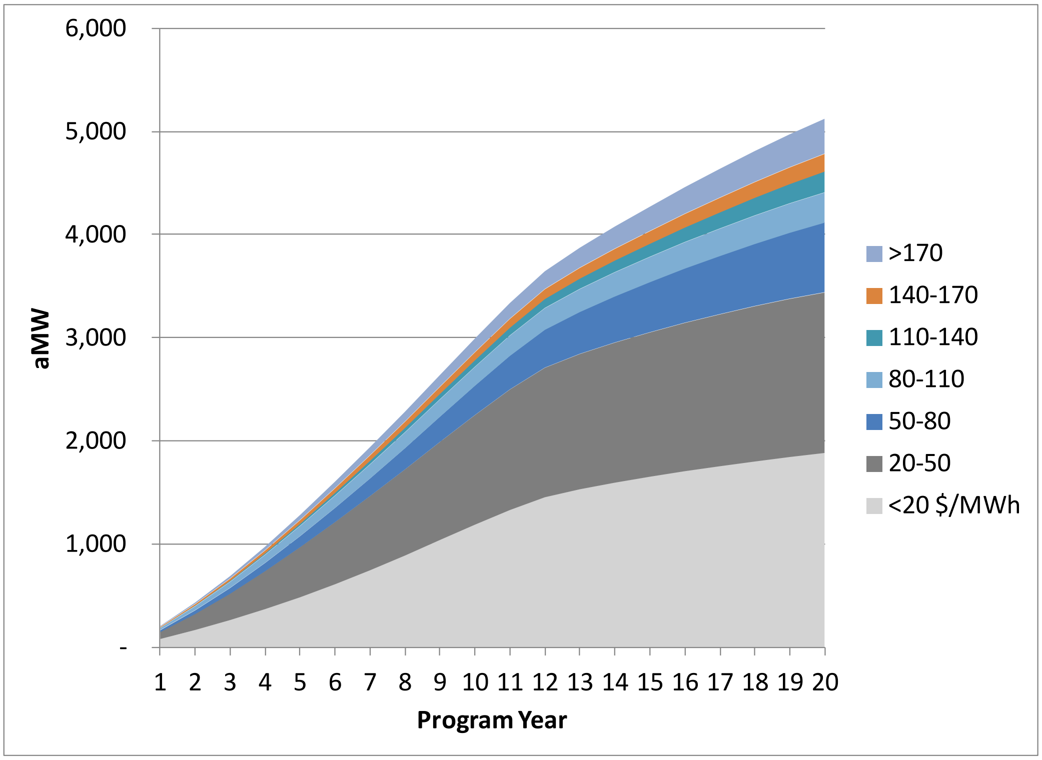
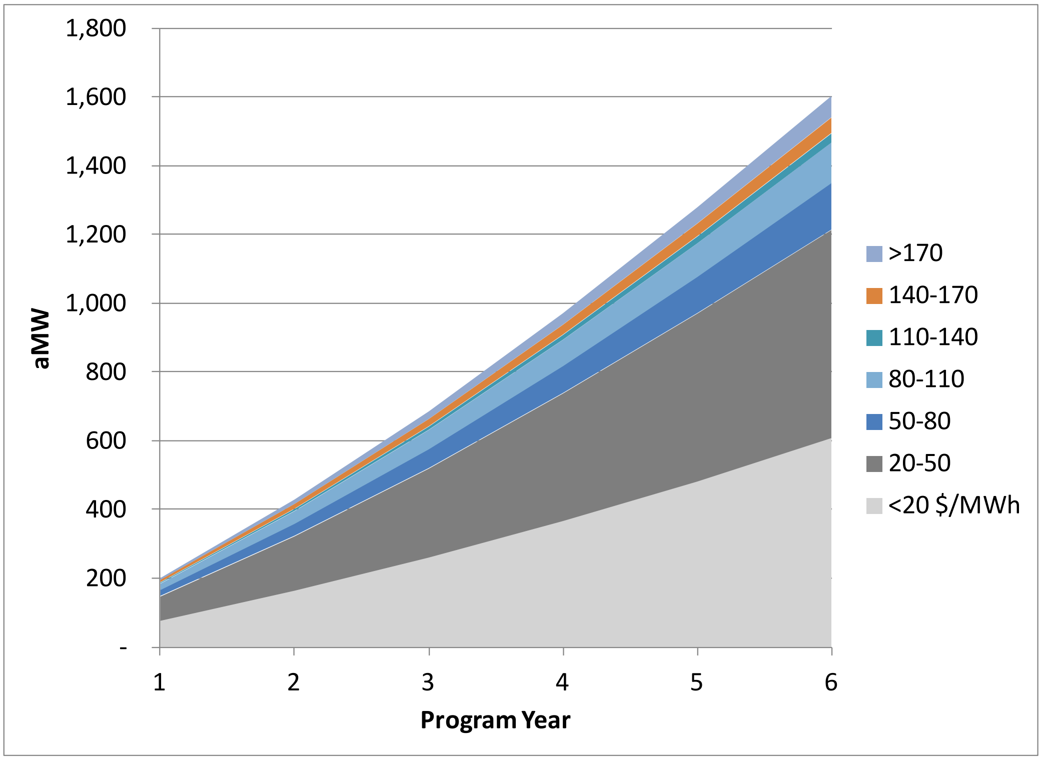


Figure 12 - 4: Maximum Cumulative Availability of Conservation Resources Over First Six Years



OVERVIEW

The conservation supply curves described in this chapter serve as *inputs* to the Regional Portfolio Model (RPM).[6] The RPM provides the Council with least-cost and least-risk portfolios of resources that include a specific amount of conservation for each resource strategy. Based on analysis of the RPM results, input from constituents, review of historical achievements, and other factors, the Council establishes new multi-year conservation targets. These targets are described in the Action Plan and in Chapter 3 on the Resource Strategy.

Power Act Requirements for Conservation

The method to determine conservation potential is outlined in the Northwest Power Act. The Act establishes three criteria for determining which conservation resources are analyzed and included as cost-effective resources. Resources must be 1) reliable, 2) available within the time they are needed, and 3) available at an estimated incremental system cost no greater than that of the least-

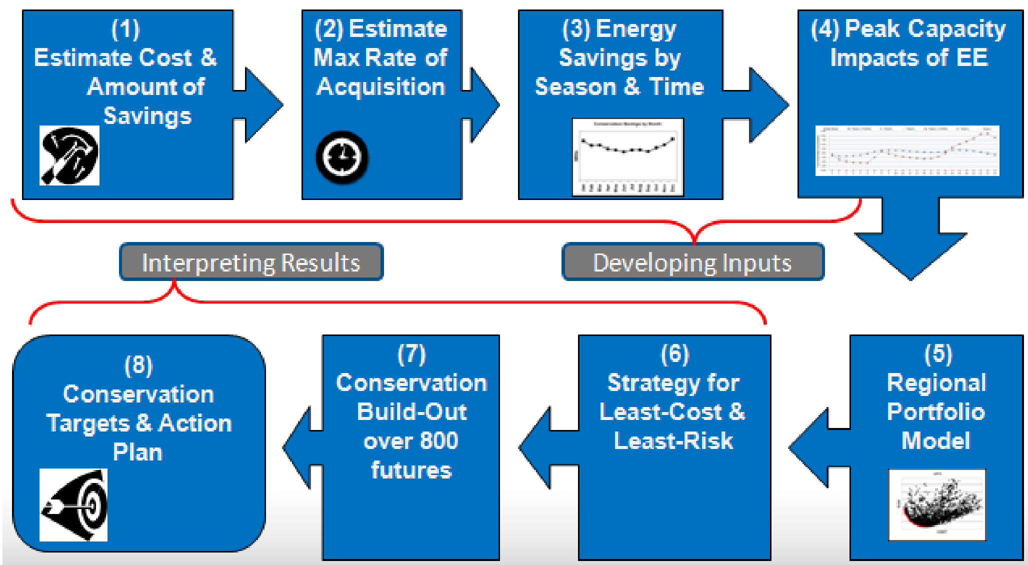
[6] See Chapter 15.

cost similarly reliable and available alternative.[7] Beginning with its first power plan in 1983, the Council interpreted these requirements to mean that conservation resources prioritized in the plans must be:

- Technically feasible (reliable)
- Achievable (available)
- Economically feasible (lower cost)

Each of these characteristics is discussed below. This chapter focuses on the first two elements – determining which conservation resources are reliable and available. Economic feasibility is determined through analysis of all resources within the RPM. The Regional Power Act also specifies that conservation resources get a 10 percent advantage when compared to non-conservation resource.[8] The Council's regional conservation target setting process is illustrated in Figure 12 - 5.

Figure 12 - 5: Approach to Setting Conservation Targets



Details for developing inputs are provided in the Methodology section below and in Appendix G (Conservation Resources and Direct Application Renewables). Chapter 15 (Analysis of Alternate Resource Strategies) provides details on interpreting the results.

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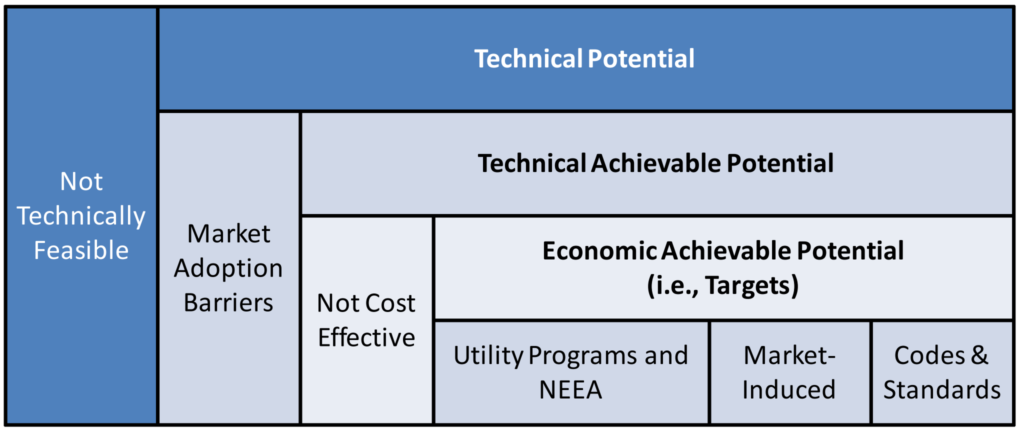
[7] See Section 839a(4)(A)(i) and (ii) of the Northwest Power Planning and Conservation Act. This section defines "cost-effective" as a measure or resource that is forecast to be "reliable and available within the time it is needed… to meet or reduce the electric power demand, as determined by the Council or the Administrator, as appropriate, of the consumers of the customers at an incremental system cost no greater than that of the least-cost similarly reliable and available alternative measure or resource, or any combination thereof."

[8] See Section 839a(4)(B) of the Northwest Power Planning and Conservation Act.

Estimating Conservation Potential

The Council considers three factors in ascertaining the cost-effective conservation potential of particular measures: technical feasibility, technical achievability and economic achievability. When each of these factors is applied, it results in different levels of potential: technical, technical achievable, and economic achievable. The relationship among the three factors and level of potential is illustrated in Figure 12 - 6.

Figure 12 - 6: Levels of Conservation Potential



Adapted from National Action Plan for Energy Efficiency[9]

Technical potential assumes that the most energy-efficient measures considered are installed everywhere they are technically feasible. The measures must be commercially available and reliable. The Council also considers emerging technologies for efficiency, but may not include them in the supply curve, depending on the Council's assessment of their current reliability. Rather, they are treated in a separate emerging technology scenario, described in the Emerging Technology scenario section. After the assessment of technical feasibility, the next step is to apply market barriers. The Council assumes that up to 85 percent of all technical potential can be achieved by the end of the plan period (20 years) to determine the technically achievable potential. Finally, through the RPM, the Council looks at whether potential conservation measures are economically achievable. This potential is then translated into savings targets, to be achieved from utility programs, market transformation activities of the Northwest Energy Efficiency Alliance (NEEA), and activities outside of programs including market-induced savings and savings from codes and standards (also known as momentum savings).

[9] National Action Plan for Energy Efficiency (2007). *Guide for Conducting Energy Efficiency Potential Studies*. Prepared by Philip Mosenthal and Jeffrey Loiter, Optimal Energy, Inc. <www.epa.gov/eeactionplan>

Distributed photovoltaics (PV) are not part of the conservation supply curves for the Seventh Power Plan, but are included as a direct application renewable (DAR) and discussed separately, along with solar water heaters.

Conservation Resource Characteristics

The cost, amount, energy and capacity contributions, and availability of conservation measures over time are key characteristics that the Council uses to compare them with generating resources, power purchases, and demand response programs.

Levelized total resource cost (TRC) of conservation is used to compare costs with other resources (more specifically, TRC is the net levelized cost in 2012 dollars per megawatt-hour). The amount of conservation resource is expressed in both energy and capacity savings. The annual, seasonal, and heavy-versus-light load hour energy uses are compared. Energy use is usually denominated in average megawatts. The effect of conservation on capacity is measured in megawatts and is estimated at the time of electric system peak. The availability of conservation over time is another key resource characteristic. Availability over time can include annual total buildable energy and capacity and the maximum rate of increased acquisition from year to year. Finally, each conservation measure is described in terms of the decision event for its adoption. Some measures are retrofit measures that can be adopted any time. For others, referred to as “lost-opportunity” measures, the adoption decision occurs only when an appliance or piece of equipment is purchased for a new installation or to replace burned-out equipment.

These resource characteristics are described for each conservation measure analyzed by the Council. The measures and their key characteristics are then combined into conservation supply curves for resource modeling. To simplify analysis, conservation resources are grouped into bins of similar cost based on levelized cost per megawatt-hour.

Although the Council includes much of the universe of measures into the supply curves, not all measures were included due to lack of data during time of supply curve development. This does not imply that the missing measures are not viable options for conservation. A list of missing measures that may prove to be viable options is provided in Appendix G.

Methodology for Determining Conservation Potential

The first step in the Council’s methodology is to identify all of the technically feasible potential conservation savings in the region. This involves reviewing a wide array of commercially available technologies and practices for which there is documented evidence of electricity savings, accounting for current baseline conditions. For example, measures need to be more efficient than current codes and standards. Around 100 conservation measure bundles were evaluated in developing the conservation potential for the Seventh Power Plan and more than1,600 measure permutations are combined into the conservation supply curves. [10] This first step also involves determining the number of potential applications in the region for each of these technologies or practices. For example, electricity savings from high-efficiency water heaters are only “technically feasible” in homes that have, or are forecast to have, electric water heaters. Similarly, increasing attic insulation in homes can only produce electricity savings in electrically heated homes that do not already have fully insulated attics.

The Council next determines the levelized total resource cost of energy savings from all measures that are technically feasible. TRC net levelized cost includes all quantifiable cost and benefits directly attributable to the conservation measures such as changes in consumption of other-fuels, operations and maintenance expenses, non-electric costs or benefits such as water savings, and environmental costs and benefits.[11] Benefits include deferred transmission and distribution expansion costs on the electric system if measures reduce coincident peak load. Estimating TRC net levelized cost requires comparing all the costs of a measure with all of its benefits, regardless of who pays those costs or who receives the benefits. In the case of efficient clothes washers, the cost includes the difference (if any) in retail price between the more efficient ENERGY STAR model and a standard efficiency model, plus utility program administrative and marketing costs.[12] On the other side of the equation, benefits include the energy and capacity savings, as well as water and wastewater treatment savings.[13] While not all of these costs and benefits are paid by or accrue to the region’s power system, the total resource cost perspective is used because all costs must be included in resource comparisons and because, ultimately, it is the region’s consumers who pay the costs and receive the benefits. For some measures, TRC net levelized cost is less than zero because electric plus non-electric benefits exceed cost.

The Council’s analysis assumes conservation measures comply with environmental regulations and thus incorporate any cost associated with compliance. In developing its methodology for determining quantifiable environmental costs and benefits, the Council also considered assessing benefits of environmental effects after compliance with environmental regulations. Health benefits are one example of environmental benefits that may be directly attributable to some conservation measures. For example, installing energy-efficiency measures that improve the heating efficiency of a home where wood is burned for heat may result in less burning of wood and thus reduced harmful particulate air emissions. For example, installing a ductless heat pump, which is often in the same room as the existing stove, might result in a homeowner relying more on the ductless heat pump to stay warm and, in return, less on the wood stove.

[10] Measure bundle, measure, and measure permutation represent different levels of aggregation, where the permutation is the most disaggregated. For example, a low-flow showerhead represents a measure bundle, 1.5 gallons-per-minute showerhead represents a measure, and a 1.5 GPM showerhead in a single-family home represents a permutation.
[11] See Appendix G for a detailed description of the components and calculation of TRC levelized cost.
[12] For the Seventh Plan, administrative costs are approximated to equal 20 percent of the measure’s incremental cost.
[13] Energy-efficient clothes washers use less water.

The contract analysts of the Council's Regional Technical Forum investigated whether health benefits from reduced wood smoke can be directly attributed to energy-efficiency program activity, and whether these benefits can be quantified and monetized given the current state of science.[14] A significant portion of electric heated homes in the Northwest use supplemental wood heating and careful analysis can show a reduction in wood use due to efficiency programs aimed at reducing space heating. The report concludes that the health effects resulting from changes in wood smoke emissions due to some efficiency programs could be quantified using the methodology that air regulators rely on. But this would require a comprehensive and costly analysis on a measure by measure basis.

For a variety of reasons, the Council decided that it is not possible to develop quantitative cost estimates related to health benefits from reduced wood smoke resulting directly from energy efficiency measures and add them into the new resource cost estimates in any consistent and reasonable way for the Seventh Power Plan.[15] At the same time, the Council recognizes the very real environmental and human health benefits that result from energy-efficiency investments that lead to a reduction in particulate emissions.

The energy savings and costs for each measure are incremental to its baseline energy use. This baseline is determined either by market practice or the pertinent code or standard. For example, the savings from a high-efficiency refrigerator are incremental to an estimate of the average efficiency energy use of refrigerators sold within the region. Where applicable, the assumptions are equivalent to those used by the Regional Technical Forum (RTF) in establishing the unit energy savings for reviewed measures.

The estimates of health impacts from reduced wood smoke have wide error bounds. As an example, a screening analysis on impacts of a region wide ductless heat pump program was conducted by Regional Technical Forum contract analysts. The analysis indicated that the monetary value of health benefits ranged from about 20 percent to 200 percent of the value of the electricity saved.

The total technical potential is determined by the per-unit savings multiplied by the number of units in the region. Using the refrigerator example again, the Council estimates (generally from secondary data such as regional stock assessments) the total number of refrigerators per household. This, multiplied by the number of households in the region, will provide the total number of refrigerators within the region. The total regional potential is then calculated by the total number of units times the savings per refrigerator. In addition, the annual technical potential accounts for the turn-over rate of refrigerators. That is, a refrigerator lasts approximately 15 years; as such, the Council estimates that each year 1/15 of all refrigerators in the region are replaced.

[14] Preliminary Report: Quantifying the Health Benefits of Reduced Wood Smoke from Energy Efficiency Programs in the Pacific Northwest RTF Staff Technical Report November 4, 2014
[15] The Council's methodology for determining quantifiable environmental benefits is described in Chapter 19.

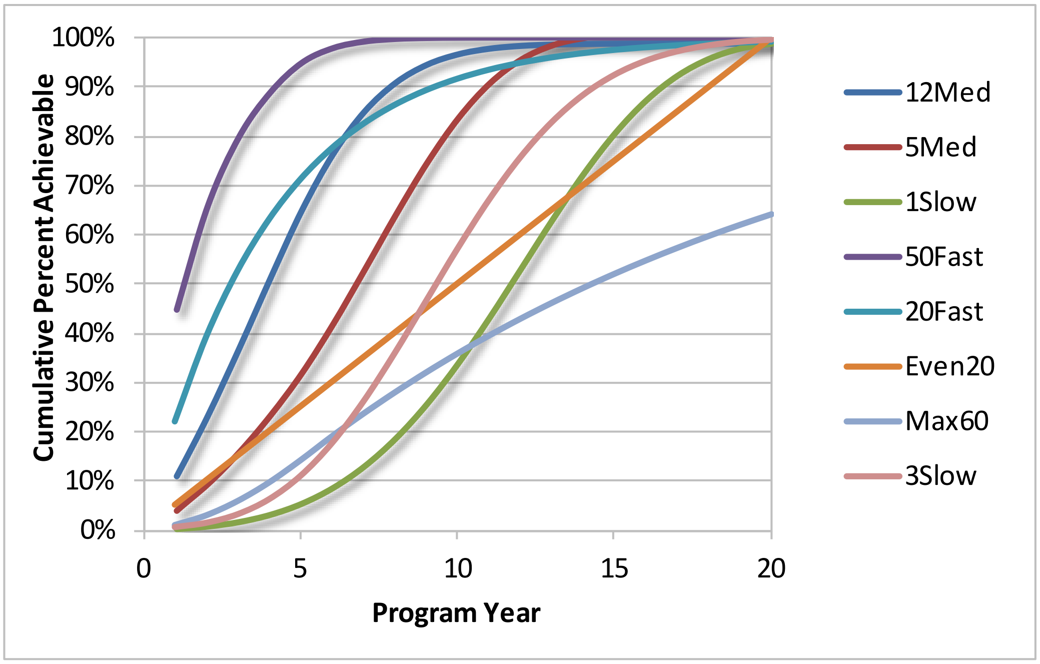
The technical achievable potential is the technical potential multiplied by two factors: the maximum achievable acquisition assumption and the annual acquisition ramp rate (step two in Figure 12 - 5). The first factor assumes that no more than 85 percent of the total potential could be acquired over the 20-year plan period.[16] The second factor is the rate of annual deployment, which represents the upper limit of annual conservation resource development based on implementation capacity. Such constraints include the relative ease or difficulty of market penetration, regional experience with the measures, likely implementation strategies and market delivery channels, availability of qualified installers and equipment, the number of units that must be addressed, the potential for adoption by building code or appliance standards, and other factors.

The upper limit of annual conservation resource development reflects the Council's estimate of the maximum that is realistically achievable. Since there is no perfect way to know this limit, the Council used several approaches to develop estimates of annual achievable conservation limits. First, the Council reviewed historic regional conservation achievements and considered total achievements, as well as year-to-year changes. The Council also considered future annual pace constraints for the mix of conservation measures and practices on a measure-by-measure basis.

The annual acquisition ramp rates used in the Seventh Power Plan are illustrated in Figure 12 - 7. This family of ramp rates is applied to all the measures to reflect the pace of acquisition over the 20-year plan period. Measures for which there is an established infrastructure or for which the market is rapidly changing are given a fast ramp rate, while measures that are new in the region, or that have experienced sluggish adoption rates are assigned a slow ramp rate. The annual acquisition rate multiplied by the total number of units available in a given year provides the maximum annual technical achievable potential. Note that acquisition year one corresponds to the first year in which that measure is selected in the RPM, which may not be the first year of the Seventh Power Plan (2016). More details on this are provided in Appendix G and Appendix L.

[16] In 2007, Council staff compared the region's historical achievements against this 85 percent planning assumption. The results of this review supported continued use of the estimate, or perhaps even the adoption a higher one in the Sixth Power Plan. The paper is on the Council website at http://www.nwcouncil.org/library/2007/2007-13.htm.

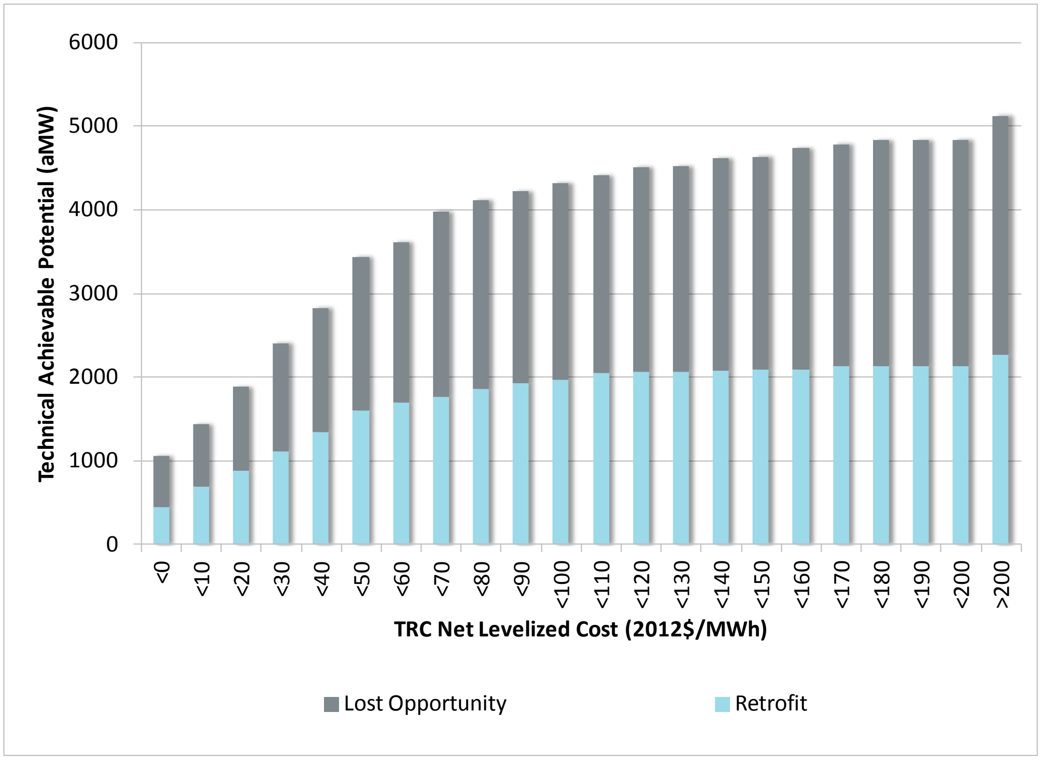
Figure 12 - 7: Conservation Acquisition Ramp Rates



In addition to the amount of conservation potential, the supply curve inputs also include the cost of achieving that potential. The costs are estimated based on a *net levelized cost* (levelized over the life of the conservation resource) of each of the conservation technologies or practices. These technologies are then ranked by net levelized cost using the same approach as for new generating resources.

One supply curve represents all of the retrofit resources. The other represents all the lost-opportunity conservation resources. Both supply curves are shown together in Figure 12 - 8 by cost bin for all conservation available through 2035. The Council divides conservation resources into these two categories because their patterns of deployment are limited by different decision events. Retrofit opportunity conservation resources can be deployed at any time, limited only by resources and infrastructure. Lost-opportunity resources, on the other hand, are only available during specific periods. For example, the option to include more wall insulation in high-rise commercial buildings is only available when new buildings are designed and constructed. In addition, savings from most appliances are available only as appliance stock turns over. If the savings from these lost-opportunity resources are not acquired within this limited window of opportunity, they are treated as lost and not available until the next decision event, for example when the appliance has reached its end of life and needs to be replaced. The figure shows that nearly half the conservation potential is in lost-opportunity resources.

Figure 12 - 8: Conservation Supply Curve by Resource Type



In addition to the energy savings, efficiency measures also provide capacity savings. These savings are estimated based on the savings shape over the year (step three in Figure 12 - 5). The savings shapes provide a relative impact of the energy savings during peak hours compared to the rest of the year. For example, whereas savings from efficient air-source heat pumps would have peak impacts for a winter-peaking system, savings from efficient residential air conditioners do not. The peak and energy savings are both included as data in the RPM.

Key Data Sources

To inform the individual measure costs and savings, several sources are used. Primary among them is the RTF. The Seventh Power Plan incorporates the most recent updates by the RTF until the date when these inputs went into the RPM (through February 2015 for the draft plan inputs). For measures not considered by the RTF, the Council relies on secondary studies, including evaluation results by regional utilities, the Energy Trust of Oregon, and the Bonneville Power Administration (Bonneville), research conducted by the U.S. Department of Energy National Labs (e.g. Pacific Northwest National Lab, Lawrence Berkeley National Lab), and other sources.

The total number of units in the region is largely based on the sector-specific stock assessments conducted by NEEA. These include:

- Residential Building Stock Assessment, completed in 2012
- Commercial Building Stock Assessment, completed in 2014
- Industrial Facilities Site Assessment, completed in 2014

These assessments provide a snapshot of the appliance and equipment saturations of buildings across the region.

In addition, to estimate the seasonal variation of the savings, the Council relies on end-use metering data; loads collected at the final point of consumption of electricity. For many end-uses, these are based on the End-Use Load and Consumer Assessment Program (ELCAP) database. The ELCAP database, it should be noted, is more than 30-years old, and so its accuracy in representing modern load shapes is questionable. The 2012 Residential Building Stock Assessment included a metering component, and so many of the residential non-heating and cooling end-use load shapes were updated based on the newer data. Additional end-use load shapes are estimated from metering work in California,[17] or lacking any metered data, engineering analysis and staff judgment.

Other sources for applicability factors or other inputs include: the Energy Information Agency's Manufactured Energy Consumption Survey and Commercial Building Energy Consumption Survey, Bonneville's energy efficiency implementation manual, other regional conservation potential assessments, EPA's ENERGY STAR program reports, federal standards rulemaking documents of the U.S. Department of Energy, and market and building codes analyses completed by NEEA.

FACTORS IMPACTING CONSERVATION POTENTIAL SINCE THE SIXTH POWER PLAN

The Seventh Power Plan's assessment of conservation potential reflects program accomplishments, changes in codes and standards, technological evolution, and the overall adoption of more energy-efficient equipment and practices since the Sixth Power Plan was adopted in 2010. There are six significant changes:

1. Accounting for utility conservation programs and other savings since 2010, including removal of measures that have saturated the market (e.g. LED TVs).
2. Adjusting both the load forecast and the conservation assessment to reflect improvements in federal and state standards for lighting, appliances, and other equipment.
3. Adding potential savings from new technologies and practices that have matured to commercial readiness since the development of the Sixth Power Plan's estimates.
4. Updating estimates of energy equipment saturation, gas and electric fuel shares, and other key building characteristics from the residential, commercial, and industrial stock assessments.
5. Updating forecasts of the number of new homes, businesses, and farms.
6. Updating costs to be in 2012 constant dollars.

[17] California Commercial End-Use Survey (CEUS), completed in 2006.

Of these, items 1 through 5 account for changes in the magnitude of conservation, while item 6 only influences cost and cost-effectiveness.[18] Details on the drivers of the changes in magnitude of conservation are discussed below.

Significant Conservation Achievements

The Sixth Power Plan recommended that the region develop at least 1,200 average megawatts of cost-effective conservation savings from 2010 through the end of 2014. Based on surveys conducted by the Council's RTF, regional conservation programs (utility and NEEA) the region had achieved more than 1,000 average megawatts of cost-effective energy savings by the end of 2013. Including savings from codes and standards that have taken effect during the Sixth Power Plan period, total regional savings are close to 1,300 average megawatts through 2013. Based on conservative projection data, the region will likely exceed 1,400 average megawatts by the end of 2015. These savings reduce the remaining potential for the Seventh Power Plan.

Federal and State Codes and Standards

Improvements in codes and standards have a significant impact on the remaining conservation potential. Since the Sixth Power Plan was adopted, the U.S. Department of Energy has promulgated new electric efficiency standards for more than 30 products for a suite of residential and commercial appliances.[19] Baseline assumptions for energy use of new appliances and equipment have been updated in the new conservation assessment to reflect these improved standards. Table 12 - 1 shows a summary of all the federal electric standards that have changed since the adoption of the Sixth Power Plan and the effective dates of these new and/or revised standards. Taken together, the Council forecasts that improvements in federal and state appliance standards reduce forecasted power loads by around 1,300 average megawatts by 2035 (see Appendix F for more details), an approximately 5 percent reduction in total regional consumption.

[18] More information on changes in the load forecast, including the impact of codes and standards (items 2 and 5), can be found in Chapter 7 and Appendix F.
[19] U.S. DOE has also promulgated a number of gas efficiency standards in this timeframe, but those are not discussed here.

Table 12 - 1: New or Revised Federal Electric Standards Incorporated in Seventh Power Plan Conservation Assessment Baseline Assumptions

Sector	Product Regulated	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
All	Battery Charger Systems*					✓						
	Candelabra & Intermediate Base Incand Lamps			✓								
	External Power Supplies							✓	✓			
	Fluorescent Lamp Ballasts					✓						
	General Service Fluorescent Lamps			✓		✓				✓		
	General Service Incandescent Lamps			✓	✓	✓						✓
	Incandescent Reflector Lamps								✓			
	Metal Halide Lamp Fixtures								✓			
Residential	Boilers			✓								
	Central Air Conditioners and Heat Pumps						✓					
	Clothes Dryers						✓					
	Clothes Washers						✓			✓		
	Dehumidifiers			✓								
	Dishwashers				✓						✓	
	Furnace Fans										✓	
	Microwave Ovens							✓				
	Pool Heaters				✓							
	Refrigerators/Freezers					✓						
	Room Air Conditioners					✓						
	Water Heaters						✓					
Commercial	Automatic Ice Makers	✓								✓		
	Boilers			✓								
	Clothes Washers				✓							
	Packaged AC and Heat Pumps (65-760 kBtu/hr)	✓									✓	
	Packaged AC and Heat Pumps (<65 kBtu/hr)									✓		
	Packaged Terminal AC and Heat Pumps	✓								✓		
	Refrigerated Beverage Vending Machines			✓								
	Refrigeration Equipment	✓		✓					✓			
	Single Package Vertical AC and Heat Pumps	✓								✓		
	Walk-in Coolers and Freezers					✓			✓			
	Water and Evaporatively Cooled CAC and HP				✓	✓						
	Water Heaters										✓	
	Water Source Heat Pumps		✓							✓		
Commercial/ Industrial	Distribution Transformers							✓				
	Pumps									✓		
	Small Electric Motors						✓					
	Electric Motors	✓						✓				

* Battery chargers are an Oregon state standard, not a federal standard

State building codes have also improved since the adoption of the Sixth Power Plan. Since then, Idaho and Montana have adopted the 2012 International Energy Conservation Code (IECC), which is a significant improvement over the codes in place at the time of the Sixth Power Plan development. In addition, Washington and Oregon both have adopted state-specific codes that are comparable, or better than, the 2012 IECC. State building code improvements also reduce forecasted power loads. For example, commercial sector state building codes adopted since the Sixth Power Plan are expected to reduce regional loads by about 100 average megawatts by 2035.

New Sources of Conservation Potential

Many new measures were added to the Seventh Power Plan that were not included in the Sixth Power Plan. In fact, new measures comprise around 40 percent of the total 20-year potential. Some examples of significant potential sources of savings include: recent advances in solid-state lighting (LEDs), variable refrigerant flow systems for HVAC loads, advanced power strips, advanced rooftop controllers, and low-energy spray application irrigation systems.

Stock Assessments

As discussed above, the Seventh Power Plan relied on saturation and fuel share estimates developed through the regional stock assessments for residential, commercial, and industrial facilities. These stock assessments were all performed since the release of the Sixth Power Plan and thus provide a more updated view of the existing building stock.

ACHIEVABLE POTENTIAL ESTIMATES BY SECTOR

The potential estimates by sector are presented below. The sectors include: residential, commercial, industrial, agriculture, and utility. High-level summaries of the findings on remaining conservation potential are discussed by sector. Appendix G contains links to all measure workbooks with details on savings and costs.

Residential Sector

The residential sector includes single-family detached homes, manufactured homes, low-rise (1-3 stories) multifamily, and medium/high-rise (4 stories and above) multifamily homes. For medium- and high-rise multifamily homes, the residential sector only assesses in-unit conservation potential (i.e., this assessment excludes improvements in building shell, common-area lighting, or building-area HVAC systems). Across the four residential segments, there are more than 700 different identified measure permutations. The Seventh Power Plan estimates over 2,300 average megawatts of potential energy efficiency in the residential sector, over 1,600 of which are less than $100 per megawatt-hour. The total potential (2,300 average megawatts) represents approximately 27 percent of the projected 2035 residential sector load.

Resource Type

Of the 2,300 average megawatts of potential in the residential sector, around two-thirds (1,600 average megawatts) are from lost-opportunity measures, including heat pump water heaters, ductless heat pumps, lighting, and clothes washers. Within the lost-opportunity measures, the annual potential is dictated by the natural turn-over of each measure. Retrofit measures (e.g., weatherization, advanced power strips, showerheads) comprise the remaining third of savings potential.

Comparison to Sixth Power Plan

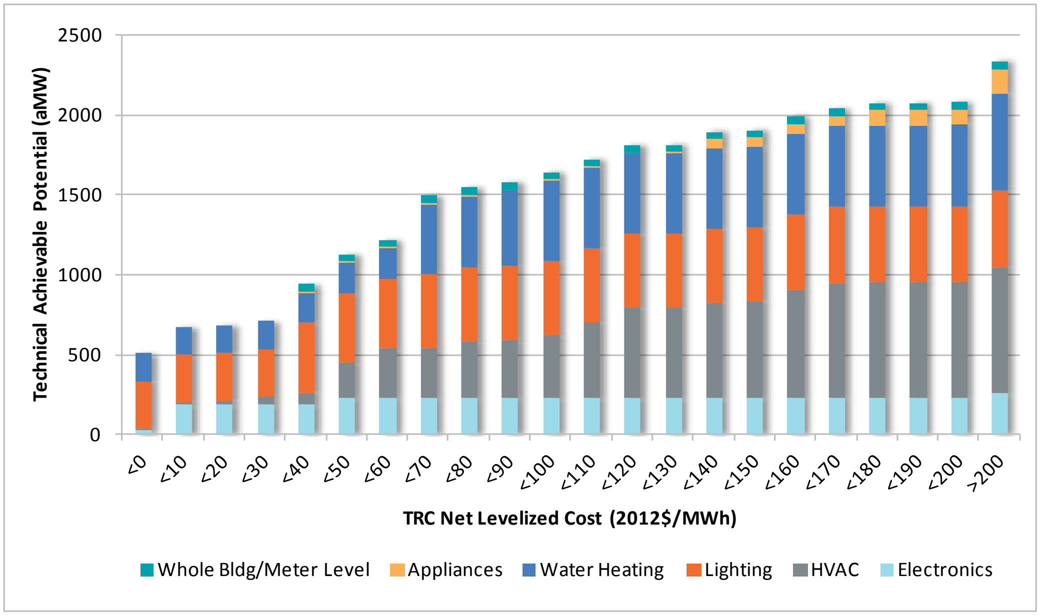
In the Sixth Power Plan, the Council estimated the residential sector to offer nearly 2,700 average megawatts of potential energy efficiency at less than $100 per megawatt-hour. The Seventh Power Plan estimates 1,600 average megawatts of potential but also includes the addition of many new measures. The decrease in potential from the Sixth Power Plan is primarily driven by programmatic accomplishments and improvements in codes and federal standards. For example, in the Sixth Power Plan, there were nearly 400 average megawatts of potential from LED backlit televisions. Television savings identified in the Sixth Plan have been already captured. As older TVs are replaced, the savings from the purchase of new TVs are incorporated as load reductions. The Seventh Power Plan sets at zero the remaining potential for TVs.[20] Another 220 average megawatts were identified in the Sixth Power Plan for residential new construction shell upgrades. With the improvement of energy codes across all states in the region, this potential is now significantly decreased and electric use forecasts for future new homes has similarly been decreased where the savings are now required and thus being realized (no longer potential) as a matter of statute or code.

Savings by End-use

The residential potential is dominated by lighting, HVAC, and water heating, as illustrated in Figure 12 - 9. Other contributing end-uses include appliances (including microwaves, refrigerators, clothes washers, and dryers), electronics (including advanced power strips, efficient computers and monitors), and whole building/meter level (including behavior and electric vehicle supply equipment).

[20] Note that the television market is rapidly changing. With the recent advent of ultra-high definition TVs, it is likely there can be new initiatives to improve the efficiency of those units. None were identified at the time of the Seventh Plan supply curve development.

Figure 12 - 9: Residential Potential by End-use and Levelized Cost by 2035



Major and New Residential Measures

The largest contributor to the potential in the residential sector is water heating. The potential is just over 600 average megawatts, 500 of which is available at less than $100 per megawatt-hour. This measure category includes heat pump water heaters, water-using appliances (dishwashers and clothes washers), as well as low-flow showerheads and bathroom aerators.

The second largest contributor is lighting, with a potential of nearly 500 average megawatts, most of which is available at less than $70 per megawatt-hour. This potential is largely driven by the advent of low-cost solid-state lighting (LEDs) in the marketplace, which allows for highly efficient bulbs that work in a variety of settings and applications. As the technology is rapidly changing, though with uncertainty about how much, the Council decided to include projected improvements in cost and efficacy of LEDs through 2017. The projections are based on work completed by Pacific Northwest National Labs in October 2013.[21] This is an exception to our standard frozen-efficiency baseline that assumes, for purposes of developing the load forecast, that the end-use consumption remains fixed over the 20-year plan period.[22]

In developing the supply curves for residential lighting, the Council needed to consider how to treat the forthcoming lighting standards, known as the Energy Independence and Security Act's backstop provision. This provision stipulates that in 2020, general service incandescent lighting must have a minimum efficacy of 45 lumens per watt. This in turn means that savings from bulbs less efficient than this backstop standard of 45 lumens per watt are only available until 2020. Given the value of continued lighting programs, and uncertainty about whether the 2020 standard will take effect, the

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[21] Tuenge, JR, *SSL Pricing and Efficacy Trend Analysis for Utility Program Planning*, October 2013. PNNL-22908.
[22] See Chapter 7 for further description.

Council decided to include a lighting potential that is more efficient than current standards, but less than the 2020 backstop. This, however, creates a challenge when modeling this in the RPM because once conservation is selected as a resource, its savings are expected to persist throughout the 20-year plan period. Therefore, the portion of lighting potential from bulbs used before the 2020 standard takes effect is treated separately from the other lighting resources.

Another significant measure not considered in the Sixth Power Plan is advanced power strips that offer 210 average megawatts of potential savings. This measure represents the growing savings from sophisticated controls. Advanced power strips can be used for home entertainment centers and home offices, shutting off peripheral and potentially primary equipment when the main appliance (TV or computer) is not actively in use.

Two measure categories that were in the Sixth Power Plan and still have significant savings potential going forward are weatherization (250 average megawatts, 100 of which is less than $100 per megawatt-hour) and ductless heat pumps (DHP), in both electric resistance zonal-heated homes and to supplement electric forced air furnaces (290 average megawatts, 165 of which is less than $100 per megawatt hour).

Residential Sector Summary

Table 12 - 2 provides a summary of the residential measure bundles' maximum achievable technical potential energy savings at years 2021, 2026, and 2035 and TRC net levelized costs of each of the bundles. The TRC net levelized costs are the weighted average cost (weighted by maximum achievable technical savings potential). Also included are the minimum and maximum levelized costs for each of the measures within each bundle.

Table 12 - 2: Summary of Potential and Cost for Residential Measure Bundles

Measure Bundle	Maximum Achievable Technical Potential (aMW)			TRC Net Levelized Cost ($/MWh)		
	2021	2026	2035	Weighted Average	Min	Max
HVAC	**248**	**460**	**793**	136		
Weatherization	166	233	248	104	(16)	843
Air Source Heat Pumps	12	45	130	363	22	1,075
Heat Pump Controls Commissioning and Sizing	4	16	46	54	29	285
DHP for zonal heated homes	12	45	132	134	94	153
DHP for forced air furnace homes	28	76	158	45	41	57
Duct Sealing	21	30	32	60	12	133
Ground source heat pumps	0	3	19	169	157	181
WIFI Enabled Thermostats	4	10	12	40	40	43
Heat Recovery Ventilation	0	3	16	124	76	140
Lighting	**177**	**380**	**484**	1		
Lighting	136	334	425	(9)	(120)	353
Lighting (pre-2020 general service lamps)	38	38	38	(59)	(74)	0
Linear fluorescent lighting	3	9	20	301	154	617
Water Heating	**111**	**261**	**603**	104		
Showerheads	67	100	121	(176)	(282)	(110)
Heat Pump Water Heaters	11	75	323	164	62	5,759
Solar Water Heater	17	35	56	656	533	705
Clothes Washer	10	27	61	33	(76)	94
Aerator	5	21	34	(263)	(300)	(171)
Dishwasher	0	0	1	(4)	(11)	2
WasteWater Heat Recovery	0	1	8	190	153	424
Electronics	**69**	**171**	**252**	45		
Advanced Power Strips	33	133	211	28	(2)	225
Computer	29	31	33	151	41	824
Monitor	6	7	8	49	49	49
Refrigeration	**1**	**9**	**56**	235		
Refrigerator	1	9	53	239	175	325

Freezer	0	1	3	154	154	154
Food Preparation	**7**	**17**	**34**	327		
Electric Oven	5	13	28	395	368	436
Microwave	1	4	6	32	32	32
Dryer	**4**	**15**	**53**	135		
Clothes Dryer	4	15	53	135	135	135
Whole Bldg/Meter Level	**17**	**39**	**53**	142		
Behavior	17	38	45	30	30	30
EV Supply Equipment	0	1	7	827	827	827
Grand Total	**634**	**1,352**	**2,328**	**95**		

Commercial Sector

The commercial sector includes 3.4 billion square feet of floor area (as of 2013) and 18 different building type categories.[23] Across the 18 building types are more than 540 measure permutations. The Seventh Power Plan estimates nearly 1,870 average megawatts of energy efficiency potential in the commercial sector, about 1,770 of which costs less than $100 per megawatt-hour. The total potential represents approximately 20 percent of the projected 2035 commercial sector load.

Resource Type

Of the 1,870 average megawatts of potential savings in the commercial sector, around two-thirds (1,200 average megawatts) are from lost-opportunity measures. Approximately 200 average megawatts of this lost-opportunity conservation is in new buildings, primarily from new lighting systems that have fairly high turnover rates for remodel and tenant improvements, as well as variable refrigerant flow (VRF) systems. For the lost-opportunity measures, the annual potential is dictated by the natural turnover of each measure and new additions. Retrofit measures (e.g. advanced rooftop unit controllers, lighting retrofits, energy management, DHP) comprise the remainder.

Comparison to Sixth Power Plan

In the Sixth Power Plan, the Council estimated in the commercial sector more than1,300 average megawatts of potential savings, costing less than $100 per megawatt-hour. The Seventh Power Plan finds an increase of around 500 average megawatts in potential, which is primarily due to new or emerging measures. These measures include solid state lighting, embedded data center improvements[24], advanced rooftop unit controllers to optimize rooftop unit HVAC systems, and variable refrigerant flow HVAC systems.

Savings by End-use

The commercial potential is dominated by lighting (LED lighting and controls for interior, exterior, and street lighting, applications), HVAC (rooftop unit controller, energy management, variable refrigerant flow systems, ductless heat pumps), and electronics (embedded data centers, smart plug power strips, computers and monitors) as illustrated in Figure 12 - 10. Other contributing end-uses include refrigeration, food preparation, and process loads (sewage treatment, water supply, motors/drives, water heating, and compressed air).

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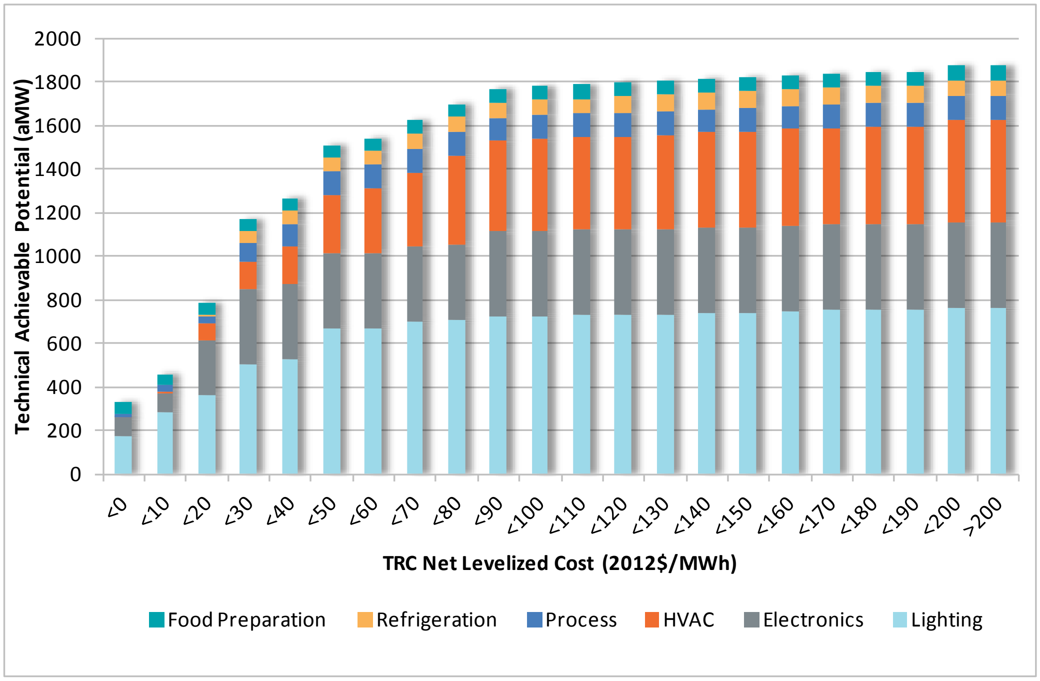
[23] Building types include: Large, medium and small office, extra large, large, medium and small retail, K-12 schools, university, warehouse, supermarket, minimart, restaurant, lodging, hospital, residential care, assembly, and other.
[24] Embedded data centers are those found in many commercial buildings and does not include the stand-alone data centers.

Figure 12 - 10: Commercial Potential by End-use and Levelized Cost by 2035



Major and New Commercial Measures

The largest contributor to savings potential in the commercial sector is lighting. The potential savings are more than 700 average megawatts, most of which are available at a cost of less than $50 per megawatt-hour. This potential is largely driven by the advent of low-cost LEDs, which allow for highly efficient bulbs and fixture combinations. Since the technology is rapidly changing, the Council decided to include projected improvements in cost and efficacy of LEDs through 2017. The projections are based on work completed by Pacific Northwest National Labs in October 2013.[21] This is an exception to our standard frozen-efficiency baseline.

The lighting end-use category is comprised of measure bundles targeted at common applications in both interior and exterior spaces. In the Sixth Power Plan, only three applications of solid-state lighting were viable – roadway lighting, refrigerator case lighting, and some down lighting. But this has changed. For each of the main lighting application types, the Council identified viable LED fixtures, retrofit kits or lamp replacement technologies. Viable savings measures now exist for all application types.

Savings are higher and costs are lower where LED technology replaces halogen incandescent lamps commonly used in display lighting or metal halide lamps commonly used in outdoor fixtures and high bay lighting. There are more viable LED measures for recessed can down lighting applications, than there are CFL sources. LED high bay fixtures are now competing against high-performance, high-output T5 fluorescent fixtures. New solid state lighting fixtures and fixture retrofit kits are available to replace the most common linear fluorescent fixtures. There are low-cost savings available from solid state lighting that promise improvement beyond today's high-performance linear fluorescent lighting systems, particularly in new, remodel and replace-on-burnout applications.

Significant savings are also available from high performance low-power fluorescent lamps in the lamp replacement markets during the transition to solid state lighting.

Significant numbers of street and roadway lighting has already switched to LED technology. Both Portland and Seattle are scheduled to complete LED streetlight installation by the end of 2015. But potential remains in other jurisdictions and in high-mast applications. Other lighting bundles include lighting control measures for interior spaces where controls are not already required by code, bi-level stairwell lighting, and bi-level parking garage lighting. The assessment also includes savings for light-emitting capacitor exit signs.

The second largest new measure bundle in the commercial sector is embedded (not stand-alone) data centers (260 average megawatts). The embedded data center measure bundle consists of 22 unique measures in three tiers. Individual measures include server virtualization, decommissioning of unused servers, energy-efficient servers, energy-efficient data storage management, efficient power supplies, and cooling-related measures.

Another significant measure is the advanced unit controller for rooftop HVAC systems. Rooftop systems provide heating, cooling, and ventilation to numerous small and mid-sized buildings throughout the region and are notoriously inefficiently maintained and operated. Approximately one third of commercial floor space is conditioned by rooftop air conditioning or heat pump systems. The advanced rooftop unit controller measure provides a relatively simple approach for targeting these systems, especially buildings that are excessively ventilated.

The variable refrigerant flow (VRF) technology represents more than 90 average megawatts of potential by 2035, with most of this potential in the range of $40-$80 per megawatt-hour. VRF is relatively new to the U.S. market and the Northwest, but is a well-developed technology utilized broadly in Japan, Europe, and Australia. One of the significant advantages of the VRF system is its design flexibility resulting in more precise temperature and air control. The Seventh Power Plan assumes VRF systems are primarily applicable to new construction and major retrofits.

The DHP measure is also new to the commercial sector in the Seventh Power Plan. The DHP is especially applicable to small commercial buildings with electric resistance zonal heat and less than five tons of cooling capacity.

As in the Residential sector, advanced power strips are a new measure in the commercial sector (47 average megawatts). This measure represents the growing savings from controls. Advanced power strips apply to the numerous miscellaneous plug loads and ancillary electronic equipment found in commercial office spaces.

A few other commercial sector new measures include secondary glazing systems, water cooler controls, web-enabled programmable thermostats (WEPT), compressed air systems, showerheads, and efficient electric resistance water heater tanks.

Commercial Sector Summary

Table 12 - 3 provides a summary of the commercial measure bundles' maximum achievable technical potential energy savings at years 2021, 2026, and 2035 and TRC net levelized costs. The TRC net levelized costs are the weighted average cost (weighted by maximum achievable technical savings potential). Also included are the minimum and maximum levelized costs for the measures within each bundle.

Table 12 - 3: Summary of Potential and Cost for Commercial Measure Bundles

Measure Bundle	Maximum Achievable Technical Potential (aMW)			TRC Net Levelized Cost ($/MWh)		
	2021	2026	2035	Weighted Average	Min	Max
Lighting	249	502	760	23		
Lighting Power Density Package	126	240	435	21	(76)	657
Low Power Linear Fluorescent Lamps	14	39	39	24	24	24
Lighting Controls Interior	8	19	44	138	40	445
Exterior Building Lighting	59	126	142	12	(128)	28
Street and Roadway Lighting	30	57	61	(34)	(119)	18
Parking Lighting	6	8	8	25	25	25
Bi-Level Stairwell Lighting	2	5	11	79	69	155
LEC Exit Sign	4	9	19	13	10	27
Electronics	104	314	392	19		
Data Centers	55	230	261	16	10	27
Advanced Power Strips	30	42	47	81	81	81
Desktop	13	28	56	(8)	(8)	(8)
Monitor	6	12	24	(8)	(8)	(8)
Laptop	0.3	1.4	4	(8)	(8)	(8)
HVAC	144	322	471	64		
Advanced Rooftop Unit Controller	22	84	119	31	12	88
Commercial Energy Management	46	67	73	44	17	168
Demand Control Ventilation in Parking Garage	8	12	13	40	40	40
Demand Control Ventilation for HVAC	15	21	22	75	0	1,391
DHP	12	43	60	61	46	74
Secondary Glazing Systems	4	18	40	216	10	334
VRF	8	34	96	70	44	140
Premium Fume Hood	0.4	1.2	4	40	40	40
Economizer	19	27	27	43	6	90
Demand Control Ventilation	6	8	8	51	38	74

Restaurant Hood						
Web-Enabled Programmable Thermostats	3	7	7	61	54	79
Refrigeration	43	69	76	34		
Grocery Refrigeration Bundle	41	57	63	35	20	112
Water Cooler Controls	2	11	12	35	18	142
Food Preparation	6	23	64	(26)		
Cooking Equipment	6	23	63	(23)	(44)	80
Pre-Rinse Spray Valve	0.6	0.9	1.0	(224)	(298)	(104)
Process Loads	19	42	47	25		
Municipal Sewage Treatment	14	32	35	26	(10)	40
Municipal Water Supply	5	11	12	24	24	24
Motors/Drives	6	17	35	23		
Electronically Commutated Motor-Variable Air Volume	4	12	30	23	20	33
Motors Rewind	2	4	5	27	5	38
Compressed Air	4.8	9	17	5	3	13
Compressed Air	4.8	9	17	5	3	13
Water Heating	4	6	10	(204)		
Showerheads	3	4	4	(510)	(689)	(217)
Electric Resistance Water Heater Tanks	0.4	1.1	2	30	23	38
Commercial Clothes Washer	0	2	4	(60)	(60)	(60)
Grand Total	581	1,305	1,871	30		

Industrial Sector

The industrial sector conservation potential is a direct function of the individual industrial segment loads. The Council's conservation assessment does not include savings potential for the Direct Service Industrial (DSI) customers of Bonneville. Non-DSI industrial consumption is forecasted to be approximately 30,800 gigawatt-hours (3,520 average megawatts) at the start of the planning period and growing to more than 39,000 gigawatt-hours, or about 4,480 average megawatts by 2035 (medium forecast). The industrial sector includes 19 distinct segments each with a unique composition of end-use loads. The resulting conservation potential is about 580 average megawatts, with most of that potential available at a cost of less than $50 per megawatt-hour. The total savings potential represents approximately 13 percent of the projected 2035 industrial sector load.

Resource Type

The industrial measures were all categorized as retrofit.

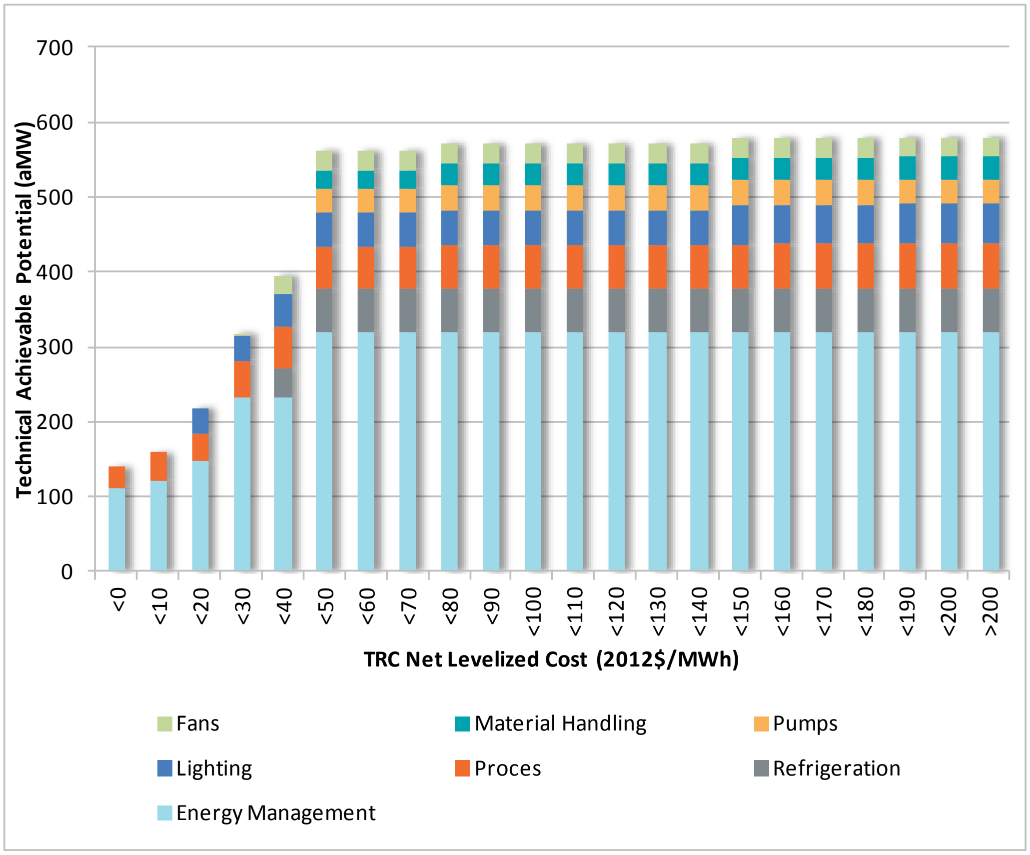
Comparison to Sixth Power Plan

In the Sixth Power Plan, the Council estimated energy efficiency savings in the industrial sector to be nearly 800 average megawatts at a cost of less than $100 per megawatt-hour. The 550 average megawatts identified in the Seventh Power Plan are a reduction in industrial sector conservation potential. This reduction is primarily due to the significant regional accomplishments that have occurred in this sector since the Sixth Power Plan. Some standards improvements also played a role in moving Sixth Power Plan potential into the baseline. In addition, total industrial production is forecast to be lower compared to Sixth Power Plan levels.

Savings by End-use

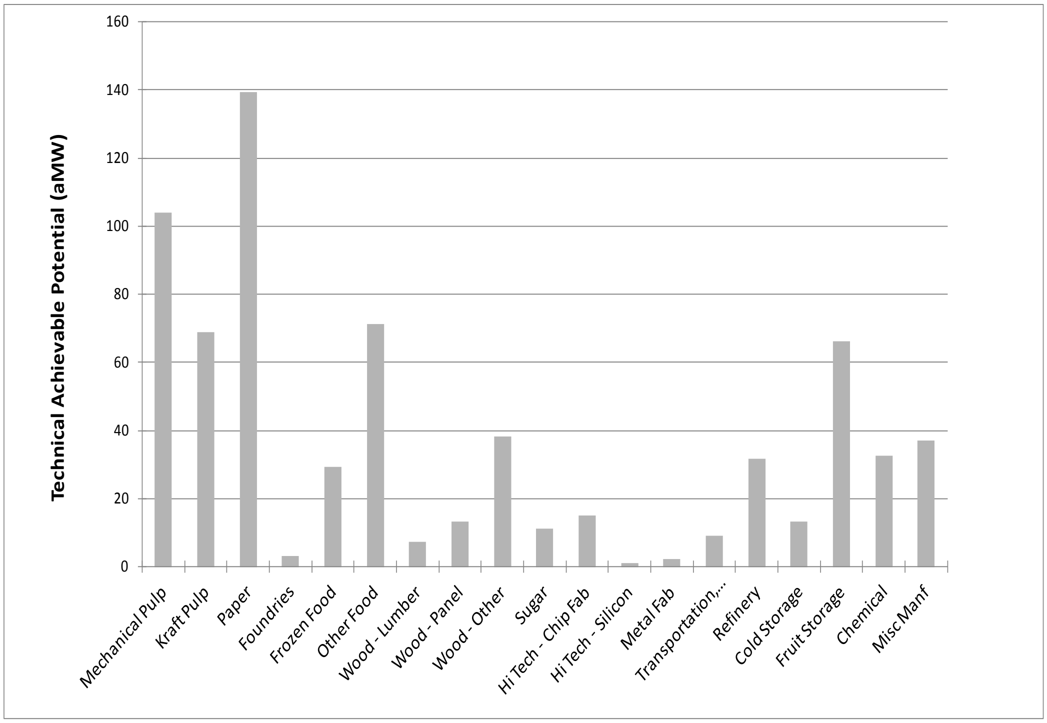
The industrial potential is dominated by the general category of "energy management" as illustrated in Figure 12 - 11. The energy management bundle includes measures and practices to optimize industrial processes. Specific measures are aimed at fan, pump, and compressed air systems, process lines, as well as whole facility energy management. Other contributing end-uses include refrigeration, process loads, lighting, pumps, fans, and material handling. Note also that the majority of the industrial conservation potential costs less than $50 per megawatt-hour.

Figure 12 - 11: Industrial Potential by End-use and Levelized Cost by 2035



Another way to look at the industrial sector conservation potential is by industry segment as shown in Figure 12 - 12. The pulp and paper industries are very strong in the Pacific Northwest, and therefore have strong conservation potential. Segments like frozen food, cold storage, and fruit storage have significant refrigeration loads and associated conservation potential.

Figure 12 - 12: Industrial Sector Savings Potential by Industry Segment by 2035



Most industrial conservation measures are complex and require considerable design and careful implementation. Many measures and practices need continuing management and operational attention to ensure continued savings. Support from the plant's employees, owners and management is also critical. Implementation strategies will need to continue to take these factors into consideration in order to achieve the industrial conservation potential.

Major and New Industrial Measures

The industrial sector measure categories and methodologies in the Seventh Power Plan are the same as those in the Sixth Power Plan. Significant updates were made based on achievements since the Sixth Power Plan, as well as new data and information obtained through the Industrial Facility Site Assessment. These data sources served primarily to adjust the end-use shares and remaining potential of the measures.

The Seventh Power Plan lighting measures are now based on LED technology similar to the residential and commercial sectors. Significant advances in high-bay lighting, for example, are included in the lighting potential.

Industrial Sector Summary

Table 12 - 4 provides a summary of the industrial measure bundles maximum achievable technical potential energy savings at years 2021, 2026, and 2035 and TRC net levelized costs. The TRC net levelized costs are the weighted average cost (weighted by maximum achievable technical savings potential). Also included are the minimum and maximum levelized costs for the measures within each bundle.

Table 12 - 4: Summary of Potential and Cost for Industrial Measure Bundles

Measure Bundle	Maximum Achievable Technical Potential (aMW)			TRC Net Levelized Cost ($/MWh)		
	2021	2026	2035	Weighted Average	Min	Max
Pumps	42	74	81	16	(16)	46
Fans	26	54	60	25	13	38
Energy Project Management	37	79	87	44	44	44
Integrated Plant Energy Management	23	42	77	(1)	(1)	(1)
Lighting	37	48	52	39	16	147
Plant Energy Management	27	38	41	26	26	26
Food Processing	9	12	14	47	47	47
Food Storage	43	61	67	33	27	43
Compressed Air	12	16	18	17	3	32
Material Handling	12	27	30	50	43	76
Hi-Tech	8	13	15	(39)	(76)	44
Pulp	3	5	8	14	5	43
Paper	4	6	12	60	23	184
Wood	8	17	19	(64)	(68)	25
Metals	0.1	0.1	0.2	(2,054)	(2,054)	(2,054)
Grand Total	290	493	580	22		

Agriculture Sector

The potential in the agriculture sector is primarily from improvements in irrigation, but also includes dairy farm measures and LED barn lighting.

Resource Type

All of the potential in the agriculture sector is treated as retrofit, except for scientific irrigation scheduling. Since irrigation scheduling measures require annual re-engagement by the farmer, the potential exists anew every year.

Comparison to Sixth Power Plan

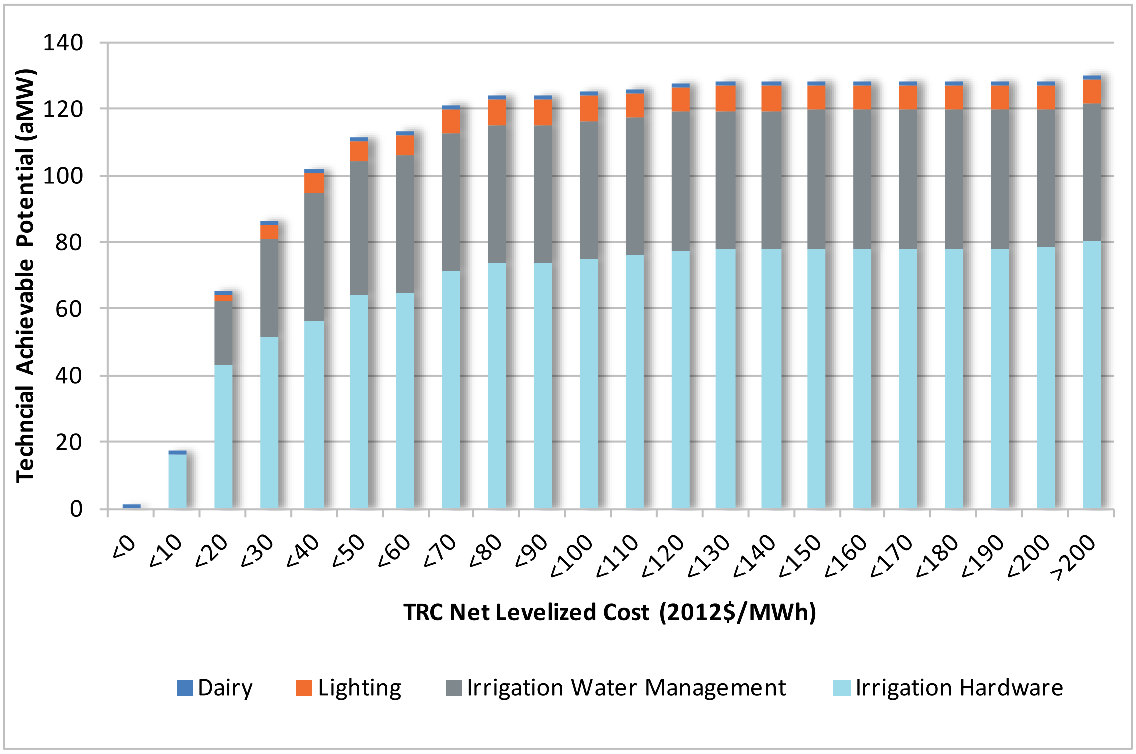
The Sixth Power Plan identified approximately 100 average megawatts of conservation potential in the region. The Seventh Power Plan is slightly higher at 130 average megawatts. The increase in potential is primarily due to an approximately 35 percent increase[25] in the number of acres of land irrigated by pressurized sprinkler systems and the addition of two new measures: barn area lighting and low-elevation spray applications (LESA).

Savings by End-use

The potential across the four major end-uses are provided in Figure 12 - 13, by TRC net levelized cost. Irrigation hardware continues to have the most savings potential (80 average megawatts), followed by irrigation water management (LESA and scientific irrigation systems [SIS]), at 41 average megawatts. The dairy savings potential is decreased from 10 average megawatts in the Sixth Power Plan, to just over 1 average megawatt in the Seventh Power Plan. The decrease in savings potential is caused by the adoption of many of the measures identified in the Sixth Power Plan as common practice. Lighting comprises the remainder at 7 average megawatts.

[25] The Sixth Power Plan relied on 2003 Farm and Ranch Irrigation Survey (FRIS), while the Seventh Power Plan relies on the 2013 FRIS.

Figure 12 - 13: Agriculture Potential by End-use and Levelized Cost by 2035



Major and New Agricultural Measures

Improvements in irrigation hardware are the largest source of agricultural savings potential in the Seventh Power Plan. This category includes: converting high/medium pressure center pivot systems to low pressure systems, converting wheel or hand-line systems to low pressure center systems on alfalfa acreage, and replacing worn or leaking hardware. Nearly half of the irrigation water management savings are anticipated from the new low-energy spray application measure. This measure converts a center pivot system into an ultra-low pressure (<10 pounds per square inch) system where the nozzles are 12 to 18 inches above the ground. Pilot testing indicates significant savings can be achieved.

The dairy measures include: installing variable frequency drives on milking machines, plate milk pre-coolers, heat recovery ventilation, and energy-efficient lighting. As many dairy farms have converted to large-scale farms (particularly in Idaho), most have already adopted many of these measures and thus limited potential savings remain.

Agricultural Sector Summary

Table 12 - 5 provides a summary of the agricultural measure bundles' maximum achievable technical potential energy savings at years 2021, 2026, and 2035 and TRC net levelized costs. The TRC net levelized costs are the weighted average cost (weighted by maximum achievable technical savings potential). Also included are the minimum and maximum levelized costs for the measures within each bundle.

Table 12 - 5: Summary of Potential and Cost for Agriculture Measure Bundles

Measure Bundle	Maximum Achievable Technical Potential (aMW)			TRC Net Levelized Cost ($/MWh)		
	2021	2026	2035	Weighted Average	Min	Max
Irrigation	59	89	118	33		
Irrigation Hardware	34	48	53	36	4	1,271
Irrigation Pressure	2	10	24	36	9	204
Irrigation Water Management	22	22	22	33	24	100
Irrigation Efficiency	2	8	19	19	19	19
Lighting	2	3	3	(25)		
Dairy	0.1	0.3	0.3	5	(8)	5
Lighting	5	7	7	33	14	68
Motors/Drives	2	3	3	27		
Dairy	0.0	0.1	0.1	(6)	(8)	5
Irrigation Motor	2	3	3	28	24	31
Refrigeration	0.3	0.7	0.8	(6)		
Dairy	0.3	0.7	0.8	(6)	(8)	5
Grand Total	**67**	**99**	**130**	**32**		

Utility Distribution Systems

The utility distribution system conservation potential is based on regulating voltage on distribution lines within closer tolerances and thus minimizing system and end-use losses. Both energy and capacity savings are produced by measures typically referred to as conservation voltage regulation (CVR). The measures also include upgrading components of utility systems where losses can be reduced. The distribution system efficiency potential consists of four measures identified by a 2007 study conducted on behalf of NEEA[26] and developed for the Sixth Power Plan. Savings occur on both the utility- and the customer- side of the meter. Customer-side savings are typically greater and are dependent on the mix of inductive and resistive loads of the equipment in homes and businesses. Performing system improvements such as phase load balancing and reactive power management is the largest contributor to energy savings on the utility side of the meter. Four measures are used to estimate the range of costs and savings available from optimizing distribution systems for energy efficiency.

1. Lowering the distribution voltage level only using the line drop compensation voltage control method.
2. System improvements including reactive power management, phase load balancing, and feeder load balancing using either line drop compensation or end-of-line voltage control methods.
3. Voltage regulators on 1 of every 4 substations and select reconductoring on 1 of every 2 substations.
4. Lowering the distribution voltage level using the end-of-line voltage control method.

The measures differ with respect to the techniques used to manage voltage and other system electrical characteristics to maximize efficiency. Line drop compensation uses a controller at the substation to lower and raise the feeder bus voltage based on the real and reactive power flowing into the source of the feeder. Using line drop compensation along with system improvements will capture the majority of the potential energy savings at a fairly low cost. However, because this method uses calculations to determine the end-of-line voltage as compared to actual metered data, additional safety margins are necessary to make sure the voltage levels are above the minimum criteria. Because of this, the voltage level is above the minimum required and not all of the potential energy savings can be achieved.

End-of-line voltage feedback control systems will achieve the maximum energy savings. This type of voltage control measures the end-of-line voltage level of the distribution system and can keep the feeder voltage level at the minimum criteria at all load levels and does not require the same margin of safety as compared to the line drop compensation voltage control method. However, the cost of the implementing, maintaining, and operating an end-of-line system is higher.

[26] Leidos (formerly RW Beck). (2007). *Distribution Efficiency Initiative*.

Other measures to improve efficiency of distribution systems exist, but were not analyzed in the Seventh Power Plan. For example, the deployment of automated metering infrastructure systems may provide for accomplishing the above measures less expensively and more efficiently.

The overall distribution system potential in the Seventh Power Plan is 215 average megawatts, all of it available at cost less than $100 per megawatt-hour.

Resource Type

The distribution system efficiency measures are all classified as retrofit.

Comparison to Sixth Power Plan

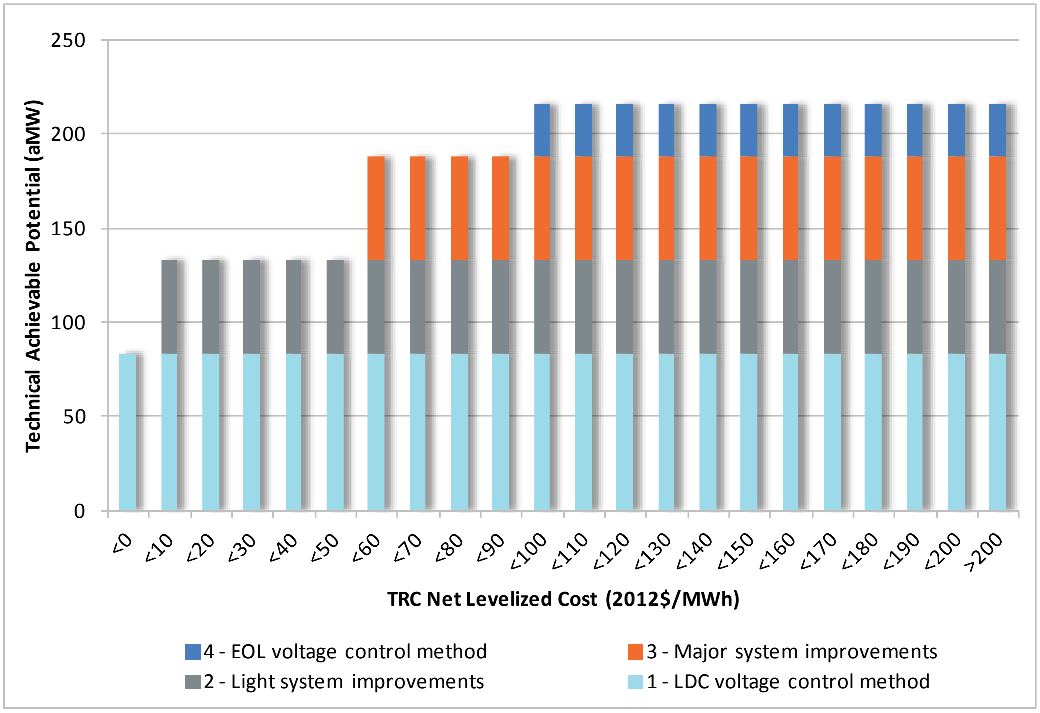
The Sixth Power Plan included 400 average megawatts of distribution system conservation potential, compared to the Seventh Power Plan potential of 215 average megawatts. The reductions in potential compared to the Sixth Power Plan are based on several factors. Some projects identified in the Sixth Power Plan have been completed. Utility experience implementing CVR since 2009 has provided information to adjust the potential, federal standards requiring more efficiency transformers have helped reduce distribution system losses and an overall lower load forecast changes the amount of electricity passing along lines. Nonetheless, significant savings potential remains.

Distribution systems savings measures are complex and require significant system engineering and analysis. The measures are not typically deployed by utility conservation departments that deliver programs to customers. Instead the measures are often part of utility distribution system maintenance and expansion efforts. Finding viable mechanisms within utilities to identify and capture these savings continues to be a challenge.

Savings by Measure

The distribution system efficiency supply curve is shown in Figure 12 - 14.

Figure 12 - 14: Distribution System Potential by Measure and Levelized Cost by 2035



Major and New Distribution System Measures

The measure with the largest distribution system savings potential and lowest cost is the line-drop compensation voltage control measure.

Utility Distribution System Sector Summary

Table 12 - 6 provides a summary of the utility measure bundles' maximum achievable technical potential energy savings at years 2021, 2026, and 2035 and TRC net levelized costs. The TRC net levelized costs are the weighted average cost (weighted by maximum achievable technical savings potential). Also included are the minimum and maximum levelized costs for the measures within each bundle.

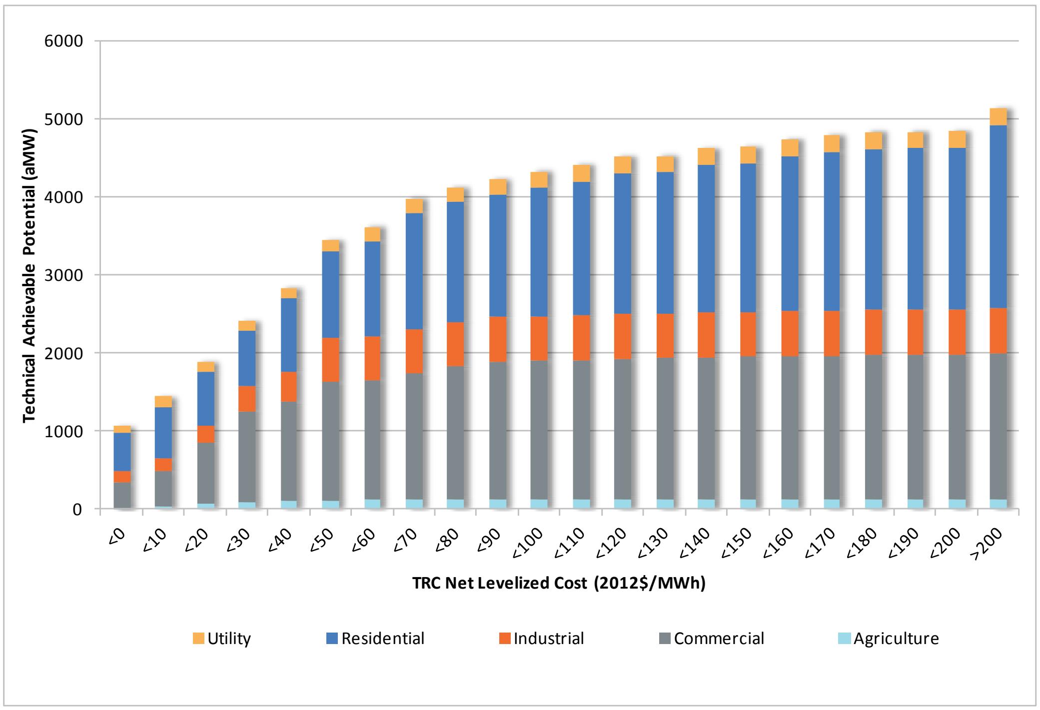
Table 12 - 6: Summary of Potential and Cost for Utility Measure Bundles

Measure Bundle	Maximum Achievable Technical Potential (aMW)			TRC Net Levelized Cost ($/MWh)		
	2021	2026	2035	Weighted Average	Min	Max
1 - LDC voltage control method	12	34	83	(2)	(2)	(2)
2 - Light system improvements	7	20	50	3	3	3
3 - Major system improvements	8	22	55	60	60	60
4 - EOL voltage control method	4	11	28	96	96	96
A - SCL implement EOL w/ major system improvements	0.3	1	2	320	320	320
Grand Total	**33**	**89**	**218**	30	-	-

Total Conservation Potential- All Sectors

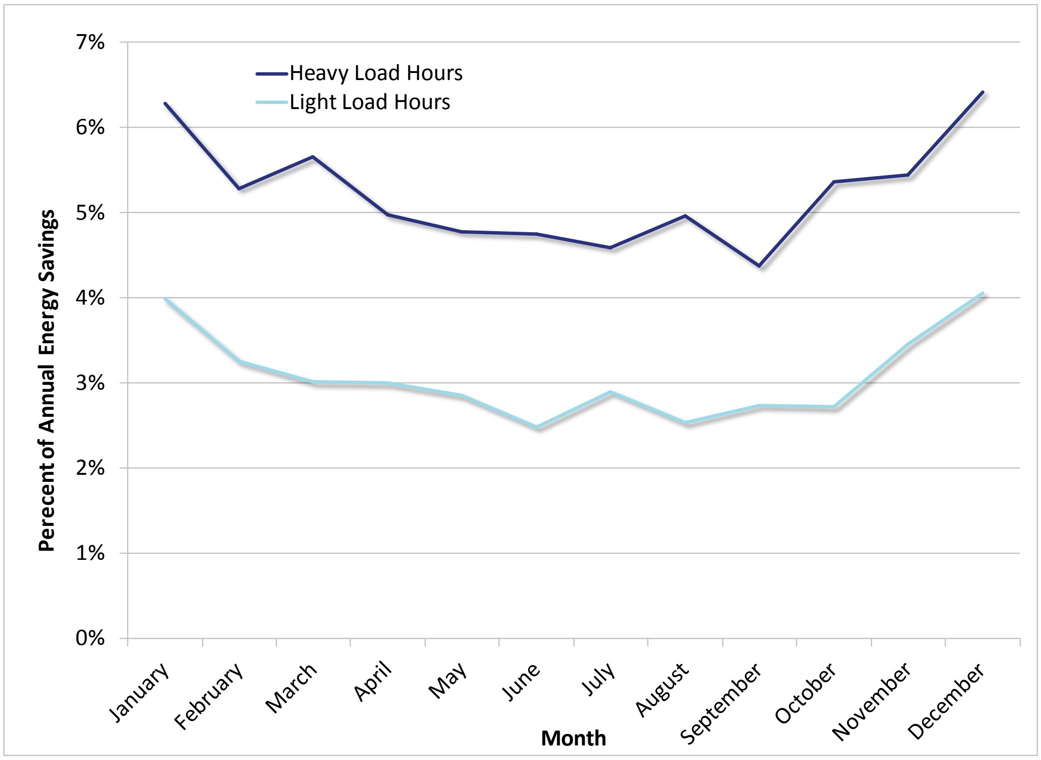
Figure 12 - 15 shows the Seventh Power Plan's estimate of the amount of conservation available by sector and TRC net levelized cost by 2035. The Council identified nearly 4,300 average megawatts of technically achievable conservation potential in the medium demand forecast by the end of the forecast period at a TRC net levelized life-cycle cost of up to $100 per megawatt-hour (2012 dollars). Slightly more than half of the potential is from lost-opportunity measures. Given the uncertainty in the demand forecast, the conservation potential has an associated uncertainty range. The Council determined, based on the range in the load forecast, that if loads were to increase or decrease by 100 percent, the potential would increase or decrease by 62 percent (an elasticity of 0.62).

Figure 12 - 15: Cumulative Potential by Sector and Levelized Cost by 2035



This energy savings potential also has a capacity benefit, the magnitude of which depends on the shape of the savings. The shape of the savings for all measures during heavy and light load hours is provided in Figure 12 - 16. As is shown, the energy savings are greater during the winter season than summer, in large part due to significant savings from conversion of electric resistance heating to more efficient heat pump technologies and increased use of lighting during the winter period.

Figure 12 - 16: Monthly Savings Shape for All Conservation Measures during Heavy and Light Load Hours



The Council estimates the technically achievable potential by 2035 is approximately 9,700 megawatts of capacity savings during the region's peak winter hour (6pm on a weekday in December, January, and February) and over 6,600 megawatts of savings during the peak summer hour (6pm on a weekday in July and August). By 2026, if all available conservation were deployed, there would be 3,300 average megawatts of energy savings; the winter peak capacity savings potential would be nearly 6,200 megawatts and summer is nearly 4,000 megawatts.

CONSERVATION SCENARIOS MODELED

The Council tested two scenarios in which the conservation inputs were modified. These scenarios include:

- Varying the annual pace of conservation by including accelerated and decelerated paces, and,
- Reviewing emerging technologies above and beyond those already considered in the supply curves, including distributed photovoltaics.

The inputs and rational behind these scenarios are discussed below. The results of these sensitivity tests within the RPM are discussed in Chapter 3.

Conservation Scenario 1: Testing Annual Pace Constraints[27]

Because the maximum annual pace of conservation achievement is to a major extent a function of the level of resources dedicated to acquiring conservation, the Council performed sensitivity tests to estimate the impact of achieving conservation faster and slower than assumed in the base case. For this scenario, the Council held total savings nearly constant at 2035 so that only the pace of conservation would impact the present value of system costs.[28] For the high-case sensitivity, the Council assumed individual program ramp rates were accelerated in early years and decelerated in later years. The resulting maximum cumulative achievable potential was about 20 percent more by year five (2020) than the base case. This means a maximum of 1,560 average megawatts of conservation within the first five years, or an average pace of about 310 average megawatts per year across all cost bins. A similar approach was taken for the low-case sensitivity, but in reverse, with program ramp rates slower in early years and higher in later years. The resulting maximum cumulative achievable potential is about 20 percent lower by year five compared to the base case. This results in a maximum of about 1,020 average megawatts that could be developed in the first five years of the plan, or on average about 200 average megawatts per year across all price bins. Figure 12 - 17 shows the total conservation available for the three scenarios over the 20 years of the plan period. Figure 12 - 18 provides the details over the first six years.

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[27] These scenarios (**Faster Pace of Conservation** and **Lower Pace of Conservation**) were only analyzed for the draft Seventh Power Plan, so updates to the supply curve inputs between draft and final are not reflected in this section. However, Appendix O describes the draft plan results for these two scenarios.

[28] The 20-year potential is not exactly constant due to rounding assumptions as well as the interplay between ramp rates and turn-over rates for lost-opportunity measures.

Figure 12 - 17: Comparison of Maximum Conservation Available For Pace Scenarios over Plan Period

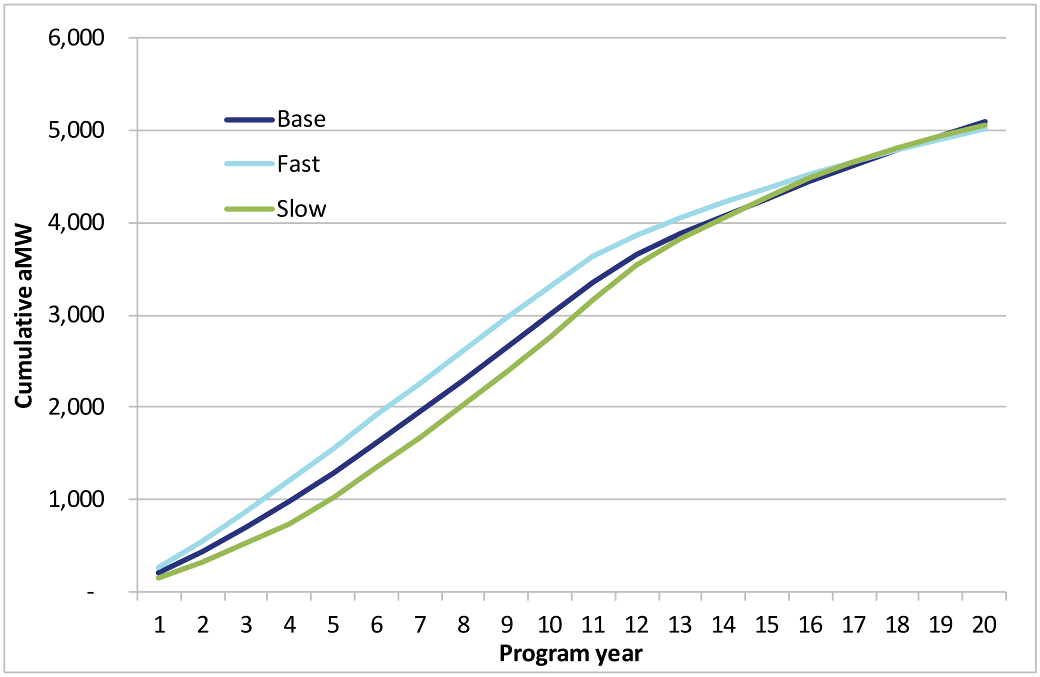
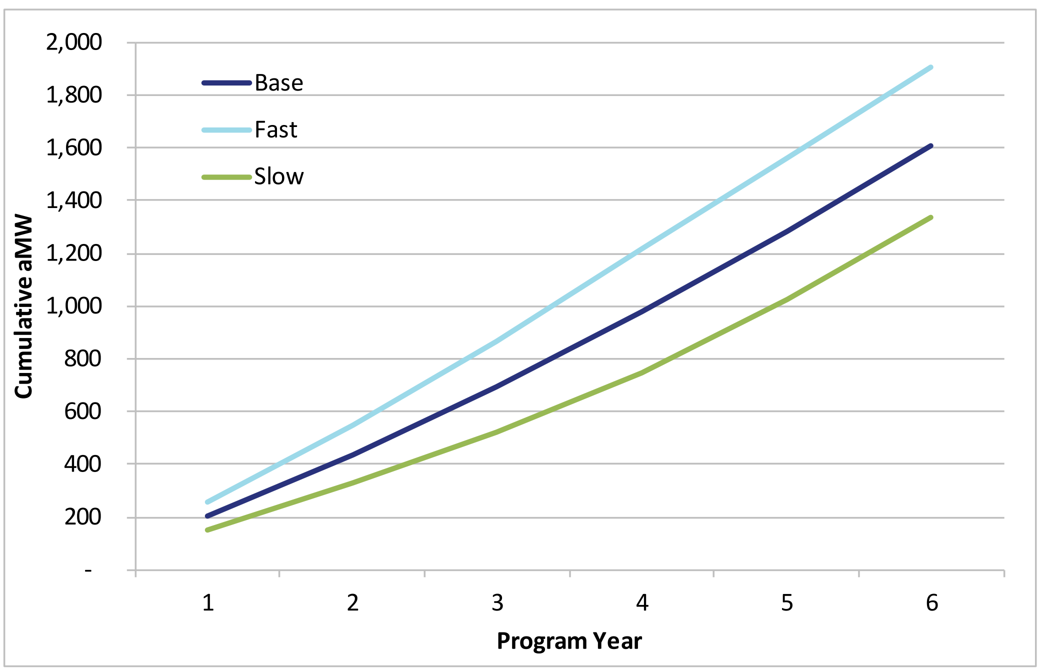


Figure 12 - 18: Comparison of Maximum Conservation Available for Pace Scenarios during First Six years of Plan



Conservation Scenario 2: Testing Emerging Technologies' Deployment Assumptions

Another scenario was tested to estimate the potential impact of emerging technologies on future resource needs. These emerging technologies are beyond what the Council includes in its standard supply curves. Within the standard set of supply curves, all measures and resources, under the Act, need to be "forecast to be reliable and available within the time it is needed".[29] As such, only those technologies that are currently available and accepted in the marketplace are included in the supply curves as resources that can be counted on to provide energy and capacity reductions. The standard supply curves include some measures considered "emerging" that are commercially available, but that have current low market penetration, for example variable refrigerant flow HVAC systems and, heat pump water heaters.

For the Seventh Power Plan, the Council also looked at technologies that are not yet commercially available, or not available at reasonable cost, but which may become available at reasonable cost within 5 to 10 years and thus could influence resource decisions in the near term. For the emerging technologies scenario, the Council estimated the cost and savings potential from these measures in 2025 and 2030. These technologies, and the associated potential energy and capacity savings, are above and beyond the most efficient measures already included within the supply curves. In addition, the Council considered two behind-the-meter generation options: combined heat and power and distributed solar photovoltaics (PV).[30] Combined heat and power is discussed in the Generation Resources Chapter 13, PV is discussed below.

To develop these estimates, the Council considered research and analysis done by others including the national laboratories, Electric Power Research Institute, U.S. Department of Energy, Washington State University Energy Program, Bonneville staff, American Society of Heating, Refrigerating, and Air-Conditioning Engineers, manufacturers, and expert judgment. Estimates from these sources were calibrated and scaled to Pacific Northwest applications and stock estimates. The results are summarized in Table 12 - 7 below. The peak impacts presented are for winter. These measures also provide summer peaking impacts, particularly evaporative coolers and distributed PV.

[29] Northwest Power Act 839a(4)(A)(i)
[30] Distributed PV is also included as a potential resource in other scenarios; see Chapter 15.

Table 12 - 7: Emerging Conservation Technologies

Emerging Technology	2025			2030			
	aMW	MW (winter)	TRC Net Lev Cost ($/MWh)	aMW	MW (winter)	TRC Net Lev Cost ($/MWh)	Required Conditions
Additional Advances in Solid-State Lighting	200	400	$0-$30	400	800	$0-$30	Continued tech improvement, resource availability
CO_2 Heat Pump Water Heater	110	200	$100-150	160	300	$90-140	UL approval; U.S. market development
CO_2 Heat Pump (space heat)	50	160	$130-170	130	350	$110-160	Best suited for hydronic heating, need research and development (R&D) for U.S. applications
Highly Insulated Dynamic Windows - Commercial	20	130	$500+	35	200	$300	Intensive R&D effort needed to bring down cost; slow ramp due to window replacement schedule
Highly Insulated Dynamic Windows - Residential	80	230	$500+	120	350	$400	
HVAC Controls – Optimized Controls	140	230	$90-120	200	350	$80-110	Significant developments expected in next 5 years
Evaporative Cooling	50	0*	$100-130	80	0*	$90-120	Need R&D on configurations & applications in PNW
Distributed Photovoltaics	800-1400	0*	$70-280	2200-4000	0*	$60-250	High penetration may require additional integration costs and distribution system upgrades

* These measures provide non-zero summer peak impacts.

From this table, the measures that are likely to have the most significant impact are solid-state lighting, combined heat and power, and CO_2 heat pump water heaters. Solid-state lighting is currently commercially available and included in the supply curves. The emerging technology scenario assumes significant (20-100 percent, depending on application) increases in efficacy over what is already within the plan at a very low cost. The increase in efficacy assumption and the cost forecasts are based on U.S. Department of Energy work that considered detailed examination of potential technological gains along with industry trends incorporating new developments.[31] Except for a portion of combined heat and power (covered in the generation resources Chapter 13), no other emerging technology measures are expected to be low cost in the timeframe of the next decade when they would have the most impact on resource decisions.

Most other emerging technologies have expected costs of about $100 per megawatt-hour or greater. Although CO_2 heat pump water heaters have been available in other markets (e.g. Japan, Europe), they are only starting to enter the U.S. market. Currently, there are a few pilot projects being performed within the region, with promising results. These units can serve both hot water and space heat needs, if coupled with a hydronic heating system. Depending on the products introduced, the CO_2 heat pump water heaters are likely to be about 50 percent more efficient than current heat pump water heater technologies.

Other technologies considered include dynamic and highly insulated windows for both commercial and residential applications. These windows provide less heat loss due to higher insulating value, and also change the solar heat gain coefficient (SHGC) depending on the amount of sunlight. The SHGC will decrease during sunny, warm days, blocking solar energy from entering the building and thus reducing cooling loads. During cloudy, cool days, more solar energy enters the building, lowering heating loads. Currently, these windows are expensive to produce and will require significant cost declines to be commercially competitive.

Over the next five to 10 years, improved controls are likely to become a major influence in energy use. Better controls will lead to lower energy use. For this scenario, the Council focused on improved HVAC controls. This market is rapidly evolving, and the deployment of these controls and their impact will be better understood after five or so years.

The final emerging conservation measure considered is evaporative coolers, in which air is cooled through the evaporation of water instead of traditional vapor-compression or absorption refrigeration cycles. These units have traditionally been used in hot and dry climates (where water quickly evaporates), and they have not garnered significant market penetration in the Pacific Northwest. As such, research is needed to better understand their applicability and likely savings within this region. Areas east of the Cascade Mountains are prime targets for evaporative cooling systems.

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[31] U.S. DOE Energy Savings Forecast of Solid-State Lighting in General Illumination Applications, August 2014.

Direct Application Renewables

In addition to the conservation resources, direct-application renewables (DARs) beyond that already reflected in the frozen efficiency load forecast are also considered as potential resources.[32] DARs are consumer-owned renewable resources used to meet on-site load requirements. The Council included two DAR resources in the Seventh Power Plan: solar water heaters and distributed solar photovoltaics (PV). Solar water heaters are included in the residential conservation supply curves, distributed PV is treated separately. These resources are treated similarly to conservation in the RPM, though DARs do not include the 10 percent Regional Act credit.

Distributed Solar Photovoltaics

In addition, the Council considered the potential from distributed solar PV panels, which can be mounted on the rooftop of a house, or commercial building or other structure to provide on-site electricity and also send power to the grid. While distributed PV technology is technically a generation technology, when deployed as a rooftop application it typically reduces site electricity consumption more than it adds to grid generation, thus making it appear much like a conservation measure. These distributed PV systems are considered in the Council's conservation emerging technology analysis because of uncertainty about the pace and magnitude of the changes in the costs and performance.

Like utility scale solar, residential and commercial distributed PV installations across the U.S. are growing. According to the U.S. Energy Information Administration, rooftop solar electricity production grew an average of 21 percent per year from 2005 through 2012. In the Northwest region, as of 2012, there are over 10,000 utility customers with installations that were selling a small amount of power back to the grid (net metering). Third party leasing became a more popular option than customer-owned systems in 2012 and it now accounts for about two-thirds of annual rooftop installations.

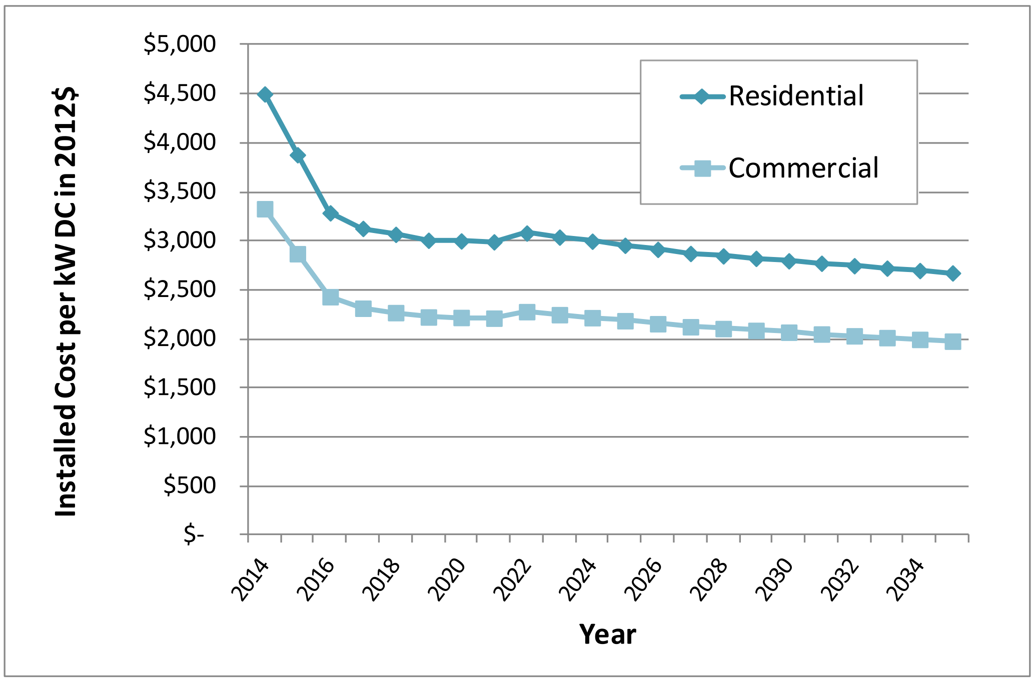
Typical residential and commercial-sized installations are used to estimate costs for distributed PV. Like utility-scale solar, a wide range of values for the TRC net levelized cost of energy can result for distributed PV depending on the location, orientation, sizing, financing model, and availability of tax credits. The Council modeled four configurations. These are divided into residential and commercial-sized applications to reflect economy of scale available in larger commercial applications. Estimates are also produced for east and west of the Cascades Mountains to account for variant insolation levels, which impact cost of energy generated. PV cost and sizing parameters are based on recent

[32] The Council's frozen efficiency (i.e., pre-conservation) load forecast includes consumer adoption of a specific amounts of distributed solar. By 2035, the Council forecast that 500 to 1,400 megawatts of solar PV systems will be installed in the region. On an annual basis, the energy generated from these distributed PV systems is forecast reduce regional loads by 80 to 220 average megawatts. In addition, these distributed solar PV systems also reduce winter and summer peak loads. Summer peak impacts from distributed solar PV are forecast to be lower by as much as 600 megawatts by 2035. See Appendix E for more details.

program data from Energy Trust of Oregon and include total installed cost and program administrative costs, marketing, and overhead.

Based on these data, the Council estimated the residential installed costs averaged $4,500 per kW_{DC} in 2014. Commercial costs are lower, $3,300 per kW_{DC}, due to economy of scale. Recent extension of the federal investment tax credit will reduce both residential and commercial costs through 2021. But underlying costs are expected to continue to drop for this emerging technology because of technology improvements and economy of scale. The Council forecasts distributed PV costs will fall by the same relative factor used for falling costs of utility-scale PV (see Chapter 13). Figure 12 - 19 shows that by 2025, costs are estimated to be about 66 percent of 2014 costs. Other key factors on costs and production are described below. The TRC net levelized cost for distributed solar PV falls in the range of $120 to $200 per megawatt-hour by 2025 depending on application and location. There is a wide band of uncertainty around these forecast cost estimates. More detail of solar PV costs is provided in Chapter 13. The upper and lower bounds of TRC net levelized costs, across all configurations, are provided in Table 12 - 7.

Figure 12 - 19: Cost Trend for Distributed Photovoltaics



Residential installation size for PV has been increasing over the last few years and is now up to 5.3 kilowatts per home.[33] Commercial installations show a wider range of sizes, but have tended to run in the 30 to 35 kilowatt size range on average. Distributed PV installations are assumed to have a 25 year lifetime, with an annual average degradation of 0.4 percent. The solar calculator PVWatts®[34] was used to estimate the expected annual capacity factor of 0.13 for west of the Cascades

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[33] Energy Trust of Oregon program data.
[34] http://rredc.nrel.gov/solar/calculators/pvwatts/version1/change.html

(Portland) and 0.17 for east of the Cascades (Boise). Generally, residential PV installations produce enough electricity to supply about half of the annual electricity requirements of a typical residential home. Prime generation months occur from April through September when there may be excess generation available to deliver to the grid. But in winter in the Pacific Northwest, PV contributes a smaller share of site energy requirements because requirements increase and solar production decreases. In the Pacific Northwest, rooftop solar systems typically deliver about three times as much energy in summer months as they do in winter months. Peak capacity contribution of PV is negligible in winter, but increases to 26 to 35 percent of installed PV capacity in summer because there is more sunlight available during the system peak hour (6pm) in the summer.

Expected fixed operations and maintenance (O&M) costs include inverter replacements at 10 years for residential and 15 years for commercial installations, along with periodic cleaning of the modules. Distributed PV costs also include a cost of integrating solar energy into the grid based on Bonneville's 2014 integration tariff. Converting DC power to AC power incurs losses for conversion, wiring, diodes and other factors. Total losses are estimated at 16 percent including inverter losses based on analysis by National Renewable Energy Lab in PVWatts. Financial parameters for development of distributed PV are based on the same parameters as residential conservation measures.[35]

Table 12 - 8: Distributed Solar PV Estimated Costs and Maximum Achievable Potential

	2025			2035		
Distributed Solar PV	Annual Energy (aMW)	Nameplate Capacity (MW_{DC})	TRC Net Lev Cost ($/MWh)	Annual Energy (aMW)	Nameplate Capacity (MW_{DC})	TRC Net Lev Cost ($/MWh)
East of Cascades Residential	330	2000	$150	1000	6000	$130
East of Cascades Commercial	200	1200	$120	630	3800	$100
West of Cascades Residential	500	3800	$200	1470	11400	$180
West of Cascades Commercial	320	2400	$150	930	7100	$140
Total	1350	9400	$120-200	4000	28100	$100-180

There is a large amount of distributed PV that is available for deployment. Its contribution as an emerging technology is more limited by the pace at which it can be deployed, than by the total megawatts of capacity that could be developed. Distributed PV is typically installed on residential and commercial building rooftops, car ports, and other structures as a matter of convenience. But

[35] See Appendix G

applications are not limited to buildings. For example, a recent trend toward towards community-based solar PV projects has emerged with projects developed on under-used urban land.

The Council estimated the available PV by considering total area of residential and commercial roofs taken from the recent residential and commercial building stock assessments and forecast growth. Only a fraction of this roof area is eligible for solar systems. Limitations include roof orientation, shading, and obstruction factors, which exclude 75 percent of residential and 40 percent of commercial roof area. With these limits, total technical potential is in the range of 40,000 to 50,000 megawatts of capacity by 2035. A small fraction of that technical potential, about 5 percent, is forecast to be developed and is included as load reduction in the Council's demand forecast.[36] Not all remaining technical potential is achievable within the 20-year forecast period. Because of the high number of installations required and other barriers to adoption, this emerging technology resource would take time to build. The Council limited the maximum achievable technical potential based on analysis done by the National Renewable Energy Lab (NREL).[37] The NREL study considers cost, adoption rates, financing alternatives, material availability, manufacturing and installation capability and other factors to estimate ranges for the achievable pace of development. At the highest rate, total achievable potential for rooftop PV capacity reaches about 20 percent of technical potential by 2025 and 50 percent of technical potential by 2035. The Council used the NREL high ranges to estimate the maximum total remaining potential in Table 12 - 8.

STATE OF WASHINGTON'S ENERGY INDEPENDENCE ACT IMPLICATIONS

The Energy Independence Act, or Initiative 937 (I-937) in the state of Washington, approved by the voters in 2006, obligates any Washington utility with more than 25,000 customers to "pursue all available conservation that is cost-effective, reliable, and feasible."[38] The law requires these utilities to develop and implement 10-year conservation plans that identify the "achievable cost-effective [conservation] potential". Every two years, each utility must review and update its assessment of conservation potential for the subsequent 10-year period. At the end of each two-year cycle, the utility's target and achievement are reviewed by a regulator or auditor.

Washington's Energy Independence Act and the Northwest Power Act intersect in that the state's utilities are to engage in conservation planning "using methodologies consistent with those used by the Pacific Northwest Power and Conservation Council in its most recently published regional power plan". The Council's conservation planning methodology is described in this chapter and in Appendix G. The Washington Department of Commerce has adopted a rule summarizing 15 elements of the

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[36] See Chapter 7 and Appendix E

[37] Easan Drury, Paul Denholm, and Robert Margolis, *Sensitivity of Rooftop PV Projections in the SunShot Vision Study to Market Assumptions*, Technical Report NREL/TP-6A20-54620, January 2013

[38] Section 19.285.040(1) of Revised Code of Washington

Council methodology used in the Sixth Power Plan.[39] Each utility is required to develop a conservation potential using data specific to its own customers and service area.

The two mandates (Washington's Energy Independence Act and the Northwest Power Act) are legally distinct. The Energy Independence Act is a matter of state law, and does not alter or obligate the Council in its conservation and power planning under the Northwest Power Act. Similarly, the Council has no authority to interpret, apply or implement the Energy Independence Act for the utilities and regulators in the state of Washington.

[39] WAC 194-37-070(5). After I-937 was enacted, Washington initially adopted a rule allowing utilities to set targets based on proportionate share of regional potential, but this rule was amended in 2014 to require utility-specific assessment using Council methodologies.

CHAPTER 13:
GENERATING RESOURCES

Contents

List of Figures and Tables

KEY FINDINGS

Hydroelectric power is the cornerstone of the existing regional power generating system. Proven technologies which could be added to the system over the next twenty years include highly efficient combined cycle combustion turbines, super flexible reciprocating engines and aeroderivative gas turbines, and clean and renewable solar, wind power, and geothermal.

For assessment purposes, generating resource technologies have been classified into three categories: primary, secondary, and long-term. Primary resources are commercially proven technologies that have the potential to be developed within the twenty year planning horizon and play a major role in the future regional power system. For the Seventh Power Plan, the primary generating resources include: natural gas-fired simple cycle and combined cycle turbines and reciprocating engines, solar photovoltaic, and onshore wind. The Council developed model reference plants with estimated costs and performance characteristics for each of the primary resources as inputs to the Regional Portfolio Model.

Natural gas-fired technologies in the region benefit from a robust existing natural gas infrastructure system and inexpensive fuel supply. Regional pipelines have the ability to tap prolific gas supply basins in the United States and Canada, and gas storage is available in several geographic locations. Combined cycle combustion turbines are the largest and most efficient of the gas technologies. Heat rates (efficiency) and operational performance for this technology continues to improve. These versatile power plants have the ability to replace baseload coal power, act as a firming resource for variable renewable generation, and fill in gaps from reduced hydro production during low water years. Combined cycle combustion turbine plants also emit carbon dioxide at significantly lower rates than coal plants, and may play a role in helping to reduce overall carbon dioxide emissions as proposed in the Federal Clean Power Plan.

Natural gas-fired reciprocating engine technology has improved in recent years and has become a valuable resource for enhancing system flexibility. Reciprocating engine generating sets are highly modular, are quick starting, and offer the best efficiency compared to simple cycle combustion turbines, especially when partially loaded. As a result, these gas plants may run more frequently than other typical peaking gas turbines.

Costs for solar photovoltaic technology have dropped significantly in the five years since the Sixth Plan was developed. Investments into research and development have paid dividends in improved solar cell efficiency, and high-tech module manufacturing on a large scale has brought solar costs down far enough to rival other variable energy resources. Photovoltaic systems (utility-scale and distributed) are relatively simple and quick to install, have no emissions, and have a generation pattern that matches favorably with summer loads in the region. However, solar does not produce at night, and during daylight hours, generation can vary due to atmospheric conditions such as cloud cover. As lower cost battery storage systems emerge, the combination of solar power with storage could offer an economical solution to these issues. Solar installations are wide spread and rapidly growing in the U.S., and, though not as common in the Northwest, activity is picking up. Future solar costs are forecast to continue to decline over the next 20 years. However there is a wide band of uncertainty around the cost of solar; actual costs may come in much lower (or higher) than expected.

Wind technology has continued to advance, resulting in higher levels of generation per turbine. The region has experienced significant wind power build-out in the Columbia Basin of Oregon and Washington, and while wind development in Montana has been limited, that region offers a generous wind resource potential. Wind generation patterns in the two areas are complementary: Columbia Basin typically produces more wind in the spring and early summer, while Montana offers better winter month wind generation. However the lack of available transmission to bring Montana wind to the load centers of Western Oregon and Washington is a significant challenge to extensive development.

Secondary resources are classified as commercially available but are limited in terms of developable potential, by cost or site limitations. Storage technologies can fall into both secondary and long-term resources. Battery storage systems may be an important component of the future power system, especially when paired with variable renewable generating resources such as solar. The manufacturing and use of battery technologies, particularly Lithium-ion batteries, is beginning to ramp up which may bring the costs down, making it a more attractive resource.

Conventional geothermal, while classified as a secondary resource for the Seventh Power Plan due to its limited development to date and limited potential, is a viable alternative renewable resource to wind and solar, as well as a baseload resource competitive with natural gas technologies.

Long-term resources include technologies that are not yet commercially available but may have significant potential. Enhanced geothermal systems, which essentially mine the earth’s heat, is a promising emerging technology which could provide renewable baseload power with little to no greenhouse gas emissions and has tremendous potential in the Northwest.

INTRODUCTION

This chapter describes the proven generating and energy storage alternatives that are commercially available and deployable to the Pacific Northwest to meet energy and capacity needs during the power plan’s 20-year planning period and the process in which these resources were evaluated and estimated for the Seventh Power Plan. Additional detailed information on generating resources is available in Appendix H and information on environmental effects, environmental regulations, and compliance actions is available in Appendix I.

The Northwest Power Act requires priority be given to resources that are cost-effective, defined as resources that are available at the estimated incremental system cost no greater than that of the least-cost similarly reliable and available alternative.[1] Since there are sufficient resources using reliable, commercially available technologies to meet the region’s forecast needs over the 20-year planning period, unproven resources, including those whose availability and quantity is poorly understood or that depend on immature technology, were not considered for the portfolio risk analysis. Certain unproven and emerging resources, including offshore wind power, wave energy, tidal currents, enhanced geothermal, and some energy storage technologies have substantial

[1] Northwest Power Act 3.(4)(A)

Northwest potential. Actions to monitor and support development of these technologies are included in the Action Plan in Chapter 4.

Role of Generating Resources in the Power Plan

The identification and assessment of generating resources provides options for the Regional Portfolio Model (RPM) when selecting the most cost-effective, least-risk power plan for the region. Resource technologies are assessed based on their cost, operating and performance characteristics, and developable potential in the region. Resources that are deemed proven and likely available to meet future needs in the region are further developed into reference plants – with a designated plant size and configuration representative for the Pacific Northwest, characteristics and performance attributes, cost estimates (capital, operating and maintenance, levelized), and other attributes such as an estimated construction schedule and economic life. These reference plants become inputs to the RPM as options for selection to fulfill future resource needs.

Generating Resource Classifications

The Council prioritized and categorized generating resources based on a resource's commercial availability, constructability, and quantity of developable potential in the Pacific Northwest during the 20-year planning period. The classifications of resources analyzed for the Seventh Power Plan are: primary, secondary, and long-term (see Table 13 - 1). The definitions and levels of assessment are as follows:

- Primary: Significant resources that are deemed proven, commercially available, and deployable on a large scale in the Pacific Northwest at the start of the power planning period. These resources have the potential to play a major role in the future regional power system. Primary resources receive an in-depth, quantitative assessment to support system integration and risk analysis modeling. Primary resources are modeled in the RPM.
- Secondary: Commercially available resources with limited, or small-scale, developmental potential in the Pacific Northwest. While secondary resources are currently in-service or available for development in the region, they generally have limited potential in terms of resource availability or typical plant size. Secondary resources receive at least a qualitative assessment to estimate status and potential and sometimes a quantitative assessment to estimate cost. While secondary resources are not explicitly modeled in the RPM, they are still considered viable resource options for future power planning needs.
- Long-term: Emerging resources and technologies that have a long-term potential in the Pacific Northwest but are not commercially available or deployable on a large scale at the beginning of the power planning period. Long-term resources receive a qualitative assessment and if available, quantification of key attributes.

Table 13 - 1: Classification of Generating Resources*

Primary	Secondary	Long-term
Natural Gas Combined Cycle	Biogas Technologies (landfill, wastewater treatment, animal waste, etc.)	Enhanced Geothermal Systems
Natural Gas Simple Cycle (Aeroderivative Gas Turbine, Frame Gas Turbine)	Biomass – Woody Residues	Offshore Wind
Natural Gas Reciprocating Engine	Conventional Geothermal	Small Modular Nuclear Reactors (SMRs)
Onshore Wind	Hydropower (new)	Storage Technologies**
Solar Photovoltaic	Hydropower (upgrades to existing)	Tidal Energy
	Storage Technologies**	Wave Energy
	Waste Heat Recovery and Combined Heat and Power (CHP)	

* Resources are in alphabetical order

** Energy storage comprises many technologies at various stages of development and availability

ENVIRONMENTAL EFFECTS AND QUANTIFIED ENVIRONMENTAL COSTS

The Northwest Power Act requires the Council to estimate the incremental system cost of each new resource or conservation measure considered for inclusion in the plan's new resource strategy. The incremental system cost must include all direct costs of a measure or resource over its lifecycle, including environmental costs and benefits that can be quantified. The Act also requires the Council to include in the plan a description of its methodology for quantifying the environmental costs and benefits of the new resource alternatives. Per the Act, the Council is required to develop the plan's resource strategy giving due consideration to, among other factors, environmental quality and the protection, mitigation, and enhancement of fish and wildlife.

The Council's methodology for quantifying environmental costs and benefits is described in Chapter 19, as well as the Council's approach to considering environmental and fish and wildlife effects broadly in analyzing and selecting new resources to add to the region's existing power supply. Consistent with these descriptions, Chapter 19 together with Appendix I describe in detail the effects on the environment associated with different types of generating resources considered for inclusion in the power plan's resource strategy, as well as the environmental regulations developed by other agencies of government to address those effects. Estimates of the capital and operating costs to comply with existing and proposed regulations are identified in the total resource costs for each resource. Chapter 9 (Existing Resources) and Appendix I also describe the environmental effects and issues related to the generating plants already in the region's power supply.

Environmental standards, the actions required for compliance, and the associated costs vary by geographic location and by the circumstances of different resources. These are best represented in the Council's planning process by representative plants characteristic of those that could be expected to be developed in the Northwest. With few exceptions, the sources of cost information for these plants available to the Council aggregate all of the costs of the plants, making it difficult to break out the embedded cost of environmental compliance. However, because the resource cost estimates are based on recently constructed or proposed plants, the Council assumes that the costs do include the cost of compliance with current and near-term planned environmental regulation.

PRIMARY RESOURCES

Detailed cost and performance estimates were developed for new resources in the primary classification – solar, wind, and natural gas technologies. These estimates were used to define new generating resource reference plants, which are used in the Council's modeling efforts, including the RPM. Each reference plant resembles a realistic and likely implementation of a given technology within the region. Additional information regarding the cost and performance of generating resources and the reference plants is available in Appendix H.

The key estimated cost and performance characteristics used to develop the reference plants include:

1. Plant size (megawatt) – the unit size or installed capacity of an individual plant
2. Capital cost ($ per kilowatt) – an estimate of the project development and construction cost in constant year dollars ($2012), normalized by plant size
3. Fixed O&M ($ per kilowatt-year) – estimate of the fixed operations and maintenance cost for the plant
4. Variable O&M ($ per megawatt-hour) – estimate for the variable operations and maintenance cost
5. Heat rate (British thermal units per kilowatt-hour) – when applicable, an estimate for the fuel conversion efficiency of the plant
6. Capacity Factor (%) – an estimate of the ratio of the actual annual output to the potential annual output if the plant is operated at full capacity
7. Fixed fuel cost ($ per kilowatt-year) and variable fuel cost ($ per million British thermal units) – when applicable, estimates for the cost of firm pipeline transmission and fuel commodity cost
8. Transmission and Integration cost ($ per kilowatt-year) – estimate of the cost for long-distance transmission and integration
9. Plant sponsor – the cost and structure of project financing may vary depending on the sponsor, such as for an Investor Owned Utility (IOU), an Independent Power Producer (IPP), or a Public Utility District/Municipality (PUD)

A financial revenue requirements model – Microfin - was used to calculate the levelized fixed cost and the full levelized cost of energy (LCOE) for each reference plant. The finance model calculates the annual cash flows which will satisfy revenue requirements over the plant lifetime. The annual cash flows are compressed and discounted into a single dollar value – Net Present Value (NPV). The NPV is then converted into a level, annualized payment (like a home mortgage payment). Two main cost values are output from the model:

1. Levelized fixed cost ($ per kilowatt-year) represents the cost of building and maintaining a power plant over its lifetime and is a primary cost input to RPM
2. LCOE ($ per megawatt-hour) is the cost per unit of energy the plant is expected to produce and which also includes variable costs such as fuel, and variable O&M.

The key financial inputs used in the model for calculating levelized costs include:

1. Discount rate – 4%[2]
2. Debt Percentage - 50% for IOU, 60 % for IPP
3. Debt service – ranges from 15 to 30 years depending on project and sponsor
4. Return on Equity – 10% for IOU, 12% for IPP sponsor
5. Federal Tax – 35%, State Tax – 5%
6. Federal Investment Tax Credit – 30%/10%[3]
7. Capacity factor

The cost characteristics for natural gas technologies and associated reference plants are summarized in Table 13 - 2. The levelized cost of energy value captures the overall cost (capital, fixed and variable O&M, fixed and variable fuel) on a per unit of production basis. Since the energy production value is in the denominator of the equation, the more energy the resource produces, the lower the cost will be given a set of fixed costs. Therefore, the value that is selected for the capacity factor variable has a large impact on the resulting cost. For illustrative purposes, a 60 percent capacity factor was used for the combined cycle combustion turbine plants, and 25 percent for the simple cycle turbines and reciprocating engines. Actual utilization of gas plants can vary, but in general, a combined cycle plant would be expected to run at a higher capacity factor than a simple cycle plant or reciprocating engine. The Council's medium natural gas price forecast was used for fuel cost calculations.

[2] See Appendix A: Financial Assumptions for more information
[3] ITC for Solar – 30% through year 2019, 26% through 2020, 22% through 2021, 10% for 2022 - 2034

Table 13 - 2: Summary of Natural Gas Generating Resources – with Service Year of 2020

Resource	Technology	Reference Plant Name	Plant Size MW	All-In Capital Cost	Levelized Fixed Cost[4]	Levelized Cost of Energy[5]
Natural Gas	Combined Cycle Combustion Turbine	CCCT Adv 1 Wet Cool[6] East	370 MW	$ 1,234 /kW	$ 182 /kW-yr	$ 71 /MWh
		CCCT Adv 2 Dry Cool[7] East	425 MW	$ 1,384 /kW	$ 196 /kW-yr	$ 74 /MWh
		CCCT Adv 2 West Side Dry Cool West	426 MW	$ 1,379 /kW	$ 204 /kW-yr	$ 78 /MWh
	Reciprocating Engine	Recip Eng East	220 MW	$ 1,315 /kW	$ 191 /kW-yr	$ 137 /MWh
		Recip Eng West	220 MW	$ 1,315 /kW	$ 208 /kW-yr	$ 149 /MWh
	Aeroderivative Gas Turbine	Aero GT East	179 MW	$ 1,124 /kW	$ 192 /kW-yr	$ 139 /MWh
		Aero GT West	178 MW	$ 1,120 /kW	$ 214 /kW-yr	$ 154 /MWh
	Frame Gas Turbine	Frame GT East	200 MW	$ 817 /kW	$ 148 /kW-yr	$ 128 /MWh
		Frame GT West	201 MW	$ 814 /kW	$ 174 /kW-yr	$ 145 /MWh

Figure 13 - 1 displays the LCOE for the reference plants by cost component. For natural gas plants, the largest cost component is fuel related.

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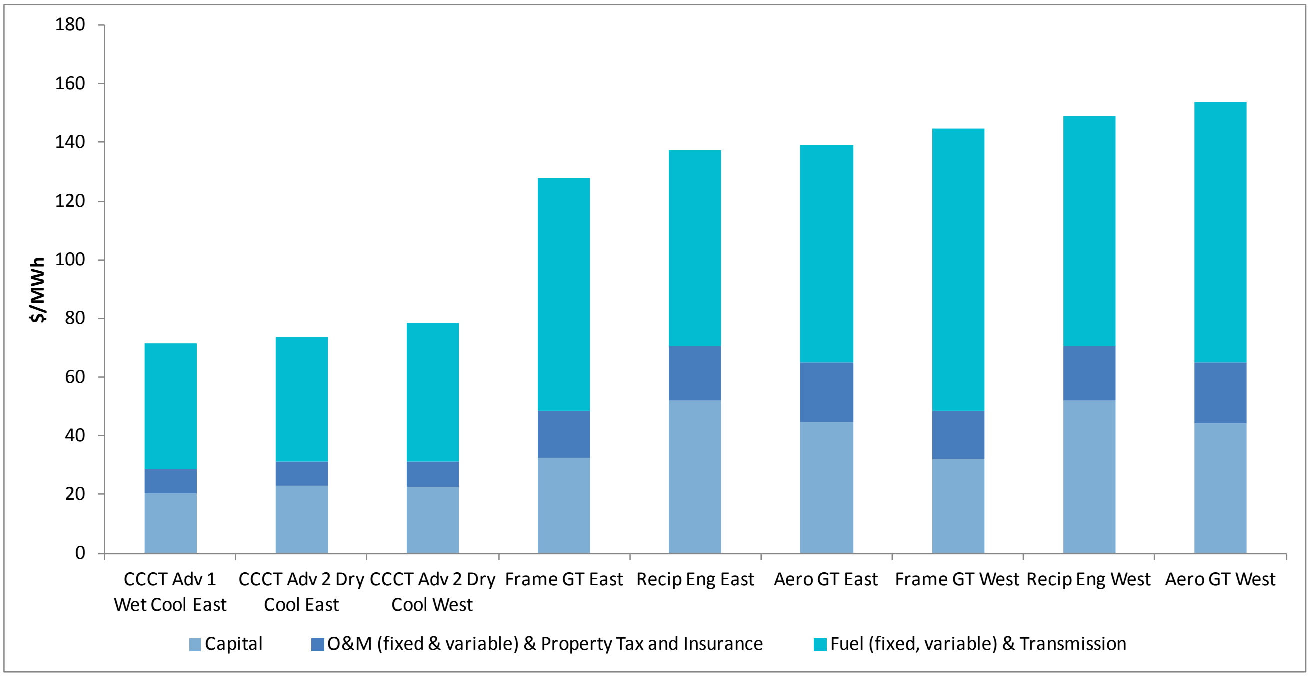
[4] West side gas plants costs include pipeline expansion cost, and transmission deferral credit
[5] Capacity Factor of 60% for Combined Cycle Plants, Capacity Factor of 25% for Aeroderivative, Frame and Recip. Eng. Plants
[6] Wet Cooling – re-circulating system includes steam condenser and cooling tower
[7] Dry Cooling – forced draft air-cooled condenser, uses much less water

Figure 13 - 1: Levelized Cost of Energy for Natural Gas Resources - with Service Year of 2020



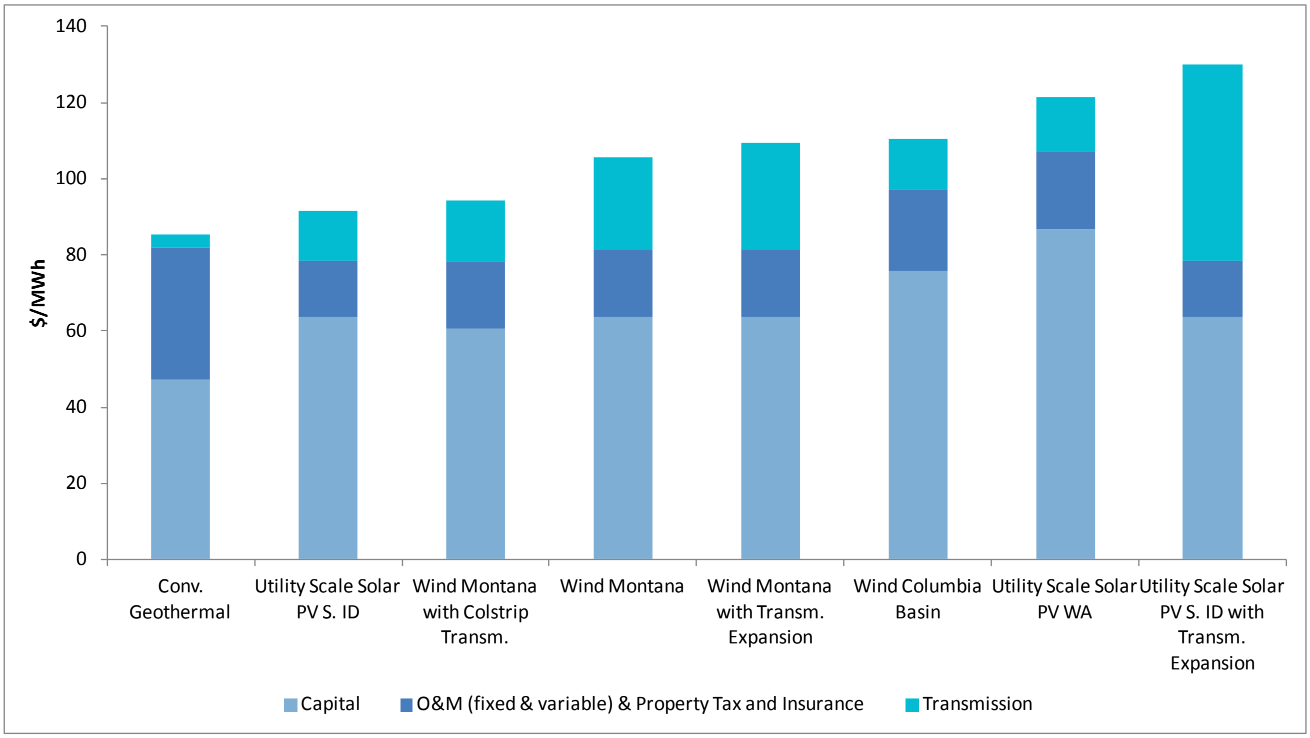
A summary of the cost components of renewable resources is provided in Table 13 - 3 and Figure 13 - 2. In the case of wind and solar photovoltaic (PV), the largest cost component is the capital cost required to install the plant; there is no fuel cost component. Unlike the natural gas plants, the capacity factor is a function of the technology and quality of the wind or solar resource that is available.

Table 13 - 3: Summary of Renewable Resources – with Service Year of 2020

Resource	Technology	Reference Plant Name	Plant Size MW	All-In Capital Cost	Levelized Fixed Cost	Levelized Cost of Energy
Solar	Utility-Scale Solar PV	Utility-Scale Solar PV ID[8]	17.4 MW	$ 2238 /kW	$ 204 /kW-yr	$ 91 /MWh
		Utility-Scale Solar PV ID with transmission expansion	17.4 MW	$ 2238 /kW	$ 292 /kW-yr	$ 130 /MWh
		Utility-Scale Solar PV WA[9]	47.6 MW	$ 2238 /kW	$ 204 /kW-yr	$ 121 /MWh
Wind	Utility-Scale Wind	Wind Columbia Basin[10]	100 MW	$ 2307 /kW	$ 303 /kW-yr	$ 110 /MWh
		Wind Montana[11]	100 MW	$ 2419 /kW	$ 363 /kW-yr	$ 106 /MWh
		Wind Montana with transmission expansion	100 MW	$ 2419 /kW	$ 375 /kW-yr	$ 109 /MWh
		Wind Montana using Colstrip Transmission[12]	100 MW	$ 2307 /kW	$ 323 /kW-yr	$ 94 /MWh
Geothermal	Conventional, Binary-cycle	Conv. Geothermal[13]	39 MW	$ 4827 /kW	$ 633 /kW-yr	$ 85 /MWh

[8] Solar PV located in Southern Idaho with 26% capacity factor
[9] Solar PV located in Washington with 19% capacity factor
[10] Columbia Basin Wind capacity factor 32 %
[11] All Montana Wind capacity factor 40 %
[12] With assumption that Colstrip Units 1 & 2 retired and Wind able to use associated transmission
[13] Geothermal located in Central/Eastern Oregon with 90% capacity factor

Figure 13 - 2: Levelized Cost of Energy for Renewable Resources – with Service Year of 2020



Transmission

The common point of reference for the costs of new generating resources is the wholesale delivery point to local load serving areas. The costs of transmission from the point of the generating project interconnection to the wholesale point of delivery are included in the estimated generating resource cost.

The cost of resources serving local loads include local (in-region) transmission costs. For example, Oregon and Washington resources serving Oregon and Washington loads include the Bonneville Power Administration Transmission rate for long term, firm point-to-point transmission. Southern Idaho resources, such as utility-scale solar PV, serving Idaho loads include the Idaho Power transmission rate.

The cost of resources serving remote loads, such as Montana-based wind power serving Oregon and Washington loads include the estimated cost both of needed long-distance transmission and local transmission. In order to bring significant amounts of wind power from Montana to the Oregon and Washington load centers, further investments in transmission may be required. To model these costs for the reference plants, the Council used cost estimates for proposed transmission expansion projects. For example, the estimated cost of the proposed Path 8 Upgrade,[14] which would relieve

[14] See https://www.wecc.biz/TransmissionExpansionPlanning/Pages/Default.aspx

congestion on Path 8 and provide additional transmission for renewable power from Broadview, Montana to the Mid-Columbia area, was used as a proxy for the transmission cost of bringing significant quantities of Montana wind power to Oregon and Washington.

Appendix I contains a discussion of the environmental effects and issues associated with the development of transmission to serve the region’s generating facilities.

Natural Gas Generating Technologies

Natural gas is a fossil fuel typically found in deep underground reservoirs of porous and permeable rocks, or gas rich shale formations. Primarily composed of methane (CH_4), natural gas also contains lesser amounts of other hydrocarbon gases, including ethane, propane, and butane. It is the cleanest burning fossil fuel, producing lesser amounts of combustion by-products and CO_2 emissions than coal or refined oil products.

Natural gas is useful for a wide variety of applications. It is used directly for numerous residential and commercial end uses, such as water heating and space heating. It is also used intensively for industrial end uses and is increasingly used as a fuel to generate electricity using steam, gas turbine, and reciprocating engine technologies. Natural gas is also the principal feedstock in the manufacture of ammonia and ammonia-based fertilizers.

The natural gas resource base in North America is enormous. Recent estimates for the total amount of technically recoverable natural gas in the U. S. alone are over 2,500 trillion cubic feet (Tcf).[15] Production continues to exceed expectations as extraction technologies improve, boosting efficiencies and cost effectiveness. In the last ten years, hydraulic fracturing combined with horizontal drilling has enabled producers to tap large gas resources previously locked up in shale rock. Hydraulic fracturing uses water, sand, and chemicals under high pressure to fracture rock, which then releases trapped gas. Horizontal drilling allows fracturing to follow long veins of gas-rich shale. Nearly all new wells that are drilled today are fractured.

The Northwest is situated between two prolific natural gas producing regions – the U.S. Rocky Mountains (Rockies), and the Western Canadian Sedimentary Basin (WCSB). In any given year, as much as two thirds of the gas purchased for use in the region is sourced from the Alberta and British Columbia Provinces of Canada. Historically, natural gas prices have been volatile, and there have been sustained periods of high prices. More recently, with the abundance of supply, natural gas spot prices at the three primary regional pricing hubs have remained relatively low and are expected to remain low in the future. The average spot price[16] (2012 dollars per million British thermal units) for the years 2010 through 2014 was:

- SUMAS (British Columbia) $3.75
- AECO (Alberta) $3.36

[15] Potential Gas Committee, April 8, 2015
[16] SNL Financial

- OPAL (U.S. Rockies) $3.71

While sustained low prices are expected going forward, prices may spike due to weather conditions or unexpected supply issues.

The natural gas delivery system is made up of:

- Producing wells (that may be far away from the end use)
- Gathering pipelines - carry gas to processing plants and then on to large transmission pipelines
- Transmission pipelines - deliver gas to the city gate station and local distribution companies
  - Gas-fired power plants may offload gas from the transmission pipelines
  - Storage facilities – above-ground liquefied natural gas (LNG) tanks and underground gas storage may draw on the transmission pipelines
- Distribution systems -deliver gas to end-use customers such as residences, businesses, industrial plants, and power plants

The existing system of pipelines and storage facilities in the Northwest is robust and has been able to meet the gas needs of the region. Several major gas pipelines serve the region and tap an ample and diverse supply base.

Table 13 - 4: Natural Gas Pipelines

Major Pipelines	Supply Access
Williams Northwest Pipeline	Rockies & WCSB
TransCanada GTN	WCSB
Kinder Morgan Ruby Pipeline	Rockies
Spectra BC Pipeline	WCSB

The ability to purchase and store natural gas for later use is a valuable characteristic of the fuel. For example, gas may be purchased in the early summer (when prices are lower), moved to storage and then withdrawn in the winter during cold weather events when gas supplies may be constrained and therefore more expensive. There are several above-ground LNG plants in the region, and two large underground storage facilities: Mist Storage (OR) and Jackson Prairie (WA).

Though the current natural gas infrastructure in the region is robust, additional capability, especially pipeline capacity, may be needed in the future. During high demand periods, typically cold weather events, pipeline limits have been reached on both the Williams Northwest Pipeline and Spectra BC systems. Additional new demand may put further stress on the system, requiring expansion. The constraint issues are not evenly distributed throughout the system. For example, pipeline capacity through the Columbia River Gorge on the Williams Northwest Pipeline has periodically brushed up against constraints; however, for much of the eastern part of the region served by the GTN system, ample pipeline capacity exists.

Combined Cycle Combustion Turbine

Combined cycle combustion turbine (CCCT) plants are highly efficient power sources that run on natural gas and can provide baseload and dispatchable power. This increasingly versatile technology can be used both as a replacement of baseload coal power, and as a complementary firming power source to renewable generation from wind and solar. With the reliable North American natural gas supply system, planned coal plant retirements, and increasing levels of renewable generation, combined cycle combustion turbines may play an important role in the future power generation landscape.

A CCCT plant consists of one or two gas turbine generators each exhausting to a heat recovery steam generator (HRSG). The steam produced in the HRSG is supplied to a steam turbine generator and condenser. The productive use of the gas turbine exhaust energy greatly increases the efficiency of CCCT plants as compared to simple-cycle gas turbines. The primary fuel is natural gas, though fuel oil may be used as a backup. The heat recovery steam generators are often equipped with natural gas burners to boost the peak output of the steam turbine (duct firing). Plants may be equipped with bypass exhaust dampers to allow the independent operation of the gas turbines to generate electricity.

The high efficiency of combined cycle plants coupled with the low carbon content of natural gas results in the lowest carbon dioxide (CO_2) production rate of any fossil fuel power generating technology. A new CCCT plant emits roughly 800 pounds of CO_2 per megawatt-hour of electricity produced. An older coal plant emits approximately 2,300 pounds of CO_2 of per megawatt-hour, nearly three times the rate of a CCCT. One element of the proposed Clean Power Plan (111d) calls for states to substitute coal-fired generation with existing combined cycle gas plants, requiring CCCT units to operate at capacity factors above 70 percent.

In the Northwest, utilization of existing CCCT plants can depend on variable hydro conditions. During low water years, CCCT plants may run at high capacity factors to make up for the lower amount of hydroelectric power. During high water years, utilization of CCCT plants may drop. There are many other factors that may impact regional CCCT utilization, such as load, renewable power generation levels, plant outages, fuel prices, and wholesale electricity prices.

There are three types of cooling used for the steam turbine/ heat recovery steam generator used in CCCT plants:

1. Once through cooling (OTC) – no longer used for new plants
2. Wet cooling – a recirculation system with a steam surface condenser and wet cooling tower
3. Dry cooling – forced draft air-cooled condenser

Regional permitting constraints may require the dry cooling option for a new plant. Implementation of dry cooling technology results in higher capital costs (14 percent higher) for the plant, slightly higher heat rates, but 96 percent less water consumption than for a wet cooled plant.[17]

Overall heat rates continue to improve for advanced, state-of-the-art CCCT technologies. A few other observations on state-of-the-art CCCT technologies include:

- Economies of scale (the larger the unit, the less expensive it is on a dollar per kilowatt basis)
- Plants are becoming more flexible with faster start times and better efficiencies at part and minimum loads

Three combined cycle combustion turbine reference plants were developed for the Seventh Power Plan. Each plant is assumed to operate on natural gas supplied on a firm transportation contract. Location-specific adjustments were made for firm service cost estimates and for the impact of elevation on output. Emission controls include low-nitrogen oxide burners and selective catalytic reduction for nitrogen oxide control and an oxidation catalyst for carbon and volatile organic compound control. The financial assumptions used for calculating levelized costs were consistent with an IOU sponsor. See Table 13 - 5 for a description of the reference plants.

Table 13 - 5: Combined Cycle Combustion Turbine Reference Plants

Reference Plant	Adv 1 Wet Cool East	Adv 2 Dry Cool East	Adv 2 West Side Dry Cool West
Base Technology	Siemens H-Class	MHI J-Class	MHI J-Class
Location	East side	East side	West side
Configuration	1 Gas Turbine x 1 Steam Turbine	1 Gas Turbine x 1 Steam Turbine	1 Gas Turbine x 1 Steam Turbine
Capacity MW	370	425	426
Heat Rate (btu/kWh)	6770	6704	6704
Cooling	Wet	Dry	Dry

Reciprocating Engine

Reciprocating engine generators consist of one or more compression spark or spark-ignition reciprocating engines driving a generator. These engines can run on many different fuels, including natural gas, biogas, and oil. The technology has been widely used for biogas energy recovery, remote baseload power, and for emergency backup purposes. More recently, reciprocating engine generator plants have been used for peak load-following, and for shaping the output of wind and solar variable energy resources. These large internal combustion engines offer rapid response and quick start-up capability. Reciprocating engine generators also offer the best efficiency of the simple-cycle gas technologies, especially during part-load conditions. As a result, these generators may run more often than a typical, peaking-type gas technology.

[17] John S. Maulbetsch, Michael N. DiFilippo, *Cost and Value of Water Use at Combined Cycle Power Plants* (prepared for the California Energy Commission April 2006)

Highly modular, a typical utility-scale installation is composed of multiple natural gas-fired units that range in size from six megawatts to 20 megawatts. The major components of a typical plant include one or two engine halls housing the engine-generator sets, one or more wet or dry cooling towers, individual or combined exhaust stacks, and a switchyard. Emission controls include selective catalytic reduction and oxidation catalysts.

Reciprocating-engine generators are excellent for providing flexibility; they start quickly (less than ten minutes), and follow load well. An advantage of the engines for load-following and variable resource shaping applications is the relatively flat heat rate curve of individual units. The multiple, independently dispatched units in a multi-unit facility provide additional flattening of the heat rate curve, allowing the plant to be operated over a wide range of output without significant loss of efficiency. Reciprocating engine generators also maintain output at increasing elevations, unlike combustion turbines.

Three reference plants were developed for reciprocating engine generator technologies, one for the east side of the region, and two for the west side. Each plant was based on the Wärtsilä 18V50SG natural gas engine. The plants are configured with 12 modules, providing 220 megawatts of capacity overall, with a heat rate of 8370 British thermal units per kilowatt-hour. A firm gas transport contract is assumed. West side reference plants were defined with and without new build out of the west-side gas pipeline system. There is assumed to be sufficient natural gas capacity on the east side. Air emission controls include a combined selective catalytic reduction and oxidation catalyst to reduce nitrogen oxides (NO_x), carbon monoxide and volatile organic compound emissions. The reference plant can provide regulation and load-following, contingency reserves, and other ancillary services. Due to the plant's high efficiency, it can also economically serve peak and intermediate load levels. The financial assumptions used for calculating levelized costs were consistent with an IOU sponsor.

Simple Cycle Gas Turbines

A simple-cycle gas turbine generator plant consists of a combustion gas turbine (sometimes multiples) driving an electric power generator, mounted on a common frame and enclosed in an acoustic enclosure. Other major components can include fuel gas compressors, fuel oil storage facilities (if used), a switchyard, a cooling tower (intercooled turbines only), a water treatment system (intercooled units and units using water injection for NO_x control) and a control and maintenance building. Emission controls on new units include low-NO_x combustors, water injection, selective catalytic reduction, and oxidation catalysts. All existing simple-cycle gas turbines in the Northwest use natural gas as a primary fuel, though fuel oil is used as a backup at some plants.

Simple-cycle gas turbines have been used for several decades to serve peak loads. Peaking units are generators that can ramp up and down quickly to meet sharp spikes in demand. Newer, more flexible and efficient models can also be used to follow the variable output of wind and solar resources. Because of the availability of hydropower, relatively few simple-cycle combustion turbines have been constructed in the Northwest, compared to regions with a predominance of thermal-electric capacity. As wind capacity has increased, simple-cycle gas turbine plants are beginning to be constructed in the Northwest for augmenting the wind-following capability of the hydropower system.

Three gas turbine technologies are marketed:

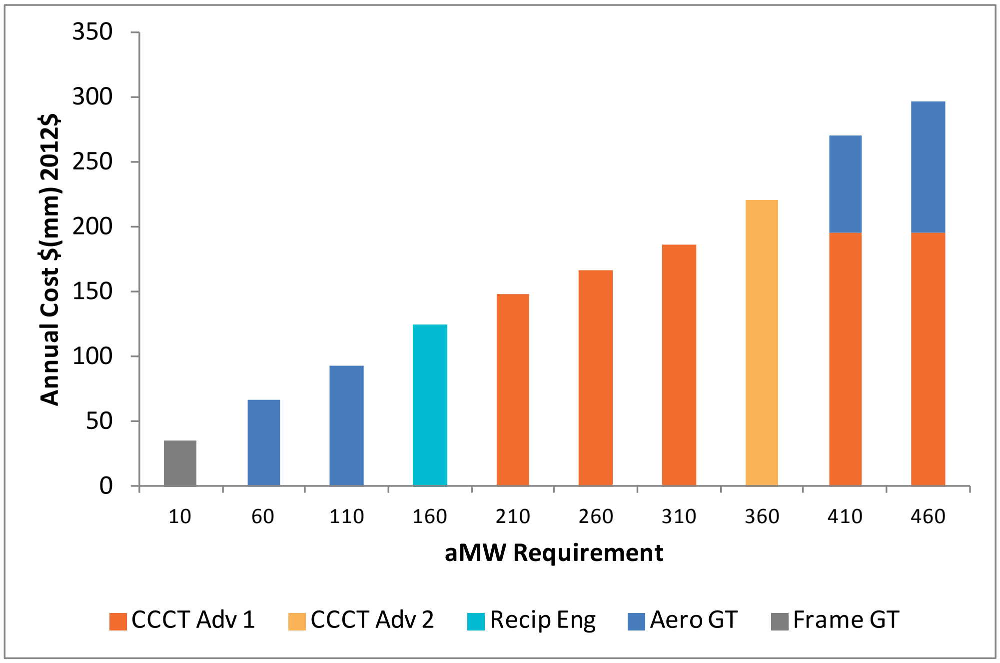
- **Aeroderivative** turbines are based on engines developed for aircraft propulsion and are characterized by light weight, high efficiency and operational flexibility.
- **Frame** turbines are heavy-duty machines designed specifically for stationary applications where weight is less of a concern. While rugged and reliable, frame machines tend to have lower efficiency and less operational flexibility than Aeroderivative machines.
- **Intercooled** gas turbines are a hybrid of frame and Aeroderivative technologies, and include an intercooler between compression stages to improve thermodynamic efficiency. Intercooled machines are expressly designed for operational flexibility and high efficiency. The intercooler requires an external cooling water supply.

Three reference plants were developed for Aeroderivative gas turbines, one for the east side of the region, and two on the west side. Each plant is based on the GE LM6000 PF with four 47 megawatts (nominal) turbine generators, providing 178 megawatts of overall capacity, with a heat rate of 9,477 British thermal units per kilowatt-hour. A firm gas transport contract is assumed. West side reference plants were defined with and without new build out of the west-side gas pipeline system. There is assumed to be sufficient natural gas capacity on the east side. Air emission controls include water injection and selective catalytic reduction for nitrogen oxide control and an oxidation catalyst for carbon and volatile organic compound reduction. This type of plant would normally serve peak load. Its rapid startup (less than 10 minutes) capability would also allow it to provide rapid-response reserves while shutdown. The financial assumptions used for calculating levelized costs were consistent with an IOU sponsor.

Three reference plants were developed for Frame gas turbines, one for the east side of the region, and two on the west side. Each plant is based on the GE 7F5S with a single 216 megawatts (nominal) turbine generator, providing 200 megawatts of overall capacity, with a heat rate of 10,266 British thermal units per kilowatt-hour. A firm gas transport contract is assumed. West side reference plants were defined with and without new build out of the west-side gas pipeline system. There is assumed to be sufficient natural gas capacity on the east side. The Frame gas turbine plant has lower upfront capital costs than the Aeroderivative, but runs at a lower efficiency and is less flexible. The financial assumptions used for calculating levelized costs were consistent with an IOU sponsor.

Each of the gas-fired technologies has different size, cost and operating characteristics. The CCCT plants are larger in size (megawatts), the most expensive in terms of fixed cost ($), and the most efficient to run. The simple cycle gas plants (Recip Eng, Aero GT, Frame GT) are smaller in size, have lower fixed costs, are less efficient to run, but have faster ramp rates (cold start to full load). The less efficient the plant, the more fuel is required to generate electricity; therefore variable costs increase for the same output level. If energy (average megawatts) requirements are limited, the simple cycle technologies are the least expensive option due to their lower capital cost. As energy requirements increase, the combined cycle technologies become least expensive. And further up the energy curve, various combinations of simple cycle and combined cycle plants result in the least expensive solution. Figure 13 - 3 shows the overall least cost gas plant option for a given energy requirement (average megawatts). For example, at an average megawatt requirement around 410, the least cost solution would be to install a combined cycle unit and an aero unit. These results only factor in cost, size, and plant efficiencies, but not other performance characteristics which would be fully considered before building a new gas plant.

Figure 13 - 3: Least Cost Gas Plant Solution by Energy Requirement



Environmental Effects of Natural Gas Technologies

The air emissions of principal concern from gas turbines, including simple-cycle and combined cycle plants, are nitrogen oxides (NO_x), carbon monoxide and to a lesser extent volatile organic compounds.[18] Sulfur oxide emissions are of potential concern if fuel oil is used. Nitrogen oxide formation is controlled using low-NO_x combustors, water injection, and operating hour and startup constraints. Low-NO_x combustors minimize excess oxygen and operate at reduced flame temperatures and residence time, thus reducing NO_x formation. Water injection can be used to reduce NO_x formation by lowering combustion temperatures. Additional, post combustion NO_x reduction is usually required for compliance with current regulations. Selective catalytic reduction (SCR) systems are installed for this purpose.

Carbon monoxide (CO) and unburned hydrocarbons originate from incomplete fuel combustion. CO and unburned hydrocarbon formation is reduced by "good combustion practices" (proper air/fuel ratio, temperature, and residence times). Additional post-combustion reduction is usually required by current regulations. This is accomplished by an oxidation catalyst (OxyCat) in the exhaust system. OxyCats promote complete oxidation of CO and unburned hydrocarbons to carbon dioxide (CO_2).

Like all fossil fuel technologies, gas turbines produce carbon dioxide as a product of complete combustion of carbon. Carbon dioxide emission factors are a function of plant efficiency, so newer units in general have lower CO_2 emissions per megawatt than older units. Though technology for

[18] The following discussion of air pollutants and controls is largely derived from Environmental Protection Agency AP-42 Compilation of Air Pollutant Emission Factors, Section 3.1 Stationary Gas Turbines.

separating CO_2 from the plant exhaust is available, as a practical matter it is unlikely that CO_2 removal technology would be employed for simple-cycle gas turbines because of the relatively low carbon content of natural gas and the relatively small size and limited hours of operation of these units. Newer units are likely to comply with the CO_2 performance standards of the proposed Clean Power Plan and will continue to serve loads, and to an increasing extent, shaping of variable output renewable resources.

Simple-cycle gas turbines do not employ a steam cycle so require no condenser cooling. Intercooled turbines do require cooling of the air intercooler. This is accomplished using a circulating water system cooled by evaporative or dry mechanical draft cooling towers. Other uses of water include water injection for NO_x control and power augmentation and for inlet air evaporative cooling systems to increase power output during warm conditions. Sulfur oxide emissions from units with fuel oil firing capability are controlled by use of ultra-low sulfur fuel oil and fuel oil consumption limits.

Air emissions of concern for natural gas reciprocating engine plants are nitrogen oxides, carbon monoxide, volatile organic compounds, particulates, and carbon dioxide. Engines utilizing fuel oil for compression ignition or backup purposes may also produce sulfur dioxides. Nitrogen oxides are produced by oxidation of atmospheric nitrogen during the fuel combustion process. NO_x formation is suppressed by "low-NO_X" combustion design. Selective catalytic converters in the exhaust system for additional NO_x removal are usually needed to meet permit limits.

Other concerns of natural gas generating technologies are water use, noise, and solid waste. Waste heat removal is usually accomplished using closed-cycle dry or evaporative cooling. Evaporative cooled plants are more efficient than dry-cooled, but evaporative cooling consumes water. While reciprocating engines are inherently very noisy, perimeter noise levels are controlled by acoustic enclosures and air intake and exhaust noise suppression. Solid waste production is limited to household and maintenance wastes and periodic catalyst replacement. Catalyst materials are recycled.

Methane (CH4), the primary component of natural gas, is a potent greenhouse gas. Though it has a much shorter lifespan (around twelve years) in the atmosphere than carbon dioxide, methane has a significantly higher capacity to trap heat. The Global Warming Potential (GWP) metric is used to compare the cumulative effect on temperature of a greenhouse gas to that of carbon dioxide on a per unit basis. Estimates for the GWP of methane range from 28 to 36[19]; meaning that one unit of methane is the equivalent of over twenty units of carbon dioxide in the atmosphere over one hundred years.

The oil and gas industry accounts for 29 percent of the overall methane emissions in the U.S.[20] Methane emissions can occur at each segment of the natural gas system as the fuel reaches its end use at a house, business, industrial site, or power plant. These segments include production,

[19] http://www3.epa.gov/climatechange/ghgemissions/gases/ch4.html
[20] ibid

gathering and processing, transmission, storage, and distribution. The emissions include both unplanned gas leaks (fugitive emissions) and intentionally vented gas.

There are various sources of methane emissions within each segment of the natural gas system. For instance, in the production segment, raw gas may be vented as the well goes through "completion." Pneumatic devices used in the gathering and processing segment also vent gas during operations. During transmission, pipelines may leak gas, and compressor stations may also vent gas during normal operations. Gas leaks can occur in the distribution segment from pipelines and metering and regulating stations. Recent studies have indicated that fugitive emissions of methane from some natural gas production areas and existing gas pipelines could be as high as ten percent. However, overall methane emission rate estimates from the natural gas system in the U.S. range from one percent to three percent.

A pair of studies have recently been released which identified the most cost-effective methods to reduce methane emissions from the natural gas and oil industries in the U.S.[21] and Canada.[22] The key finding of the studies is that significant reductions in methane emissions could be made at a very low resulting cost. The value of the recovered gas helps to make the reduction efforts inexpensive – less than $0.01 per Mcf of gas produced[23], which is well within the Council's natural gas price forecast range. In the U.S., projected methane emissions could be reduced by 40 percent by 2018, which would result in an overall emission rate of around one percent. In Canada, projected emissions could be reduced by 45 percent, which also results in an overall emission rate of around one percent.

For more detailed information on the environmental effects and regulation of methane emissions, please see Appendix I.

Solar Technologies

There are two basic types of solar electricity generating technologies: solar photovoltaic (PV) and concentrated solar power (CSP).

Solar PV cells convert sunlight directly into electricity. The first modern solar cell was developed in Bell Labs in 1954.[24] In the 1960s, the space industry was an early adopter of the technology and spurred further development. Today, solar PV cells are manufactured from a variety of semiconductor materials and are significantly more efficient at turning sunlight into electricity.

PV is considered a variable renewable energy resource since generation requires sunlight and therefore does not generate power during the nighttime. Electricity generation can also be affected

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[21] Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries, March 2014, Prepared by ICF International for Environmental Defense Fund
[22] Economic Analysis of Methane Emission Reduction Opportunities in the Canadian Oil and Natural Gas Industries, September 2015, Prepared by ICF International for Environmental Defense Fund
[23] ibid
[24] John Perlin, *The Silicon Solar Cell Turns 50* (NREL Report No. BR-520-33947, August 2004)

by changing atmospheric conditions such as cloud cover. In the future, this issue may be alleviated by pairing solar PV installations with emerging storage technologies such as batteries. Battery technologies are rapidly improving, and in the future could be a key component of PV systems. Battery systems could firm up variability in generation, and shift delivery into early morning or evening/nighttime as needed. See the Storage section later in this chapter for more discussion on battery storage.

CSP technologies typically redirect and focus sunlight in order to generate the thermal energy required to drive a steam turbine to generate electricity. CSP can be configured as a firm generation source by adding thermal storage capabilities.

Solar power is riding a strong wave of popularity. Over 5,000 megawatts of solar capacity was added in the U.S. alone in 2014, representing a record year.[25] Growth in new solar power development is expected to continue to be strong since the 30 percent Federal Investment Tax Credit (ITC) was extended to the year 2019. California and Arizona have strong solar insolation characteristics and have led the way in solar build-outs in the U.S. Additionally, California has an aggressive renewable portfolio standard (RPS), which is helping to drive builds.

A few reasons for solar power's popularity include:

- Clean and renewable source of electricity
- Convenient and relatively simple to install (solar PV)
- Shrinking costs to produce power coupled with improving technology and performance
- Prime generation coincident with summer demand peaks
- Financial incentives and state RPS

Recently, some very large CSP projects have come on-line, such as the Ivanpah Solar Power Facility (392 megawatts) in the California desert. CSP projects have longer construction times and higher costs per watt than PV systems. Solar resource requirements may limit these large scale U.S. plants to locations in the southwest. Though CSP could play a future role in the Northwest due to the technology's ability to provide dispatchable power, for the Seventh Power Plan, the focus was on PV.

PV can be divided into two categories: utility-scale systems and distributed systems. Utility-scale PV refers to relatively large systems (from a few megawatts to several hundred megawatts) installed on the ground, generating electricity for the wholesale market. The largest PV facility currently operating in the Northwest is the 50 acre, 5.7 megawatt Outback Solar Project in Christmas Valley, Oregon. Several large PV projects have been installed recently in California and Arizona, such as the California Valley Solar Ranch near San Luis Obispo (250 megawatts) and the Agua Caliente Solar Project (290 megawatts) in Yuma County, Arizona. In the Northwest, the best solar resource areas are in the inter-mountain basins of south-central and southeastern Oregon, and the Snake River plateau of southern Idaho.

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[25] Miriam Makyhoun, Ryan Edge, Nick Esch, *Utility Solar Market Snapshot Sustained Growth in 2014* (SEPA, May 2015)

Smaller PV systems can also be deployed as a distributed power sources to generate electricity on-site for residences and commercial businesses. In this case, the modules are often mounted on top of roofs or other building structures.

The US Department of Energy's SunShot Initiative was launched in 2011 in order to coordinate scientific efforts at reducing the cost structure of solar power. The stated goal of the initiative is to reduce solar PV costs to $1.00 per watt (direct current) by 2020 for utility-scale, $1.25 per watt (direct current) for commercial rooftop, and $1.50 per watt (direct current) for residential rooftop.[26] This would represent a 75 percent drop from the cost of solar PV in 2010. While module prices have steadily declined, costs for the other system components have not dropped as sharply. Further declines in cost across all components and/or significant improvements in power efficiencies will be required to meet the target.

Utility-Scale Solar Photovoltaic

For utility-scale installations, PV cells are assembled into modules, ground mounted to fixed plates or tracking mechanisms on large land sites, and connected to the electricity grid. There are three main cost components for a utility-scale PV system:

1. PV module
2. Power Electronics
3. Balance of System (BOS)

PV modules are typically manufactured from semiconductor materials. Some commonly used materials include crystalline silicon (c-Si), and for thin film PV, cadmium tellurium (CdTe). Efficiencies for commercially available c-Si cells range from 14 to 16 percent, and 9 to 12 percent for thin film. Though thin film technologies tend to be more flexible for installations, c-Si systems are currently the most common choice. Efficiencies for both have been improving. Since 1976, costs for globally manufactured PV modules have been dropping by 20 percent for every doubling of production.[27] More recently, solar PV manufacturing has piggybacked on advances in the computer chip manufacturing industry. As a result, module prices have been declining at a faster pace than the other cost components, and are now estimated to comprise a little under half of the overall cost of a solar installation.

Inverters, which are required to convert electricity from direct to alternating current for the grid, are the main cost driver in the power electronics category. Like PV modules, inverters are sold on the world market. Balance of system (BOS) catches the remaining costs, such as hardware to hold the panels, tracking mechanisms (single or dual-axis), land, and permitting.

Utility-scale solar PV project financing is complex due to the high upfront capital costs involved, the dynamic costing landscape, and the capability of the sponsor to best utilize available tax incentives. Federal incentives for solar projects come in two forms:

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[26] SunShot Vision Study (DOE/GO-102012-3037 February 2012)
[27] ibid

- Accelerated tax depreciation (MACRS)[28]
- Investment tax credit (ITC)

These two factors push tax savings early on in the project financing; both reduce costs when the time value of money is at its highest. The challenge for the project sponsor becomes how to fully capture the value of both of these tax benefits in order to lower the overall cost of financing the project. The Federal Investment Tax Credit (ITC) stands at 30 percent, and was scheduled to drop to 10 percent starting in 2017. However, through the Consolidated Appropriations Act signed in December 2015, the ITC has been amended to extend the 30 percent credit for solar PV until 2019 and then incorporate gradual step downs in the credit to reach 10% in 2022 and each year thereafter. The cost savings attributed to these two tax incentives can vary depending on the "tax appetite" of the sponsor and the project financial model type, resulting in a range of potential value for the plant's expected levelized cost of energy.[29]

Utility-scale solar PV plants can be built in a wide range of sizes, from under 3 megawatts to greater than 500 megawatts – but a commonly installed size is around 20 megawatts.

The reference plant is defined as a 20 megawatt (alternating current) solar PV installation located in southern Idaho using c-Si modules mounted on single-axis trackers. It is assumed to be located on low-grade or distressed agricultural land or other disturbed site with little existing or potential ecological value and no threatened or endangered species present. The plant is sited or shielded to avoid unacceptable visual impacts. The plant is assumed to have a 30 year lifetime, with an annual average degradation of 1 percent. The solar calculator PVWatts® (available on the NREL website) was used to estimate the annual capacity factor. Prime generation months occur from April through September. The expected fixed operations and maintenance (O&M) include inverter replacements at 15 years, along with periodic cleaning of the modules. To be consistent with utility-scale PV development across the country, the project sponsor is assumed to be an independent power producer (IPP). A second reference plant was defined with additional cost estimates required to bring power from the same Southern Idaho location to the west side of the region, which would likely require an expansion of the Bonneville transmission system. A third solar reference plant was defined for a location west of the Cascade Mountains, near Kelso, Washington. This plant was designed to be large in size (50 megawatts), but similar to the other reference plants in terms of configuration. Access to the Bonneville transmission system was assumed. The plant is modeled to have a lower capacity factor than the reference plant in Idaho, due to the lower solar resource that is available in Western Washington.

Due to the rapidly changing cost environment for solar technology, the Council developed a forecast of system installation costs across the planning horizon, using historic data and forward looking analysis. From this, the Council developed a forecast of the fixed capital costs, and levelized cost of energy for the solar PV reference plant. Figure 13 – 4 displays the forecast of expected overnight

[28] Modified Accelerated Cost Recovery System – tax depreciation as defined by the Internal Revenue Service
[29] Mark Bolinger, *An Analysis of the Costs, Benefits, and Implications of Different Approaches to Capturing the Value of Renewable Tax Incentives* (LBNL-6610E, May 2014)

capital cost for the reference plant, along with the SunShot goal and a range of collected analyst's forecasts. [30]

Figure 13 - 4: Forecast of Capital Costs for Utility-Scale Solar PV

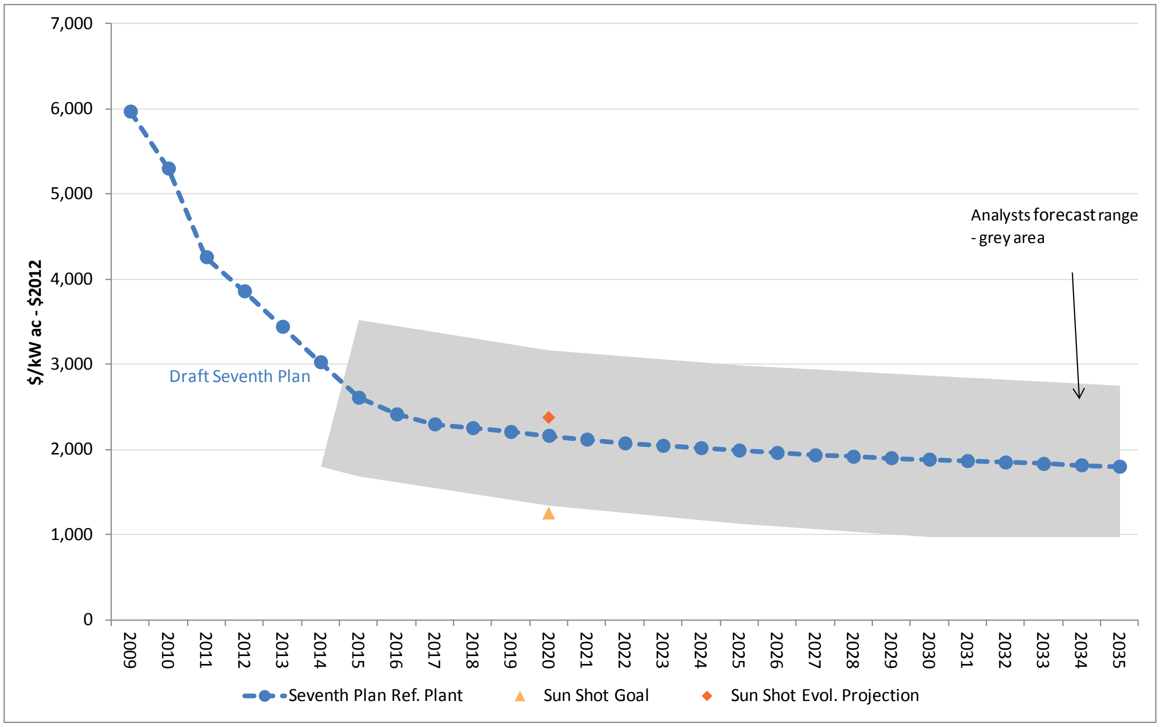

Figure 13 - 5 shows the forecast for the levelized cost of energy for solar.

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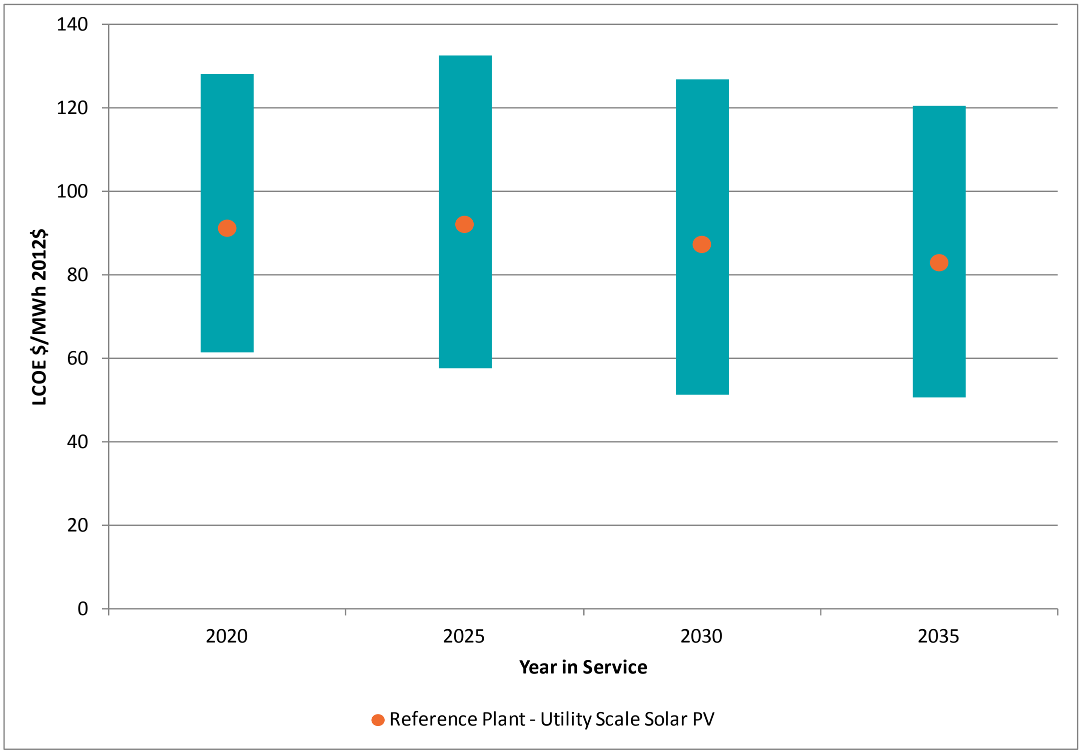
[30] *Photovoltaic System Pricing Trends Historic, Recent, and Near-Term Projections 2014 Edition,* (NREL/PR-6A20-62558, September 2014)

Figure 13 - 5: LCOE Forecast Range for Utility-Scale Solar PV



Distributed Solar Photovoltaic

Solar PV panels can be mounted on the rooftop of a residence or commercial building structure to provide on-site electricity and also send power to the grid. The amount of power generated depends on the amount of sunlight that is available, the roof angle and orientation, and the amount of shading from trees and other buildings. A typical residential rooftop system is around 5 kW in size, while commercial systems are around 32 kW.

Like utility-scale solar, residential and commercial distributed solar PV installations across the US are growing. According to the Energy Information Administration (EIA), rooftop solar electricity production grew an average of 21% per year from 2005 through 2012. In the Northwest region, as of 2012 there are over 10,000 utility customers with installations that were selling back power (net metering). Third party leasing has become a more popular option than outright customer owned systems.

Historically, costs for distributed solar installations have been higher than for utility-scale. Residential solar PV installations have run about 1.5 times the cost of utility-scale, while commercial systems have been around 1.35 times more expensive.[31]

[31] Galen Barbose, Samantha Weaver, Naim Darghouth *Tracking the Sun VII, an Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2013* (LBNL, September 2014)

See Chapter 12 for further information on distributed solar PV.

Environmental Effects of Solar Technologies

Potentially significant environmental impacts of utility-scale solar plants include visual impact, air particulate release during construction, land use conversion, habitat loss, and direct avian mortality. Other, less significant, impacts may include minor greenhouse gas releases during construction and operation, disturbance of archeological and other cultural resources, preemption of recreational features and mineral resources, energy consumption during construction and operation, release of hazardous materials, noise during project construction, socio-economic impacts of construction and operational personnel, transportation impacts during construction, and consumption of water.[32]

The visual character of the site of a utility-scale PV plant is changed from agricultural or natural use to an extensive array of solar modules and ancillary facilities. While the plant profile is low, the modules are highly reflective and can produce severe glare at great distances. The glare may affect road, rail, and air transportation safety, create nuisance for nearby residential and other uses, and may impact the visual integrity of historic, recreational, and natural sites. Visual impacts are mitigated by careful site selection, shielding, and module positioning restrictions.

While no significant air emissions occur during operation, particulates can be released by grading and other construction activities. These are typically controlled by watering susceptible surfaces.

PV plant construction results in conversion of a former agricultural or natural site to one largely covered with photovoltaic modules and ancillary facilities. While vegetative ground cover can be maintained under a portion of the arrays, loss of potentially productive agricultural land or natural habitat may occur. Utility-scale photovoltaic plants require about 6 - 8 acres of land per megawatt of capacity,[33] so the reference plant will occupy about 160 acres. Significant land use impacts can be avoided by use of low-grade agricultural and other disturbed sites. In the long-term, because modules are usually supported on driven piles or screw mounts, the site of a photovoltaic plant could be restored to previous condition without excessive difficulty.

Further details concerning the environmental effects of solar generation and the environmental regulations and compliance actions associated with those effects are described in Appendix I.

Wind Power

There are two primary forms of wind power resources - the established terrestrial, utility-scale onshore wind power and the emergent offshore wind power. A third form is distributed generation wind power, which typically comprises small output (average of 100 kilowatt) turbines used directly by the end-user to power a residence or commercial entity.

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[32] List of potentially significant and less significant impacts adapted from Merced County (California) Planning Department. Notice of Preparation of an Environmental Impact Report for the Quinto Solar Photovoltaic Project. December 2010.
[33] 6 acres from NREL, 8 is average of a sample of 13 WECC PV plants ranging from 5 to 250 MWac.

Utility-scale, onshore wind power is classified as a primary resource for the Seventh Power Plan, and therefore received an in-depth, quantitative analysis for modeling purposes. Offshore wind, while an established technology in other parts of the world, is still emerging in the United States and therefore is classified as a resource with long-term potential for the Pacific Northwest.

Wind power is a naturally occurring, renewable form of energy that is harnessed and transferred into electricity through power plants made up of individual turbines. Wind turbines primarily consist of a tower, two or three blades, hub and rotor, and a nacelle (consisting of interconnected shafts (low and high speed), a gear box, and a generator). As the wind blows, the turbine blades (connected at the hub and attached to the rotor) are rotated, with the rotor causing the low speed shaft to spin within the nacelle. Housed in the gearbox, the low speed shaft is connected to the high speed shaft, which increases the speed of the rotation. The gearbox is attached to the generator, which produces the electricity. Wind turbines typically possess weather vanes and anemometers (an instrument to measure wind speed) that transfer information to a controller. Between the controller computer system and remote operators, a wind turbine can be turned on and off depending on the wind speed as well as positioned depending on the wind direction. Today's wind turbines typically cannot operate in winds higher than 55 miles per hour, and are therefore shut down to preserve the equipment when wind reaches that speed.

Wind power is a variable energy resource that produces intermittent generation output and little firm capacity; therefore, wind power often requires supplemental firm capacity and balancing reserves in order to integrate it into a power system. An existing surplus of balancing reserves and firm capacity within the Pacific Northwest enabled the early growth of wind power without the need or cost of additional capacity reserves. However, significant recent development and the concentration of installed wind capacity within a single balancing area has led to a few substantial ramping events, putting pressure on the balancing area's ability to integrate the wind power without, for example, displacing other must-run resources. Additional wind power development will need to take this into consideration. Measures such as improved load forecasting, up-ramp curtailment, and sub-hourly scheduling can reduce the amount of flexibility required to integrate a given amount of wind capacity.

Utility-scale, Onshore

Since the first wind turbine technologies were developed in the 1980's, there has been a significant reduction in capital cost and subsequent increase in performance as the technology has been streamlined and improved. Capital costs rose from 2003-2010 due to rising global commodity and raw materials prices, increased labor costs, and the economic recession that peaked in the US in 2008-2009. Since then, costs have again begun to decline and performance has continued to improve. As the diameter of the rotors and the hub heights have both increased, the nameplate capacity per turbine has increased. The ability of these turbines to achieve a greater wind sweep area has improved efficiency and capacity factors, allowing for development in areas that may have suboptimal wind resources.

Over the past decade, wind development both regionally and nationally has grown significantly. According to the American Wind Energy Association (AWEA), there was 65,879 megawatts installed nameplate capacity of wind in service in the United States at the end of 2014. In the Pacific Northwest, about 8,700 megawatts nameplate capacity of wind has been developed since the first project in 1998. Regional development trends have mirrored national trends, with development waxing and waning with the expiration and renewal of tax incentives and the onset of state renewable portfolio standards (RPS). To date, 2012 has been the strongest year for wind development for the region and nation, with development dropping off since then.

The rapid rate of development reflects the fundamental attributes of wind power as an abundant, mature, relatively low-cost source of low-carbon energy with local economic benefits. These attributes, combined with an array of market and financial incentives and strong political and societal support within the Northwest and elsewhere in the Western Electricity Coordinating Council (WECC) region spurred the development over the past decade. Developing and purchasing wind power to meet state RPS requirements has arguably been the largest driver of development to-date. With the federal tax incentives set to wind down and expire over the next 5-7 years[34], and many near-term RPS targets met, wind power will have to stand on its own economic and operational strengths when compared to other new resource options.

The wind power reference plant for the Seventh Power Plan is a 100 megawatt nameplate capacity plant consisting of arrays of conventional three-blade, 2.5 megawatt wind turbine generators. The plant is assumed to have in-plant electrical and control systems, interconnection facilities and on-site roads, meteorological towers, and support facilities. The economic life of the reference plant has improved since the Sixth Power Plan, from 20 years to 25 years, based on improved technologies. The capital cost for projects in 2012 dollars is $2,307 per kilowatt. There are two locations (and capacity factors) for the reference plant – one is located in the Columbia River Gorge and the other in Central Montana with delivery into the Bonneville Power Administration service territory. The capacity factor in the Columbia basin is 32 percent, while in central Montana where the wind resource is very high, the capacity factor is 40 percent.

Five wind resource blocks were defined to use as inputs to the RPM.

1. Columbia Basin wind with Bonneville transmission
2. Montana wind with existing transmission
3. Montana wind with a potentially new 230kV transmission line
4. Montana wind with a potentially large upgrade to the transmission system
5. Montana wind using transmission available if Colstrip Units 1 and 2 were retired at some future date

The levelized costs for each wind resource were developed assuming that the Production Tax Credit would not be renewed after its expiration in 2014. Although it has since been renewed by the Consolidated Appropriations Act in December 2015, the levelized costs remain nearly unchanged. The financial assumptions used for calculating levelized costs were consistent with an IOU sponsor. See Figure 13 - 2 for levelized costs of wind compared with solar PV.

[34] See discussion on amended PTC and ITC in Chapter 9.

Utility–Scale, Offshore

Offshore wind potential off the coasts of the United States and in the Great Lakes is estimated to be as significant as 4,000 gigawatts. Realistically, feasible potential is likely to be much less when barriers such as competing economic enterprises, maritime traffic, and environmental issues and wildlife refuges are taken into consideration. While there is about 7,000 megawatts of offshore wind capacity installed globally, primarily off the coasts of Northwestern Europe and China, there are no operating plants installed in the United States as of mid-2015. There are, however, fourteen projects considered to be in advanced development on the East Coast, with two projects totaling about 530 megawatts under construction and expected to be commercially operable in 2016.

Offshore wind turbines tend to be larger in both size and energy output than their terrestrial counterparts. The average offshore turbine has a capacity between four to five megawatts compared to 1.5 to three megawatts onshore. When the turbine capacity is combined with the higher offshore wind speeds, the capacity factors tend to also be higher than onshore plants. Due to the logistics of being offshore, wind turbines and their surrounding structures need to be able to withstand harsh environmental conditions as maintenance has proven to be difficult and costly. There are currently many offshore wind turbine prototypes and proven technologies, ranging from turbines that are designed to be drilled into the ocean floor and turbines that can float and therefore be placed further out in the ocean.

The estimated capital cost of offshore wind is between $5,000 and $6,000 per kilowatt, more than double the average cost of onshore wind projects. In addition to the challenge of making offshore wind more cost-competitive with onshore wind and other renewable energy sources, the Department of Energy has identified a lack of infrastructure (e.g. transmission) and an uncertain regulatory environment as significant barriers to development in the near term.[35]

Environmental Effects of Onshore Wind Power Technologies

The proliferation of wind facilities has the potential to cause a variety of impacts, including harm to wildlife, plants, water and air quality, human health, and cultural and historical resources.

Wind turbines have the potential to affect a variety of wildlife, including birds, bats, and non-flying animal species. This impact may occur in at least three ways: direct contact with the turbine blades, contact with areas of rapidly changing pressure near spinning turbines, and habitat disruption from the construction and operation of turbines.

Wind facilities kill an estimated 140,000 to 328,000 birds annually in the U.S., although those figures are subject to considerable debate.[36] Bird deaths are primarily the result of direct contact with

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[35] "Offshore Wind Market and Economic Analysis: 2014 Annual Market Assessment." Navigant report prepared for U.S. Department of Energy, 2014.

[36] http://www.sciencedirect.com/science/article/pii/S0006320713003522. That figure represents only a fraction of the birds killed by domestic cats, buildings, and transportation. http://www.nytimes.com/2011/03/21/science/21birds.html?_r=0.

spinning wind turbines, the tips of which can travel at speeds ranging from 150 to 200 miles per hour.[37] The average wind project reports fewer than four bird fatalities per megawatt (nameplate capacity) per year, the majority of which are songbirds.[38]

Eagles and other raptors may be affected by the operation of wind facilities in and around their soaring locations, through direct contact with spinning turbine blades. Raptor mortality from wind development, however, does not appear to be as significant a concern in the Northwest as it is in California.[39] Wind developers and project owners can limit a facility's impact on raptors by engaging in a pre-development site evaluation to determine raptor abundance, siting in areas of low prey density, and mitigation measures designed to curtail turbine operation when raptors are present.[40] Another avian species of concern to wind development is the Greater Sage Grouse because its range coincides with prime wind resources in the region.[41]

Many bat species are also affected by wind energy development, through both contact with the spinning blades and contact with areas of rapidly changing pressure caused by the turbines. Abrupt changes in pressure may cause barotrauma in bats, resulting in internal hemorrhaging that can be fatal.[42] Wind turbines kill an estimated 600,000 to 900,000 bats annually in the United States. Risk to bats can be reduced significantly by curtailing operation during wind speeds at which bats are active, typically below 7.8 miles per hour.[43]

Wind power development may have adverse impacts on water quality during construction, operation, and decommissioning phases, depending on the location of the project and its proximity to surface waters; however, these water quality impacts are not likely to be significant. In addition, wind power development and operation may result in a variety of human health impacts and impacts to cultural and historical resources. Primary human health impacts include aesthetic and noise disturbances, shadow flicker, and aviation safety lighting.

Further detail on environmental effects, environmental regulations, and compliance actions will be found in Appendix I. Appendix I also contains a discussion of the environmental effects and issues associated with the development of transmission facilities to serve the development of renewable resources across the region's landscape. See also the discussion of the region's existing generating resources in Chapter 9.

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[37] http://www.aweo.org/windmodels.html.
[38] http://www1.eere.energy.gov/wind/pdfs/birds_and_bats_fact_sheet.pdf.
[39] Ib*id.*
[40] Ib*id.*
[41] http://www.pnl.gov/main/publications/external/technical_reports/PNNL-18567.pdf at 2.2.
[42] http://www1.eere.energy.gov/wind/pdfs/birds_and_bats_fact_sheet.pdf.
[43] http://www.popsci.com/blog-network/eek-squad/wind-turbines-kill-more-600000-bats-year-what-should-we-do, *see also* http://www.smithsonianmag.com/smart-news/scientists-save-bats-and-birds-from-wind-turbine-slaughter-130262849*/.*

SECONDARY RESOURCES

The following resources were deemed to be secondary in terms of analysis for the Seventh Power Plan. While these resources have potential in the Pacific Northwest and utilize technologies that are commercially available, the quantity of the potential compared to the primary resources is less. The secondary resources were not explicitly modeled in the Regional Portfolio Model, though they are still considered viable resource options for future power planning needs within the region.

Hydroelectric Power

The Pacific Northwest power system is dominated by hydroelectric power. Stemming from the mountains of the Pacific Northwest and British Columbia, the heavy precipitation experienced there (often in the form of snow) produces large volumes of annual runoff. About 360 hydroelectric projects have been developed in the Columbia River and its associated tributaries to capture that runoff, providing about 33,000 megawatts nameplate capacity to the region and accounting for over half of the energy generated in the region each year.

The region has been undergoing renovations and upgrades to many of its existing hydroelectric dams, often resulting in increased efficiency (average megawatts) of existing nameplate capacity or the added nameplate capacity through the addition of turbines and new equipment. Renovations to restore the original capacity and energy production of existing hydropower projects, and upgrades to yield additional energy and capacity are often much less costly than developing new projects. Most existing projects date from a time when the value of electricity was lower and equipment efficiency less than now, and it is often feasible to implement upgrades such as advanced turbines, generator rewinds, and spillway gate calibration and seal improvement. Even a slight improvement in equipment efficiency at a large project can yield significant energy.

New small hydropower projects have also been assessed for feasibility in the Pacific Northwest. Snohomish PUD developed its 7.5 megawatt installed capacity Youngs Creek small hydro project in 2011. It was the first new hydroelectric project in Washington in twenty years. Recent regulatory actions have helped pave the way for future small hydro development at existing non-powered dams. President Obama signed into law the Hydropower Regulatory Efficiency Act of 2013[44], of which one of its goals is to streamline the licensing process for development of conduit projects and small hydroelectric projects at existing non-powered dams. In some cases, projects meeting certain criteria are exempt from having to secure a license at all.

The Council's last major assessment of hydroelectric potential was conducted during the development of the Fourth Power Plan in 1994. That plan identified 480 megawatts of additional nameplate capacity, producing about 200 average megawatts of energy. Since then, there have been numerous regional and national studies that speculate that large amounts of hydroelectric potential remain to be developed in the region. These studies vary in scope, objective and

[44] http://www.ferc.gov/legal/fed-sta/bills-113hr267enr.pdf

methodology, and use different parameters and screens to narrow down and define hydroelectric potential. One of the most prevalent reports was a 2014 Department of Energy (DOE) hydropower potential assessment[45] that identified almost 85,000 megawatts of physical developable hydropower in new stream reaches in the United States. The largest of this potential – 25,000 megawatts - was identified in the Pacific Northwest. Other studies looked at potential at existing non-powered dams, upgrades to existing hydroelectric facilities, and varying size, site, or region-specific assessments.

In order to gain a better understanding of Pacific Northwest potential for new hydroelectric development and upgrades to existing units, and the costs associated with that potential development, the Council commissioned a scoping study in 2014[46] to review the published reports and estimates and determine if a realistic, reasonable assumption could be derived from the existing work.

The results of the scoping study identified 211 megawatts of potential new capacity at existing non-powered dams, conduit and hydrokinetic sites, and from general assessments. In addition, in a survey of the region's hydroelectric owners, it identified 388 megawatts new capacity in upgrades to existing projects. Finally, the scoping study identified an additional 2,640 megawatts of new pumped storage capacity in the region.

Not included in these results is the potential identified by the 2014 DOE study because that report was not site-specific. However, while working with StreamNet[47] and the Oak Ridge National Laboratory (who developed the DOE report), it was determined that only about 12 percent of the potential identified was located in sites that were outside of the Protected Areas. Extensive further analysis would need to be done on this remaining potential to determine if any of it would be economically and environmentally feasible to develop. In all likelihood, economics and environmental barriers would diminish this potential significantly. In addition, the remaining studies reviewed likely duplicate these areas and that potential was found to be extremely low. For more detail, see the Council's Regional Hydropower Scoping Study.[48]

Because the results of the Council's scoping study determined that there was not significant new hydropower capacity available for development in the Pacific Northwest, it was omitted as a new resource choice option in the RPM. However, small hydropower and upgrades to existing units should be evaluated on a site-by-site basis by owners and prospective developers.

Pumped Storage

Pumped storage hydropower is an established and commercially mature technology. However the Council considers it as an emerging technology because new advances in technology have expanded its role from primarily shifting energy to providing additional ancillary services and capabilities that are beneficial in today's power system which has increasing amounts of variable

[45] http://energy.gov/articles/energy-dept-report-finds-major-potential-grow-clean-sustainable-us-hydropower
[46] http://www.nwcouncil.org/energy/grac/hydro/
[47] http://www.streamnet.org/
[48] http://www.nwcouncil.org/media/7149312/final-nwha-power-council-11-17-14_v2.pdf

output resources, such as wind. Most existing pumped-storage projects were designed to shift energy from off-peak hours or low demand periods to times of peak demand. Advances in technology, for example adjustable speed and ternary units instead of fixed speed pumping units, have made it possible for pumped storage to better provide capacity, frequency regulation, voltage and reactive support, load following, and longer-term shaping of energy from variable-output resources. In addition, pumped storage is able to provide these services without the fuel consumption, carbon dioxide production, and other environmental impacts associated with thermal generating resources providing similar services. Importantly for the Pacific Northwest, pumped storage could provide within-hour incremental and decremental response to large amounts of variable energy generation.

A typical project consists of an upper reservoir and a lower reservoir connected by a water transfer system with reversible pump-generators. Energy is stored by pumping water from the lower reservoir to the upper reservoir using the pump-generators in motor-pumping mode. Energy is recovered by discharging the stored water through the pump-generators operating in turbine-generator mode. Current pumped storage projects have cycle efficiencies ranging from 70 percent to 85 percent. Pumped-storage projects require suitable topography and geologic conditions for constructing upper and lower reservoirs at significantly different elevations within close proximity. Subsurface lower reservoirs are technically feasible, though much more expensive. A water supply is required for initial reservoir charge and makeup.

The Pacific Northwest has one existing pumped storage project - the six-unit, 314 megawatt Grand Coulee pumped-generator at Banks Lake. This plant is primarily used for pumping water up to Banks Lake, the headworks of the Columbia Basin Irrigation System. There are 17 projects with existing FERC permits located in the Pacific Northwest, with a few that are in active development including EDF Renewable Energy’s Swan Lake North Pumped Storage Project and the Banks Lake North Dam Pump/Generation Project. Recently, Klickitat County PUD announced the decision to stop work on the licensing effort for the John Day Pool Pumped Storage Project due to unsuccessful efforts to obtain necessary financing to complete the licensing effort. The efforts of Klickitat PUD highlight one of the biggest barriers to development that pumped storage projects face – these projects are usually larger in size than one party alone needs, but collaborating with multiple parties to commit financing can prove very difficult. Included in that issue is the fact that pumped storage facilities no longer just provide straight capacity – there are many values to the power system inherent in pumped storage projects that don’t provide direct compensation. Some of the benefits of storage are reflected in the system as a whole, not just solely to a specific power purchaser or end-user, and therefore it can be difficult to raise funds for storage projects if the purchaser is not directly benefiting from all of the services, or is paying for a service that benefits others who are not also contributing funds. For example, if a pump storage project that provides load following and up and down regulation is not compensated – there is not a revenue stream that can help in the financing of a pumped storage project for that service. Action item ANLYS-15 attempts to address this issue.

The Council’s 2014 hydropower scoping study identified 2,640 megawatts capacity of pumped storage potential in three projects that were considered realistic in terms of development outlook. These projects were the John Day (JD) Pool Pumped Storage Project at the John Day Dam, Swan Lake North Pumped Storage Project near Klamath Falls, Oregon, and Banks Lake Pumped Storage Project at Banks Lake and Lake Roosevelt in Washington. Since the Council’s study was published, the developers of the JD Pool project (led by Klickitat PUD) have suspended their FERC licensing efforts due to limited time for the necessary studies in the licensing process to be completed and a lack of co-funders. The estimated cost for new pumped storage projects range from $1,800 per kilowatt to $3,500 per kilowatt of installed capacity. The range in cost is driven by the length of tunnel needed for the project, the overall head (the higher the head, the smaller the machine dimensions and thus the lower the cost), the amount of above ground infrastructure required, and the variable speed technology selected for the pump/turbines.

Combined Heat and Power

An on-site generation option, often owned by the facility and not the utility, is combined heat and power (CHP), at usually less than 10 megawatts nameplate capacity. CHP uses a generator (often a reciprocating engine) to produce electricity, while capturing the waste heat to use for water heating loads, increasing the overall efficiency up to 80 percent. Given this, CHP units are most applicable to facilities that have coincident thermal and electric loads. Most industrial manufacturing, hospitals, lodging, universities, and prisons would benefit. Except for biogas or biomass systems, CHP generators use natural gas, and thus the operating cost of these units is highly dependent on fuel costs. The uncertainty in future costs is a major barrier to adoption; however, significant potential remains with short payback periods. The potential identified relies on a 2014 study by Oregon Department of Energy, a 2010 (rev 2013) assessment for Washington by the Northwest CHP Technical Assistance Partnerships. This group also provides estimates for Idaho and Montana potential.[49] Based on these studies, the total technical potential region-wide is nearly 6,000 megawatts nameplate capacity.

While there may be a significant amount of technical potential in the region, there are also significant barriers to development. The full benefits of CHP are rarely seen by the individual parties (utility, host facility, developer) involved in the decision to develop CHP. Many of the barriers to CHP stem from these differing perspectives and include:

- The required return on investment of the host facility is often higher than that of a utility
- Unless participating as an equity partner, the utility sees no return, and a loss of load
- Limited capital and competing investment opportunities often constrain the host facility's ability to develop CHP
- Energy savings benefitting the host facility may not be worth the hassle of installing and operating a CHP plant.
- Difficulty establishing a guaranteed fuel supply for wood residue plants.
- Uncertainties regarding the long-term economic viability of the host facility.
- The location value of CHP is often not reflected in electricity buy-back prices.
- The relative complexity of permitting and environmental compliance for small plants.

Information on the environmental effects of CHP generation can be found in Appendix I.

[49] http://www.northwestchptap.org/Markets.aspx

Geothermal Power Generation

The crustal heat of the earth, produced primarily by the decay of naturally occurring radioactive isotopes, may be used for power generation. Conventional geothermal electricity generation requires the coincidental presence of fractured or highly porous rock at temperatures of about 300 degrees Fahrenheit or higher and water at depths of about 10,000 feet or less. Enhanced geothermal systems (EGS) involve engineering to build the necessary conditions for generation by creating micro fractures in hot rock and pumping an external water supply through the created pathway.

With nameplate capacity of 28.5 megawatts, the Neal Hot Springs geothermal project in South Eastern Oregon is the largest conventional geothermal plant operating in the Northwest. Basin and range geothermal resources have been developed for generation in Nevada, Utah, and California, and recently in Idaho as well. There are no commercially proven EGS projects as of yet; however, the most promising EGS research project currently underway in the U.S. is in Oregon at the Newberry Crater.

Conventional Geothermal Power Generation

Depending on resource temperature, flashed-steam or binary-cycle geothermal technologies could be used with the liquid-dominated hydrothermal resources of the Pacific Northwest. A preference for binary-cycle or heat-pump technology is emerging because of modularity, applicability to lower temperature geothermal resources, and the environmental advantages of a closed geothermal-fluid cycle. In binary plants, the geothermal fluid is brought to the surface using wells and passed through a heat exchanger where the energy is transferred to a low boiling point fluid. The vaporized low boiling point fluid is used to drive a turbine generator, then condensed and returned to the heat exchanger. The cooled geothermal fluid is re-injected to the geothermal reservoir. This technology operates as a baseload resource. Flashed steam plants typically release a small amount of naturally occurring carbon dioxide from the geothermal fluid, whereas the closed-cycle binary plants release no carbon dioxide.

A 2008 U.S. Geological Survey assessment[50] of moderate (90° to 150° C) and high (greater than 150° C) temperature hydrothermal resources identified roughly 1,400 average megawatts of potential resource in the Northwest. However, geothermal development has historically been constrained by high-risk, low-success exploration and well field confirmation. See Appendix H for a more detailed description of the available and estimated potential.

While conventional geothermal is categorized as a secondary resource, a reference plant was created for inclusion in the RPM to provide a potentially cost-competitive, dispatchable renewable resource option. Historically, conventional geothermal has seen limited deployments in the Pacific Northwest, but with resource potential identified, it is seen as an alternative to both renewable resources and baseload thermal resources. The reference plant is based primarily off of the

[50] United States Geological Survey. *Assessment of Moderate- and High-Temperature Geothermal Resources of the United States*, 2008.

estimates made for the Sixth Power Plan, as there have not been significant changes in terms of cost and potential.

The reference plant consists of three 13 megawatt units, creating a total plant installed nameplate capacity of 39 megawatts. The plant is assumed to use closed-loop organic Rankine cycle binary technology suitable for low geothermal temperatures. The reference plant is located in central Oregon, with existing transmission.

Not fully captured in the estimates of capital cost and the levelized cost of energy of conventional geothermal is the cost of exploration to find a suitable plant site. Initial exploration above ground is required before developers drill a production well underground to determine if a water source exists at the site. If a water source is not available, the well is known as a “dry hole” and conventional geothermal is not feasible. Developers must weigh the risk of drilling dry holes when considering construction of a conventional geothermal plant. This initial testing of a geothermal site can equal about 40% of the total project cost.[51]

Enhanced Geothermal Systems

Enhanced geothermal systems (EGS) essentially mine the earth’s stored thermal energy. EGS involves drilling to depth and stimulating or fracturing rock in order to allow fluid flow and heat transfer. Water is pumped down and run through the fractures to collect heat. A production well connects to the created reservoir and completes the loop by bringing the heated fluid to surface in order to drive a steam turbine that generates electricity. Since there are no commercially proven projects to date, EGS is considered an emerging technology in the Seventh Power Plan.

EGS could provide renewable, baseload power with little to no greenhouse gas emissions. The potential in the Northwest is very large as hot dry rock is widely available in the region at depths of 3 to 5 kilometers. The Northwest contains two very high-grade resource regions - the Snake River Plain of Idaho and the Oregon Cascade mountain range. Levelized cost of energy estimates for sites in the region range from $175 to $240 per megawatt-hour, with a mature technology estimate of $50 to $52 per megawatt-hour.[52]

The four basic steps to developing an EGS project include:

1. Identifying and characterizing a suitable site;
2. Drilling injection wells into hot dry rock, stimulating or fracturing the rock to create flow rates at sufficient temperatures and volumes;
3. Drilling production wells to close the loop; and,
4. Generating electricity using a steam turbine or binary plant power system.

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[51] *Research and Development in Geothermal Exploration and Drilling*, Geothermal Energy Association, 2009. https://www.novoco.com/energy/resource_files/reports/geo_rd_1209.pdf

[52] *The Future of Geothermal Energy – Impact of Enhanced Geothermal Systems on the United States in the 21st Century* (Massachusetts Institute of Technology, 2006)

Hydraulic fracturing produces tiny crack-like networks that combine with existing fractures and faults in the rock to create a flow network. It is difficult creating optimal flow. If the cracks are too large, fluid passes through without reaching high enough temperatures. If the cracks are too small, it requires a higher pressure drop between wells.[53] EGS stimulation differs from the hydro-fracking methods used for oil and natural gas production in that EGS involves deep vertically drilling only and not horizontal drilling. In addition, EGS fractures the rock at lower pressures using water only, and not chemical-water slurry.

There are a number of technological challenges to overcome before EGS can become commercially feasible. Research and development in EGS is focused on three main categories:

1. Imaging and characterization of the resource;
2. Deep well drilling techniques; and,
3. Improvement of flow and extending well lifetimes.

Were breakthroughs to occur in each of these categories, the development of enhanced geothermal power could be significant and rapid, especially in the Northwest.

Information on the environmental effects of geothermal generation can be found in Appendix I.

Biomass

Before wind and solar PV became the renewable powerhouses they are today, biomass was the largest renewable generating resource in the United States. While still a valuable baseload energy alternative, the potential for biomass in the Pacific Northwest is varied depending on fuel and average size of a typical plant. Because of this, it was not treated as a primary resource and assessed in the Regional Portfolio Model. A few small biomass plants have been developed in the last five years, primarily landfill gas recovery projects and animal waste projects on dairy farms. Overall, the potential resource has remained unchanged since the Sixth Power Plan assessment – see Chapter 6 of the Sixth Power Plan for a detailed breakdown of resource potential by fuel.[54]

Portland General Electric is suspending coal operations at its Boardman power plant in 2020. As a potential alternative, PGE is evaluating the possibility of re-using the boiler and generating equipment and transforming Boardman into a biomass plant. Along with determining the cost-effectiveness, operating logistics, and environmental effects of this alternative, PGE is studying and testing various biofeedstocks to determine their viability as an alternative fuel to coal. Should PGE determine that this is a course of action they wish to pursue, Boardman could become the biggest biomass plant in the country.

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[53] *Enhanced Geothermal Systems* (The MITRE Corporation, December 2013)
[54] http://www.nwcouncil.org/media/6371/SixthPowerPlan_Ch6.pdf

Energy Storage Technologies

Energy storage systems convert electricity into a storable form of energy at one point in time and release the energy back as electricity at a later point in time. Storage systems may be located at various locations including:

1. Customer site
2. Distribution system
3. Transmission system
4. Generation site

Energy storage systems also have many applications, such as:

1. Electric energy time shifting
2. Renewable generation capacity firming
3. Peak capacity
4. Quick response ancillary services – frequency regulation and voltage support
5. Transmission and distribution system deferral

Some storage systems, such as pumped hydro and compressed air storage systems require specific geographies to operate. Battery storage systems are not geographically dependent and can be utilized at multiple locations and for a variety of applications.

The ability to store and release energy can make renewable generation more valuable. For example, a portion of the solar electricity generation that peaks during the afternoon could be stored and released to the grid during the nighttime. The ability of storage to respond quickly to needs would allow the grid to operate more efficiently, and not just for renewable resources, but anything connected to the grid. Storage can be used to defer infrastructure upgrades to the transmission system by reducing wear and tear from operating in overloaded conditions.

Mechanical types of storage include hydro pumped storage, compressed air energy storage, and flywheels. Electrochemical technologies include conventional battery types such as lithium-ion, nickel cadmium, and lead acid. Flow batteries – vanadium redox and zine bromine – are another evolving electrochemical technology. Since not every type of storage is suitable for every application, a storage portfolio may be required. Individual technology characteristics are important for deciding which storage technology to deploy for a particular application,[55] such as:

- Response time – how quickly can the storage device discharge when needed
- Duration – the period of time the device can discharge in a single cycle
- Frequency – the number of charge-discharge cycles per unit of time
- Depth – the fraction of the device's total capacity that can be called on in a single cycle
- Efficiency – the ratio of energy output to energy input for a single cycle

[55] *Utility Scale Energy Storage Systems* (State Utility Forecasting Group, June 2013)

Pumped hydro storage is an established, large-scale technology. It can provide discharge times in the tens of hours and at a large scale, up to 1,000 megawatts.[56] A pumped hydro system uses off-peak electricity to pump water from one reservoir to another reservoir at a higher elevation. When electricity is needed, water is released from the upper reservoir and run through a hydroelectric turbine to generate electricity. Compressed air energy storage (CAES) is another large scale storage technology that stores energy in the form of pressurized air in underground caverns. Both of these technologies require very specific physical geographies.

Electrochemical battery technologies convert electricity to chemical potential to store, and then convert back to electricity as needed. These technologies are smaller in scale and provide shorter discharge times, anywhere from a few seconds to around six hours. Battery technologies can be more easily sited and built, but have not enjoyed widespread deployment yet due to power performance, limited lifetimes, and high system cost.

A common constraint to deploying energy storage systems is that the project developer is unable to capture the full value of the system's services. The generation, transmission and distribution sectors may each realize benefits, but it is often difficult for the developer of a storage project to fully capture the benefits of the project.

Battery storage systems may be an important component of the future power system since battery technologies are rapidly improving, manufacturing is ramping, and costs are expected to decline.

Battery Technologies

Conventional batteries are composed of cells which contain two electrodes - a cathode and an anode - and electrolyte in a sealed container. During discharge a reduction-oxidation reaction occurs in the cell and electrons migrate from the anode to the cathode. During recharge, the reaction is reversed through the ionization of the electrolyte. Many different combinations of electrodes and electrolytes have been developed. Three common battery storage technologies include lead-acid, nickel cadmium, and lithium-ion.[57]

Lead acid batteries are the most mature of the technologies. They are the low cost solution, though they suffer from short life cycles, high maintenance requirements, and toxicity. Green Mountain Power, a Vermont public utility, is currently constructing the Stafford Hill Solar Farm and micro-grid. This project will pair two megawatts of solar PV with four megawatts of lead-acid battery storage.

Nickel cadmium batteries are known as dry cell batteries. They have better life expectancy and higher power delivery capabilities than the lead acid batteries, but are higher in cost.

Lithium-ion (Li-ion) batteries are composed of a graphite negative electrode, a metal-oxide positive electrode, and organic electrolyte with dissolved lithium ions and a micro-porous polymer separator.

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[56] *Grid Energy Storage* (U.S. Department of Energy, December 2013)
[57] *Utility Scale Energy Storage Systems* (State Utility Forecasting Group, June 2013)

When the battery is charging, lithium ions flow from the positive metal oxide electrode to the negative graphite electrode, and when discharging the flow of ions is reversed.[58]

Lithium-ion battery technology has long been used in the consumer electronics and electric vehicles. Now Li-ion battery systems are quickly emerging as a favored choice for grid-scale storage systems in the U.S. Li-ion systems typically provide less than four hours of storage. The battery technology is scalable and can be used both on utility-scale of several megawatts, and small residential applications.

In the Northwest, Puget Sound Energy (PSE), Portland General Electric (PGE), and the Snohomish County Public Utility District (SnoPUD) are establishing storage projects using lithium-ion battery technology. PSE's Glacier Battery Storage Project (2 megawatts and 4.4 megawatt-hours) will serve as a backup power source, reduce system load during high demand periods, and help integrate intermittent renewable generation on the grid. The project is expected to come on-line in late 2015. PGE's Smart Power Project (5 megawatt) is a working smart grid demonstration. It will also test the ability of battery storage to provide dispatchable backup power, provide demand response, and integrate solar power. SnoPUD is currently installing a battery storage system comprised of three lithium-ion batteries and one flow battery. The project is being developed to improve reliability and integrate variable resources.

Advantages for the technology include a good cycle life and high charge and discharge efficiencies. Challenges include high manufacturing cost and intolerance to deep discharges. Large scale manufacturing of Li-ion batteries could result in lower overall cost battery packs.

Vanadium redox flow batteries (VRB) are a type of flow battery. It's a developing technology that utilizes vanadium ions. Flow batteries have a unique cell construction. The electrolyte material is stored in tanks, external to the electrodes. During discharge and charge, electrolyte is pumped from its container into the cell to interact with the electrodes. They are capable of going from zero to full output within milliseconds. The technology can be used for megawatt-scale applications and has been demonstrated in large-scale field trials. Typically, flow batteries have a longer life cycle and can perform a high number of discharge cycles, but have a complicated design and are costly to construct. They are a battery option when discharge duration requirements exceed five hours. VRB could be a useful technology for utility applications requiring long discharge durations with rated power between 100 kilowatts and 10 megawatts, and could be used for peak shaving and renewable resource balancing. Costs for VRB systems are relatively high, but could fall as the technology matures.

Battery storage systems may be especially valuable when used in combination on-site with a renewable resource such as solar PV. During the day, dynamic cloud conditions can hamper solar PV electricity generation, resulting in variable output. An integrated battery storage system could smooth the solar output to provide a steadier source of electricity. With an integrated battery storage system, a solar PV plant could provide electricity over wider range of hours, such as the evening or

[58] Ib*id.*

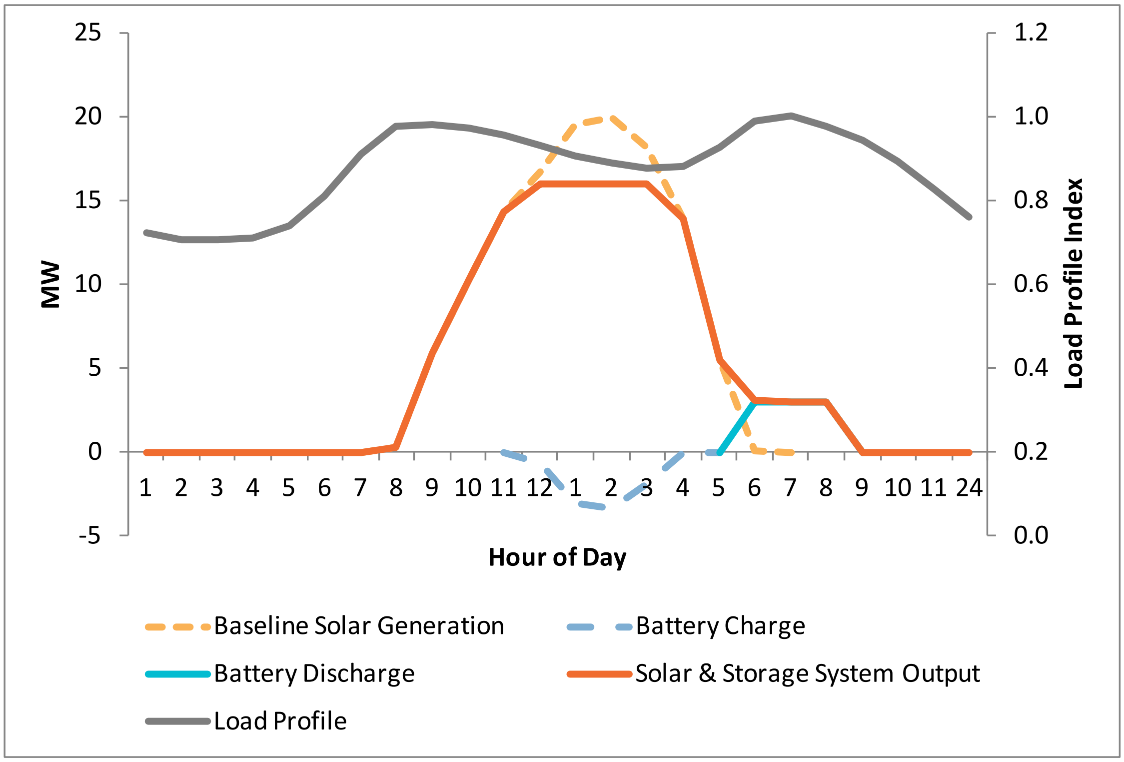
nighttime. By strategically charging a battery storage system during the day when solar PV production is high, storing the energy and discharging in the evening or night, a solar PV plant could cover an expanded range of load conditions.

The U.S. Department of Energy has developed near term and long term cost and performance targets for battery systems, including lithium-ion, flow, and other battery technologies. The near term capital cost target is $1,750 per kilowatt, and the longer term target is $1,250 per kilowatt.[59] Currently, lithium-ion systems fall in a cost range from around $2000 to $4000 per kilowatt.[60]

Figure 13 - 6 displays an example of a utility-scale solar PV plant with an integrated battery storage system. The solar PV plant in the example is modeled as a grid connected, 50 megawatt (alternating current) single-axis tracker plant in Western Washington. The battery storage system is modeled as a 10 megawatt Lithium-ion system with discharge capability of up to 4 hours. The chart shows how the solar PV and storage system might be utilized over a winter day in order to provide generation after the sun has set. The grey line shows a typical hourly load pattern for a winter day in the region with peaks in the morning and evening. The dashed yellow line displays the expected solar PV generation, with peak generation in the early afternoon and dropping to zero in the early evening. In this case, the battery storage system could be charged in the afternoon using solar PV generation, and discharged in the evening time to provide output for the evening peak. The orange line shows the overall system output.

[59] Grid Energy Storage, U.S. Department of Energy, December 2013
[60] DOE/EPRI Electricity Storage Handbook, February 2015

Figure 13 - 6: Example of Utility-Scale Solar PV and Battery Storage System



LONG-TERM POTENTIAL, EMERGING TECHNOLOGIES

In addition to certain battery storage technologies, enhanced geothermal systems, and offshore wind described in the sections above, there are several other emerging technologies that may play a role in the future Pacific Northwest power system. In particular, emerging technologies that can serve as viable alternatives to base load energy and/or zero carbon-emitting technologies that can serve as replacement resources if needed for a zero-carbon future.

Wave Energy

Beyond traditional hydroelectric power, there are other energy resources that can be derived from the naturally occurring phenomenon in the Earth's oceans and rivers and harnessed into electricity, including currents, tidal action, and waves. While all are considered emerging and may yet become viable resources with commercially available technologies in the future, wave energy appears to be an appealing match for the Pacific Northwest power system with high energy potential along the Pacific coastline from California to Alaska. Wave power devices and converters capture energy through motion at the surface or through the pressure fluctuations from the waves below the surface. While highly seasonal and subject to storm-driven peaks, wave energy is relatively continuous and is more predictable than wind - characteristics that suggest lower integration costs. The seasonal output of a wave energy plant would generally coincide with winter-peaking regional load and its location puts it in close proximity to West-side load centers.

The Electric Power Research Institute (EPRI) released a study in 2011[61] estimating the potential of wave energy in the United States. The Pacific Northwest ranks highly in terms of resource potential, with an estimate of 7,600 – 11,900 average megawatts of technically recoverable potential on the inner continental shelf of the ocean off the coast of Oregon and Washington.[62] This potential would be moderated by competing economic enterprises, maritime traffic, and environmental issues and wildlife refuges, along with other barriers. The realistic potential is likely much less, however further assessment needs to be done to determine this.

Recognizing the relative merits of wave energy, several Northwest utilities have supported the development of marine hydrokinetic projects or research and development efforts. This includes Snohomish PUD, PNGC Power, Douglas County PUD, and Portland General Electric. Although these efforts have been undertaken in coordination or collaboration with some other partners, they have generally not represented investments in regionally coordinated objectives or cross utility cost and benefit sharing.

A Flink Energy Consulting report for the Oregon Wave Energy Trust (OWET) delves into the wave energy industry and its potential in the Pacific Northwest, developing technologies, and barriers to successful deployment, and identifies recommendations within the region to collaborate and help make wave energy a reality.[63] Chief among the recommendations was to foster better coordination of utility efforts across the utility community in collaboration with wave energy developers and other stakeholders.

Numerous and diverse wave energy conversion concepts have been proposed and are in various stages of development ranging from conceptualization to pre-commercial demonstration. Wave energy conversion devices will need to perform reliably in a high-energy, corrosive environment, and demonstration projects will be needed to perfect reliable and economic designs. Successful technology demonstration will be followed by commercial pilot projects that could be expanded to full-scale commercial arrays. The Pacific Marine Energy Center South Energy Test Site (PMEC SET) is being developed off the coast of Newport, Oregon. Planned to be operational in 2018, this facility will enable wave energy conversion device testing through interconnection with the local grid and provide device certifications.

Small Modular Reactors

Nuclear power plants produce electricity from energy released by the controlled fission of certain isotopes of heavy elements such as uranium, thorium, and plutonium. Nuclear is a source of

[61] "Mapping and Assessment of the United States Ocean Wave Energy Resource," EPRI, 2011. http://www1.eere.energy.gov/water//pdfs/mappingandassessment.pdf

[62] See EPRI report for analysis specifics. The inner continental shelf is considered to be within tens of kilometers off the coast at a depth of 50 meters. An additional 8,400 – 14,500 average megawatts potential is identified at the outer continental shelf – up to 50 miles off the coast at a depth of 200 meters. This potential would require extensive transmission builds.

[63] "Wave Energy Industry Update: A Northwest Perspective." Flink Energy Consulting for Oregon Wave Energy Trust, 2015.

dependable capacity and baseload zero-carbon energy that is largely immune to high natural gas prices and climate policy. However, a new conventional nuclear unit would entail the risks of construction delay to an already lengthy construction lead time, escalating costs, and the reliability risk associated with a large single-shaft machine. Rather, the emerging small modular reactor (SMR) technology's smaller size (300 megawatts or less) and modular construction is intended to reduce capital cost and investment risk by utilizing a greater degree of factory assembly, shortening construction lead time, and better matching plant size to customer needs and finances through scaling of multiple units. The smaller plant size of SMRs may also permit greater siting flexibility, load following capability, and cogeneration potential and can benefit system reliability through reduction in "single shaft" outage risk.

While there are multiple SMR designs being developed and tested, one of the leading developers is NuScale Power, headquartered in Corvallis, Oregon. In 2013 NuScale was the recipient of a U.S. Department of Energy cost-sharing award in which they receive funding from DOE to support their SMR technology and move the design certification with the Nuclear Regulatory Commission (NRC) forward with the goal of commercialization.

NuScale is working with Energy Northwest and the Utah Associated Municipal Power System (UAMPS) on siting the first SMR at the Idaho National Laboratory in Idaho Falls, Idaho. Assuming key design certification and development milestones are met along the way, Energy Northwest and UAMPS intend to submit a combined construction and operating license application (COLA) to the Nuclear Regulatory Commission by early 2018. To aid in this application, the U.S. DOE recently awarded NuScale and UAMPS $16 million to complete the COLA. It is estimated that the first module will be operational in 2023 and the full 12-module, 600 megawatt SMR plant will be operational in 2024. Energy Northwest and UAMPS estimate that the capital cost of this first plant will be around $2.9 billion, with a full plant levelized cost of electricity around $75 per megawatt-hour.

CHAPTER 14: DEMAND RESPONSE

Contents

List of Figures and Tables

KEY FINDINGS

The Seventh Power Plan assumes the technically achievable potential for demand response in the region is over eight percent of peak load during winter and summer peak periods by 2035. This assumption is based on the Demand Response Program Potential Study commissioned by the Council[1] and feedback from regional stakeholders. This figure represents approximately 3,500 megawatts of winter peak load reductions and nearly 3,300 megawatts of summer peak load reductions by the end of the study period. In addition, the study identified additional potential for summer and winter demand response that could be available by the end of the study period to provide for load and variable generation balancing services.

While the study included an assessment of the demand response potential for balancing services, this use of demand response was not modeled in the Council's Regional Portfolio Model (RPM) analysis. Only the technically achievable potential for demand response to provide peaking services was included in the RPM analysis. The RPM used this data to determine the amount of demand response to develop in the least cost resource strategy for each of the scenarios tested by the model. In order to model the technical and economic viability of demand response resources to provide balancing services, further modeling enhancements and research are necessary.

INTRODUCTION

The Council's definition of Demand Response (DR) is a voluntary and temporary change in consumers' use of electricity when the power system is stressed. The change in consumer use is usually a reduction, although there are situations in which an increase in use would relieve stress on the power system and would qualify as DR.

The need for DR arises from the mismatch between power system costs and consumers' prices. While power system costs vary widely from hour to hour as demand and supply circumstances change, consumers generally see prices that change very little in the short term. The result of this mismatch is that consumers do not have the information that might incent them to curb consumption at high-cost times and/or shift consumption to low-cost times. The ultimate result of the mismatch of costs and prices is that the increased power system needs require building more peaking capacity, building more transmission, and incurring more system upgrades than would be necessary if customers changed their use in response to price changes in the market. Programs and policies to encourage demand response are efforts to provide this information to consumers and create the infrastructure to allow them to respond to price signals in the market.

[1] The Navigant Potential Report, "Assessing Demand Response (DR) Program Potential for the Seventh Power Plan", was delivered as a document and a supporting spreadsheet, , NPCC_Assessing DR Potential for Seventh Power Plan_UPDATED REPORT_1-19-15.pdf and NPCC_7thPowerPlan_DR_Programs_UPDATE_2015 01 16.xlsx, respectively.

Demand response has the potential to provide significant value to the Northwest's power system by:

- Reducing Peak Load, which,
    - Defers the build of generating resources that provide peaking capacity[2].
    - Defers the build of new transmission and/or distribution resources
- Providing Ancillary Services[3], including,
    - Contingency reserves
    - Operating reserves (e.g. load following and regulation)
    - Transmission and/or distribution congestion relief

In the Seventh Power Plan, the Council focuses primarily on DR that reduces peak load, and even more specifically, DR that defers the build of generating resources and new transmission resources. Other potential applications of demand response resources, such as the integration of variable resources like wind, were not explicitly modeled for the development of the Seventh Power Plan. However, this does not mean that such applications of demand response would not provide cost-effective options for providing such services. Therefore, the Seventh Power Plan resource strategy also recommends that demand response resources be considered for the provision of other ancillary services, such as variable resource integration.

DEMAND RESPONSE IN PREVIOUS POWER PLANS

The Council considered demand response as a potential resource[4] in its Sixth Power Plan[5] after considering it for the first time in its Fifth Power Plan.[6] The Sixth Power Plan described pricing and program options to encourage demand response. It also developed a very rough estimate of 2,000 megawatts of demand response that might be available in the Pacific Northwest over the 2010-2029 planning period, and described some estimates of the cost-effectiveness of demand response. The Sixth Plan included an action item to advance the state of knowledge of demand response in the region.[7]

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[2] See definitions of generation resource options in Seventh Power Plan, Chapter 13: Generating Resources.
[3] See definitions of ancillary services in Seventh Power Plan, Chapter 10: Operating and Planning Reserves.
[4] According to the strict legal definitions of the Northwest Power Act, demand response is probably not a "resource" but a component of "reserves." For ease of exposition, the plan refers to demand response as a resource in the sense of the general definition of the word - "a source of supply or support."
[5] The Sixth Power Plan is posted at https://www.nwcouncil.org/energy/powerplan/6/plan/ with Chapter 5 on DR at https://www.nwcouncil.org/media/6368/SixthPowerPlan_Ch5.pdf and Appendix H on DR at https://www.nwcouncil.org/media/6314/SixthPowerPlan_Appendix_H.pdf.
[6] The Fifth Power Plan is posted at http://www.nwcouncil.org/energy/powerplan/5/Default.htm, with Chapter 4 on DR at http://www.nwcouncil.org/energy/powerplan/5/(04)%20Demand%20Response.pdf and Appendix H on DR at http://www.nwcouncil.org/energy/powerplan/5/Appendix%20H%20(Demand%20Response).pdf
[7] The Sixth Power Plan's treatment of demand response is laid out in more detail in Appendix H of that plan.

Progress Since the Sixth Power Plan

Since the release of the Sixth Power Plan, the region has made progress on developing demand response programs. Idaho Power, PacifiCorp, and Portland General Electric have expanded existing demand-response programs. Multiple utilities within the region have continued progress towards installing advanced metering for all their customers, which facilitates demand response programs and enables time-sensitive pricing. Utilities in the region continue to evaluate demand response as an alternative to peaking generation in their integrated resource plans.

The Council and the Regulatory Assistance Project have continued to work together to coordinate the Pacific Northwest Demand Response Project (PNDRP), composed of parties interested in the development of demand response in the region. PNDRP has historically mostly focused on defining cost-effectiveness of demand response, discussing a role for pricing, and considering the transmission and distribution system costs that can be avoided by demand response. However, focus seems to be shifting to studying DR usefulness in mitigating system needs for balancing and flexibility. The region's system operators are increasingly concerned with the system's ability to achieve minute-to-minute balancing when faced with increasingly peaky demands for electricity and increasing amounts of variable generation. Demand response is recognized as a potential source of some of the "ancillary services" necessary for this balancing. Bonneville has partnered with Energy Northwest, City of Port Angeles, and Emerald Public Utility District in pilot programs exploring the use of DR as a balancing resource.

These areas of progress are covered in more detail in Appendix J.

DEMAND RESPONSE IN THE SEVENTH POWER PLAN

Estimation of Available Demand Response

In order to evaluate the potential role that demand response might play in a least cost resource strategy for the region, it was first necessary to develop the inputs for evaluating the cost-effectiveness of DR resources in the Regional Portfolio Model (RPM). These inputs include each DR resource's seasonal shape, its fixed and variable costs, and its associated capacity and energy value. To develop these inputs the Council commissioned a regional DR Program Potential Study. The scope of this study was limited to a review of information from previous DR program potential studies for investor owned utilities, existing DR program literature and interviews with regional stakeholders. The Council released for stakeholder review the initial results of the study early in 2015. Stakeholder comments were then integrated with the results of the potential study.

A description of the major forms of DR considered for the Seventh Power Plan appears below.

Direct load control (DLC) for air conditioning. Direct control of air conditioners, by cycling or thermostat adjustment, is one of the most common demand-response programs across the country, and is most attractive in areas where electricity load peaks in the summer. The Pacific Northwest as a whole is still winter-peaking, but forecasts continue to show the region's summer peak load growing faster than winter peak load. PacifiCorp's Rocky Mountain Power division and Idaho Power already face summer-peaking loads. Idaho Power has almost 45 peak megawatts of demand response from direct control of air conditioning under contract within the region. In the RPM, this resource is limited to 50 hours in the summer.

Irrigation. PacifiCorp and Idaho Power are currently reducing irrigation load by more than 450 megawatts through scheduling controls. Both utilities are in the process of modifying their programs to give them more control of the resource, increasing the load reduction available when the utilities need it. In the RPM, this resource is limited to 50 hours in the summer.

Direct load control of space heat and water heat. Direct load control of electric space heating (i.e. heat pumps, forced air furnaces, baseboard) and electric resistance water heating, by cycling or thermostat adjustment, is useful in reducing winter peak electricity use. While there has been some experience with direct control of water heating in the region, experience with direct control of space heating is limited to pilot programs. The assumption for space heating DLC is a maximum of 50 hours per winter whereas water heating DLC can be dispatched 50 hours year round.

Load Aggregators. Increasingly, load aggregators facilitate demand response by acting as middlemen between utilities or system operators on the one hand and the end-users of electricity on the other. These aggregators are known by a variety of titles such as "demand response service providers" for the independent system operators in New York and New England and "curtailment service providers" for the regional transmission organization in the Mid-Atlantic States (PJM). Aggregators could recruit customers to participate in demand response programs already described here, in which case aggregators would not add to the total of available demand response. However, in the Council's analysis, aggregators are assumed to achieve additional demand response by recruiting commercial and small industrial load that is not otherwise captured. The resource is assumed available for a maximum of 60 hours year round.

Curtailable/Interruptible contracts. Interruptible contracts offer rate discounts to customers who agree to have their electrical service interrupted under defined circumstances. This is a well-established mechanism, even within the Pacific Northwest, for reducing load in emergencies. Bonneville has had agreements with its direct service industry customers to reduce load at times of peak need. These contracts usually are arranged with large industrial customers, and PacifiCorp, PGE, and Bonneville have had almost 300 megawatts of interruptible load under such contracts in the region.

The study separated the DR programs into three sectors: Residential, Commercial, and Industrial/ Agricultural. The percentage of potential in each sector by year and season is in Table 14 - 1.

Table 14 - 1: Demand Response Potential Percentage by Sector

	Winter Potential in 2021	Winter Potential in 2026	Winter Potential in 2035	Summer Potential in 2021	Summer Potential in 2026	Summer Potential in 2035
Residential	48%	48%	48%	35%	35%	35%
Commercial	8%	8%	8%	17%	17%	17%
Ag/Industrial	44%	44%	44%	48%	48%	48%

The individual programs considered in the development of regional DR potential are categorized by sector in Table 14 - 2.

Table 14 - 2: Demand Response Programs Studied

	DR Sector	DR Component	DR Technology[8]	Seasonality
1	Residential DR	Space Heating	Direct Load Control (DLC) and Programmable Communicating Thermostats (PCT)	Winter Only
		Water Heating	DLC and Automatic Water Heater Controls	Summer and Winter
		Space Cooling – Central Air Conditioning (CAC)	DLC and PCT	Summer Only
		Space Cooling – Room Air Conditioning (RAC)	DLC and PCT	Summer Only
2	Commercial DR	Space Cooling, Small Commercial - Central Air Conditioning	DLC and PCT	Mostly Summer
		Space Cooling, Medium Commercial - Central Air Conditioning	DLC and PCT	Mostly Summer
		Lighting Controls	AutoDR	Summer and Winter
3	Agricultural / Industrial DR	Irrigation Pumping	DLC and AutoDR	Mostly Summer
		Curtailable/Interruptible Tariffs	DLC and AutoDR	Summer and Winter
		Load Aggregator	AutoDR	Summer and Winter
		Refrigerated Warehouses	AutoDR	Summer and Winter

[8] "DLC programs for space cooling and water heating typically require installation of a receiver system to signal the interruption or cycling of equipment. Water heaters can either use a radio- or digital internet gateway- activated switch. Historically, DLC for cooling has relied on switches but increasingly utilities are utilizing more advanced programmable communicating thermostats (PCTs). DLC programs for space heating are also trending toward the use of PCTs. While still in pilot phases, there is increasing interest toward using certain types of DLC for load balancing purposes, particularly for water heating applications. The technology application for water heating DLC for balancing purposes is exclusively aimed toward internet gateway-activated switches…. AutoDR consists of fully automated signaling from the utility to provide automated connectivity to customer end-use control systems, devices and strategies", per the DR Potential Study.

Demand Response Assumptions

Demand Response in the Regional Portfolio Model

In the Seventh Power Plan, the Regional Portfolio Model (RPM) explicitly analyzes the need for peak capacity.[9] Thus, the need for peaking resources forms the basis for the modeling of DR resources in the RPM.

DR can be characterized by the following attributes:

- Seasonality – Some DR resources are only available and/or most effective to reduce peak loads during summer (space cooling, irrigation) or winter (space heating) whereas others are available year-round (lighting, water heating, curtailable/interruptible tariffs, load aggregators).

- Firmness – DR resources allowing either interruptions of electrical equipment or appliances that are directly controlled by the utility or are scheduled ahead of time are considered to be firm. Non-Firm DR resources are outside of the utility's direct control and are driven by modified customer usage based on pricing mechanisms that pass on some portion of the changing price of electricity to the customer.

- Sector – Residential, commercial, industrial, and agricultural sectors have different characteristics and methods of acquisition.

For RPM modeling purposes, the primary distinguishing attributes for DR resources are cost, and secondarily, seasonal shape. The Council modeled four DR resources in the RPM. Each of the demand response programs listed in Table 14 - 1 above was assigned to one of four bins, characterized by cost and seasonal shape. The cost and seasonal shape of each bin represents the weighted average cost and shape of the programs making up the bin.

Council Assumptions

Based on the DR Potential Study results, stakeholder comments and experience elsewhere, the Council adopted cost and availability assumptions for nineteen demand response programs listed in Table 14 - 1 above. The Council sorted all the programs into one of four price bins based on the Total Resource Cost (TRC)[10] net levelized cost of the resource. Table 14 - 3, Table 14 - 4, Table 14 - 5, and Table 14 - 6, show the cumulative annual build-out available from each of the bins, and are indicative of which programs have a larger influence in the price of the bins. Note that both the winter and summer potential of each program is listed.

[9] See discussion in Appendix L of the Seventh Power Plan related to RPM redevelopment for more detail.
[10] TRC net levelized cost is "all quantifiable costs and benefits" associated with a particular DR program, as described in more detail in the Methodology section of Chapter 12 of Seventh Power Plan.

Table 14 - 3: Price Bin 1 Cumulative Achievable Potential in MW

	Winter Potential			Summer Potential		
Bin 1 - Cumulative MW	2021	2026	2035	2021	2026	2035
Irrigation Pumping - DLC	-	-	-	10	10	11
Curtailable/Interruptible Tariff - DLC	557	583	646	557	583	646
Curtailable/Interruptible - AutoDR	557	583	646	557	583	646
Load Aggregator - AutoDR	139	146	161	139	146	161
Space Cooling, Medium Commercial– DLC	9	10	11	47	49	54

Table 14 - 4: Price Bin 2 Cumulative Achievable Potential in MW

	Winter Potential			Summer Potential		
Bin 2 - Cumulative MW	2021	2026	2035	2021	2026	2035
Space Cooling, Small Commercial – DLC	4	4	4	18	18	20
Refrigerated Warehouses - AutoDR	92	96	106	102	107	118
Space Heating – DLC	280	294	325	-	-	-
Lighting Controls – AutoDR	171	179	198	171	179	198
Irrigation Pumping - AutoDR	-	-	-	5	5	6
Water Heating – DLC	483	508	562	483	508	562

Table 14 - 5: Price Bin 3 Cumulative Achievable Potential in MW

	Winter Potential			Summer Potential		
Bin 3 - Cumulative MW	2021	2026	2035	2021	2026	2035
Space Cooling - CAC DLC	-	-	-	102	108	119
Space Cooling, Medium Commercial - AutoDR	44	46	51	219	230	254
Space Cooling - RAC DLC	-	-	-	5	5	5
Space Cooling, Small Commercial – PCT	4	4	5	20	21	24

Table 14 - 6: Price Bin 4 Cumulative Achievable Potential in MW

	Winter Potential			Summer Potential		
Bin 4 - Cumulative MW	2021	2026	2035	2021	2026	2035
Water Heating - WH Controls	54	56	62	54	56	62
Space Cooling - CAC PCT	-	-	-	239	251	278
Space Cooling - RAC PCT	-	-	-	107	113	125
Space Heating – PCT	653	687	759	-	-	-

The Total Resource Cost (TRC) levelized cost calculation includes two major components: implementation costs and enablement costs. Implementation costs are the costs associated with continually running a DR program such as staffing costs, marketing costs, and customer incentive payments. Enablement costs are the costs associated with getting a demand response resource set up for use, such as technology costs and installation costs. The use of these costs in the calculation of the TRC levelized costs is discussed further in Appendix J.

Figure 14 - 1 shows the TRC levelized cost of each price bin in the blue columns, and the subsequent weighted average levelized costs of each bin into which it was sorted. Each bin was sized to best fit programs with similar costs together while minimizing cost variation within the bin. This was done to ensure that if the RPM selected the minimum amount of megawatts from any price bin (i.e., 10 MW) it would be fairly representative of any program within the same bin.

Figure 14 - 1: Demand Response Programs and Cost Bins

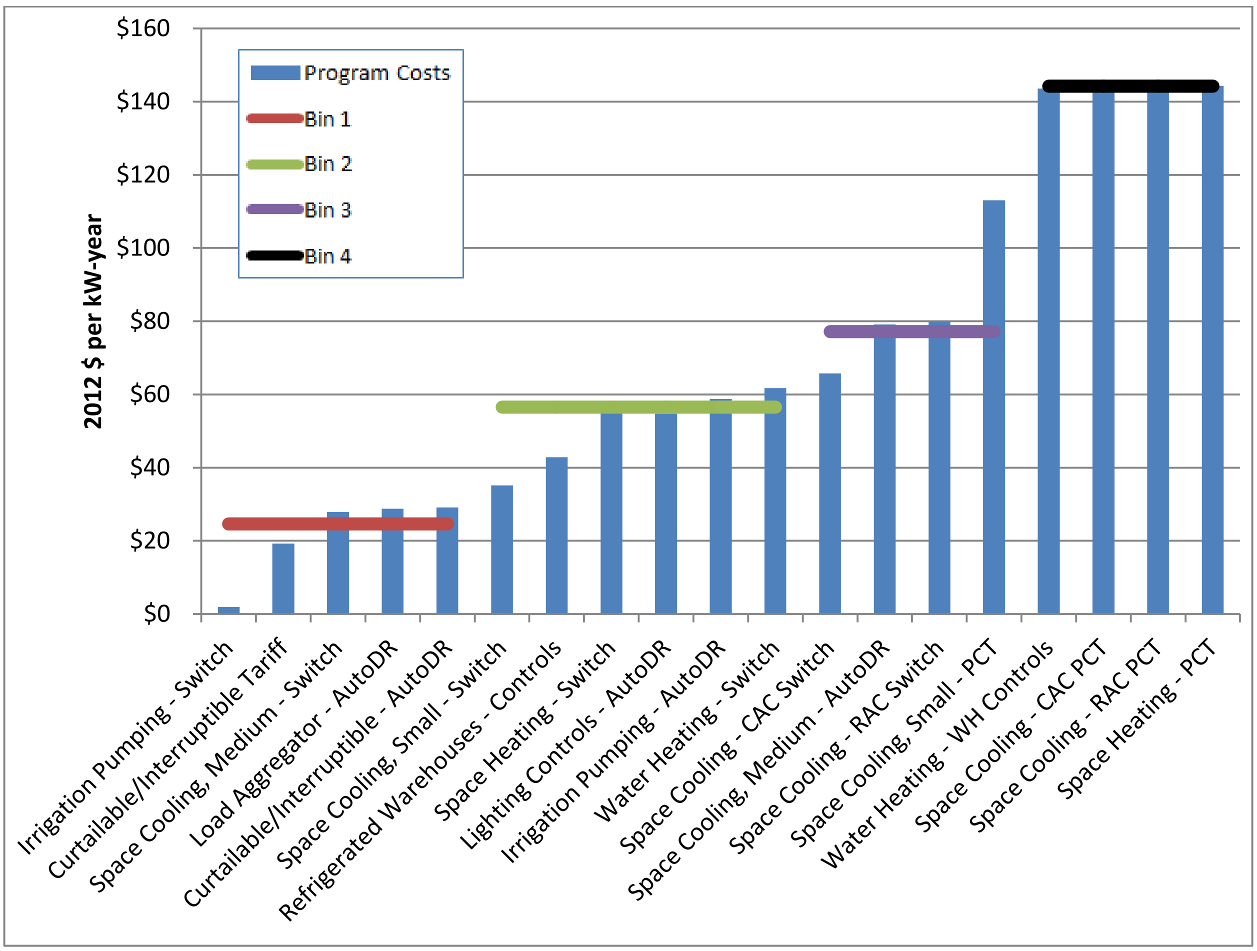
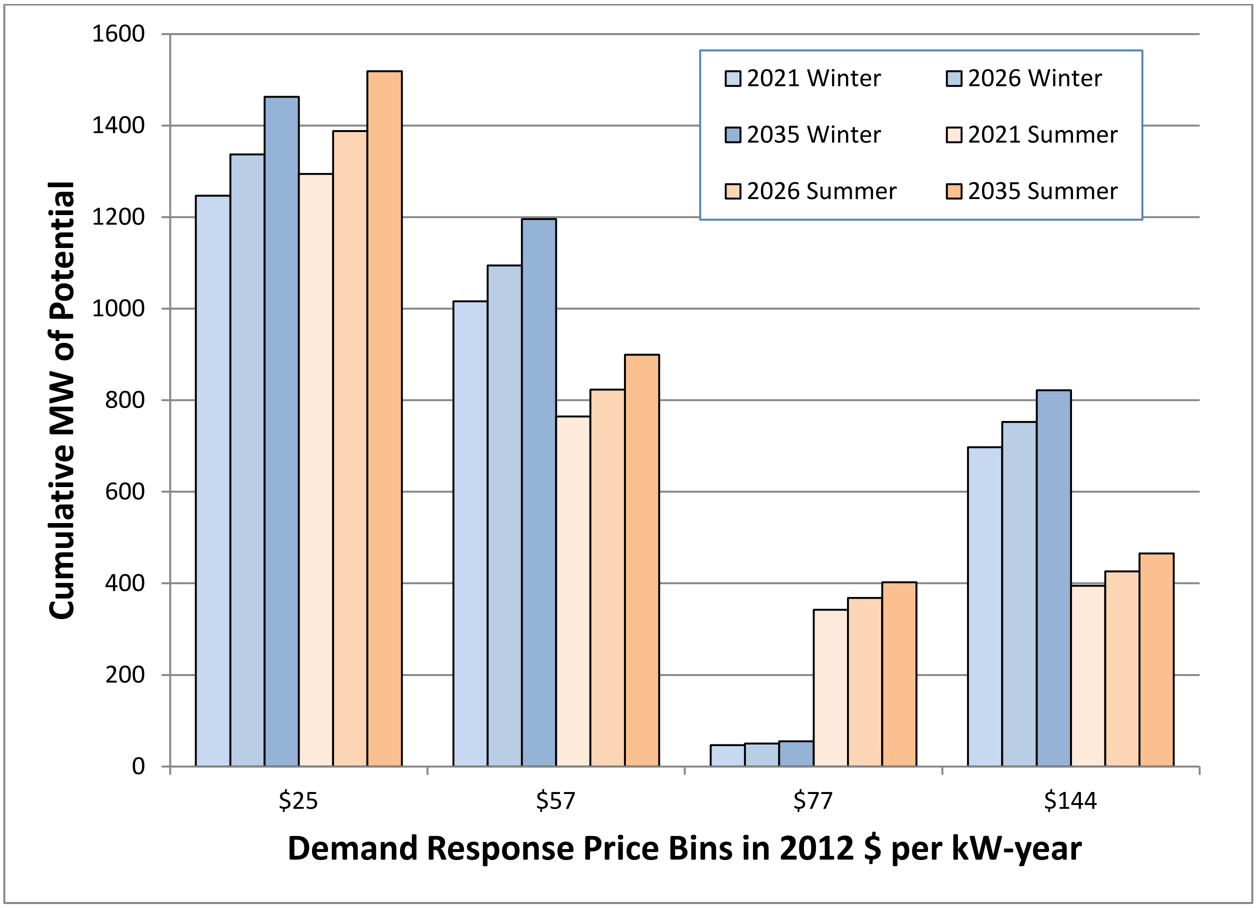


Figure 14 - 2 shows the cumulative technical DR potential of each price bin (in megawatts) to meet summer and winter peak load needs by the years 2021, 2026, and 2035. This figure highlights the different seasonal aspects of the price bins.

Figure 14 - 2: Demand Response Resource Supply Curve



Caveats for Demand Response Assumptions

The cost and DR potential shown in Figure 14 - 2 were provided as input into the RPM to analyze the impact of DR on the expected system costs and risk of alternative resource strategies. Accordingly, for the purposes of the Seventh Power Plan they are regarded as technically achievable potential, with the portfolio model analysis determining the programs and amounts that are cost-effective and/or mitigate risk less expensively than other options.[11] The technically achievable potential does not include consideration of institutional barriers for entities like Bonneville, but does consider market impediments such as customer turnover, participation, and availability.

While the Council regards these assumptions as reasonable for the region as a whole, each utility service area has its own unique characteristics that determine the demand response available and the programs that are cost-effective for that particular sub-region.

[11] For more information about the portfolio model, see Chapters 3 and 15.

Discussion of Demand Response Not Modeled in the Regional Portfolio Model

Non-Firm Demand Response

The Council is not currently using assumptions about the amount of demand response that might be available from pricing structures, often described as non-firm demand response. There is no doubt that time-sensitive prices can reduce load at appropriate times, but the region does not yet appear to be ready for general adoption of these pricing structures. While hourly meters are becoming more common, many customers do not have them yet, which make time-of-day pricing, critical-peak pricing, peak-time rebates, and real-time pricing programs currently unavailable to those customers. Many in the region are concerned that some customers will experience big bill increases with different pricing structures. There also is the possibility for overlap in the assumed potential between firm demand-response programs and any pricing structure initiatives.

The Pacific Northwest Demand Response Project is continuing to pursue the subject of pricing structures as a means to achieve demand response. In addition, Idaho Power and Portland General Electric have and continue to conduct pilot projects of time-sensitive electricity pricing structures, which have achieved only mixed acceptance among customers.

Dispatchable Standby Generation

This resource is composed of emergency generators in office buildings, hospitals, and other facilities that need electricity even when the power is unavailable from the grid. The generators also can be used by utilities to provide contingent reserves, an ancillary service. Ancillary services are not explicitly simulated in the RPM, but dispatchable standby generation (DSG) is a resource fulfilling a similar niche as demand response that has significant potential and cannot be overlooked. Portland General Electric (PGE) has pursued this resource aggressively, taking over the maintenance and testing of the generators in exchange for the right to dispatch them as reserves when needed. PGE had 93 megawatts of dispatchable standby generation available in 2013, and plans to have 116 megawatts by 2017. This potential will grow over time as more facilities are built with emergency generation and existing facilities are brought into the program. The Council does not currently incorporate potential from new dispatchable standby generation explicitly in the RPM modeling, but considers existing DSG in the reliability modeling in GENESYS.

Providing Ancillary Services with Demand Response

Demand response usually has been regarded as an alternative to generation at peak load (or at least near-peak load), that occurs a few hours per year. But demand response can do more than help meet peak load. It can help provide ancillary services such as contingency reserves, regulation and load following. Historically, additional supply of ancillary services has not been considered a need in the Pacific Northwest due to the large supply of flexible hydropower in the region. As loads have grown, and as variable energy resource generation (primarily wind) has increased, power system planners and operators have become more concerned about ancillary services. Not all demand response resources can provide such services because they have different requirements than meeting peak load.

Ancillary services are not explicitly simulated in the RPM so the potential value of using demand response resources to meet these needs was not evaluated in the Seventh Power Plan. However, the Demand Response Potential Study conducted for the Council identified some DR resources available in the region for meeting ancillary service needs and regional entities have explored DR resources for this purpose, so further study of the use of DR is encouraged.

CHAPTER 15: ANALYSIS OF ALTERNATIVE RESOURCE STRATEGIES

Contents

List of Figures and Tables

KEY FINDINGS

Developing low cost, economic low risk resource strategies for the power system in a robust manner requires stress testing alternative resource mixes over a large range of potential future conditions. Those resource strategies that exhibit low cost and economic low risk across a wide range of future conditions are the most desirable. In addition, if components of the resource strategy that are within the control of utilities are amenable to adapting to future conditions such strategies are also more desirable. For example, if the success of a resource strategy relies on low natural gas prices, it is less desirable than one that relies on increased deployment of energy efficiency or demand response. Future natural gas prices are beyond the control of utilities, while development of energy efficiency or demand response resources is within utility control. Making good decisions with due consideration for uncertainty requires understanding the dynamic between the decisions that are within the realm of a utility planner and the uncertainty beyond their control. This chapter describes the approach used to model this dynamic and to estimate future system costs under a wide range of potential future conditions.

UNCERTAINTY ABOUT THE FUTURE

The future is uncertain. Therefore, the ultimate cost and economic risk of resource development decisions made today are impacted by factors that are largely out of the control of decision makers. To assess the cost and economic risk of different resource strategies, it is essential to identify those future uncertainties that have the potential to significantly affect a resource strategy's cost or economic risk, and to bracket the range of those uncertainties. The primary uncertainties examined by the Council's Regional Portfolio Model (RPM) are demand for electricity, generation from the hydroelectric system, market prices for both electricity and natural gas, and carbon dioxide (CO2) policy. Each of these is discussed below.

Demand for Electricity

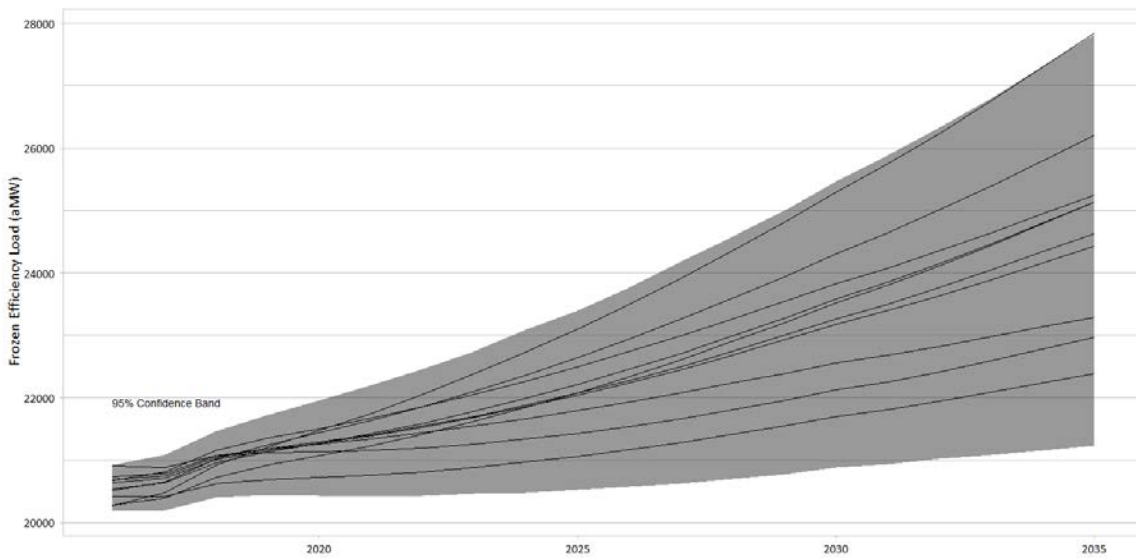
One of the principal uncertainties faced by the region is how much electricity will be needed in the future. Since future economic conditions could vary significantly, the Council develops a range forecast for those variables, such as population and employment growth that drive the demand for electricity. Chapter 7 and Appendix E describe the derivation of the Council's electric load growth forecast range (i.e., low, medium and high). Because conservation is treated as a potential resource when developing a resource strategy, the forecast of future electricity loads intentionally excludes any conservation savings, except those from codes and standards that have already been enacted. This forecast is, therefore, referred to as a "frozen efficiency load forecast."

To analyze the impact of the uncertainty surrounding future demand for electricity on alternative resource strategies, the "frozen efficiency" load forecast is translated into 800 "potential futures."[1]

[1] A discussion of how these futures are developed appears in Appendix L which describes the Regional Portfolio Model (RPM).

To represent future business cycles and overall economic growth patterns, each of these 800 potential futures has a unique load growth rate and pattern. Figure 15 - 1 shows a sample of the 800 future load paths across the 20-year study horizon that were considered when testing alternative resource strategies.

Figure 15 - 1: Example of forecast potential future load for electricity



Hydroelectric Generation

Future generation from the hydroelectric system is uncertain and will vary over a wide range from year to year. The method the Council uses to estimate the impact of that uncertainty is to use historic streamflows to develop a range of potential hydroelectric generation based on the current configuration of the hydroelectric system. An 80-year history of streamflows provides the basis for hydroelectric generation in the Regional Portfolio Model (RPM).

The hydroelectric generation modeled in the RPM also reflects all known constraints on river operation. These include those river operations associated with the NOAA Fisheries 2014 biological opinion and in the Council's fish and wildlife program. In addition, all scenarios evaluate resource choices assuming no emergency reliance on the hydropower system, even though such reliance might not violate biological opinion constraints.

In addition to meeting fish and wildlife requirements, hydropower operations must satisfy other objectives. These objectives include system flood control, river navigation, irrigation, recreational, and refill requirements.

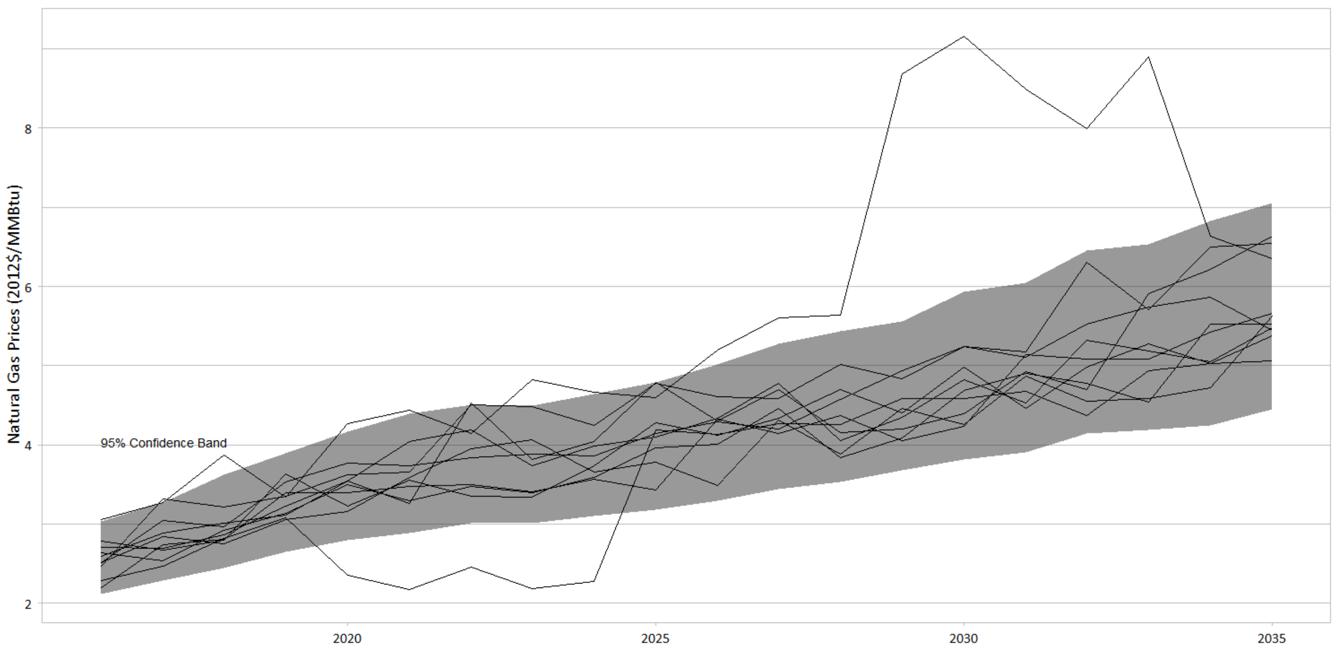
Wholesale Market Prices for Natural Gas and Electricity

There are many market-based prices that impact the cost of the regional power system. In order to test the cost and risk of pursuing different resource strategies, the two types of prices that are most critical are the price of the fuel for thermal generators and the price of buying from or selling into the regional or west coast markets.

Fuel Prices

Forecasts for fuel prices for thermal generators including coal, uranium and natural gas are described in Chapter 8. Because natural gas is often the marginal fuel source in the region, the price of natural gas is modeled as varying over potential futures. Details of how these future gas price profiles are developed are included in Appendix L. Since coal and uranium are seldom on the margin in setting the price of the market, the forecasts for these fuel prices are held constant over the potential futures. Figure 15 - 2 illustrates the potential range for natural gas prices over the 20-year study horizon.

Figure 15 - 2: Example of forecast potential future natural gas prices



External Electricity Market Prices

The Northwest is interconnected to power markets in other regions, most importantly California, the Southwest and British Columbia. These interconnections help the Northwest reduce the cost of serving regional load. Northwest utilities and Bonneville, by either selling electric power to other regions when the Northwest has surplus or buying power from other regions when it is less expensive than producing power from generators within the Northwest, can reduce the cost to consumers in the region. The price of buying and selling power outside the region is impacted by the supply and demand dynamics inside the region. When testing different resource strategies, both the price for importing and exporting electricity and the interaction of those prices with the operation of the power system in the Northwest are modeled as varying over the 800 futures. Regional electricity market prices are estimated by the Regional Portfolio Model (RPM), based on the amount of hydroelectric generation and the dispatch of regional resources. These prices result from supply and demand equilibrium within the region. This equilibrium price can differ from the external market price as is seen by comparing Figure 15 - 3 which shows the market price for imports and exports to Figure 15 - 4 which shows the equilibrium price for in-region generators. A detailed discussion of how these prices are developed appears in Appendix L. The interaction of external market prices with the resource strategy being tested in the RPM is discussed further in the section on *Testing Resource Strategies* later in this chapter.

Figure 15 - 3: Example futures for the prices of importing or exporting electricity

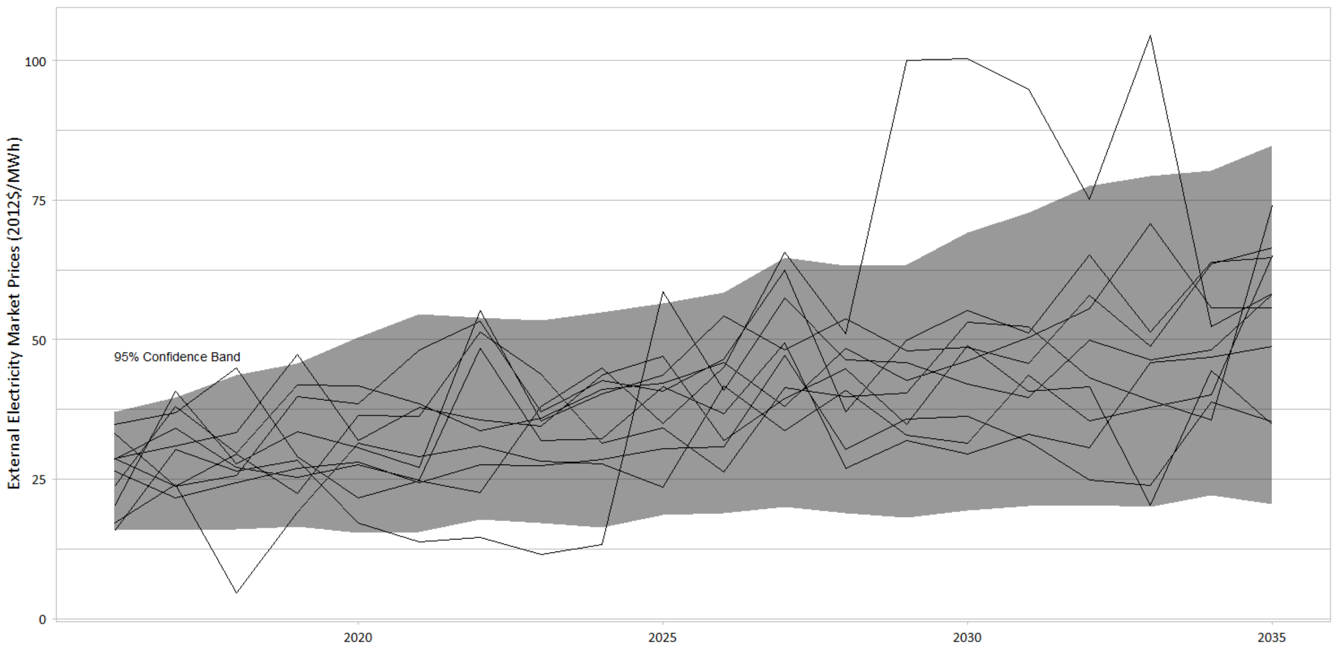
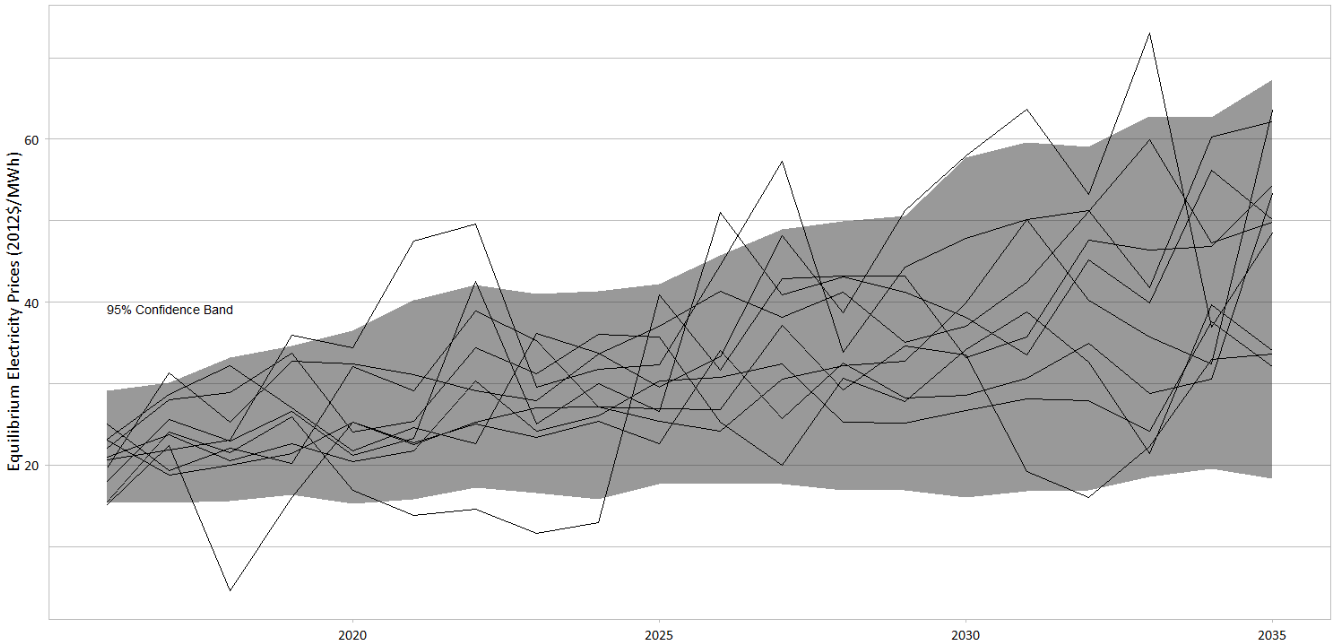


Figure 15 - 4: Examples of equilibrium prices for generators in the region



Carbon Dioxide Emissions Policies

When the Council commenced development of the Seventh Power Plan, state and federal carbon emissions policies were uncertain. Although the federal government recently issued its final regulations covering carbon dioxide emissions from new and existing power generation, state compliance plans are not scheduled (or required) to be completed before the Seventh Power Plan is adopted. Therefore, the Council tested alternative carbon emissions reduction policies to assess their impact on the cost and risk of alternative resource strategies.

Policies to reduce carbon dioxide (CO2) emissions can take several different forms. One policy option is to assign a price to the emission of CO2, whether implicit or explicit. Another approach is to assume the re-dispatch or retirement of resources that emit CO2. A third policy option is to require that a minimum share of resources be non-CO2 emitting (e.g. establish renewable portfolio standards). In analyzing alternative resource strategies, all three of these policy options were tested. The various approaches are discussed further in the section on *Developing Resource Strategies* later in this chapter.

ESTIMATING FUTURE SYSTEM COST

Comparing alternative resource strategies requires measuring differences between these strategies. Perhaps the most important measurement is an estimate of the future cost of the power system. This requires estimating the carrying cost for the existing power generation system as well as forecasting new costs associated with any particular resource strategy. The significant costs and benefits that are evaluated in the RPM are those for conservation, new generating resources and demand response, additional resources to meet renewable portfolio standards (RPS) and operating costs of the existing system.

Conservation

Acquiring conservation has both costs and benefits. To evaluate the value of conservation, the supply is aggregated into blocks of sufficient granularity to not obscure comparison to other resources. The conservation measures and block aggregation strategy are described in Chapter 12. Limitations on the rate at which conservation can be acquired changes throughout the 20-year period of the study. These limits and their derivation are also described in Chapter 12.

All resource strategies tested by the RPM assume that the availability of conservation differs between discretionary and lost opportunity measures. In the case of discretionary conservation, the supply decreases as more is purchased. In the case of lost opportunity conservation, if it is not purchased there is a lag time, determined by the expected life of the measure, before the next opportunity to purchase it occurs. For a more in-depth discussion of how each type of conservation is modeled see Appendix L.

The acquisition of conservation is generally assumed to be dynamically altered based on market conditions. That is, when market prices are higher, higher levels of conservation are cost-effective to develop than when market prices are lower. The RPM, when searching for least cost resource strategies, tests alternative limits on the maximum cost (and hence, the quantity) of conservation it develops. This tests the risk (to the system cost) of getting more or less conservation.

When a conservation measure is acquired it is assumed that its cost covers resource acquisition for the duration of the study. The RPM models the power system on a quarterly basis, i.e., four quarters per year, 80 quarters over the 20 year planning period. Thus, starting with the quarter after conservation is acquired; the levelized cost of the conservation is included in the system cost.

On the benefit side, conservation reduces the need for regional generation to serve load, both energy and capacity. This translates into a benefit when regional generation can sell into the external market and make a profit or when purchases from outside the region can be reduced and thus reduce the system costs.

New Generating Resources and Demand Response

The analysis of resource strategies involves selecting options to develop new generating resources and demand response. In the RPM, as in the real world, establishing an option to develop new resources incurs a small cost for engineering, permitting and siting. A far more significant cost is incurred when a resource is constructed. Because the longest lead time for new resources considered for development in the Seventh Power Plan is 30 months, for a combined cycle natural gas plant, it is assumed that once construction is started that it will be completed.

The Regional Portfolio Model (RPM) uses two decision rules to determine when a generating resource moves from an option to construction. Resources are built if they are needed to satisfy a regional adequacy requirement or if they are economical, i.e., can recover their full cost by selling into the market. For each resource strategy, the RPM forecasts the need for new resources to meet adequacy as well as the potential for a resource to recover its full cost through sales into the wholesale market. If either one of these evaluations is positive (i.e., the resources is needed to meet adequacy requirements or the resource can recover its full cost through market sales) a resource option will move into the construction phase. When that occurs, the cost of constructing the resource is added into the system costs and the dispatch costs are added in after the construction is complete and the resource is operational.

The RPM calculates the benefits of new generating resources and demand response by comparing the variable cost of the resource to the price for importing or exporting power. If the cost of the new resource, such as conservation, is lower than market prices, the net cost of importing power is reduced or revenue from selling power outside the region increases and is credited toward reducing regional system cost.

Renewable Portfolio Standards

Fulfilling Renewable Portfolio Standards, including accounting for the banking of Renewable Energy Credits, is part of estimating system cost. Currently the states of Montana, Oregon and Washington have Renewable Portfolio Standards. Assumptions for RPS requirements by state, used to evaluate system cost are shown in Table 15 - 1. The percentages of state sales assumed to be served by RPS resources are shown in Table 15 - 2. Finally the estimated fraction of load in each state that is obligated under the RPS is given in Table 15 - 3. All resource strategies are assumed to meet RPS requirements in the most cost-effective manner.

Table 15 - 1: Initial RPS Assumptions

	MT	OR	WA
Current qualifying resources (aMW/ yr)	**105**	**759**	**945**
Credits remaining at beginning of study	**69**	**3747**	**1229**
REC Expiration Time (Years)	**3**	**RECs do not expire**	**2**

Table 15 - 2: Percent of Sales required to be served by RPS Resources

Calendar Year	MT	OR	WA[2]
2015	**15.0%**	**15.0%**	**3.0%**
2016 to 2019	**15.0%**	**15.0%**	**9.0%**
2020 to 2024	**15.0%**	**20.0%**	**13.9%**
2025 to 2035	**15.0%**	**19.8%**[3]	**13.9%**

Table 15 - 3: Fraction of State Retail Sales Net of Conservation Obligated under RPS

	MT	OR	WA
2015 to 2024	**56%**	**71%**	**76%**
2025 to 2035	**56%**	**100%**	**76%**

Existing Resource Operating Costs

The operating costs of the system, such as fixed operations and maintenance (O&M), variable O&M and fuel costs, are part of the RPM's system cost estimation. Included in the operating costs for existing resources are any fixed O&M or variable O&M that are represent the incremental costs for complying with existing regulations. The fixed portions of these costs are incurred while the existing resources are still in operation and thus are included in the model until a plant retires. The variable costs are part of the dispatch of the system and are included in system costs when an existing resource is dispatched.

In addition to the operating cost of existing resources the RPM computation of average present value system cost includes the capital cost of investments required to satisfy environmental regulations. For utility owned generation, the capital costs for environmental compliance are typically recovered in rate revenues. As a result, they rarely alter the operating (i.e., dispatch) cost of resources. However, in order to ensure that known future regulatory compliance cost are considered, the RPM's estimate of each scenarios average system cost is adjusted to reflect such cost. This is done outside the RPM model.

For evaluation of operating costs, the existing natural gas resources are grouped by heat rate. The hydroelectric system is assumed to have a dispatch that varies based on water conditions as

[2] Numbers for Washington are based on anticipated renewable generation build which are one element of complying with the law that governs RPS; a cost cap of four percent of a utility's retail revenue requirement spent on the incremental cost of renewable energy and a cost cap of one percent if a utility experiences no load growth in a given year serve as alternative sources of compliance. While Oregon and Montana employ similar cost cap mechanisms, only Washington's target was modified to reflect the reality of utilities already running into the cost cap and therefore complying through alternative routes.

[3] In Oregon in 2025, small- and mid-size utilities are included in the requirement.

described in Chapter 11. Coal resources without an announced retirement date are grouped into a single dispatch block. Resources that do not dispatch to market prices, also called "must-run" resources are grouped into a single block. The largest of the must run resources is the Columbia Generating Station nuclear plant. These blocks are dispatched according to estimated market conditions in economic merit order (i.e., least cost first) when compared to any new resources that are available for dispatch within the same period.

TESTING RESOURCE STRATEGIES

Resource Strategy Definition

A resource strategy is a plan on how to acquire resources. It includes two decision points for a utility. When a utility planner needs to start planning for a resource and when a utility needs to start the construction of a resource. Because of uncertainty about the future, it makes sense to have circumstances where a utility would plan for a resource but choose not to construct it. Thus, each of these decisions must be treated distinctly.

A scenario is a different set of assumptions about future conditions. Scenarios can examine things such as the effect of enacting new legislation on the region's power system or the effect of market regime changes on the power system. Scenarios combined elements of the future that the region controls, such as the type, amount and timing of resource development, with factors the region does not control, such as natural gas and wholesale market electricity prices. Therefore, resource strategies reflect decisions that can be made by utilities, whereas scenarios reflect circumstances beyond the control of a utility. A resource strategy is considered *robust* if it exhibits both *low cost* and *low economic risk* across many different scenarios.

The Regional Portfolio Model

The Regional Portfolio Model (RPM) is used to estimate the system costs of a resource strategy under a given scenario. The RPM is described exhaustively in Appendix L. The RPM tests a wide range of resource strategies including the timing and amount of conservation developed, the timing and amount of demand response optioned and the timing and amount of thermal and renewable resources optioned across 800 potential futures. For each of the 800 potential futures examined, the RPM estimates capital costs for constructing new resources and operating costs of new and existing resources, as described in the previous section of this chapter. Each future then results in an estimate of the system costs.

One of the characteristics of a least-cost resource strategy in the RPM is that options for new generation and DR that are not built in at least one of the 800 futures are removed from testing. That is, it is assumed that the options are not established until there is at least some probability that they would be exercised. Therefore, least cost resource strategies identified in the RPM recommend that options be taken at specific times in the future. In all scenarios examined and for all resources considered, having open options at every opportunity (i.e. continuous optioning) is more expensive. This is primarily due to the fact that the longest lead time for generating resource construction assumed was 30 months, so the potential need for an option can be forecast with much more certainty than when resource construction lead times were 10 to 12 years. Maintaining these options strictly for crucial times should be a less costly approach for regional utilities to meet the needs of their system.

Resource strategies that minimize both cost and economic risk are considered optimal for a scenario. The RPM minimizes system cost by seeking resource strategies that reduce the average of the 800 future system cost estimates. The model minimizes system economic risk by seeking resource strategies that minimize the average of the 80 most expensive future system cost estimates. In this case "optimal" is limited to a comparison of the range of strategies tested by the RPM. Because of the complexity of the system cost calculation in the RPM, it is impossible to guarantee an optimal result without calculating every possible resource strategy. Modern computers are not yet powerful enough to complete this level of calculation in a reasonable amount of time. Instead some enhanced methods of searching through the resource strategies were used. Further discussion of this is found in Appendix L.

Uncertainty in System Costs

As described in the previous section, each resource strategy results in a distribution of system costs. These distributions highlight the fact that future system costs are unknown. Figure 15 – 5 illustrates the cost distributions for two different strategies and Figure 15 - 6 gives an example of the system cost distribution for several different scenarios, which will be detailed later in this chapter.

Figure 15 - 5: How to interpret distribution graphs

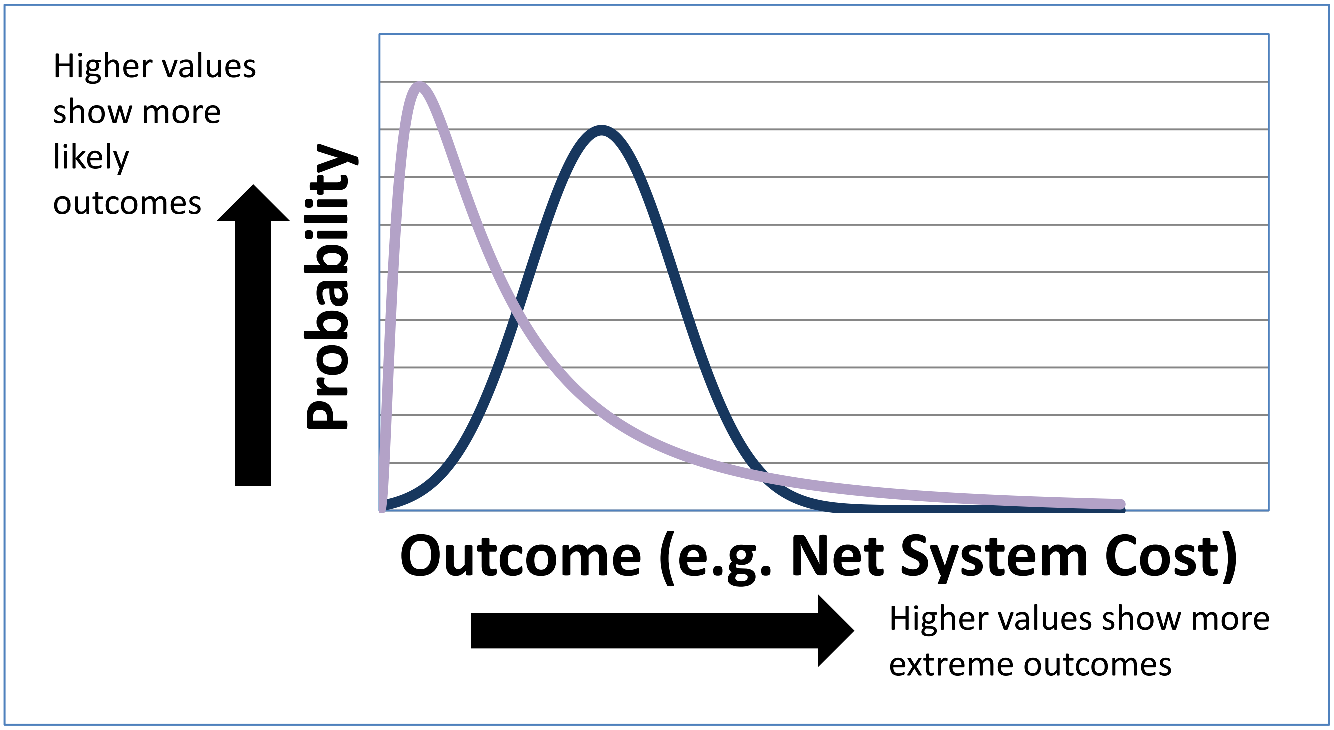
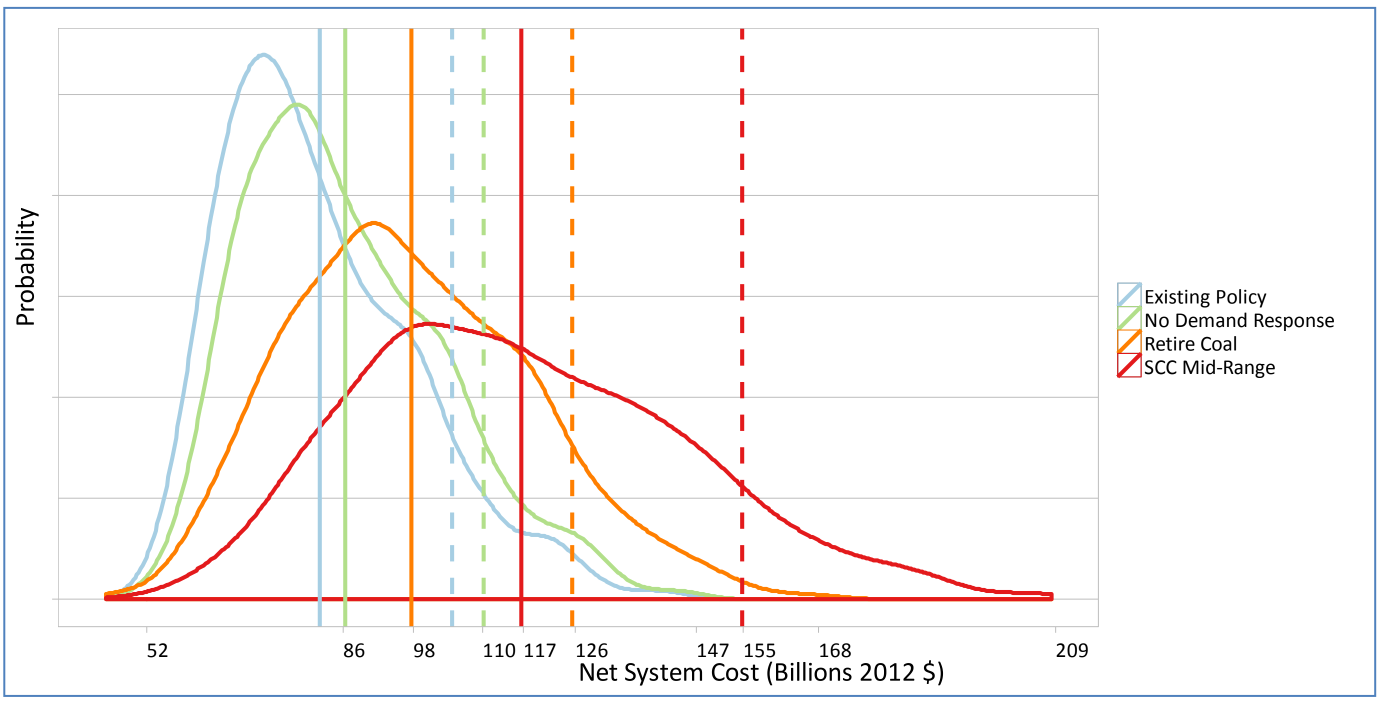


Figure 15 - 6: Distribution of System Costs Example, Including Carbon Revenue



When testing resource strategies, the uncertainty represented by the cost distribution associated with a scenario helps describe the impact of a scenario. How the impact is interpreted depends on the scenario. For example, in a scenario where low gas prices are assumed to persist throughout the study the power system costs are much lower than a scenario that assumes broader range of future gas prices. However, while the lower cost in this scenario would likely be a boon for the consumers of electricity, the least cost resource strategy for this scenario might be highly dependent upon future conditions that are outside of the control of the Northwest. In contrast, under a scenario which assumes retirements of generating resources, regional decision-makers can implement a least cost resource strategy that might include more conservation, options for demand response and construction of new thermal generators. Therefore, when there is uncertainty in future system cost it is important to understand the sources of that uncertainty and specifically whether options to mitigate that cost risk are within the control of the region. The resource strategy described in Chapter 3 was developed by considering these criteria.

Resource Strategy Adequacy

A detailed description of how the Council's resource adequacy standard is implemented in the Regional Portfolio Model is provided in Chapter 11. The RPM tests a resource strategy for adequacy by testing whether its resources meet a minimum build requirement for both energy and capacity adequacy standards. In the event that the strategy does not have sufficient resource to meet adequacy standards, a cost penalty is assessed. Further, if the deficiency in resources leads to a load curtailment during the dispatch of resources, a further cost penalty is assessed. When the RPM looks for an optimal (i.e., low cost, low economic risk) resource strategy, the cost penalty is part of that calculation. The cost penalty is set around $6 million per quarter in real 2012 dollars. This cost penalty is added to the system cost per peak megawatt or average megawatt for capacity and energy inadequacies. The amount of the cost penalty imposed was selected to make being inadequate more expensive than the development of any of the resource options for a single quarter. The penalty for load curtailment is $10,000 per megawatt-hour curtailed (2012$). A more detailed description of how resource adequacy is modeled in RPM appears in Appendix L.

When average system costs are reported they do not include the cost penalty. This is because the cost penalty is simply a mechanism used in the RPM to ensure sufficient resources are development to satisfy the regional adequacy standards, rather than an actual cost that must be recovered in utility revenue requirements.

In the Seventh Power Plan all least cost resource strategies must also provide similar levels of adequacy. As a result, the least-cost resource strategy identified by the RPM is often the same or very similar to the least-risk resource strategy. That is, because the resource adequacy cost penalties make it very expensive to pursue a high risk strategy, minimizing economic risk is not much different that minimizing cost. For all scenarios where optimization was run on minimizing cost and then on minimizing economic risk, no significant differences were present. In the Sixth Power Plan, there was extensive discussion about a trade-off between cost and economic risk in resource strategies. This is well-founded portfolio theory, which described the dynamics of the economics of the power system at that time. Currently, the RPM does not show significant trade-offs for strategies that meet adequacy criteria. However, future technologies or market conditions may change this dynamic. Part of analyzing resource strategies for future plans will be determining if there is significant difference between minimizing cost and minimizing risk and describing what factors drive the difference, if any.

DEVELOPING SCENARIOS

Testing resource strategies over many potential futures helps determine if those strategies are cost-effective including consideration of potential future economic risks. One concern in assessing these risks is that the estimated range of these risks does not have an appropriate assessment of the likelihood of a specific future condition occurring. While many of the methods have underlying models that assign a probability or likelihood to a potential future condition, developing scenarios helps test if resource strategies are robust under different future conditions. For a more detailed description of the underlying likelihood models or distributional assumptions used in developing the futures see Appendix L. The rationale for selecting the scenarios tested in the development of the Seventh Power Plan and general description of these scenarios appears in Chapter 3. This section describes how these scenarios were characterized in the RPM.

Scenarios Added or Updated Based on Public Comment[4]

Existing Policy

In this scenario, the price associated with CO2 emissions was set to zero. This scenario tested resource strategies that have no consideration for CO2 emission cost or risk. However, it does reflect the impact of existing state laws and regulations. For example, due to existing state regulations in Oregon, Washington and Montana that limit CO2 emissions from new power generation facilities, new coal plants were not considered for development in the Seventh Power Plan. State Renewable Portfolio Standards were also reflected in this scenario. This scenario did not explicitly consider the Environmental Protection Agency's limits on CO2 emissions from new and existing power generation. All other uncertainties (e.g., gas and electricity market prices, load growth) were included.

This scenario was updated to include seasonal requirements for adequacy and a system-based capacity contribution for additional resources. It was also updated to reflect revisions to the natural gas price and external market price. Additional resource options were also included for renewable resources, including a geothermal option. A few other smaller data changes were included, for example, a revision in the Renewable Portfolio Standards (RPS) to base the requirements on retail sales rather than "loads" which include transmission line losses.

[4]The Council evaluated over 20 scenarios in the development of the draft Seventh Power Plan. This section describes those that were updated or added based on public comment on the draft plan. The results of the scenarios and sensitivity studies tested for the draft plan that were not updated are detailed in the following section "Additional Scenarios Evaluated for the Draft Plan."

Maximum Carbon Reduction - Existing Technology

This scenario was modeled by retiring all existing coal plants serving regional load by 2026 and retiring all existing natural gas plants serving regional load with heat rates greater than 8,500 Btu/kWh by 2031. Only the first six blocks of conservation resources described in Chapter 12 were available for development. The levelized cost of utility scale solar PV resources was assumed to decline by 19 percent by 2030. This scenario was updated consistent with the **Existing Policy** scenario and was run to allow comparison with scenarios that were added based on comments.

Regional 35 Percent RPS

This scenario involves applying the RPS requirements to all regional retail sales and increasing that requirement to 35 percent by 2027. This was ramped in for both the percentage of retail sales (net of conservation) to which it applied and the level of RPS. Table 15 - 4 shows the RPS requirement assumptions by state and Table 15 - 5 shows the percentage of retail sales in each of the four states to which the RPS was applied. Both of these were designed to reach the full RPS requirements by 2027 so the two-year rolling average of CO_2 emissions in 2030 would reflect the full RPS achievement. The annual requirements only reflect potential incremental changes to get from current RPS requirements to the 35 percent renewable generation for 100 percent of the retail sales in each state. This scenario was updated consistent with the **Existing Policy** scenario and was run to allow comparison with scenarios that were added based on comments.

Table 15 - 4: RPS Requirement Scenario Assumptions

Simulation CY	MT	OR	WA	ID
2015	**15%**	**15%**	**3%**	**0%**
2016	**17%**	**17%**	**9%**	**3%**
2017	**18%**	**18%**	**11%**	**6%**
2018	**20%**	**20%**	**14%**	**9%**
2019	**22%**	**22%**	**16%**	**12%**
2020	**23%**	**23%**	**18%**	**15%**
2021	**25%**	**25%**	**21%**	**18%**
2022	**27%**	**27%**	**23%**	**20%**
2023	**28%**	**28%**	**26%**	**23%**
2024	**30%**	**30%**	**28%**	**26%**
2025	**32%**	**32%**	**30%**	**29%**
2026	**33%**	**33%**	**33%**	**32%**
2027 to 2035	**35%**	**35%**	**35%**	**35%**

Table 15 - 5: Percent of Obligated Sales Assumptions

Simulation CY	MT	OR	WA	ID
2015	**56%**	**71%**	**76%**	**0%**
2016	**60%**	**73%**	**78%**	**8%**
2017	**63%**	**76%**	**80%**	**17%**
2018	**67%**	**78%**	**82%**	**25%**
2019	**71%**	**81%**	**84%**	**33%**
2020	**74%**	**83%**	**86%**	**42%**
2021	**78%**	**86%**	**88%**	**50%**
2022	**82%**	**88%**	**90%**	**58%**
2023	**85%**	**90%**	**92%**	**67%**
2024	**89%**	**93%**	**94%**	**75%**
2025	**93%**	**95%**	**96%**	**83%**
2026	**96%**	**98%**	**98%**	**92%**
2027 to 2035	**100%**	**100%**	**100%**	**100%**

No Demand Response - No Carbon Cost

For this scenario, the resource strategies were restricted so that they could not select demand response resources as options. For a description of the optioning logic in the RPM see the earlier section in this chapter on estimating the cost of new generating resources and demand response. This scenario was updated consistent with the **Existing Policy** scenario to examine the impacts of seasonal adequacy requirements and existing resource capacity revisions.

Lower Conservation - No Carbon Cost

In this scenario, the resource strategy was limited so that conservation could only be purchased if its cost was anticipated to be at or below short-run market prices. These same restrictions were not applied to other resources. This scenario is useful in examining the cost of this conservation purchasing scheme compared to developing conservation at a level that minimizes future power system costs where it is purchased on an equivalent basis to other resources. This scenario was updated consistent with the **Existing Policy** scenario.

Increased Reliance on External Markets

One of the RPM’s input assumptions is the maximum level of reliance on out-of-region markets permitted to meet regional adequacy standards. In this scenario, this assumption was relaxed, i.e., reliance on out-of-region markets was increased. To implement this, the GENESYS model was run to determine the Adequacy Reserve Margins (ARM) under the assumption that maximum market reliance is 3,400 MW during high load hours in the winter instead of 2500 MW during high load hours in the winter and 900 MW during high load hours in the summer instead of 0 MW during high load hours in the summer currently used in the Resource Adequacy Assessment.[5] Since the ARM is a “reserve margin” over in-region utility controlled resources, the assumption of greater external market reliance lowers the ARM requirements. The ARM values were recalculated with a higher expectation of import availability. The result of this is that fewer in-region resources are required to be built for capacity. This scenario was updated consistent with the **Existing Policy** scenario and the ARM changes were based on seasonal adequacy requirements.

Social Cost of Carbon - Mid-Range

This scenarios assumed that alternate values of the federal government’s estimates[6] for damage caused to society by climate change resulting from carbon dioxide emissions, referred to as the Social Cost of Carbon, are imposed across the entire western power market beginning in 2016. The mid-range scenario used the average cost estimated with a 3 percent discount rate. Values for this scenario are given in Table 15 - 6.

By internalizing carbon costs, this analysis identifies strategies that minimize all costs, including carbon. The RPM reduces carbon emissions when they can be avoided at the social cost of carbon or less. The policy basis for these scenarios is that the cost of resource strategies developed under conditions which fully internalized the damage cost from carbon emissions would be the maximum society should invest to avoid such damage.

This scenario was updated consistent with the **Existing Policy** scenario.

[5] The basis of and methodology used to develop the Adequacy Reserve Margins are described in Chapter 11.
[6] Estimated cost of the damage of carbon emissions by the Interagency Working Group on Social Cost of Carbon

Table 15 - 6: Mid-Range Estimate of the Social Cost of Carbon Assumptions (2012$/Metric Ton of CO_2)

Fiscal Year	Mid-Range
FY16	$40.99
FY17	$42.07
FY18	$43.15
FY19	$45.31
FY20	$46.39
FY21	$46.39
FY22	$47.47
FY23	$48.54
FY24	$49.62
FY25	$50.70
FY26	$51.78
FY27	$52.86
FY28	$53.94
FY29	$55.02
FY30	$56.10
FY31	$56.10
FY32	$57.17
FY33	$58.25
FY34	$59.33
FY35	$60.41

Coal Retirement - No Carbon Cost

This scenario is the same as the **Maximum Carbon Reduction - Existing Technology** scenario except existing natural gas plants with heat rates higher than 8,500 Btu/kWh were not retired.

Coal Retirement - Social Cost of Carbon

This scenario examined the implications of both the retirement of all existing coal plants as in the **Coal Retirement - No Carbon Cost** scenario and also included the internalized cost of carbon included in the **Social Cost of Carbon - Mid-Range** scenario.

Coal Retirement - No New Thermal Builds

This scenario is the same as the **Coal Retirement - Social Cost of Carbon** scenario except the option for constructing new natural-gas-fired resources was removed and both lower cost and greater availability were assumed for distributed and utility scale solar PV resources. Because this scenario's resource strategy relies only on existing technology, it did not achieve a level of reliability similar to the other scenarios tested. Therefore, this scenario's results should be considered directional in nature when making comparisons.

Additional Scenarios Evaluated for the Draft Plan

Maximum Carbon Reduction - Emerging Technology

This scenario was modeled by retiring all existing coal plants serving regional load by 2026 and retiring all existing natural gas plants serving regional load with heat rates greater than 8,500 Btu/kWh by 2031. However, unlike the **Maximum Carbon Reduction – Existing Technology** scenario, no new natural gas-fired generation was available for development. All seven blocks of conservation resources, plus 1100 average megawatts of emerging energy efficiency technologies were made available for development. In addition, distributed solar PV technology in both the residential and commercial sectors was considered for development. Although costs were not considered in this scenario, the levelized cost of utility scale solar PV were assumed to decline by 28 percent by 2030. This assumption increased the maximum availability of this resource. The emerging generating technologies considered are described in Chapter 11 and the emerging energy efficiency technologies considered are described in Chapter 12.

Low Fuel and Market Prices - No Carbon Cost

This scenario explores the implications of extremely low natural gas prices and the corresponding impacts on other fuel and electricity prices. This includes a reduction in coal prices, for example the price for coal in Montana start around $0.03 less per MMBTU in this scenario and by 2035 are around $0.17 less in real 2012 dollars. The range of natural gas prices is based on re-centering the prices around the low forecast range as described in Chapter 8. The resulting range of natural gas prices can be seen in Figure 15 - 7. The electricity prices used in examining the resource strategies under this scenario are then centered around an electricity price forecast based on this low natural gas price forecast and the resulting range of electricity prices for importing or exporting power generation can be seen in Figure 15 - 8.

Figure 15 - 7: Range of Natural Gas Prices

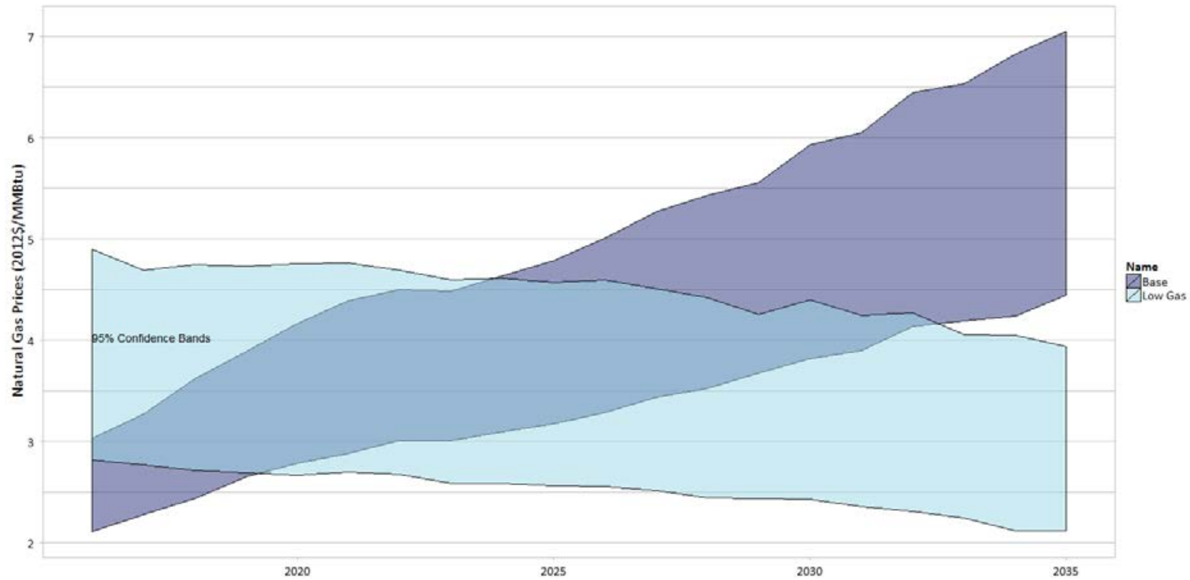
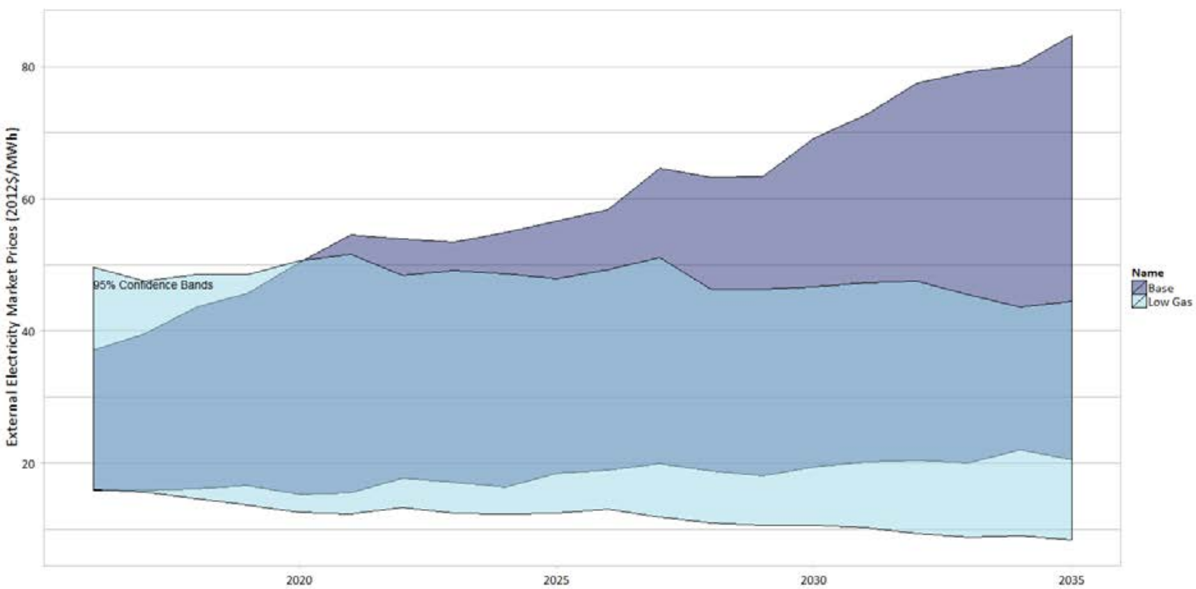


Figure 15 - 8: Range of Electricity Prices



No Coal Retirement

In this scenario, the announced retirements of the Boardman, Centralia and North Valmy resources were not assumed. This was used to determine the impacts of these retirements on the resource strategy and on regional carbon dioxide emissions.

Social Cost of Carbon - High-Range

This scenario assumed that alternate values of the federal government's estimates[7] for damage caused to society by climate change resulting from carbon dioxide emissions, referred to as the Social Cost of Carbon, are imposed beginning in 2016. The high-range scenario used an estimate of possible damage cost that should not occur more than 5 percent of the time. Values for these scenarios are given in Table 15 - 7.

Table 15 - 7: High Estimate of the Social Cost of Carbon Assumptions

(2012$/Metric Ton of CO2)

Fiscal Year	High-Range
FY16	$121.00
FY17	$125.00
FY18	$129.00
FY19	$134.00
FY20	$138.00
FY21	$141.00
FY22	$145.00
FY23	$148.00
FY24	$151.00
FY25	$154.00
FY26	$158.00
FY27	$161.00
FY28	$164.00
FY29	$167.00
FY30	$172.00
FY31	$175.00
FY32	$178.00
FY33	$181.00
FY34	$186.00
FY35	$189.00

Carbon Cost Risk

In this scenario, the price associated with CO2 per metric ton was modeled as a regulatory risk. The range of the potential carbon price was fixed between $0 and $110 in real 2012 dollars. The price can be applied starting from 2015 through 2035. Uncertainty about the starting date of the potential CO2 price makes this pricing scheme more consistent with an explicit price for CO2. This scenario was consistent with the CO2 risk scenario analyzed in the Sixth Power Plan and allows for some comparison between plans. More detail on the CO2 risk model is included in Appendix L.

[7] Estimated cost of the damage of carbon emissions by the Interagency Working Group on Social Cost of Carbon

Resource Uncertainty – Planned and Unplanned Loss of a Major Resource

Two scenarios were run to examine the impacts of resource uncertainty. In the first scenario non-CO2 emitting resources were retired in 2016, 2019, 2022 and 2025 for a combined total of about 1,000 megawatts nameplate. The other scenario involved a single similarly sized non-CO2 emitting resource, which was randomly shut down or retired sometime between 2016 and 2035. This was done using a uniform probability of retirement during each quarter.

Faster and Slower Conservation Deployment

These scenarios involved changing the input assumptions for maximum achievable conservation per year. Chapter 12 discusses the development of the input assumptions for faster and slower ramping of conservation programs. For a more detailed description of how the maximum available conservation per year, the percent of that conservation that can be achieved by program year and the maximum conservation that can be achieved over the 20-year study period were modeled see Appendix L.

No Demand Response – Carbon Cost

This scenario is the same as the **No Demand Response - No Carbon Cost** scenario except that it includes the carbon prices from the **Social Cost of Carbon - Mid-Range** scenario.

Low Fuel and Market Prices – Carbon Cost

This scenario is the same as the **Low Fuel and Market Prices - No Carbon Cost** scenario except that it includes the carbon prices from the **Social Cost of Carbon - Mid-Range** scenario.

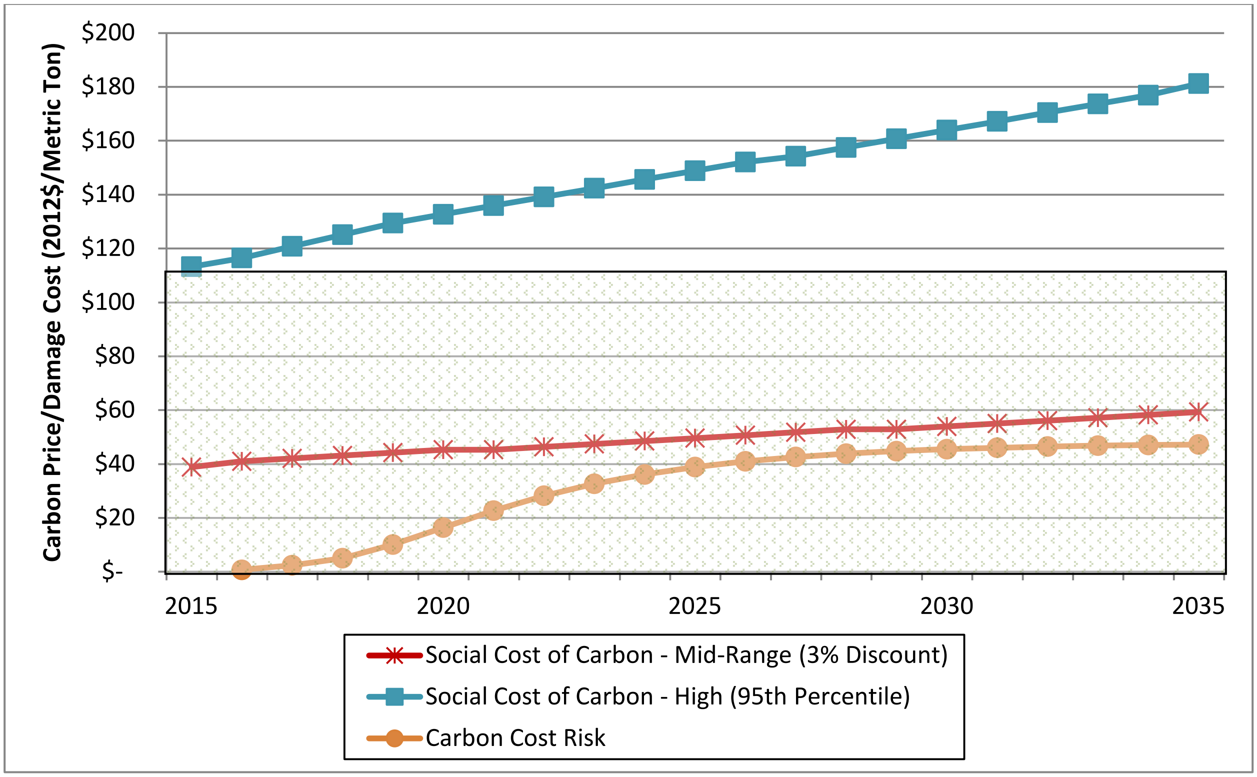
EXAMINING RESULTS

Carbon Emissions

As in the Sixth Power Plan, one of the key issues identified for the Seventh Power Plan is climate-change policy and the potential effects of proposed carbon dioxide emissions regulations. In addition, the Council was asked to address what changes would be needed to the power system to reach a specific carbon reduction goal and what those changes would cost. This section summarizes how alternative resource strategies compare with respect to their cost and ability to meet carbon dioxide emissions limits established by the Environmental Protection Agency. In providing analysis of carbon emissions and the specific cost of attaining carbon emission limits, the Council is not taking a position on future climate-change policy. Nor is the Council taking a position on how individual Northwest states or the region should comply with EPA's carbon dioxide emission regulations. The Council's analysis is intended to provide useful information to policy-makers.

Figure 15 - 9 shows the two U.S. Government Interagency Working Group's estimates used for the two **Social Cost of Carbon** scenarios and the range (shaded area) and average carbon prices across all futures that were evaluated in the $0-to-$110-per-metric ton **Carbon Risk** scenario.

Figure 15 - 9: Carbon Regulatory Cost or Price and Societal Cost of Carbon Tested in Scenario Analysis



In order to compare the cost of resource strategies that reflect both “carbon-pricing” and “non-carbon pricing” policy options for reducing carbon dioxide emissions, it is useful to separate a strategy’s cost into two components. The first is the direct cost of the resource strategy. That is, the actual the cost of building and operating a resource strategy that reduces carbon dioxide emissions. The second component of any strategy is the revenue collected through the imposition of carbon taxes or pricing carbon damage cost into resource development decisions. This second cost component, either in whole or in part, may or may not be paid directly by electricity consumers. For example, the “social cost of carbon” represents the estimated economic damage of carbon dioxide emissions worldwide. In contrast to the direct cost of a resource strategy which will directly affect the cost of electricity, these “damage costs” are borne by all of society, not just Northwest electricity consumers.

In the discussion that follows, the direct cost of resource strategies are reported separately from the carbon dioxide revenues associated with that strategy. Carbon prices or estimated damage costs are only included in the three scenarios describe earlier in this chapter that include the social cost of carbon. Therefore, comparing the cost and emissions from these scenarios to those without carbon cost imposed can provide insights into the impact of alternative policy options for reducing carbon emissions.

Figure 15 - 10 shows the resource strategy direct average system costs from scenarios and sensitivity studies conducted to specifically evaluate carbon emissions reduction policies (and economic risks) for the development of the Seventh Power Plan. This figure shows the average net present value system cost (bars) for the least cost resource strategy for each scenario, both with carbon revenues included for scenarios where carbon pricing was included in the resource

decisions. Figure 15 - 11 shows the average carbon emissions projected for the generation that serves the region in 2035.

Figure 15 - 10: Average System Costs

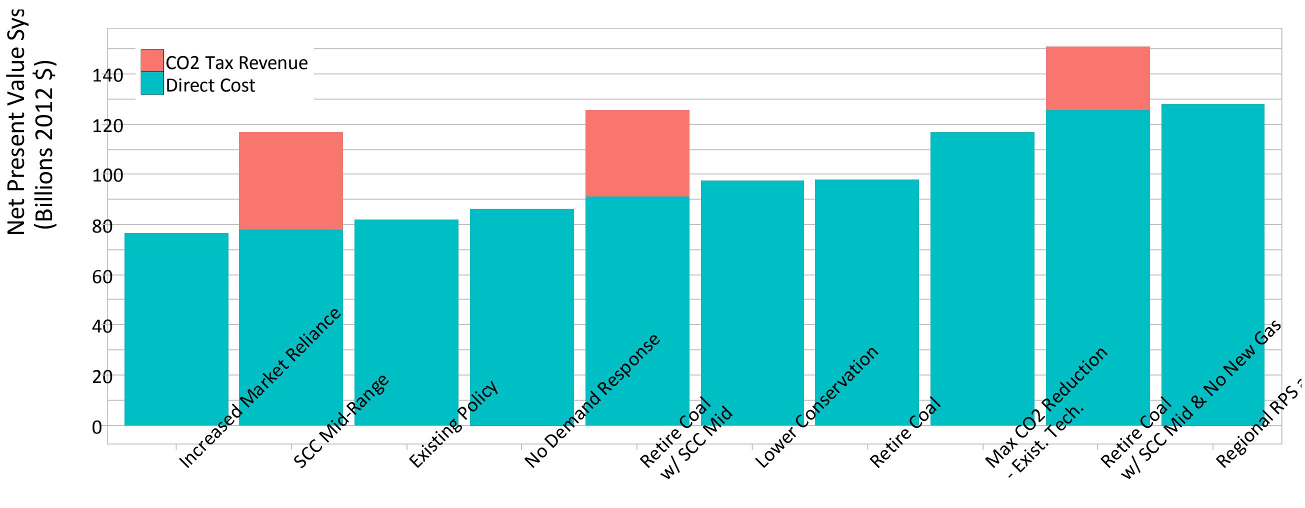


Figure 15 - 11: PNW Power System Carbon Emissions by Scenario in 2035

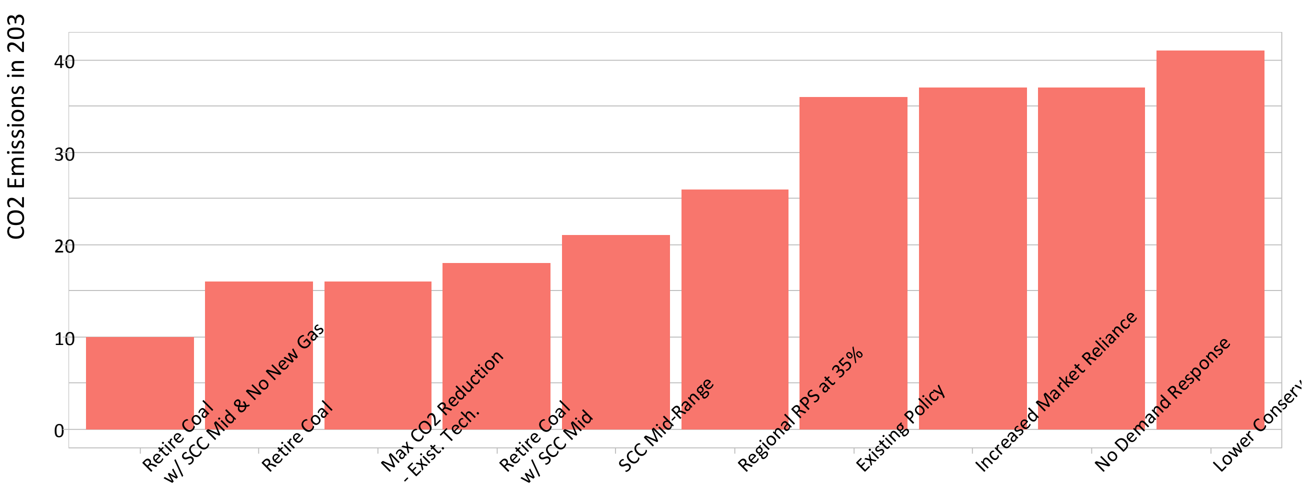


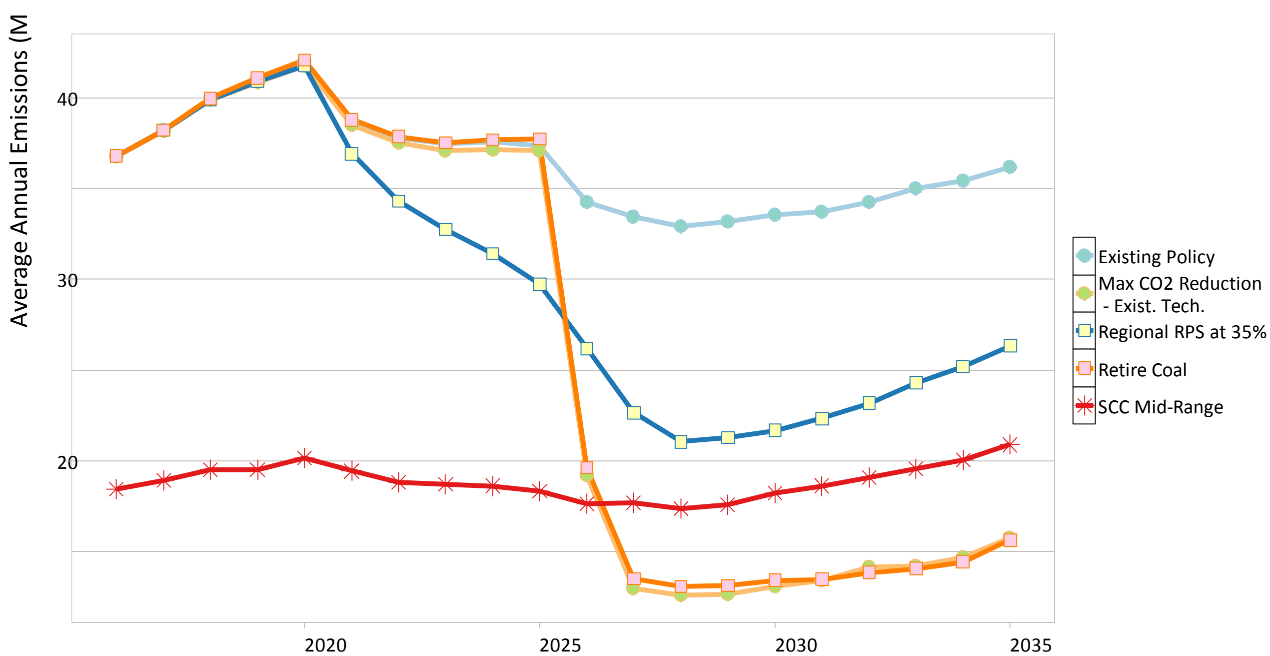
Figure 15 - 11 shows the **Existing Policy** scenario results in carbon emissions in 2035 of 36 million metric tons. This scenario assumed no additional policies to reduce carbon emissions beyond currently announced coal plant retirements are pursued. The average present value system cost of this resource strategy is $83 billion (2012$).

The **Social Cost of Carbon – Mid-Range** (SCC-Mid-Range) scenario reduce carbon emissions to about 21 million metric tons in 2035. Under the **Maximum Carbon Reduction – Existing Technology** scenario, 2035 carbon emissions are reduced to 16 million metric tons and average system cost is are approximately $34 billion over the **Existing Policy** scenario. The large increase in average system cost for this scenario over the **Existing Policy** case results from the replacement of all of the region's existing coal and inefficient natural gas fleet with new, more efficient natural gas-fired combustion turbines.

The **Regional RPS at 35%** scenario reduces 2035 carbon emissions to just over 26 million metric tons. This is a reduction of around 10 million metric tons per year compared to the **Existing Policy** scenario. The direct cost of this resource strategy is approximately $129 billion or $46 billion more than the **Existing Policy** scenario.

Comparing the results of these scenarios based on a single year's emissions can be misleading. Each of these policies alters the resource selection and regional power system operation over the course of the entire study period. Figure 15 - 12 shows the annual emissions level for each scenario. A review of Figure 15 - 12 reveals that the scenarios that include the social cost of carbon, which assume carbon dioxide damage costs are imposed in 2016, immediately reduce carbon dioxide emissions and therefore have impacts throughout the entire twenty year period covered by the Seventh Power Plan. In contrast, the other three carbon dioxide reduction policies phase in over time, so there cumulative impacts are generally smaller.

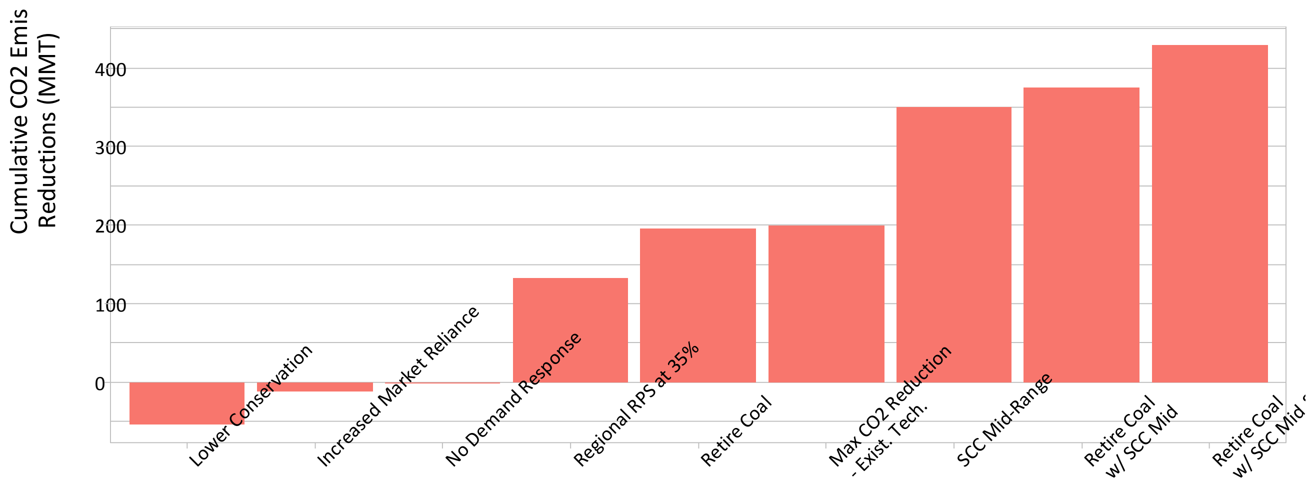
Figure 15 - 12: Average Annual Carbon Emissions by Carbon Reduction Policy Scenario



The **Regional RPS at 35%** scenarios gradually reduce emissions, while the **Maximum Carbon Reduction** scenario dramatically reduces emission as existing coal and inefficient gas plants are retired post-2025. The difference in timing results in large differences in the cumulative carbon emissions reductions for these policies. All scenarios show gradually increasing emissions beginning around 2028 as the amount of annual conservation development slows due to the completion of cost-effective and achievable retrofits. This lower level of conservation no longer offsets regional load growth, leading to the increased use of CO2 emitting generation.

Figure 15 - 13 shows the cumulative reduction in carbon emissions from 2016 through 2035 for the carbon reduction policy scenarios compared to the **Existing Policy** scenario.

Figure 15 - 13: Cumulative 2016 to 2035 Carbon Emissions Reductions for Carbon Policy Scenarios



A comparison of Figure 15 - 12 with Figure 15 - 13 shows that the policy options that produce the lowest emission rate in 2035 do not necessarily result in the largest cumulative emissions reductions over the planning period. For example, the **Social Cost of Carbon** scenario results in higher emission levels *in* 2035 than the **Maximum Carbon Reduction – Existing Technology** scenario. However, the **Social Cost of Carbon** scenario produces much larger cumulative reductions over the entire planning period.

The differences in cumulative emissions across these policy options are largely an artifact of the scenario modeling assumptions, which assumes immediate imposition of the social cost of carbon. It is unlikely that such large carbon damage cost would or could be imposed in a single step without serious economic disruption. Therefore, the cumulative carbon emission reductions from the implementation of a carbon pricing policy which phases in carbon cost over time are likely more representative of the actual impacts of imposing a carbon price based on the social cost of carbon.

Table 15 - 7 shows cumulative emissions reduction in carbon from the **Existing Policy** for the six carbon reduction policy options. This table also shows the total difference in incremental present value system cost and present value system cost per metric ton of carbon dioxide emission reduction. All cost are net of carbon revenues. As can be seen from Figure 15 - 12, the **Retire Coal w/SCC MidRange & No New Gas** scenario has the lowest average annual carbon emissions from the regional power system in 2035, but as shown in Table 15-7 this resource strategy also has a

significantly higher total average system cost ($34 billion) and cost per unit of carbon dioxide reduction ($170/metric ton).

It should be noted that the direct cost of the resource strategies shown for the three carbon-pricing policies are likely understated. This is because all of three scenarios, but especially the social cost of carbon scenarios, result in immediate and significant reductions in the dispatch of the region's existing coal-fired generation in the model. In practice, at such reduced levels of dispatch, most or all of these plants would likely be retired as uneconomic. As a result, the actual direct cost of carbon reduction under these scenarios would probably be closer to the **Retire Coal** scenario.

Table 15 - 7: Average Cumulative Emissions Reductions and Present Value Cost of Alternative Carbon Emissions Reduction Policies without Carbon Damage Compared to Existing Policy Scenario

Scenarios	Cumulative Emission Reduction Over Existing Policy Scenario (MMT)	Incremental Average System Cost Net of Carbon Revenues Over Existing Policy Scenario (billion 2012$)	Present Value Average Cost/Metric of Carbon Emissions Reduction (2012$/Metric Ton)
SCC - MidRange	351	$ (3.9)	$ (11)
Retire Coal w/SCC MidRange	377	$ 8.9	$ 23
Retire Coal	197	$ 15.4	$ 78
Retire Coal w/SCC MidRange & No New Gas	430	$ 43.2	$ 100
Max. CO2 Reduction - Exist. Tech.	201	$ 34.2	$ 170
Regional RPS at 35%	132	$ 46.0	$ 349

Table 15 - 7 also shows that the **SCC - MidRange** scenario has a negative incremental present value system of carbon reduction compared to the **Existing Policy** scenario. This lower cost results from increased revenue from exports outside the region. This occurs, because in all scenarios where a carbon cost was assumed, it was imposed across the entire western power market. Because the region has a competitive advantage with respect to the average carbon emissions per unit of electricity, the imposition of carbon taxes across the western market results in higher regional exports. To isolate the marginal impact of other carbon emissions reduction policies requires that this scenario be used as the "baseline."

Table 15 - 8 compares shows the incremental carbon dioxide emissions reductions and present value system cost per metric ton of carbon reduction compared of the two coal retirement scenarios which also assume the imposition of the mid-range estimate for the social cost of carbon. Table 15 - 8 shows that retiring the region's coal plants and replacing them with either natural gas or renewable resources have incremental cost per metric ton of carbon emissions reductions in the $500 to $600 range. These relatively high costs result from the fact that the imposition of the social cost of carbon in the "baseline" scenario already significantly reduces the economic dispatch of existing coal

resources. Therefore, these plants' contribution to regional carbon emissions at the time of their assumed retirement (2025) is quite small.

Table 15 - 8: Average Cumulative Emissions Reductions and Present Value Cost of Alternative Carbon Emissions Reduction Policies without Carbon Damage Compared to Social Cost of Carbon - Mid-Range Scenario

Final Plan Scenarios	Cumulative Emission Reduction Over Existing Policy Scenario (MMT)	Cumulative Emission Reduction Over SCC-MidRange Scenario (MMT)	Incremental Average System Cost Net of Carbon Revenues Over SCC-MidRange Scenario (billion 2012$)	Present Value Average Cost/Metric of Carbon Emissions Reduction Over SCC-MidRange (2012$/Metric Ton)
SCC - MidRange	351	-	-	-
Retire Coal w/SCC_MidRange	377	26	$ 12.7	$ 488
Retire Coal w/SCC_MidRange & No New Gas	430	79	$ 47.0	$ 598

Maximum Carbon Reduction – Emerging Technology

In the preceding discussion the lower bound on regional power system carbon dioxide emissions was limited by existing technology. Under that constraint, the annual carbon dioxide emissions from the regional power system could be reduced from an average of 54 million metric tons per year today to approximately 16 million metric tons in 2035.[8] If limits are placed on the type of existing technology that can be developed, as was assumed in the **Retire Coal w/SCC MidRange & No New Gas** scenario, then emissions can be reduce still further to 10 million metric tons. While this represents nearly an 80 percent reduction in emissions[9], it does not eliminate power system carbon dioxide emissions entirely. In order to achieve that policy goal, new and emerging technology must be developed and deployed.

To assess the magnitude of potential additional carbon dioxide emission reductions that might be feasible by 2035, the Council created a resource strategy based on energy efficiency resources and non-carbon dioxide emitting generating resource alternatives that might become commercially viable

[8] Average regional power system carbon dioxide emissions from 2000 – 2014 were approximately 54 million metric tons.

[9] The change in the natural gas price forecast between draft and final scenarios resulted in more natural gas fired generation dispatch in the final scenarios and thus higher regional emissions under the **Maximum Carbon Reduction - Existing Technology** scenario when compared to the draft scenario of the same name. When balanced with increased exports, while this scenario shows more emissions in the region, the WECC-wide emissions would likely be lower based on the revised natural gas price forecast. Comparison of numbers between the draft and final scenarios requires careful consideration of all the model revisions.

over the next 20 years. While the Regional Portfolio Model (RPM) was used to develop the amount, timing and mix of resources in this resource strategy, no economic constraints were taken into account. That is, the RPM was simply used create a mix of resources that could meet forecast energy and capacity needs, but it made no attempt to minimize the cost to do so. The reason the RPM's economic optimization logic was not used is that the future cost and resource characteristics of many of the emerging technologies included in this scenario are highly speculative.

Tables 15 - 9 and 15 - 10 summarize the potential resource size and cost of energy efficiency and generating resource emerging technologies considered in this scenario that were modeled in the RPM. A review of Table 15 - 9 shows that an additional 650 average megawatts of emerging energy efficiency technology could be deployed by 2025. If this technology were cost-effective to acquire, it could reduce winter peak demands in that year by 1,350 megawatts. Five years later, by 2030, potential annual energy savings could reach 1,125 average megawatts and reduce winter peak demands by 2,350 megawatts. Only about one-third of these potential savings is currently forecast to cost less than $30 per megawatt-hour and the remaining two-thirds of the potential savings is anticipated to cost more than $80 per megawatt-hour. See Chapter 12 and Appendix G for a more detailed discussion of these emerging energy efficiency technologies.

The regional potential of both utility scale and especially distributed solar PV resources, as shown in Table 15 - 10, is quite large. Assuming significant cost reductions in utility scale solar PV system installations by 2030, the levelized cost of power produced from such systems could be around $50 per megawatt-hour. However, while both utility scale and distributed solar PV systems can significantly contribute to meeting summer peak requirements, they provide less winter peak savings. In the near term, this limits their applicability to the region's needs. However, since the region's summer peak demands are forecast to grow more rapidly than winter peak demands, the system peak benefits of these systems are expected to increase over time. See Chapter 11 and Appendix H for a more detailed discussion of these emerging technologies.

Table 15 - 9: Energy Efficiency Emerging Technologies Modeled in the RPM in the Maximum Carbon Reduction – Emerging Technology Scenario

Emerging Technology	Regional Potential - 2025			Regional Potential - 2030		
	Energy (aMW)	Winter Peak Capacity (MW)	TRC Net Levelized Cost (2012$ /MWh)	Energy (aMW)	Winter Peak Capacity (MW)	TRC Net Levelized Cost (2012$ /MWh)
Additional Advances in Solid-State Lighting	200	400	$0-$30	400	800	$0-$30
CO_2 Heat Pump Water Heater	110	200	$100-150	160	300	$90-140
CO_2 Heat Pump Space Heating	50	160	$130-170	130	350	$110-160
Highly Insulated Dynamic Windows - Commercial	20	130	$500+	35	200	300
Highly Insulated Dynamic Windows - Residential	80	230	$500+	120	350	400
HVAC Controls – Optimized Controls	140	230	$90-120	200	350	$80-110
Evaporative Cooling	50	0*	$100-130	80	0*	$90-120
Total	650	1,350	N/A	1,125	2,350	N/A

Table 15 - 10: Non-Carbon Dioxide Emitting Generating Emerging Technologies Modeled in the RPM in the Maximum Carbon Reduction – Emerging Technology Scenario

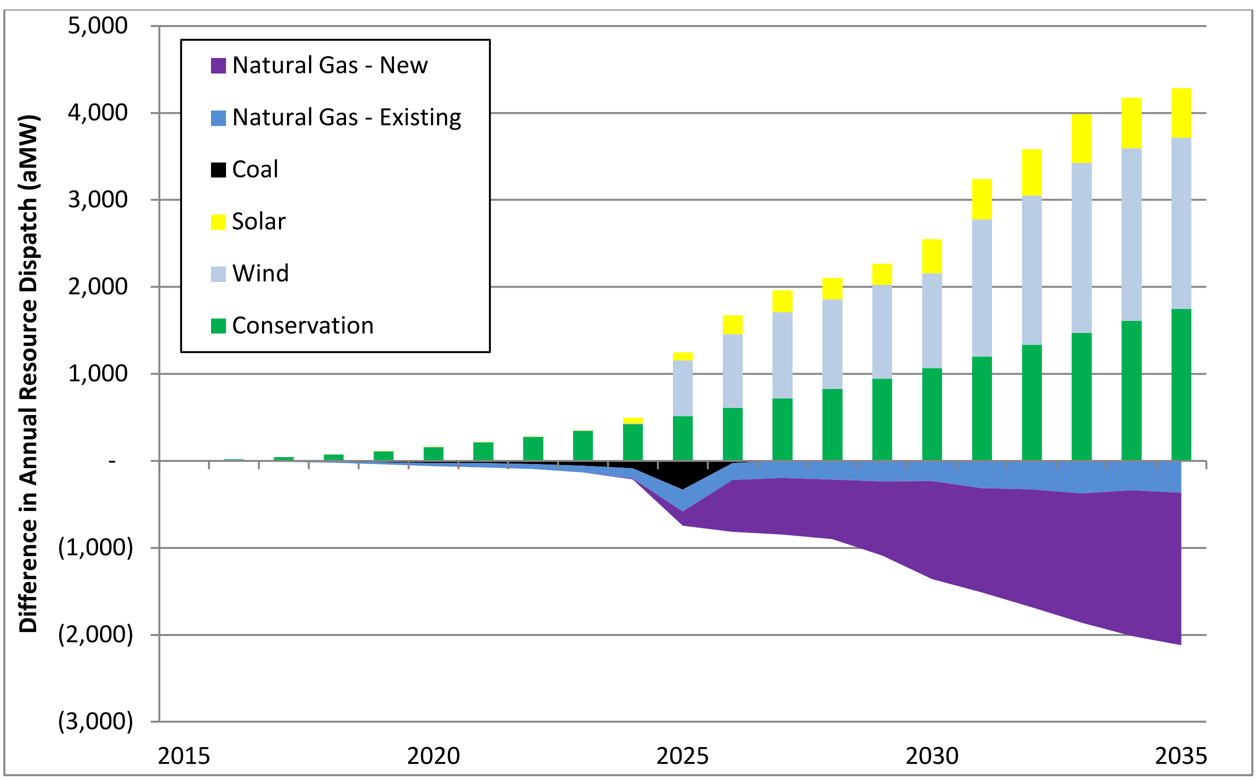
	Utility Scale 48 MW Solar PV Plant Low Cost – Southern Idaho				**Utility Scale 48 MW Solar PV Plant Low Cost – Kelso WA**				**Distributed Solar (Residential and Commercial Sectors)**			
	Potential regional installed capacity = 624 MW				Potential regional installed capacity = 2,544 MW				Potential regional installed capacity = 28,100 MW			
Year	Energy (aMW)	Winter Peak (MW)	Summer Peak (MW)	Real Levelized Cost (2012$ /MWh)	Energy (aMW)	Winter Peak (MW)	Summer Peak (MW)	Real Levelized Cost (2012$ /MWh)	Energy (aMW)	Winter Peak (MW)	Summer Peak (MW)	Real Levelized Cost (2012$ /MWh)*
2020	12	-	24	$61	9	-	24	$80	340	2	700	$180
2025	12	-	24	$58	9	-	24	$75	1350	6	2800	$170
2030	12	-	24	$51	9	-	24	$66	2880	13	6000	$150
2035	12	-	24	$51	9	-	24	$66	4000	18	8300	$150
*High penetration of distributed solar resources will likely require additional integration cost and distribution system upgrades												

The difference in annual resource dispatch over time between the **Maximum Carbon Reduction – Emerging Technology** scenario and **the Maximum Carbon Reduction – Existing Technology** scenario is shown in Figure 15 -14. As can be observed from Figure 15 - 14 the primary differences is the increased amount of energy efficiency and renewable resources developed (shown by the bars above the origin on the vertical axis) under the emerging technology scenario and less reliance on both existing and new gas-fired generation (shown by the wedges below the origin on the vertical axis). It should be emphasized that under the emerging technology scenario this tradeoff between new natural gas generation and emerging conservation and renewable resource development *is not* based on economics. Rather, their development occurs because new natural gas-fired generation was specifically excluded from consideration under the emerging technology scenario.

Figure 15 - 14 shows that under the **Maximum Carbon Reduction – Emerging Technology** scenario just over 2,000 average megawatts of gas-fired generation must be displaced by approximately 2,500 average megawatts of renewable resources and 1,750 average megawatts of additional energy efficiency. The large difference in the amount of natural gas resources displaced versus the amount of conservation and renewable resources added reflects the limited contribution to supplying winter peak demands provided by solar PV and wind resources.

In order to lower the cost of achieving the carbon emissions reductions in the **Maximum Carbon Reduction - Emerging Technology** scenario and/or to further reduce the power system's carbon emissions requires the development of non-greenhouse gas emitting technologies that can provide both annual energy and winter peak capacity.

Figure 15 - 14: Difference in Annual Resource Dispatch Between Maximum Carbon Reduction – Existing Technology Scenario and Maximum Carbon Reduction – Emerging Technology Scenario



The most promising of these technologies in the Northwest are enhanced geothermal, solar PV with battery storage and small modular nuclear reactors. The potential costs, annual energy, winter and summer peak contribution of these resources are shown in Tables 15 - 11 and 15 - 12.

Both enhanced geothermal and small modular reactors can provide year-round generation and can, within limits, be dispatched based on resource need. However, neither of these technologies, even if proven, is likely to contribute significantly to regional energy needs until post-2025. In contrast, solar PV with battery storage offers more near-term potential for meeting much of the region's summer energy needs as well as supplying more or all of the summer system peak demand. The current cost of such PV systems, however, is not economically competitive with gas-fired generation. See Chapter 13 for a more detailed discussion of these emerging technologies.

Table 15 - 11: Enhanced Geothermal and Small Modular Reactor Emerging Technologies' Potential Availability and Cost

	Enhanced Geothermal Systems				**Small Modular Reactors**			
	Potential Installed Capacity by 2035 = 5025 MW				Potential Installed Capacity by 2035 = 2580 MW			
Year	Energy (aMW)	Winter Peak (MW)	Summer Peak (MW)	Real Levelized Cost (2012$ /MWh)	Energy (aMW)	Winter Peak (MW)	Summer Peak (MW)	Real Levelized Cost (2012$ /MWh)
2025	310	345	345	$102	513	520	520	$95
2030	1,485	1,650	1,650	$73	1,026	1,140	1,140	$88
2035	4,522	5,025	5,025	$58	2,053	2,280	2,280	$81

Table 15 - 12: Utility Scale Solar PV with Battery Storage Emerging Technologies' Potential Availability and Cost

	48 MW Solar PV Plant Low Cost with 10 MW Battery System – Roseburg OR				**48 MW Solar PV Plant Low Cost with 10 MW Battery System – Kelso WA**			
	Regional Potential – Nearly Infinite				Regional Potential – Nearly Infinite			
Year	Energy (aMW)	Winter Peak (MW)	Summer Peak (MW)	Real Levelized Cost (2012$ /MWh)	Energy (aMW)	Winter Peak (MW)	Summer Peak (MW)	Real Levelized Cost (2012$ /MWh)
2020	10	9	24	$112	9	9	24	$124
2025	10	9	24	$102	9	9	24	$113
2030	10	9	24	$86	9	9	24	$95
2035	10	9	24	$85	9	9	24	$94

Federal Carbon Dioxide Emission Regulations

As the Seventh Power Plan was beginning development, the US Environmental Protection Agency (EPA) issued proposed rules that would limit the carbon dioxide emissions from new and existing power plants. Collectively, the proposed rules were referred to as the Clean Power Plan. In early August of 2015, after considering nearly four million public comments, the EPA issued the final Clean Power Plan (CPP) rules. The "111(d) rule," refers to the Section of the Clean Air Act under which EPA regulates carbon dioxide emissions for existing power plants. The CPP's goal is to reduce national power plant CO2 emissions by 32 percent from 2005 levels by the year 2030. This is slightly more stringent than the draft rule which set an emission reduction target of 30 percent. Along with the 111(d) rule, the EPA also issued the final rule under the Clean Air Act section 111(b) for new, as opposed to existing, power plants and the EPA also proposed a federal plan and model rules that would combine the two emissions limits.

To ensure the 2030 emissions goals are met, the CPP requires states begin reducing their emissions no later than 2022 which is the start of an eight year compliance period. During the compliance period, states need to achieve progressively increasing reductions in CO2 emissions. The eight year interim compliance period is further broken down into three periods, 2022-2024, 2025-2027, and 2028-2029, each associated with its own interim emission reduction goals.

Under the EPA's final rules, states may comply by reducing the average carbon emission rate (pounds of CO2 per kilowatt-hour) of all power generating facilities located within their state that are covered by the rule. In the alternative, states may comply by limiting the total emissions (tons of CO2 per year) from those plants. The former compliance option is referred as a "rate-based" path, while the latter compliance option is referred to as a "mass-based" path. Under the "mass-based" compliance option, EPA has set forth two alternative limits on total CO2 emissions. The first, and lower limit, includes only emissions from generating facilities either operating or under constructions as of January 8, 2014. The second, and higher limit, includes emissions from both existing and new generating facilities, effectively combining the 111(b) and 111(d) regulations.

The Council determined that a comparison of the carbon emissions from alternative resource strategies should be based on the emissions from both existing and new facilities covered by the EPA's regulations. This approach is a better representation of the total carbon footprint of the region's power system and is more fully able to capture the benefits of using energy efficiency as an option for compliance because it reduces the need for new generation. Table 15 - 13 shows the final rule's emission limits for the four Northwest states for the "mass-based" compliance path, including both existing and new generation.

Table 15 - 13: Pacific Northwest States' Clean Power Plan Final Rule CO2 Emissions Limits[10]

Mass Based Goal (Existing) and New Source Complement (Million Metric Tons)					
Period	Idaho	Montana	Oregon	Washington	PNW
Interim Period 2022-29	1.49	11.99	8.25	11.08	32.8
2022 to 2024	1.51	12.68	8.45	11.48	34.1
2025 to 2027	1.48	11.80	8.18	10.95	32.4
2028 to 2029	1.48	11.23	8.06	10.67	31.4
2030 and Beyond	1.49	10.85	8.00	10.49	30.8

EPA's regulations do not cover all of the power plants used to serve Northwest consumers. Most notably, the Jim Bridger coal plants located in Wyoming serve the region, but are not physically located within regional boundaries defined under the Northwest Power Act[11]. In addition, there are many smaller, non-utility owned plants that serve Northwest consumers located in the region, but which are not covered by EPA's 111(b) and 111(d) regulations. Therefore, in order for the Council to compare EPA's CO2 emissions limits to those specifically covered by the agency's regulations it was necessary to model a sub-set of plants in the region. Table 15 - 14 shows the fuel type, nameplate generating capacity for the total power system modeled by the Council and the nameplate capacity and fuel type of those covered by the EPA's Clean Power Plan regulations modeled for purposes of comparison to the 111(b) and 111(d) limits shown in Table 15 - 13.

[10] Note: EPA's emissions limits are stated in the regulation in "short tons" (2000 lbs). In Table 15 - 8 and throughout this document, carbon dioxide emissions are measured in "metric tons" (2204.6 lbs) or million metric ton equivalent (MMTE).

[11] The Power Act defines the "Pacific Northwest" as Oregon, Washington, Idaho, the portion of Montana west of the Continental Divide, "and such portions of the States of Nevada, Utah, and Wyoming as are within the Columbia River drainage basin; and any contiguous areas, not in excess of seventy-five air miles from [those] area[s]… which are a part of the service area of a rural electric cooperative customer served by the Administrator on December 5, 1980, which has a distribution system from which it serves both within and without such region." (Northwest Power Act, §§ 3(14)(A) and (B).)

Table 15 - 14: Nameplate Capacity of Thermal Generation Covered by EPA Carbon Emissions Regulations Located Within Northwest States

Fuel Type	Modeled for Total PNW Power System Emissions Nameplate Capacity (MW)	Modeled Generation Affected by EPA 111(b)/111(d) Emissions Limits (MW)
Total	16,787	12,044
Coal	7,349	4,827
Natural Gas	9,329	7,218
Oil/Other	109	0

Under the Clean Power Plan, each state is responsible for developing and implementing compliance plans with EPA's carbon dioxide emissions regulations. However, the Council's modeling of the Northwest power system operation is not constrained by state boundaries. That is, generation located anywhere within the system is assumed to be dispatched when needed to serve consumer demands regardless of their location. For example, the Colstrip coal plants are located in Montana, but are dispatched to meet electricity demand in other Northwest states. Consequently, the Council's analysis of compliance with EPA's regulations can only be carried out at the regional level. While this is a limitation of the modeling, it does provide useful insight into what regional resource strategies can satisfy the Clean Power Plan's emission limits.

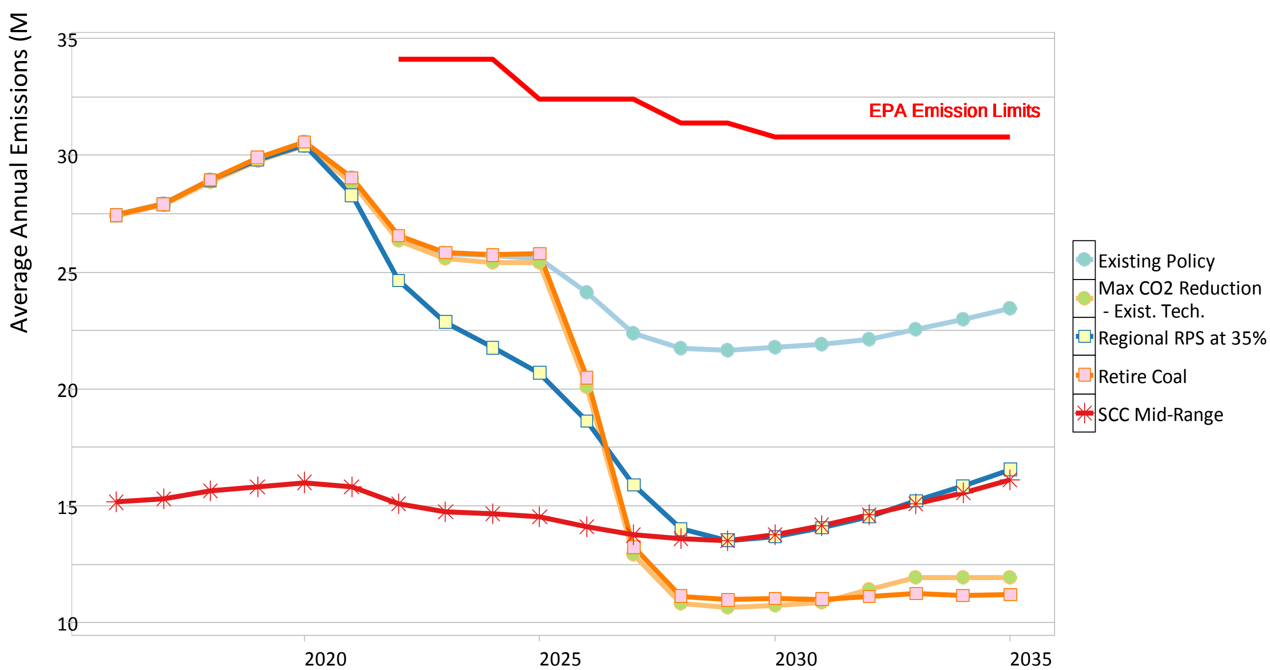
Figure 15 - 15 shows the annual average carbon dioxide emissions for the least cost resource strategy identified under each of the major scenarios and sensitivity studies evaluated during the development of the Seventh Power Plan. The interim and final Clean Power Plan emission limits aggregated from the state level to the regional level is also shown in this figure (top heavy line). Figure 15 - 15 shows that all of the scenarios evaluated result in average annual carbon emissions well below the EPA limits for the region. This includes two of the scenarios that were specifically designed to "stress test" whether the region would be able to comply with s the Clean Power Plan's emission limits if one or more existing non-carbon emitting resources in the region were taken out of service.

In the **Unplanned Loss of a Major Resource** scenario, it was assumed that a single large resource that does not emit carbon dioxide with 1,200 megawatts of nameplate capacity, producing 1,000 average megawatts of energy would randomly and permanently discontinue operation sometime over the next 20 years. Because this scenario was designed to test the vulnerability of the region's ability to comply with the Clean Power Plan's emission limits in 2030, it was assumed that there was a 75 percent probability that this resource would discontinue operation by 2030 and a 100 percent probability it would do so by 2035. In the second scenario, the **Planned Loss of a Major Resource**, it was assumed that a total of 1,000 megawatts nameplate capacity producing 855 average megawatts of energy resources that do not emit carbon dioxide were retired by 2030. Figure 15 - 15 shows that under both scenarios the average regional carbon dioxide emissions are well below the EPA's limits for 2030 and beyond.

One of the key findings from the Council's analysis is that *from a regional perspective* compliance with EPA's carbon emissions rule should be achievable without adoption of additional carbon reduction policies in the region. This is not to say that no additional action is required.

All of the least cost resource strategies that have their emission levels depicted in Figure 15 - 15 include development of between 3,800 and 4,400 average megawatts of energy efficiency by 2035. All of these resource strategies also assume that the retiring Centralia, Boardman and North Valmy coal plants are replaced with only those resources required to meet regional capacity and energy adequacy requirements. Utility development of new gas-fired generation to meet local needs for ancillary services, such as wind integration, or capacity requirements beyond the modest levels included under these scenarios are not modeled and would increase regional emissions. All of the least cost resource strategies also assume that Northwest electricity generation is dispatched to meet regional adequacy standards for energy and capacity rather than to serve external markets.

Figure 15 - 15: Average Annual Carbon Dioxide Emissions for Least Cost Resource Strategies by Scenario for Generation Covered by the Clean Power Plan and Located Within Northwest States



The key findings from the Council's assessment of the potential to reduce power system carbon dioxide emissions are:

- Without any additional carbon control policies, carbon dioxide emissions from the Northwest power system are forecast to decrease from about 54 million metric tons in 2015 to around 36 million metric tons in 2035.[12] This reduction is driven by: 1) The retirement of three coal-

[12] This is the level of carbon dioxide emissions estimated to be generated to serve regional load under average water and weather conditions. Actual 2015 carbon dioxide emission could differ significantly from this level based on actual water and

fired power plants (Centralia, Boardman, and North Valmy) by 2026. These plants currently serve the region, but their retirement has already been announced; 2) Increased use of existing natural gas-fired generation to replace these retiring resources; and 3) Developing roughly 4,300 average megawatts of energy efficiency by 2035, which is sufficient to meet all forecast load growth over that time frame under most future conditions. If these actions do occur, then the region will have a very high probability (98 percent) of complying with the EPA's carbon emissions limits, even under critical water conditions. If these actions do not occur, the level of forecast emissions is likely to increase.

- The maximum deployment of existing technology could reduce regional power system carbon dioxide emissions from approximately 54 million metric tons today to about 16 million metric tons, a nearly 70 percent reduction. If limits are placed on the type of existing technology that can be developed, as was assumed in the **Retire Coal w/SCC MidRange & No New Gas** scenario, then emissions can be reduce still further to 10 million metric tons. While this represents nearly an 80 percent reduction in emissions. Implementing either of these resource strategies would increase the present value average power system cost by between $36 and $43 billion (41 to 52 percent) over resource strategies that are projected to satisfy the Environmental Protection Agency's recently established limits on carbon dioxide emissions *at the regional level*.

- By developing and deploying current emerging energy efficiency and non-carbon emitting resource technologies, it may be possible to reduce 2035 regional power system carbon dioxide emissions to approximately 8 million metric tons, about 50 percent below the level achievable with existing technology. Due to the speculative nature of these technologies, the cost of achieving these additional emissions reductions was not evaluated.

- At present, it's not possible to entirely eliminate carbon dioxide emissions from the power system without the use of nuclear power or emerging technology breakthroughs in both energy efficiency and non-carbon dioxide emitting renewable resource generation.

- Deploying renewable resources to achieve maximum carbon reduction presents significant power system operational challenges and much higher costs.

- Given the characteristics of wind and utility-scale solar PV and the energy and capacity needs of the region, policies designed to reduce carbon emissions by increasing state

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weather conditions. Average regional carbon dioxide emissions from 2001 – 2012 were 54 MMTE, but ranged from 43 MMT to 60 MMT.

renewable portfolio standards are the most costly and produce the least emissions reductions.

- Imposing a regionwide cost of carbon, equivalent to the federal government's social cost of carbon highest estimate, results in lower forecast emissions, without significantly increasing the use of energy efficiency or renewable resources.

Resource Strategy Cost and Revenue Impacts

The Council's Regional Portfolio Model (RPM) calculates the net present value cost to the region of each resource strategy to identify the strategies that have both low cost and low risk. The RPM includes only the forward-going costs of the power system; that is, only those costs that can be affected by future conditions and resource decisions.

Table 15 - 15 shows a comparison of scenarios and the incremental cost from the **Existing Policy** scenario. Scenarios that have significantly higher costs generally involve capital investment needed in replacement resources, largely new combined-cycle combustion turbines. Note that under scenarios assuming a cost of carbon, coal plants serving the region dispatch relatively infrequently. As a result, such plants might be viewed by their owners as uneconomic to continue operation. If this is indeed the case, the average present value system cost of these scenarios would likely be much closer to the **Maximum Carbon Reduction – Existing Technology** scenario.

The least cost resource strategy under the **Lower Conservation** scenario develops about 2,400 average megawatts less energy savings and 3,800 megawatts less of winter peak capacity from energy efficiency by 2035 than the **Existing Policy** scenario. As a result, its average system cost is nearly $16 billion higher because it must substitute more expensive generating resources to meet the region's needs for both capacity and energy.

Under the **Regional RPS at 35%** scenario, the $46 billion increase in average present value system cost over the **Existing Policy** scenario stems from the investment needed to develop a significant quantity of additional wind and solar generation in the region to satisfy the higher standard. The average present value system cost for the least cost resource strategy under the **Increased Market Reliance** scenario is $5 billion lower because fewer resources are developed in the region to meet regional resource adequacy standards, resulting in lower future costs. The **Social Cost of Carbon - Mid-Range** scenario is lower because of increased regional revenues from outside markets where carbon emissions are higher.

The scenarios that include retirement of all coal generation have higher costs to cover the replacement of some or all of the capacity for resource adequacy. The **Coal Retirement - No New Thermal Builds** scenario costs $35 billion more than the **Coal Retirement - Social Cost of Carbon** because restricting the options for replacement generation to not include thermal resources requires more capital investment to meet resource adequacy standards.

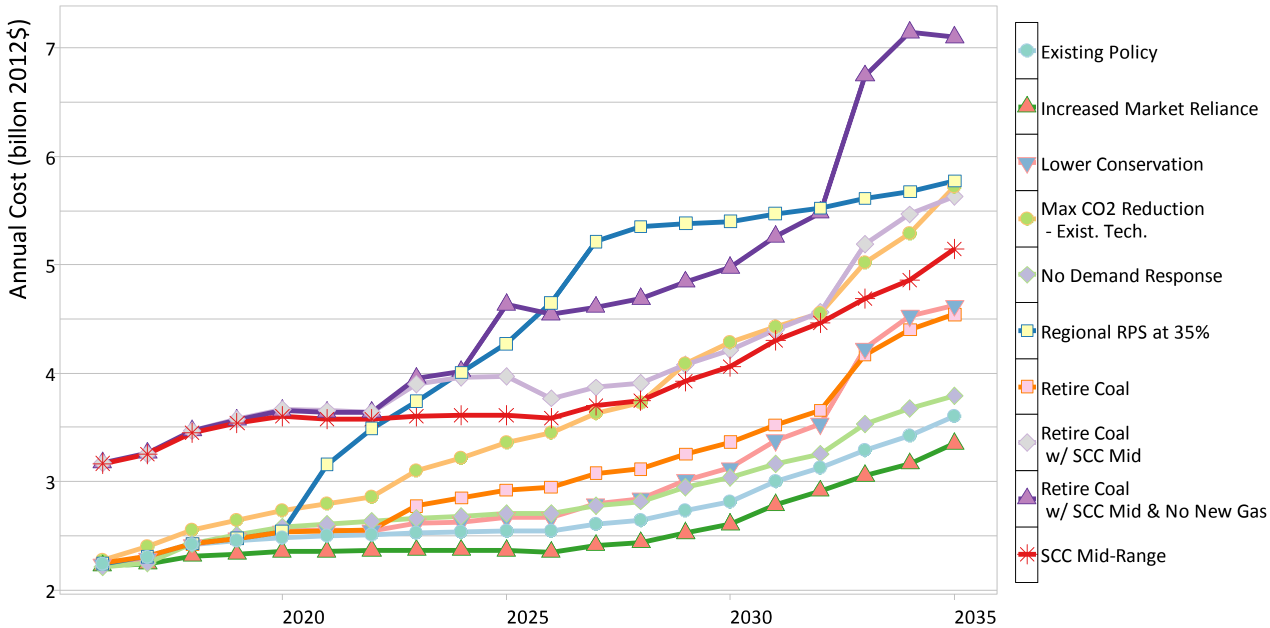
Table 15 - 15: Average Net Present Value System Cost without Carbon Revenues and Incremental Cost Compared to Existing Policy, No Carbon Risk Scenario

Scenario	System Cost w/o Carbon Dioxide Revenues (billion 2012$)	Incremental Cost Over Existing Policy Scenario (billion 2012$)
Increased Market Reliance	$ 77	$ (5)
SCC - Mid-Range	$ 79	$ (4)
Existing Policy	$ 83	$ -
No Demand Response	$ 87	$ 4
Retire Coal w/SCC_MidRange	$ 91	$ 9
Retire Coal	$ 98	$ 15
Lower Conservation	$ 98	$ 16
Max. CO2 Reduction - Exist. Tech.	$ 117	$ 34
Retire Coal w/SCC_MidRange & No New Gas	$ 126	$ 43
Regional RPS at 35%	$ 129	$ 46

Reporting costs as net present values does not show patterns over time and may obscure differences among individual utilities. The latter is unavoidable in regional planning and the Council has noted throughout the plan that different utilities will be affected differently by alternative policies. It is possible, however, to display the temporal patterns of costs among scenarios. Figure 15 - 16 shows forward-going power system costs for selected scenarios on an annual basis.

Forward-going costs include only the future operating costs of existing resources and the capital and operating costs of new resources. The 2016 value in Figure 15 - 16 includes mainly operating costs of the current power system, but not the capital costs of the existing generation, transmission, and distribution system since these remain unchanged by future resource decisions.

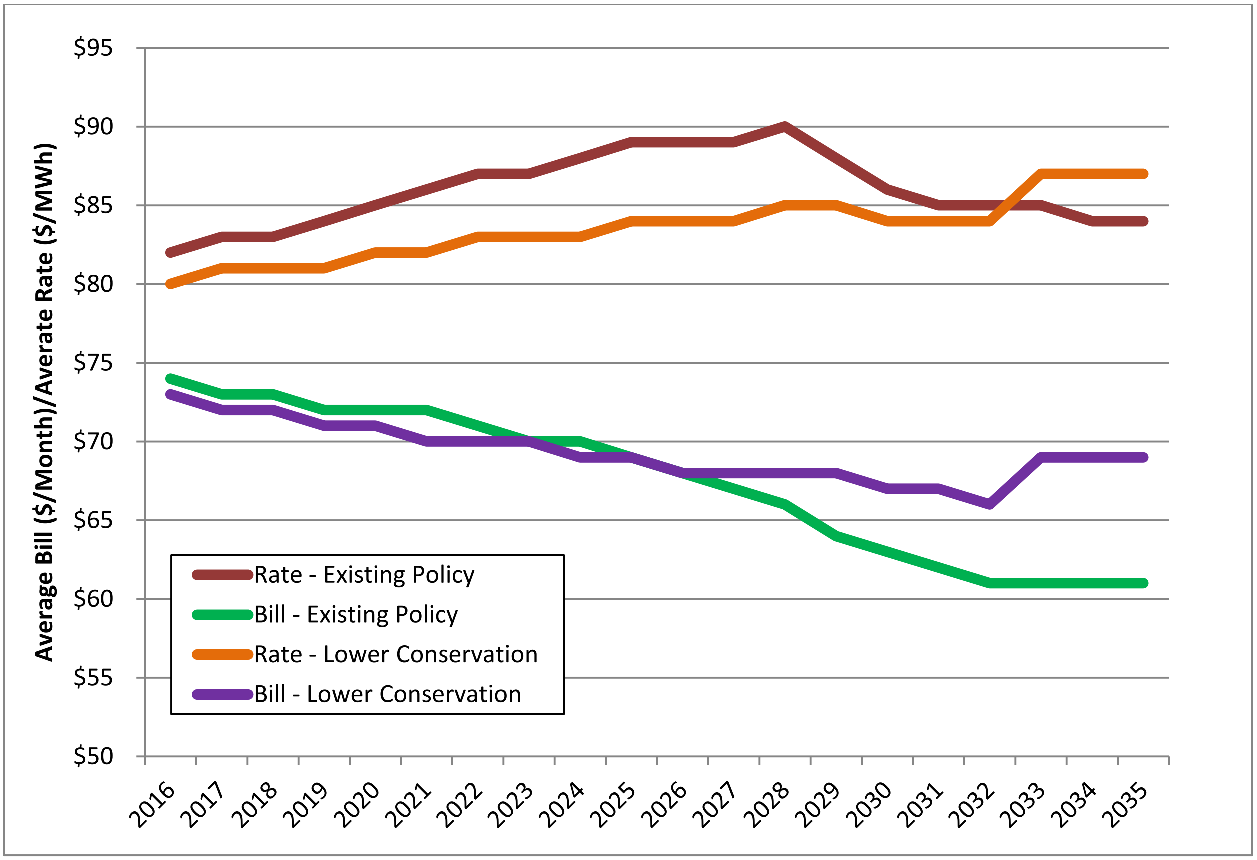
Figure 15 - 16: Annual Forward-Going Power System Costs, Including Carbon Revenues



A review of Figure 15 - 16 shows that power system costs increase over the forecast period even in the **Existing Policy** scenario due to investments in energy efficiency, demand response, resources needed to comply with existing renewable portfolio standards, and gas-fired generation to meet both load growth and replace capacity lost through announced coal plant retirements. The resource strategies with the highest cost are those that include either carbon cost or those that were specifically designed to reduce future carbon emissions. The rapid increase in the annual cost for the least cost resource strategy in the **Regional RPS at 35%** scenario occurring post-2020 results from increased investments in renewable resources beyond current state standards in order to satisfy the higher standard by 2030.

Generally average revenue requirements per megawatt-hour (a proxy for "average rates") and monthly electric bills generally move in the same direction as the average net present value of power system cost reported in this plan. The exception to this relationship is when resources strategies differ significantly in the amount of conservation developed. The **Lower Conservation** scenario develops 2,400 average megawatt few conservation resources than the Existing policy resource strategy. Figure 15 - 17 illustrates how **Existing Policy** and **Lower Conservation** scenarios can have much closer average revenue requirements per megawatt-hour, but significantly different monthly bills over the planning period.

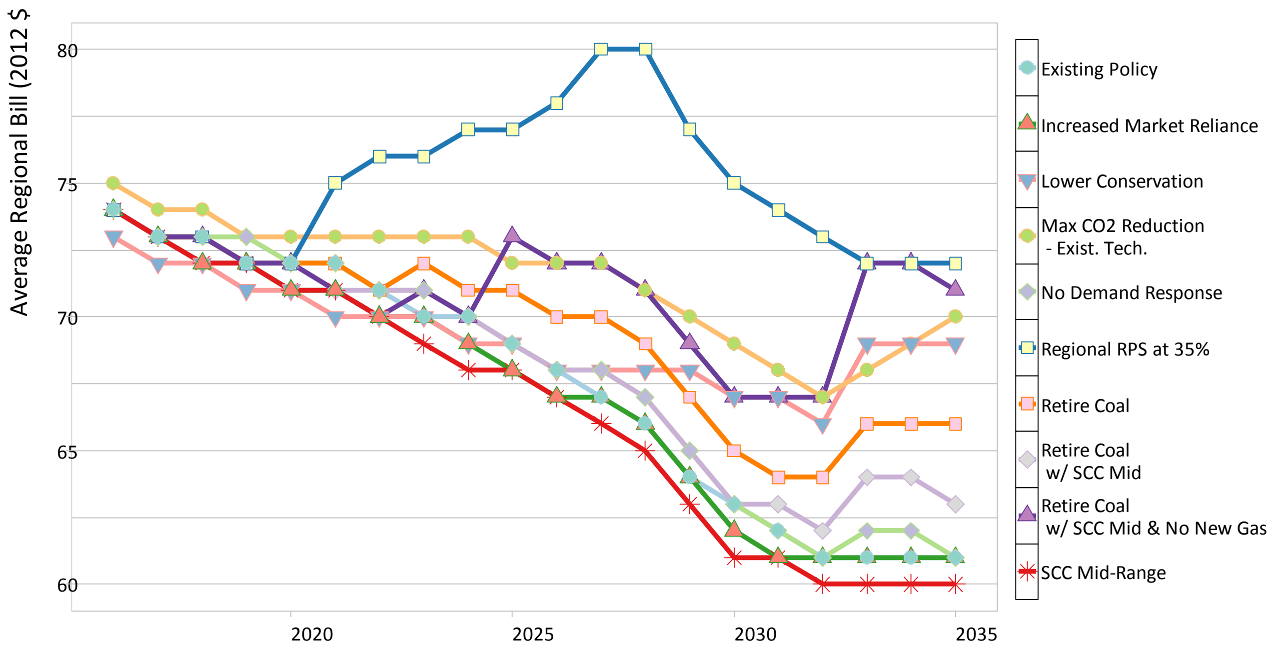
Figure 15 - 17: Residential Electricity Bills With and Without Lower Conservation



As can be seen from Figure 15 - 17 the **Lower Conservation** least cost resource strategy, even though it has much higher rates, results in very similar monthly bills compared to the **Existing Policy** least cost resource strategy until about 2025 where they start to diverge. While this reduces the investment in energy efficiency, it increases the investment in new gas and renewable resource generation as well as increases the use of existing coal resources. In aggregate, the average system cost of the **Lower Conservation** scenario is nearly $18 billion more than the average system cost of the **Existing Policy** scenario. This additional cost results in roughly equivalent rates, but higher total bills over the 20-year planning period.

Figure 15 - 18 shows monthly residential bills and figure 15 - 19 shows average revenue requirement per megawatt-hour of electricity for ten different scenarios. Neither figure includes carbon revenues in the average revenue requirement or bills.

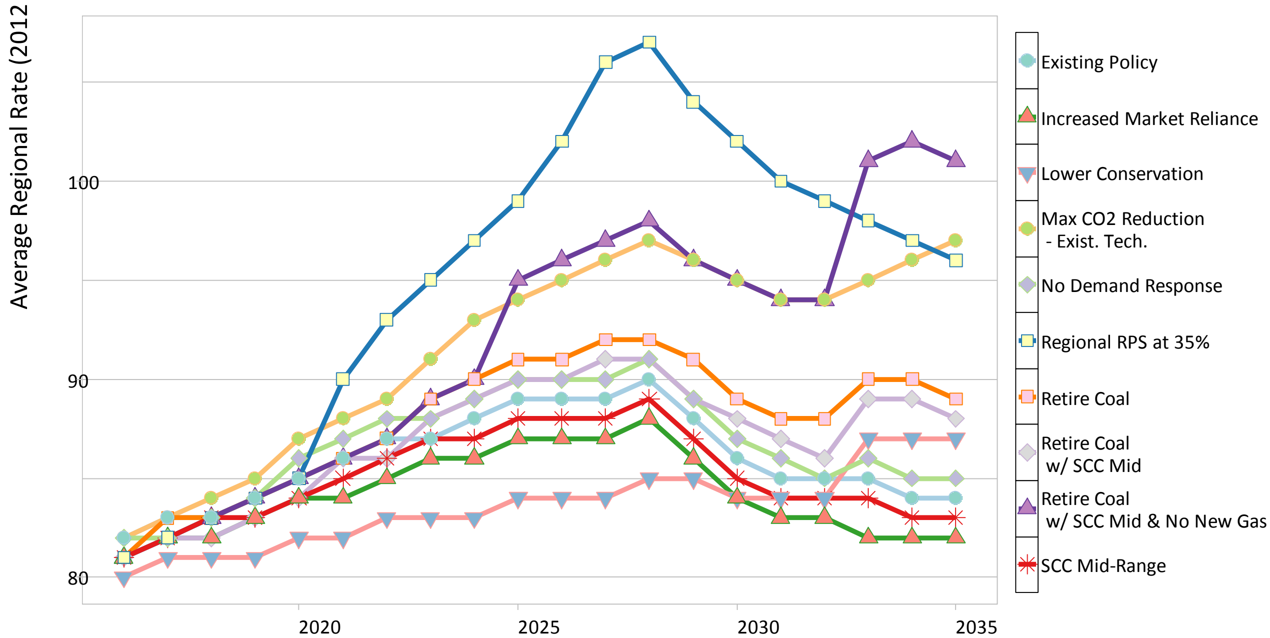
Figure 15 - 18: Monthly Residential Bills Excluding the Cost of Carbon Revenues



A review of Figure 15 - 18 reveals that the highest monthly bills occur under scenarios with significant investments made in new renewable or gas-fired generation to lower regional carbon emissions. In the **Lower Conservation** scenario, average monthly bills are higher than the **Existing Policy** scenario because less conservation is developed; therefore average electricity consumption per household is higher and larger investments in new gas-fired generation are needed to meet demand. The lowest monthly bills occur in scenarios that rely on the existing system and defer requirements for capital investments, like the **Existing Policy, Social Cost of Carbon – Mid-Range** and **Increased Market Reliance** scenarios.

Figure 15 - 19 shows that the lowest average revenue requirement per megawatt-hour is also in scenarios that rely on the existing system and defer requirements for capital investments. In the **Lower Conservation** scenario, the lower average revenue requirement is the result of spreading higher average total power system costs over larger number of megawatt-hours. The highest monthly revenue requirement is in scenarios that require significant investments made in new renewable or gas-fired generation to lower regional carbon emissions.

Figure 15 - 19: Electricity Average Revenue Requirement per MWh Excluding Carbon Revenues



Scenario Results Summary

Results in this chapter are often presented for the “average” case across all 800 futures tested in the Regional Portfolio Model (RPM). While these averages are useful, readers should keep in mind that the distribution of results across futures can be equally, if not more, instructive. A more detailed summary of the RPM’s output by scenario is available here: http://www.nwcouncil.org/energy/powerplan/7/technical

CHAPTER 16: ANALYSIS OF COST EFFECTIVE RESERVES AND RELIABILITY

Contents

List of Figures and Tables

KEY FINDINGS

This analysis shows that the existing regional power system, supplemented by actions recommended in the Seventh Power Plan's resource strategy, has sufficient capability to provide all required reserves. However, individual balancing authorities may be in a different position than the region as a whole. Further, the cost and availability of reserves varies depending on water conditions. To minimize the cost of providing reserves the region should continue to explore methods to better coordinate resource dispatch.

INTRODUCTION

This chapter focuses on the general category of reserves commonly referred to as balancing reserves.[1] While the term "balancing reserves" is most often associated with actions that are used to match generation and demand within an hour, the discussion in this chapter extends the definition to cover balancing across longer periods of time. Balancing reserves can be provided by generating resources or by demand side management measures.

For a resource to provide balancing reserves, it must be able to respond very quickly. For a generating resource this would correspond to being able to change its generation level very quickly. For a demand side management program this would correspond to being able to change load requirements from the grid within a short time frame. Balancing reserves that require additional generation or decreased load are referred to as incremental (INC) reserves and those that require reduced generation or increased load are referred to as decremental (DEC) reserves.

Within-hour balancing reserves are most commonly called upon to fill in the gaps due to short-term load variation or due to fluctuations in variable generation resources like wind or solar generation. For example, during peak load hours of the day, should expected wind generation not materialize, INC reserves are called upon to fill in the need. During light load hours, usually during the night, if wind generation exceeds expectations, DEC reserve resources will cut back their generation or alternatively, load is increased to absorb the additional and unexpected generation. Generally, some level of fast acting INC and DEC reserves must be held at all times to respond to forecast and scheduling error in the power system.

This chapter addresses the two main issues surrounding these reserves; 1) how much does the region's power system need and 2) what is the best and most cost-effective means of providing these reserves.

[1] For more information on reserves and ancillary services see Chapter 10.

RESERVES IN THE POWER ACT

The Power Act directs the Power Plan to include an analysis of reserve and reliability requirements and cost-effective methods of providing reserves designed to ensure adequate electric power at the lowest possible cost.[2] With the expansion of variable generation resources, the requirement for reserves to balance that generation has steadily increased. The operation of the system has evolved in such a manner that many different entities, called Balancing Authorities (BAs), have the responsibility to provide reserves for the region and the larger western electric grid.

While there are requirements[3] on how far each BA can deviate from its scheduled interchange of power with other BAs in an operational time-frame, there is no formal requirement on how a BA plans for future reserves. Further, there are limited and differing levels of detail available as public information on how each BA provides or plans for reserves. The Seventh Power Plan recommends that utilities and Bonneville provide more public information on how they plan for operating reserves as part of the Action Plan.[4] Given the current lack of public information, it is not possible to quantify the lowest possible cost for providing reserves in the models used for developing this plan. However, qualitative assessment is possible and actions that will help move toward more quantitative methods are recommended in this plan.

Reliability

Reliability is defined as having two distinct parts, adequacy and security. A power system is reliable if it is:

- Adequate - the electric system can supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
- Secure - the electric system can withstand sudden disturbances, such as electric short circuits or unanticipated loss of system elements.

“Adequacy” refers to having sufficient resources – generation, efficiency and transmission – to serve loads. To be adequate, the power supply must have sufficient energy across all months, sufficient capacity to protect against the coldest periods in winter and the hottest periods in summer, and sufficient flexibility to balance loads and resources within each hour. In determining adequacy, the Council uses a sophisticated computer model that simulates the operation of the power system over many different futures. Each future is simulated with a different set of uncertainties, such as varying water supply, temperature, wind generation and thermal resource performance. The adequacy standard used by the Council deems the power supply inadequate if the likelihood of needing to take

[2] Northwest Power Act, §4(e)(3)(E), 94 Stat. 2706
[3] NERC Resource and Demand Balancing standards
[4] See Action Item REG-4

emergency action to avoid curtailment five years in the future is higher than 5 percent.[5] The Council uses probabilistic analysis to assess that likelihood, most often referred to as the “loss of load probability.”

“Security” of the regional power supply is achieved largely by having reserves that can be brought on line quickly in the event of a system disruption and through controls on the transmission system. These reserves can be in the form of generation or demand side curtailment that can take load off the system quickly. The North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC) establish reserve requirements, frequently expressed in terms of a percentage of load or largest single contingency. An additional resource requirement for the region is maintaining the reserves required for security and thus for a reliable power system.

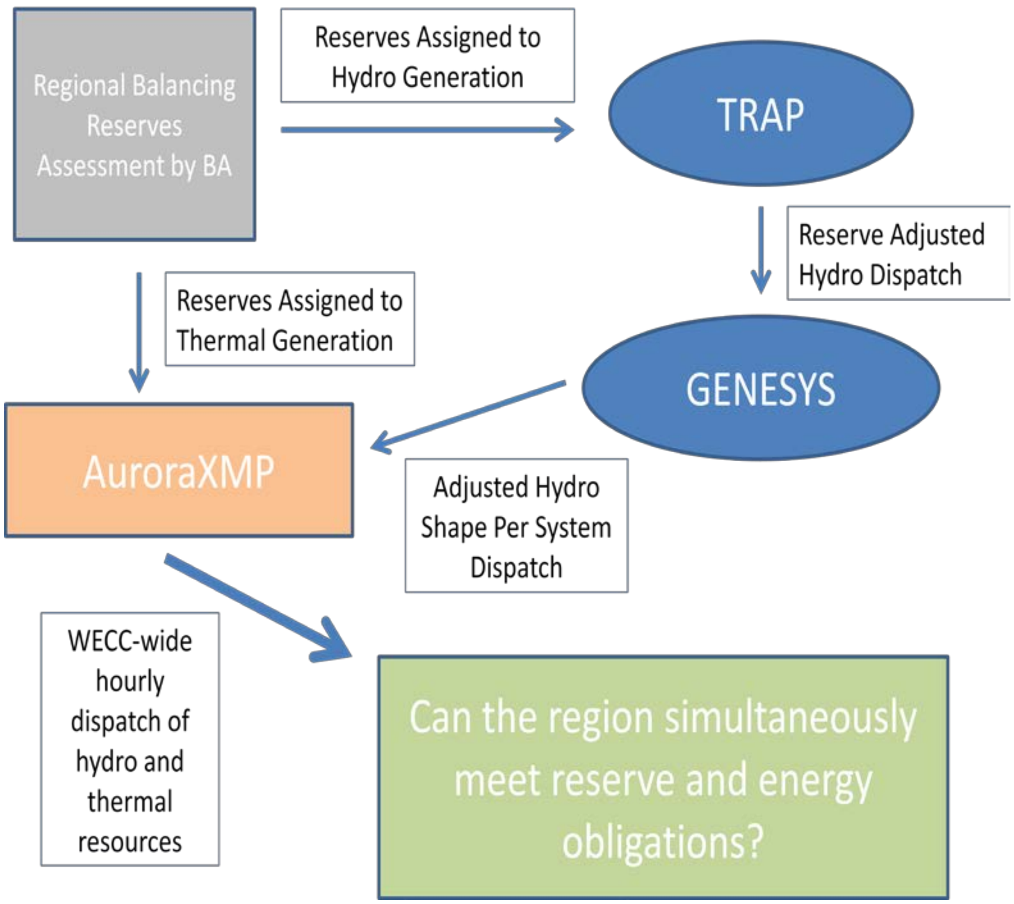
Provision of Cost-Effective Reserves

Determining how to allocate cost-effective reserves in an individual utility’s portfolio, when the balancing authority requires it to self-supply its own reserves, is a challenging prospect that requires a systems operations model for each BA. Determining a methodology to assign cost-effective reserves for the region over the length of the plan period is even more problematic considering the uncertainty related to known market structures and transmission congestion. The future of market structures in the region (energy imbalance markets and Independent System Operators or ISOs) is currently in flux with issues including: geographic footprint, market participants, scheduling, and available products. These issues alone make modeling future regional reserve sufficiency challenging. Determining the most economic reserve assignment within the regional portfolio is virtually impossible. However, considering that difficulty, the Council has attempted to assign reserves to regional hydro and thermal generation resources to best determine if there are sufficient reserves, while simultaneously attempting to acknowledge some fundamental principles of power economics in the region.

[5] For information on the adequacy standard used by the Council see Chapter 11.

The Council's methodology is represented by the flow diagram in Figure 16 - 1, and summarized in more detail in the sections below.

Figure 16 - 1: Methodology Testing Regional Balancing Reserve Capability



Were there a liquid reserve market, reserves would be assigned to the marginal unit within the system constraints. However, since there is neither a liquid reserve market nor even a price signal for those reserve products in the region, the Council assigns the reserves proportionally among reserve-providing units. The majority of reserves in the region have traditionally been provided by hydro generation resources with some sort of storage capability due to abundant, cheap and flexible fuel supply and the ramping capability of the hydro generation units. Thermal units have been used to provide reserves during periods when the hydroelectric system was heavily constrained or for utility portfolios that did not have enough hydroelectric capability to provide all reserves. Using similar reasoning, the Council's methodology assigns a majority of the regional reserve requirements to the hydroelectric system, and the remaining reserve requirements to capable thermal units.

Imbalance Markets

One possible method for reducing the need for or cost of reserves is to create new market structures that allow for the scheduled exchange of power to happen on a more frequent basis. An example of this type of market is the California ISO and PacifiCorp Energy Imbalance Market. Several studies on the cost and benefits of these markets have been completed and have shown that it is likely the benefits of these types of markets exceed the cost. In concept, these markets are formed to solve for the least system cost for providing reserves, and thus should be considered as part of a lowest possible cost provision of reserves.

ASSESSING THE NEED FOR RESERVES

The first step in testing whether the region has sufficient balancing reserves is to determine the need for balancing reserves in the region. The need for reserves is driven by short-term uncertainty in load and variable generation levels. A recent study from the Pacific Northwest National Lab[6] estimated the need for reserves by Balancing Authority. One element of this study took the intra-hour load and variable generation imbalance and assumed that 95 percent of the deviations from a baseline schedule as a level for establishing reserve needs.[7] The maximum reserve requirement for each BA by month was extracted from these data and assigned to thermal and hydro generation resources, per Table 16 - 1. The resulting reserve requirements were used as inputs into the Council's analysis. The Council assumed that if the maximum reserve level can be provided by regional resources, then the system has sufficient reserves.

Note that the total INC and DEC reserve requirements from Table 16 – 1 should not be summed to determine the maximum regional reserve requirement. This is because the maximum within-hour reserve requirement for individual BAs are not necessarily coincident with other BAs in the region. The maximum coincident INC reserve requirement for the region is 2,645 megawatts in January, while the maximum coincident DEC reserve requirement for the 3,063 MW in November.

[6] Analysis of Benefits of an Energy Imbalance Market in the NWPP

[7] Per the description of balancing reserves in Chapter 10, deviations from schedule are inevitable for load and generation due to forecast error and uncertainty. Thus, the balancing reserves held out by a BA ensure enough resources can be provided to the system to keep the system's Area Control Error within allowable limits. Note that the scenario using reserve requirements calculated to cover 95% deviations from the baseline schedule was used as the base case in the PNNL study.

Table 16 - 1: Maximum Within-Hour Reserve Requirement Assumptions for Regional BA's Under Periods of Hydro System Stress[8]

Balancing Authority	Hydro Reserve Level (MW)[9]		Thermal Reserve Level (MW)	
	INC	DEC	INC	DEC
BPA[10]	900	900	0	0
Avista	153	160	52	54
Idaho Power	187	228	80	98
Mid-Columbia	98	101	0	0
Northwestern	90	0	106	153
Pacificorp[11]	102	0	269	295
Portland General	219	258	384	452
Puget Sound Energy	167	205	269	324
Seattle City Light	148	156	0	0

ESTIMATING RESERVES PROVIDED BY RESOURCES

The second step in testing whether the region has sufficient balancing reserves is to determine the supply for balancing reserves in the region. There are two primary types of resources that provide balancing reserves: hydroelectric and thermal. Other types of resources such as demand response have also been used to provide balancing reserves in some BAs but for the Council's analysis these have been excluded[12].

Hydro Resources

Providing INC reserves with hydroelectric resources requires decreasing their maximum allowed generation. Providing DEC reserves requires increasing their minimum allowed generation, leaving the remaining range available for shaping energy. The Council's hourly hydroelectric simulation model (TRAP) was used to calculate the maximum and minimum generation available from the

[8] Note that there are other BA's in the region that were not part of the PNNL dataset. Since generally, their reserves are held on BPA's system, it is assumed for this study that BPA reserves assigned would be a proxy for the reserves on the rest of the BA's in the region.
[9] Reserves assigned to hydro resources are based on regulated hydro resources owned by a particular utility. For
[10] BPA Reserve requirements used are per current status, not the PNNL study.
[11] Pacificorp and Northwestern Hydro resources showed flow restrictions during certain times of the year that did not allow hydro reserve requirements as assigned to be held on those resources. Since both Pacificorp and Northwestern had available thermal capability, reserves were shifted to thermal units during those times.
[12] However, new and existing demand response resources are dispatched in AuroraXMP to offset total system peak needs during periods of system stress.

hydroelectric system[13]. To analyze the effects of carrying reserves using the hydroelectric system, the maximum and minimum allowed generation was reduced and increased, respectively, on groups of hydro resources that correspond to balancing authority resources.

Table 16 - 2 shows the amount of reserve requirements served within BAs with hydro generation. Note that these amounts do not necessarily correspond to hydro reserve requirements in Table 16 - 1, since some of the BAs (utilities) listed have contracts on the Mid-Columbia generating resources. Thus, the difference between reserve levels for a particular BA, in Table 16 - 1 and Table 16 – 2, represents the amount of reserves requirements assigned to the Mid-Columbia hydro generating resources.

The maximum and minimum hydroelectric generation limits from the TRAP model are then used in the Council's adequacy model (GENESYS) to determine the overall dispatch of the hydroelectric system under differing water conditions. When the hydroelectric system dispatches at a level that is not at either the minimum or maximum allowed generation, it has remaining upward or downward flexibility. This remaining flexibility on the hydro system is then considered with the remaining upward or downward flexibility on the thermal resources described below[14].

Table 16 - 2: Reserve Requirements Assigned to be Served By Hydro Resources Within BA

BA	Reserve Requirements Assigned (MW)[15]	
	INC	DEC
BPA[16]	900	900
Avista	137	143
Idaho Power	187	228
Mid-Columbia	326	329
Northwestern	90	0
Pacificorp	95	0
Portland General	128	151
Puget Sound	0	0
Seattle City Light	148	156

[13] See Appendix K for more information on the TRAP model.
[14] Note that during a limited amount of extreme hydro conditions in the 80 years of hydro conditions simulated in TRAP, the additional constraints on the hydro system imposed by the INC/DEC reserve requirements for some regulated hydro projects had to be relaxed so the other hydro constraints could be met. The amount of reserve requirements that were unable to be met on the hydro system for all 80 hydro years were assigned as additional reserve requirements on the appropriate thermal resources. See Appendix K for more details on the TRAP model.
[15] Reserves assigned to hydro resources are based on regulated hydro resources owned by a particular utility.

Thermal Resources

Similarly to method used to assign reserves to hydroelectric resources, reserves were assigned by modifying the operating range of thermal resources: decreasing their maximum allowed generation and increasing their minimum allowed generation for INC and DEC reserve assignment respectively. When allocating the reserve obligations, the maximum and minimum allowed generation was reduced on groups of thermal resources that correspond to specific balancing authority thermal resources. Using the modified thermal plant ranges and remaining hydro generation flexibility, the AuroraXMP model was used to dispatch thermal resources within the new maximum and minimum generation levels. See Appendix K for additional information on the AuroraXMP model methodology.

RESULTS

Within-Hour Balancing Reserve Requirements

The regional power system was tested to assess whether it could meet the adequacy criteria for within-hour load following and regulation requirements with and without the implementation of the Seventh Power Plan Action Plan's resource strategy using AuroraXMP to dispatch all the resources in the entire Western Electric Coordinating Council (WECC)[17]. Based on the Council's methodology, and assuming the region implements the Seventh Power Plan Action Plan's resource strategy, the regional power system met the adequacy criteria for within-hour load following and regulation requirements in the test period (October 2020 through September 2021) when evaluated under 80 different water year conditions.[18] Without developing the energy efficiency and demand response resources called for in the Seventh Power Plan's resource strategy, AuroraXMP cannot dispatch or import enough generation to meet the region's within-hour load following and regulation requirements.

Table 16 – 3 reports the number of hydro years tested with a curtailment[19] assuming the region's portfolio contains existing resources and the resources developed under the Seventh Power Plan's resource strategy. As can be seen from Table 16-3, the region cannot dispatch or import enough generation to meet the region's within-hour load following and regulation requirements in 37 out of the 80 water years tested, or just over 46 percent, with the existing system's resources. When it was

[17] The WECC is dispatched on a zonal basis with market import and export limits representing transmission constraints between geographic areas (zones). The Pacific Northwest load is represented by multiple zones in the current topology.
[18] Seventh Power Plan's resource strategy calls upon the region to develop 1400 average megawatts of energy efficiency and at least 600 megawatts of demand response by end of 2021. For this analysis the median value of 1360 MW of demand response developed over all 800 futures tested in the RPM was assumed.
[19] Note that because this is referred to as a curtailment does not necessarily mean that power would be curtailed. These "curtailment" situations are indicative of having to take some emergency action like violating flow constraints to meet load. The AuroraXMP model defines these situations as curtailments and so they are referred to as curtailments in the text. For more on this see the definition of the adequacy standard used by the Council in Chapter 11.

assumed that the region would develop 1400 average megawatts of energy efficiency and deploy 1360 megawatts of demand response per the Seventh Power Plan's resource strategy, the number of water years where curtailments occurred dropped to three out of 80, or just under four percent.

Table 16 - 3: Number of Water Year Conditions with Curtailments

Name of Scenario	Hydro Years (Out of 80)	Percent of Hydro Years
Existing System	37	46.25%
Existing System +1400 aMW EE + 1360 MW DR[20]	3	3.75%

The Existing System scenario in Table 16 – 3 is meant to be used as baseline against which the Seventh Power Plan's resource strategy could be compared. The resource strategy in the Seventh Power Plan Action Plan time period (i.e., through 2021), is further discussed below by exploring monthly unused capability distributions.

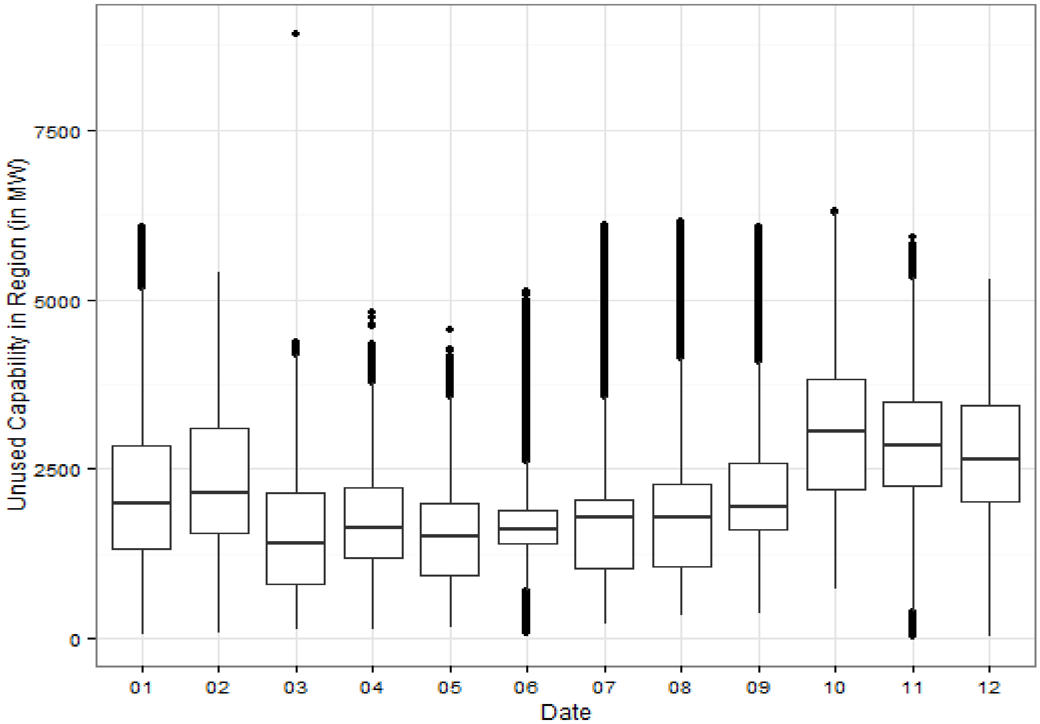
In the hours where there were not curtailments, the unused capability of the system was always greater than zero. Unused capability of the system in this context is defined as the difference between the capability of hydroelectric and thermal generation resources and the amount that those resources were dedicated to meeting system load, contingency reserve requirements, and within-hour balancing reserve requirements (load following and regulation). While unused capability is not a perfect metric for when the region could be close to or in a curtailment situation, low unused capability is often indicative of periods of greater system stress.

Since more generation is dispatched during heavy load hours than during light load hours the Council tested whether heavy load hours and light load hours had significantly different unused capability. In addition, during the morning and evening ramp periods, system loads and resource dispatch often changes dramatically, so distributions of unused capability were analyzed. The benefit in considering distributions of unused capability is the ability to consider seasonal trends of both average and minimum unused capability. The average unused capability gives a general sense of how much room the system has to change dispatch in all hydro conditions whereas the minimum unused capability gives insight on the least amount of system flexibility left under the worst conditions.

Figure 16 - 2, Figure 16 - 3, Figure 16 - 4, Figure 16 - 5 and Figure 16 - 6 show the average unused capability remaining on the system for each month of the study period for all hours, light load hours[21], heavy load hours[22], morning[23] and evening[24] ramp hours of the month, respectively.[25]

[20] Note that the 1360 MW of acquired DR is equivalent to 1117 MW during winter peak hours and 1054 MW during summer peak hours.

Figure 16 - 2: Average Unused Capability All Hours



In Figure 16 - 2, the minimum unused capability of the system is below 50 megawatts in late fall and early winter. In general, these results show the system having slightly more unused capability on average during late fall months and winter months, but the unused capability during those months is highly dependent on water conditions. During late winter and early spring months, the unused capability varies less with water conditions, but the unused capability is lower on average. This shows that in general, the risk of adverse hydro conditions increasing system stress in late fall and early winter may be less than at other times of year, but with more severe result.

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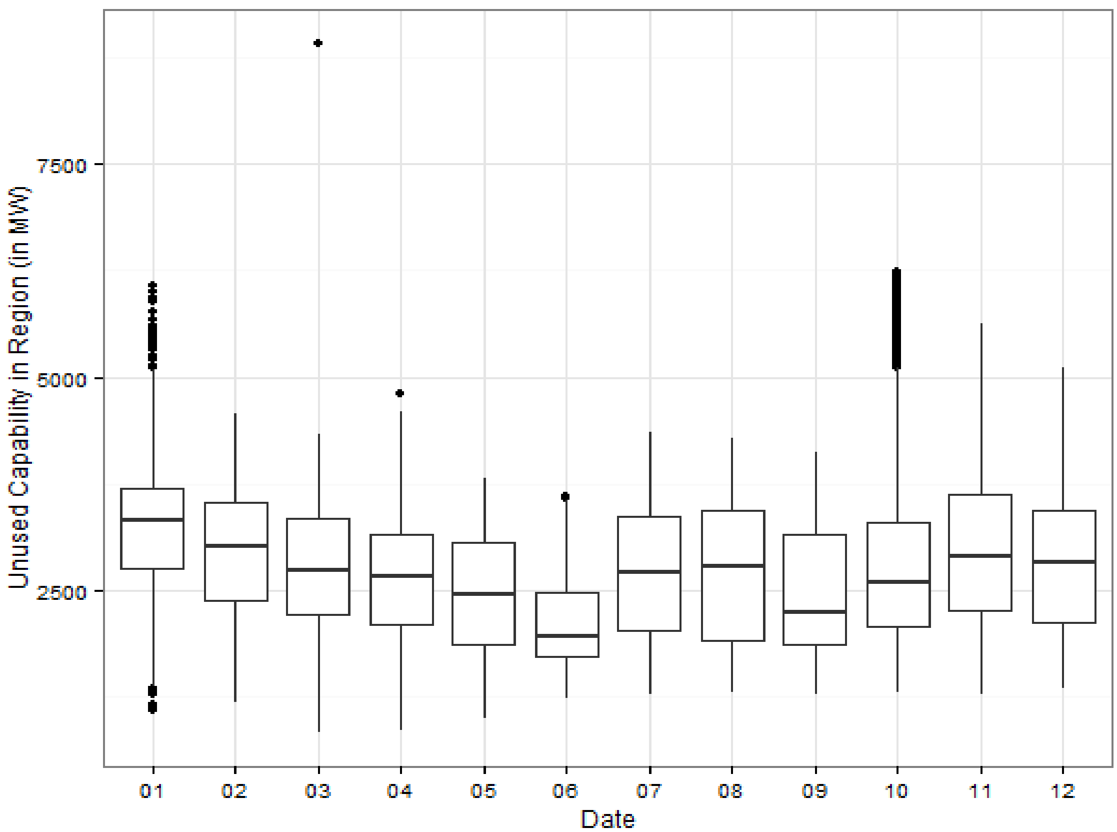
[21]Light load hours are defined as hours ending 100 to 500.
[22] Heavy load hours are defined as hours ending 900 to 2100.
[23] Morning ramp hours are defined as hours ending 600 to 800.
[24] Evening ramp hours are defined as hours ending 2200 to 2400.
[25] In the Box and Whiskers plot style, the dark line inside the "box" indicates the median (2nd quartile), the vertical "box" boundaries are indicative of the 1st and 3rd quartiles (25th and 75th percentiles), the "whiskers" indicate 1.5 times the interquartile range of all the 80 simulations, and the dots are outliers which can contain the maximum or minimum values of the sampled data.

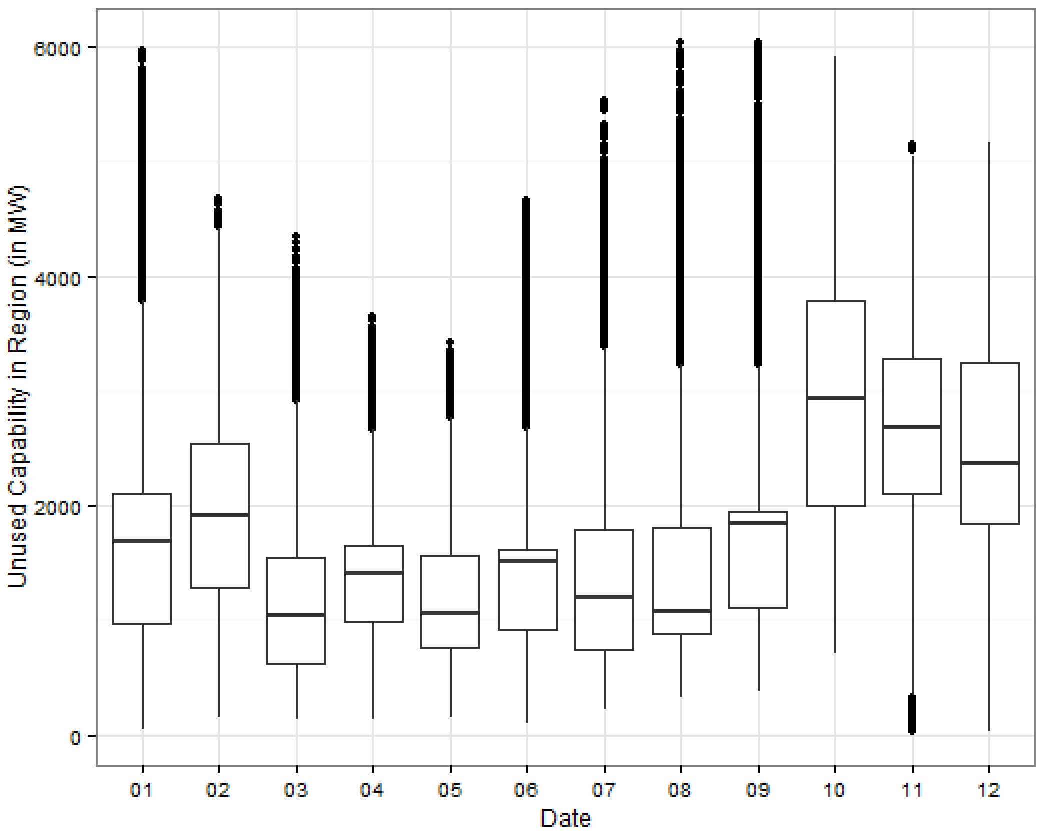
Figure 16 – 3 shows the unused capability only drops below 1,000 megawatts rarely in March and April for light load hours and does not drop below 2,000 megawatts on average during any month. This, perhaps not surprisingly, shows that there are likely to very few incidents of system stress in any water conditions in light load hours.

Figure 16 - 3: Average Light Load Hours Unused Capability



In Figure 16 - 4, like in Figure 16 – 2 the minimum unused capability of the system is below 50 megawatts in late fall and early winter. In general, also like in figure 16 – 2 these results show the system having slightly more unused capability on average during late fall months and winter months, but the unused capability during those months is highly dependent on water conditions. During late winter and early spring months, the unused capability varies less with water conditions, but the unused capability is lower on average. This mirrors the analysis for the unused capability in all hours that in general, the risk of adverse hydro conditions increasing system stress in late fall and early winter may be less than at other times of year, but with more severe result. Notice there is approximately 1,000 megawatts less unused capability on average during heavy load hours than in light load hours.

Figure 16 - 4: Average Heavy Load Hours Unused Capability



In Figure 16 - 5, also like in Figure 16 – 2, the minimum unused capability of the system during the morning ramp period occurs in late fall and winter dropping to under 100 megawatts in February. In general, also like in figure 16 – 2 these results show the system having slightly more unused capability on average during fall and early winter months, but the unused capability during those months is highly dependent on water conditions. During late winter, spring and summer months, the unused capability varies less with water conditions, but the unused capability is lower on average.

In Figure 16 – 6, describing evening ramp period, the minimum unused capability of the system is under 300 megawatts from late fall through spring. The average unused capability does not ever get under 1,700 megawatts. While there is more variability in system flexibility in these hours, the evening ramp period seems to be similarly dependent on hydro conditions to the morning ramp and heavy load hour periods but overall the system is under less stress.

Figure 16 - 5: Average Morning Ramp Hours Unused Capability

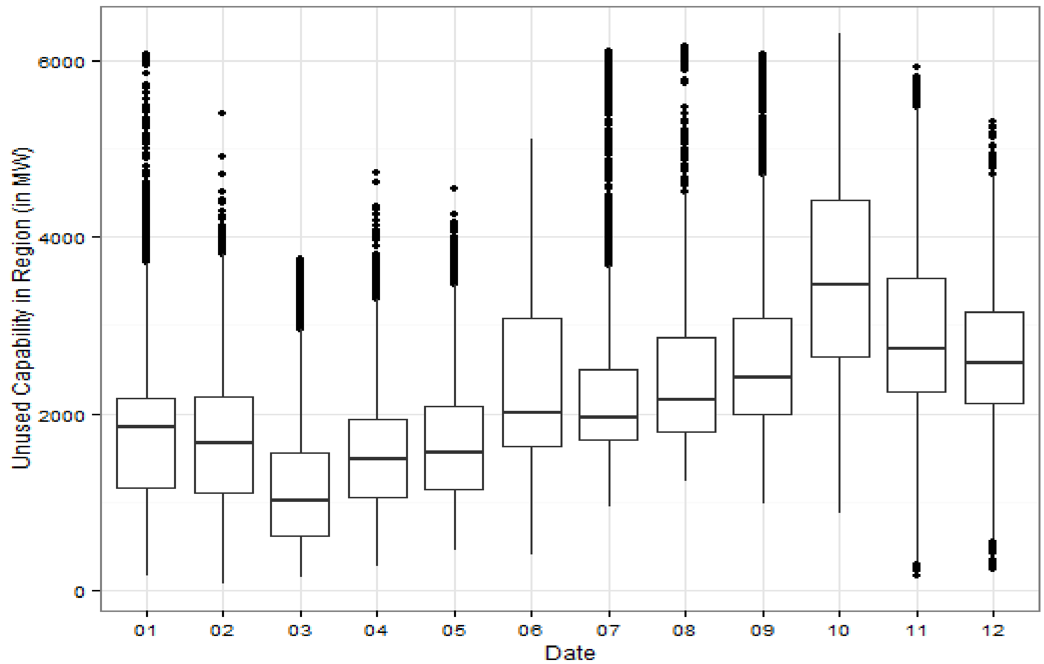
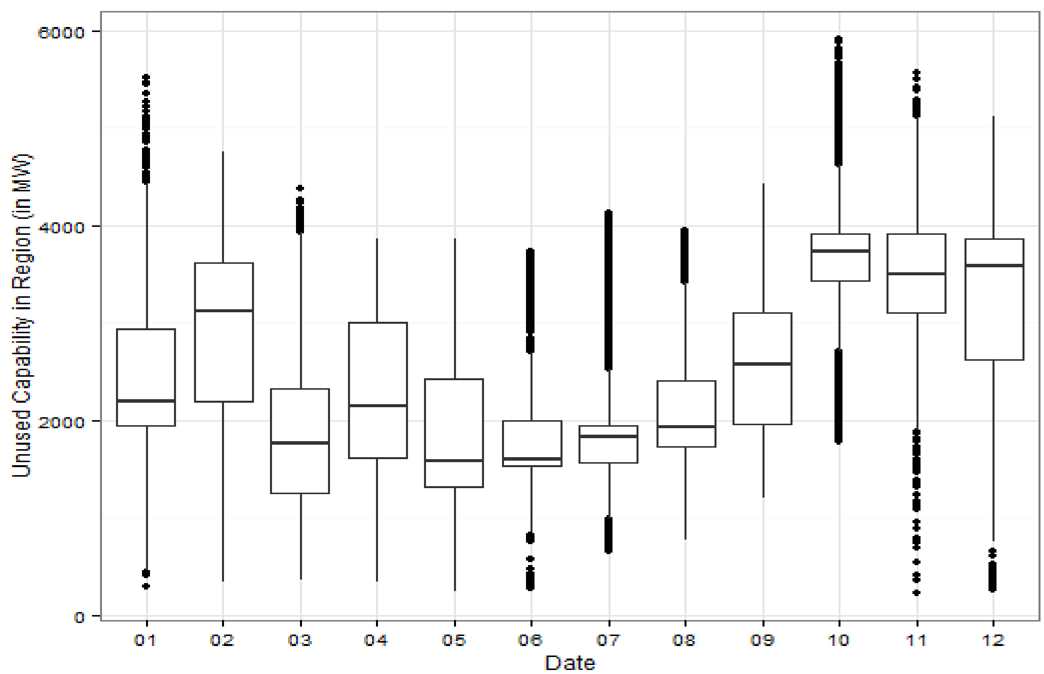


Figure 16 - 6: Average Evening Ramp Hours Unused Capability



In general, these results show that morning ramp and heavy load hours seem to be more effected by adverse hydro conditions than during the evening ramp and light load hours. This result indicates that the capability of the hydroelectric system is being used slightly more in heavy load and morning ramp hours and than in light load and evening ramp hours. The differences between heavy and light load hydropower utilization, in general, corresponds to the traditional operation of hydroelectric plants by shifting generation with limited fuel into the higher priced heavy load hours. This operation can be seen more clearly in Table 16 - 4 and Table 16 - 5 below, by comparing the monthly unused hydro capability over 80 water conditions.[26]

Table 16 - 4: Unused Hydropower Capability (MW) in Light Load and Evening Ramp Hours

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average	-	-	0.2497	0.2660	7.0716	6.7896	0.0275	0.0006	0.0002	0.0138	0.0001	-
Max	-	-	4,953	1,102	66	116	6	2	1	4	1	-
Min	-	-	-	-	-	-	-	-	-	-	-	-

Table 16 - 5: Unused Hydropower Capability (MW) in Heavy Load and Morning Ramp Hours

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average	-	-	-	0.009	0.594	0.907	0.001	-	-	-	-	-
Max	-	-	-	6	47	64	3	-	-	-	-	-
Min	-	-	-	-	-	-	-	-	-	-	-	-

Perhaps more importantly, for a large part of the year, there is not much remaining unused capability on the hydroelectric system. Therefore, during summer, fall and winter, thermal resources must be used if there is a need for additional shaping during the heavy load and morning ramp hours in almost all but the most abundant hydro years. However, as can be seen in Figure 16 - 4, the regional thermal resources still have the capability to provide these services in almost every hydro condition.

Inter-hour Balancing Reserve Requirements

While regional inter-hour balancing reserve requirements were not considered explicitly in the Council's analysis, some conclusions can be drawn from the observed inter-hour ramping requirements. Operationally, ramping requirements between multiple hours in conjunction with within-hour reserve requirements can sometimes be problematic. These coordination issues are

[26] Note that in Tables 16 – 4 and 16 – 5 when unused hydro capability is marked 0 it indicates that it is non-zero

amplified by uncertainty in load and variable generation forecasts, limited ramping capability in the regional system's resource portfolio, and limited extra-regional market availability. For this analysis, the region's inter-hour operating constraints were adhered to for both hydroelectric and thermal resources. This was modeled by ensuring that the multi-hour sustained peaking requirements of TRAP and GENESYS, and operating constraints of AuroraXMP were met.

In the modeling, when the region experienced curtailment situations, they occurred during late fall and early winter periods, which is consistent with the analysis on unused capability in the region. Analysis of the curtailment record shown in Table 16 – 6 revealed that curtailments had certain characteristics in common. These included large hour-to-hour regional load changes, no available regional hydropower flexibility and minimal regional thermal flexibility coupled with significant changes in hour to hour extra-regional market availability.[27] In addition, analysis of the curtailment record shown in Table 16 – 6, indicates that during periods of system stress, peak hour system stresses were more of an issue than ramping and light load hours.

Further analysis of different load and variable generation combinations in conjunction with the 80 hydro conditions might yield more robust results, and will be an area for further study by the Council.

Table 16 - 6: Curtailment Periods

Name of Scenario	Total Events	Morning Ramp Hours	Evening Ramp Hours	Heavy Load Hours	Light Load Hours
Existing System	260	95	7	748	2
Existing System +1400 aMW EE + 1360 MW DR[20]	8	1	0	13	2 [28]

[27] In this case, significant changes in market availability are characterized by two main phenomena: most of the resource capability in the region being on the east side and the most of the load served on the west side; in conjunction with significant load resource balance swings in California affecting the market availability in the entire WECC.

[28] Note that the two light load hour curtailments are just before the morning ramp, so it could be that the effect of the load ramp started earlier in those instances.

CHAPTER 17: MODEL CONSERVATION STANDARDS

Contents

INTRODUCTION

The Northwest Power Act directs the Council to adopt and include in its power plan model conservation standards (MCS) applicable to (i) new and existing structures; (ii) utility, customer, and governmental conservation programs; and (iii) other consumer actions for achieving conservation. The Act requires that the standards reflect geographic and climatic differences within the region and other appropriate considerations. The Act also requires that the Council design the MCS to produce all power savings that are cost-effective for the region and economically feasible for consumers, taking into account financial assistance from the Bonneville Power Administration and the region's utilities.

In addition to the requirements set forth in the Act, the Council believes the model conservation standards in the plan should produce reliable savings and that the standards should, where possible, maintain and improve upon the occupant amenity levels (e.g., indoor air quality, comfort, window areas, architectural styles, and so forth) found in typical buildings constructed before the first standards were adopted in 1983.

The Power Act provides for broad application of the MCS. In the earlier plans, a strong emphasis was needed to improve residential and commercial building construction practices beyond the existing codes. Beginning with the first standards adopted in 1983, the Council has adopted a total of six model conservation standards. These include the standard for new electrically heated residential buildings, the standard for utility residential conservation programs, the standard for all new commercial buildings, the standard for utility commercial conservation programs, the standard for conversions to electric heating systems, and the standard for conservation programs not covered explicitly by the other model conservation standards.[1] Since the Council adopted its first standards, all four states within the Northwest have adopted strong energy codes that incorporate the model conservation standards set forth in previous plans.

OVERVIEW

Since there are few cost-effective measures beyond current and proposed building energy codes in the region, the Seventh Power Plan MCS focuses on the other aspects of the Power Act provision: utility, customer, and governmental conservation programs, and other consumer actions for achieving conservation. The MCS for the Seventh Power Plan has two main components. The first is an expansion of the standard for utility conservation programs. The utility conservation program standards are the same as in the Sixth Power Plan at a high level, but the Council adopts three specific components to the existing standard to ensure adoption and implementation. The specifics include (1) standards to achieve full participation in programs, (2) incorporation of voltage optimization in distribution systems, and (3) enhancement of codes and standards. Second, it provides the standard for conversions (similar to prior MCS) from an electric space or water heating system from another fuel.

[1] This chapter supersedes the Council's previous model conservation standards and surcharge methodology.

CONSERVATION PROGRAM STANDARDS

This model conservation standard applies to all conservation actions except those covered by the standard for electric space conditioning and electric water heating system conversions. This model conservation standard is as follows: All conservation actions or programs should be implemented in a manner consistent with the long-term goals of the region's electrical power system, as established in the Seventh Power Plan. In order to achieve this goal, the following objectives should be met:

1. Conservation acquisition programs should be designed to ensure that regionally cost-effective levels of efficiency are economically feasible for the consumer.
2. Conservation acquisition programs should be targeted at conservation opportunities that are not anticipated to be developed by consumers.
3. Conservation acquisition programs should be designed so that their benefits are distributed equitably.
4. Conservation acquisition programs should be designed to secure all measures in the most cost-efficient manner possible.
5. Conservation acquisition programs should be designed to take advantage of naturally occurring "windows of opportunity" during which conservation potential can be secured by matching the conservation acquisitions to the schedule of the host facilities or to take advantage of market trends. In industrial plants, for example, retrofit activities can match the plant's scheduled downtime or equipment replacement; in the commercial sector, measures can be installed at the time of renovation or remodel.
6. Conservation acquisition programs should be designed to capture all regionally cost-effective conservation savings in a manner that does not create lost-opportunity resources. A lost-opportunity resource is a conservation measure that, due to physical or institutional characteristics, will lose its cost-effectiveness unless actions are taken now to develop it or hold it for future use.
7. Conservation acquisition programs should be designed to maintain or enhance environmental quality. Acquisition of conservation measures that result in environmental degradation should be avoided, mitigated or minimized.
8. Conservation acquisition programs should be designed to enhance the region's ability to refine and improve programs as they evolve.

The focus of the Seventh Power Plan MCS is on three areas intended to improve program design and delivery. These include

- Ensuring full participation in programs;
- Achieving voltage optimization; and,
- Enhancing codes and standards.

Standard to Ensure Full Participation in Programs

The model conservation standard to ensure full participation in programs is as follows: To ensure that the region captures all regional cost-effective savings, utilities should secure proportional savings from hard to reach populations. Implementation of Action Plan item MCS-1 is required to satisfy this standard.

The data collected by the Council through the Regional Technical Forum's Regional Conservation Progress report show that the region has exceeded the Council Plan's targets every year since 2005. However, this does not necessarily mean that the region has captured all-cost effective savings identified in the Plan. In pursuing all cost-effective conservation, there are segments of the population that typically participate in programs at lower rates than others, often due to cost barriers. These segments can be classified as "hard to reach (HTR)" or "underserved". Although low-income customers are often an underserved segment, other hard-to-reach (HTR) segments may include: mid-income customers, customers in rural regions, small businesses owners, commercial tenants, multifamily tenants, manufactured home dwellers, and industrial customers if they are unable or unwilling to participate in conservation programs.

The up-front cost required to purchase or install higher efficiency products or technology is often a significant barrier to HTR consumer adoption of energy-efficient measures, particularly for low- and moderate-income customers. Regional entities (including Bonneville, utilities, Energy Trust of Oregon, Northwest Energy Efficiency Alliance [NEEA]) frequently provide financial incentives to consumers to overcome this barrier, but these financial incentives usually only cover a portion of the measure's cost. The requirement for "cost-sharing" and other program design elements or marketing approaches limits the number of consumers who can participate in energy efficiency programs and thus the amount of cost-effective savings that can be achieved.

Voltage Optimization Standard

The model conservation standard for voltage optimization is as follows: The standard requires utilities to assess and implement all cost-effective potential for voltage optimization on their distribution systems. Significant savings could be acquired by optimizing the distribution system using optimization of voltage and reactive power (known as Volt/VAR Optimization or VVO) or conservation voltage regulation (CVR), per the analysis of distribution system savings for the conservation supply curves (see Chapter 12 and Appendix G). Completion of Action Plan item MCS-2 that calls for evaluation of savings on utility distribution circuits and implementation of all cost-effective conservation within a reasonable timeframe are required to satisfy this standard.

Enhance Codes and Standards

The standard requires states and utility-funded programs, including NEEA, to continue to work together to develop conservation options that could be included in future codes and standards updates. Implementation of Action Plan items MCS-3 through MCS-7 that call for a review of state codes, improved federal test procedures utilizing data from the region, pilot programs for emerging technologies that may be included in codes and standards, regional input on federal standards updates, and development of best practices guides for processes not covered by codes or standards are required to satisfy this standard.

One of the most cost-efficient ways to ensure adoption of conservation measures is through their enactment as codes and standards. Some examples include:

- Commercial building energy reductions – include variable refrigerant flow systems, low lighting power densities, and dedicated outside air systems
- Industrial processes, including indoor agriculture and data centers – develop best practice guides to run processes as efficiently as possible
- Federal standards test procedures – develop data in support of the federal standard test procedures to accurately predict in-field energy use of regulated products

CONVERSION TO ELECTRIC SPACE CONDITIONING AND WATER HEATING

The model conservation standard for existing residential and commercial buildings converting to electric space conditioning or water heating systems is as follows: State or local governments or utilities should take actions through codes, service standards, user fees or alternative programs or a combination thereof to achieve electric power savings from such buildings. These savings should be comparable to those that would be achieved if each building converting to electric space conditioning or water heating were upgraded to include all regionally cost-effective electric space conditioning and water heating conservation measures.

SURCHARGE RECOMMENDATION

The Power Act authorizes the Council to recommend a surcharge and the Bonneville Administrator may thereafter impose such a surcharge on customers that have not implemented conservation measures that achieve energy savings comparable to those which would be obtained under the Model Conservation Standards in the plan. The Council does not recommend a surcharge to the Administrator under Section 4(f) (2) of the Act at this time.

The Council intends to continue to track regional progress toward the Plan's MCS and will review its decision on the recommendation, should accomplishment of these goals appear to be in jeopardy. Should utilities fail to enact these standards, then Bonneville may need the ability to recover the cost of securing those savings. In this instance the Council may wish to recommend that the Administrator be granted the authority to place a surcharge on that customer's rates to recover those costs.

Surcharge Methodology

Section 4(f)(2) of the Northwest Power Act directs the Council to include a surcharge methodology in the power plan. The surcharge must, per the Act, be no less than 10 percent and no more than 50 percent of the Administrator's applicable rates for a customer's load or portion of load. The surcharge is to be applied to Bonneville customers for those portions of their regional loads that are within states or political subdivisions that have not, or on customers who have not, implemented conservation measures that achieve savings of electricity comparable to those that would be obtained under the model conservation standards.

The purpose of the surcharge is twofold: 1) to recover costs imposed on the region's electric system by failure to adopt the model conservation standards or achieve equivalent electricity savings; and 2) to provide a strong incentive to utilities and state and local jurisdictions to adopt and enforce the standards or comparable alternatives. The surcharge mechanism in the Act was intended to ensure that Bonneville's utility customers were not shielded from paying the full marginal cost of meeting load growth.

As stated above, the Council does not recommend that the Administrator invoke the surcharge provisions of the Act at this time. However, the Act requires that the Council's plan set forth a methodology for surcharge calculation for Bonneville's administrator to follow.

Should the Council alter its current recommendation to authorize the Bonneville administrator to impose surcharges, the method for calculation is set out below.

Identification of Customers Subject to Surcharge

The administrator should identify those customers, states or political subdivisions that have failed to comply with the model conservation standards set forth within this chapter.

Calculation of Surcharge

The annual surcharge for non-complying customers or customers in non-complying jurisdictions is to be calculated by the Bonneville administrator as follows:

1. If the customer is purchasing firm power from Bonneville under a power sales contract and is not exchanging under a residential purchase and sales agreement, the surcharge is 10 percent of the cost to the customer of all firm power purchased from Bonneville under the power sales contract for that portion of the customer's load in jurisdictions not implementing the model conservation standards or comparable programs.

2. If the customer is not purchasing firm power from Bonneville under a power sales contract, but is exchanging (or is deemed to be exchanging) under a residential purchase and sales agreement, the surcharge is 10 percent of the cost to the customer of the power purchased (or deemed to be purchased) from Bonneville in the exchange for that portion of the customer's load in jurisdictions not implementing the model conservation standards or comparable programs.

If the customer is purchasing firm power from Bonneville under a power sales contract and also is exchanging (or is deemed to be exchanging) under a residential purchase and sales agreement, the surcharge is: a) 10 percent of the cost to the customer of firm power purchased under the power sales contract; plus b) 10 percent of the cost to the customer of power purchased from Bonneville in the exchange (or deemed to be purchased) multiplied by the fraction of the utility's exchange load originally served by the utility's own resources.

Evaluation of Alternatives and Electricity Savings

A method of determining the estimated electrical energy savings of an alternative conservation plan should be developed in consultation with the Council and included in Bonneville's policy to implement the surcharge.

CHAPTER 18: COORDINATING WITH REGIONAL TRANSMISSION PLANNING

Contents

KEY FINDINGS

The Council should continue to coordinate resource data with organizations responsible for regional transmission planning. This leads to more accurate planning for both resource and transmission expansion.

REGIONAL TRANSMISSION PLANNING AND THE POWER ACT

The Power Act defines a resource as electric power or actual or planned load reduction.[1] The Act directs the Council to develop a general scheme for implementing conservation measures and developing resources with priority to be given to those resources which the Council determines to be cost-effective. The Act does not require the Council to develop a transmission plan for new resources.

The Act does, however, direct the Council to consider transmission and distribution costs to the consumer when determining whether a resource is cost-effective. Thus this plan includes estimates of costs associated with transmission and distribution for both conservation and generating resources. See chapters 12 and 13 for more information.

Convergence of Resource and Transmission Planning

Historically, regional transmission planning has occurred as a separate and distinct undertaking from resource planning. However, as the power system has become more complex with the addition of variable resources, distributed generation and demand response measures, both transmission and resource planners have come to realize that a more coordinated planning effort is needed. To that end, transmission planners have moved to adopt similar models and methods to those used by resource planners. The Western Electricity Coordinating Council (WECC), ColumbiaGrid and the Northern Tier Transmission Group (NTTG) all currently use production cost models that are similar to models used by resource planners in the region. These production cost models use data that is consistent with data used in the AURORAxmp model and in the Regional Portfolio Model, both of which were used to develop this power plan. See chapters 8 and 15 for more information.

This convergence of modeling and planning methods has created both the need and opportunity for the Council to coordinate more closely with transmission planning organizations on data and analyses. The Council has and will continue to participate in the long-term transmission planning committees and forums whenever these opportunities arise.

[1] The Pacific Northwest Electric Power Planning and Conservation Act defines "resource" as "electric power, including the actual or planned electric power capability of generating facilities, or actual or planned load reduction resulting from direct application of a renewable energy resource by a consumer, or from a conservation measure." (Northwest Power Act, Section 3(19)(A) and (B)).

Coordination on Planning Data

The Transmission Expansion Planning Policy Committee (TEPPC) at WECC is chartered to oversee and maintain a public database for production cost and related analysis. All three transmission planning organizations, WECC, ColumbiaGrid and NTTG, use the database produced by TEPPC in their planning activities. To ensure coordination with these regional transmission planning entities, the Council also works with TEPPC to verify that Council assumptions for generating resources are similar to those used by TEPPC[2].

[2] See Chapter 4 ANLYS-24 and ANLYS-25 for transmission action items related coordination with regional transmission planners and TEPPC, respectively.

CHAPTER 19: METHODOLOGY FOR DETERMINING QUANTIFIABLE ENVIRONMENTAL COSTS AND BENEFITS AND DUE CONSIDERATION FOR ENVIRONMENTAL QUALITY, FISH AND WILDLIFE, AND COMPATIBILITY WITH THE EXISTING REGIONAL POWER SYSTEM

Contents

KEY FINDINGS

One of the Northwest Power Act's required elements for the Council's power plan is "a methodology for determining [the] quantifiable environmental costs and benefits" of electric generating and conservation resources.[1] Having a method for determining environmental costs and benefits is an important part of the Council's effort to estimate and compare total costs of new resources and choose those that are the most cost-effective. In this chapter, the Council describes the methodology it is using to determine these quantifiable environmental costs and benefits. Implementation of the methodology is described in other chapters, particularly in the chapters on generating and conservation resources.

The primary method the Council has used to include quantifiable environmental costs in power planning has been to incorporate estimated costs of compliance with environmental regulations in the capital and operating costs of conservation and generating resources. These regulations reflect environmental policy choices that already have been made by governments and society, and the costs associated with compliance are directly attributable to the resource and largely quantifiable. The Council used this method through the first six power plans, and it is again central in developing the Seventh Power Plan.

The Council is deciding again in the Seventh Power Plan that it is not possible to develop quantitative cost estimates related to residual effects that remain after regulatory compliance and add them into new resource cost estimates in any reasonable way. Instead, the Council gives due consideration to residual and unregulated environmental effects that are hard to quantify through other means, including through scenario analysis and possibly qualitative risk adjustments or contingencies in the resource strategy.

The Act also instructs the Council to set forth its conservation and generation resource strategy in the power plan "with due consideration" for, among other things, "environmental quality" and "protection, mitigation, and enhancement of fish and wildlife and related spawning grounds and habitat, including sufficient quantities and qualities of flows for successful migration, survival, and propagation of anadromous fish." In addition to these factors, the Council is to give "due consideration" to the "compatibility with the existing regional power system" of the new resources considered for development in its plan.[2] This chapter also describes how the Council is giving due consideration to all these factors in crafting the resource strategy.

[1] Northwest Power Act, Section 4(e)(3)(C). The Act is available on the Council's website at http://www.nwcouncil.org/reports/poweract/.
[2] Northwest Power Act, Section 4(e)(2).

METHODOLOGY FOR DETERMINING QUANTIFIABLE ENVIRONMENTAL COSTS AND BENEFITS

In developing the new resource strategy for the power plan, the Northwest Power Act requires that the Council compare the "incremental system cost" of different generating and conservation resources and give priority to those resources which the Council determines to be "cost-effective." In estimating the system cost of a particular resource, the Council must include any quantifiable environmental costs and benefits associated with that resource over its effective life.[3] Section 4(e)(3)(C) of the Act then requires that the Council also include in the power plan the "methodology" the Council develops "for determining quantifiable environmental costs and benefits under section 3(4)," the section that defines what it means for a resource to be considered "cost effective." The development and application of the methodology to quantify the environmental costs and benefits of resources is thus one important part of the work the Council is required to do in the development of its power plan in order to identify the most cost-effective conservation and generating resources to recommend for addition to the region's power system over the twenty-year plan period.[4]

Several key concepts in developing a methodology are embedded in the language of the Act. One is that the methodology is to consider costs and benefits to the "environment," as opposed to other types of costs. Another is that the costs and benefits have to be "quantifiable," recognizing that not all environmental effects can be reduced to quantified costs and benefits. Moreover, the costs and benefits must be "directly attributable" to the resource, not incidental or indirect. Since none of these terms is defined in the Act, the Council has historically applied a common-sense understanding of these terms, as guided by the context of the Act and the discussions in the legislative history. For

[3] Northwest Power Act, Sections 3(4), 4(e)(1).

[4] Note that the Act states that the Council's estimates of the "system cost" for the various new conservation measures and generating resources must include "such quantifiable environmental costs and benefits *as the [Bonneville] Administrator determines, on the basis of a methodology developed by the Council as part of the plan* … are directly attributable to such measure or resource." Northwest Power Act, Section 3(4)(B). Read strictly, the Council is to develop the methodology and include it in the plan. Then Bonneville is to use that methodology from the plan to determine the quantifiable environmental costs and benefits to assign to particular resources. Then, the Council would need to take Bonneville's determination of quantifiable environmental costs and benefits and incorporate those numbers into the total resource cost estimate of each new resource being considered for incorporation into the 20-year resource strategy – in the power plan. The back-and-forth mechanism is not workable in practice, as the Council is required to both develop the quantification methodology and to use the resulting numerical estimate in the same draft and then final power plan. There is no explanation in the Act or in its legislative history for why Congress chose such a cumbersome mechanism. Practical experience quickly showed this to be unworkable for the power planning process from the outset, as it would make it impossible for the Council to timely prepare the power plan called for by Congress, the centerpiece of which is to be a conservation and generating resource strategy in which the resources are chosen on the basis of a cost-effectiveness comparison that begins by estimating all direct costs of the resources, including environmental cost estimates. In other words, the Council has to be able to develop *and* apply, in the same power planning process, the methodology for quantifying environmental costs and benefits in order for the Council to be able to select the most cost-effective resources for the plan. The customary practice has therefore been for the Council to provide Bonneville (and others) with the opportunity during the development of the draft power plan, and again between the draft and final power plans, to weigh in on the Council's estimates of environmental costs. This is the course the Council and Bonneville have followed in all previous power plans, and how the Council is proceeding in the Seventh Power Plan.

the most part, whether and what costs are “environmental” in nature, or “quantifiable,” or “directly attributable” has been without significant controversy. But questions about the meaning and application of these concepts do occur, and at times the Council has to exercise its judgment and discretion in making these determinations on a reasonable basis.

Even if environmental effects of resources cannot be quantified as costs or benefits, that does not mean these effects are irrelevant in the Council’s power planning process. Section 4(e)(2) of the Act calls for the Council to develop the scheme for implementing conservation measures and developing generating resources “with due consideration” for, among other things, “environmental quality” and the “protection, mitigation, and enhancement of fish and wildlife and related spawning grounds and habitat, including sufficient quantities and qualities of flows for successful migration, survival, and propagation of anadromous fish.” Important environmental effects that cannot be quantified as hard resource cost estimates are still taken into consideration in some fashion by the Council through these provisions. That is the subject of the second part of this chapter.

Costs of compliance with environmental regulations

The primary method the Council has used to include quantifiable environmental costs in power planning has been to incorporate the estimated costs of compliance with environmental regulations in the capital and operating costs of conservation and generating resources. The Council used this method through the first six power plans, and it is again central in developing the Seventh Power Plan.

The Council’s planning assumes that all generating and conservation resources – existing and new -- will meet existing federal, state, tribal, and local environmental regulations. Therefore, the Council includes what it estimates to be the costs of compliance with these regulations as part of the total cost estimates for new resources. This includes the costs of complying with regulations governing fuel extraction and production, air and water emissions, land use siting protections, waste disposal, and fish and wildlife protection and mitigation. These regulations reflect environmental policy choices that already have been made by governments and society, and costs associated with compliance are directly attributable to the resource and largely quantifiable.

Generating resource characteristics are described in Chapters 9 (existing generating resources) and 13 (new generating resource alternatives), Chapter 12 discussed distributed solar photovoltaic generating resources and conservation resources. Together with the much more detail in Appendix I on the environmental effects of electric power production, these descriptions include known environmental effects from the use of each resource and any environmental regulations that address these effects. Chapter 13 also identifies the estimated capital and operating costs of new generating resource alternatives, which include estimated capital and operating costs to comply with environmental regulations. The environmental compliance costs are not always able to be broken out and displayed separately, as they form just one of the many elements of the capital installment costs or the ongoing fixed and variable operating costs. However, to the extent practicable, the costs for new generating resources are based on equipment or projects that satisfy known environmental regulations. Chapter 12 describes the conservation measures analyzed as part of the plan, including their costs. Those costs also include whatever environmental compliance costs that are quantifiable and directly attributable to these measures.[5]

The Council's cost estimates in the plan for new resource alternatives are provided at different levels of detail. Resource alternatives whose estimated levelized costs are low enough to be likely candidates for selection in the plan's resource strategy have the most detailed cost estimates, and the costs are included in the Regional Portfolio Model. These include a variety of natural gas-fired plants, wind, conventional geothermal and solar generation, and a variety of conservation and demand response measures. The Council did not develop detailed resource cost estimates for new resource alternatives that have no chance to be selected for the resource strategy based on a preliminary assessment of costs, lack of commercial availability, or lack of significant generating potential (or some combination of all three factors). This includes, at this time, the siting of new coal or nuclear thermal plants in the region. Thus the environmental compliance cost estimates for those plants are less developed in the plan.

One other issue concerns how to account for environmental regulations that have been proposed by an agency with regulatory authority, but which the agency has not yet finalized. The Council could address proposed regulations in a number of ways in the new resource cost estimates, decided on a case-by-case basis as circumstances allow. For the Seventh Power Plan, the only proposed regulation significantly relevant in the early stages of the analysis of new resource costs was the Environmental Protection Agency's proposed regulation of greenhouse gas emissions from new, modified or reconstructed power plants, under §111(b) of the Clean Air Act. EPA issued a final regulation on August 3, 2015.[6]

Whether and how to address regulatory compliance and compliance costs for natural gas plants with new carbon emission regulations proposed and then finalized under §111(b) has been a relatively simple consideration. This is because EPA designed the proposed rule so that the most efficient new-generation gas-fired plants comply with the new emissions standards. Plants which meet or exceed EPA's §111(b) regulations were selected for consideration in the power plan resource strategy. The capital and operating costs of these new gas plants are included in the cost estimates highlighted in Chapter 13 and included in the Regional Portfolio Model.

Compliance costs for a new coal-fired power plant might be more difficult to assess and compare. However, as noted above, the Council did not need to develop for the Seventh Power Plan detailed resource cost estimates for new coal plants with detailed estimates of the costs of compliance with the emissions standards proposed and then just finalized by EPA under §111(b). This is because preliminary analyses indicated that a new coal plant would not be a cost-effective resource to include in the resource comparison or the resulting resource strategy. This was because costs of

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[5] The role in the power plan of the estimated costs of environmental compliance for *existing* generating resources is not relevant to the methodology for determining and comparing the estimated costs of new resources, and is discussed instead in the second part of this chapter.

[6] http://www.epa.gov/airquality/cpp/cps-final-rule.pdf. The final rule became effective in December of 2015. A number of states and other entities have filed for judicial review in the federal Circuit Court of Appeals for the District of Columbia. That litigation is pending as of the final Seventh Power Plan.

meeting existing state-level requirements indicate that new coal plants would not be a cost-effective resource for the region and hence not likely to be built in the region within the 20-year plan period. Instead, many of the region's existing coal plants are retiring early, due primarily to the economics of compliance with these and other regulations.

The Council also considered the fugitive methane emissions from the production and transportation of natural gas, as well as from coal production during the development of the Seventh Power Plan. Methane is a highly active greenhouse gas, with global warming potential 28 to 36 times that of carbon dioxide. However, they are not yet the subject of significant regulation, although the Environmental Protection Agency is expected to propose regulations in 2016. The costs for the natural gas fuel for new natural-gas power plants thus include whatever costs industry incurs and passes on to reduce methane emissions through best practices and new technologies. But the costs do not currently include regulatory compliance costs, as no direct regulations exist. Chapters 3 and 13 and Appendix I describe in more detail how the Council considered methane emissions in developing its resource strategy. A general description appears below.

Residual environmental effects after compliance with environmental regulations

Compliance with environmental regulations reduces the impact of new resources on the environment, and the financial costs of that compliance can be quantified. Environmental regulation usually controls or mitigates for a large portion but not all of the effects on the environment from a new resource. Examples are obvious: not all emissions from a fossil fuel-fired power plant are controlled by regulation; not all bird kills from wind turbine operations are prevented; not all adverse effects on fish habitat from a new hydropower resource are prevented or mitigated. The issue for the Council's methodology is whether and how to consider environmental effects not prevented or mitigated completely by environmental regulations, and in particular whether these residual effects can in some way be quantified as environmental resource costs and included in the comparison of new resource system costs.

In most cases, the relevant regulatory body has determined that further reduction in environmental effects is not necessary to protect the public interests, or that the additional costs of further reduction significantly outweighs the benefits. One approach the Council could take is to decide that these residual effects do not constitute damage or "cost" at all. It is within reason to say that the relevant government entities authorized to address these environmental effects have already determined, through the environmental regulations they have enacted, the environmental costs of these resources.

Even so, the Council has recognized in past power plan methodologies that residual environmental effects do exist and should be considered in power planning in some way, even if not through quantitative assigning of dollar costs to those effects. Moreover, the Council recognizes that this category logically includes not just residual environmental effects after regulatory compliance, but also environmental damage or social costs of environmental effects that are not yet comprehensively regulated, such as an environmental cost related to the methane emissions associated with the production and use of natural gas. Recognizing that effects exist is one thing; quantification of these effects as resource costs has been a different issue, however. The Council's past experience has been that the methods and information have not been sufficient to allow for reasonable estimates of the costs to society of environmental effects that exist after regulatory compliance.

The Council is deciding again in the Seventh Power Plan that it is not possible to develop quantitative cost estimates related to these residual effects and add them into the new resource cost estimates in any reasonable way. There are a number of reasons for this. One reason is that in most cases the existing information is simply not sufficient to identify reasonable quantitative estimates of costs for these effects, at least not without dedication of more staff and agency resources to this one task than the Council has available. Another is that while information may be sufficiently available to incorporate costs of this nature for a very few environmental effects, (such as the "social cost of carbon" estimates developed by the U.S. Interagency Working Group on Social Cost of Carbon), the lack of consistent treatment across the range of residual and unregulated effects would likely skew the new resource cost comparisons in an unreasonable way. Third, it is useful to be able to compare new resource costs at the level of the costs actually imposed on the power system itself, as the costs of adverse environmental effects have already been internalized to a great degree through regulation. Instead, the Council gives due consideration to residual and unregulated environmental effects that are hard to quantify through other means, including through scenario analysis and possibly qualitative risk adjustments or contingencies in the resource strategy.

The best example in this power plan relates to the social or damage cost of carbon emissions, the area in which arguably the best information exists about efforts to quantify social or damage costs of a resource that go beyond regulatory compliance costs. The Council is not adding an estimate of the social cost of carbon to the baseline new resource cost estimates for new gas plants. This is in part because EPA *used* the social cost of carbon estimates developed by the Interagency Working Group to develop the emission standards for new gas and coal plants under §111(b), deeming the proposed regulations as protective of society from these damage costs. Moreover, adding a "social cost of carbon" cost estimate to the costs of a gas plant, but not, for example, a cost estimate for the social costs of the adverse effects to fish and wildlife resulting from the residual effects of a new renewable resource – effects that presumably exist, but for which there is not good information for reasonable quantification – would skew the resource cost comparison. Instead, as described in Chapter 15 in particular, the Council analyzed several scenarios in which a "cost of carbon" has been added to reflect the not-yet-regulated effects and damage from carbon emissions, from both new and existing sources. The resulting resource strategies with these carbon costs are compared to each other and to scenarios that do not include such costs or reflect other forms of carbon policies and costs.

While burning natural gas produces significantly less carbon dioxide emissions per unit of electricity generation than coal, its production and distribution releases methane into the atmosphere. Methane is a highly active greenhouse gas, with a global warming potential per unit of mass that is 28 to 36 times that of carbon dioxide.[7] Recent studies have indicated that fugitive emissions of methane from some natural gas and oil production areas could be as high as 10 percent. In contrast, fugitive

[7] See Appendix I for a more complete description of methane's potential environmental impacts and the uncertainties surrounding fugitive emission sources and levels.

methane emissions from new production facilities and pipelines have been shown to be far lower, on the order of one percent. In developing the resource strategy for the Seventh Power Plan, the Council seriously considered whether the carbon dioxide reduction benefits of the increased use of natural gas would be significantly offset by increases in methane emissions. The Council determined that the cost of reducing fugitive methane emissions to an acceptable level would not significantly alter the price of natural gas and that the impact on natural gas prices of these potential regulations was within the range of the natural gas prices assumed for the Seventh Plan's development.[8]

Quantifiable environmental benefits

The Act calls for a methodology to be capable of determining not only the quantifiable environmental costs, but also the quantifiable "environmental benefits" of new resources. In past power plans, the concepts and existing information have not been sufficient to allow the Council to quantify in dollar terms the environmental benefits of new resources, or even to identify these benefits and beneficial effects other than in a general sense. The only example even close to this concept that has been factored into the resource cost estimates in the past involved investments in new energy-efficient clothes washers and dishwashers. These washers not only save energy but also reduce the amount of water used. As a proxy for the environmental benefit associated with less water use and thus the need for less water and wastewater treatment, the Council used the reduced water and wastewater bills paid by consumers who directly benefit as part of the resource cost estimates for the more efficient clothes washers. The reductions in the amount of water also benefit the environment, although the broader environmental benefits in this one example have not been quantified, and would be difficult or impossible to quantify reasonably.

The particular issue for the Seventh Power Plan has been whether the Council can and should factor into the costs of a new resource a quantitative estimate of the environmental benefit of being able to reduce some existing activity that has an environmental cost. That is, whether and how to account for environmental benefits that occur when an existing harmful environmental activity can be reduced or eliminated by an investment in a new power system resource.[9]

The example that dominated the discussions of the Seventh Power Plan has been the fact that installing energy-efficiency measures (such as a ductless heat pump) in a home where wood is burned for heat may result in less burning of wood and thus reduced particulate air emissions. The reduction in particulate emissions benefits the environment and human health, especially in areas that are not in attainment with particulate emissions standards. The question is whether and how to account for these benefits in assessing the costs of the energy-efficiency measure itself; that is, in the estimate of what it costs to install and operate the ductless heat pump in a house that also burns

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[8] See Chapter 13 and Appendix I for a discussion of the potential impacts on natural gas prices from regulations designed to reduce methane emissions at new and existing facilities.

[9] Note that it does not make sense to include as a quantified "benefit" in the resource cost estimate of one new resource (e.g., a conservation measure) the fact that the region could avoid investments in another new resource with an environmental cost (e.g., a coal plant). As long as the environmental costs of the second new resource are properly captured in its resource cost estimates that is sufficient -- to do more would constitute double counting the same quantified effect.

wood to heat. The consumer savings in reduced wood purchases – like the water savings attributable to energy efficient washers – are a direct benefit of installing the ductless heat pump, savings that can be quantified and are included in the resource costs. The broader environmental and health benefits are a more difficult challenge, however. Clearly the Council (and the region) should consider these benefits to the environment and public health in some fashion in conservation planning and in developing new resource strategies. But the questions for the power plan methodology itself have been whether it is possible to quantify in dollars – as part of the "costs" of the ductless heat pump for comparison to other resources – the health and environmental benefits that result from burning less wood and reducing air emissions, and whether these quantified benefits could be said to be the "direct" benefits of and "directly attributable" to the new resource (e.g., the installation of the ductless heat pump), or incidental or indirect as the result of contingent behavior choices (e.g., some people might choose to burn less wood after installation; others might choose to burn as much as before so as to be warmer). All these questions make it difficult to quantify in dollars (for the new resource cost estimates) in a systematic way the broad environmental benefits that may be related to investments in certain resources.

The issues with regard to any effort to try to quantify environmental benefits are similar to those discussed above with regard to residual environmental effects and the concepts of environmental and social damage costs. Reasonable quantitative estimates in dollars for the bulk of environmental benefits of this nature do not exist. The Council does not have the resources or capability to develop them even if it were possible – the Council is a power planning entity and not a general environmental quality agency, and so is dependent on the work of others in this realm and relies on existing information. Moreover, broader environmental effects are rarely as directly attributable to the relevant resource or conservation measure as other costs or as any consumer savings that might directly accrue. To incorporate figures for a few environmental benefits of this type (even if that were possible) but not for most could lead to oddly skewed resource cost comparisons, and to a situation in which some resources are compared on the basis of costs and benefits the power system directly bears to other resources that include a value not borne by the power system. For all these reasons, the Council decided not to attempt to engage in piece-meal quantification of a few environmental benefits to add to resource costs. At the same time, the Council is including an item in the Action Plan (Chapter 4) to further study the issue of non-energy benefits that result from conservation measures.

The general principles described apply to the one example studied during the beginning of the planning process – the wood smoke example. For these reasons the Council concluded it was not able at this time to quantify in dollars these broader environmental benefits and add them directly into the base resource cost estimates for these conservation measures. At the same time, the Council recognizes and gives consideration to the very real environmental and human health benefits that result from these energy-efficiency investments and the resulting reduction in particulate emissions. The Council developed the conservation supply curves for the Seventh Power Plan without including an estimate of the health benefits, but is separately describing and highlighting the environmental and health benefits associated with these measures. See Chapter 12. Utilities and other entities in the region that invest in these measures may well be justified by the social benefits of reduced particulate emissions, regardless of whether the measures are cost-effective as compared to other energy-efficiency measures or generating resources on the basis of the energy costs and benefits alone.

DUE CONSIDERATION FOR ENVIRONMENTAL QUALITY; FOR PROTECTION, MITIGATION, AND ENHANCEMENT OF FISH AND WILDLIFE; AND FOR COMPATIBILITY WITH THE EXISTING REGIONAL POWER SYSTEM

Section 4(e)(2) of the Northwest Power Act sets for a list of considerations the Council has to take into account *as* the Council develops the new resource strategy for the power plan:

> "The plan shall set forth a general scheme for implementing conservation measures and developing resources pursuant to section 6 of this Act to reduce or meet the Administrator's obligations with due consideration by the Council for (A) environmental quality, (B) compatibility with the existing regional power system, (C) protection, mitigation, and enhancement of fish and wildlife and related spawning grounds and habitat, including sufficient quantities and qualities of flows for successful migration, survival, and propagation of anadromous fish, and (D) other criteria which may be set forth in the plan."[10]

This part of Chapter 19 illustrates how the Council gave consideration to these factors in developing the Seventh Power Plan. Note that the considerations listed in the Act are not general considerations of what is best for environmental quality in the Northwest, nor what is best for fish and wildlife, nor what is the best future course for the power system's existing resources. The Council is not an environmental quality agency, a fish and wildlife agency, or an owner or operator of existing plants. The considerations for the Council at this point instead are quite specific to developing the new conservation and power resource strategy to reduce or meet Bonneville's obligations: What can the Council do -- as it analyzes new resource alternatives and selects the resource strategy's mix of new conservation measures, generating resources, and demand response measures -- to assess, protect, and enhance the region's environmental quality and fish and wildlife resources? And do so with a resource strategy that is also compatible with the existing region power system and sustains its benefits.

The Council considers these factors while also complying with its other responsibilities under the Act in developing the resource strategy and the power plan. For example, other provisions of the Act and the Council's analyses might drive the Council towards including a robust set of conservation measures as part of the power plan resource strategy. But the required considerations of environmental quality and fish and wildlife and compatibility with the existing system add important weight to that strategy, too. Aggressive and ongoing implementation of energy-efficiency measures is not just a lower cost way of maintaining benefits of the regional power system. Such a strategy

[10] The reference to "section 6" of the Act is to the section of the Northwest Power Act authorizing Bonneville to acquire new resources, and specifying the conditions, standards and procedures for doing so, including consistency with the Council's power plan.

also helps the region avoid or delay development of generating resources that have adverse effects on the environment and fish and wildlife, whether those effects can be quantified as resource costs or not. In this sense, the factors listed in Section 4(e)(2) for due consideration in crafting the resource strategy are not separate and distinct concepts that the Council considers in a vacuum and that lead to separate and distinct power plan elements. Instead, these are considerations integrated into every aspect of the power plan analyses and elements at every stage of the power planning process, from decisions about resource inputs and assumptions to various modeling scenarios, to the final resource strategy.

In this context, it is also clear what this provision does not mean and what these considerations are not: Developing a new resource strategy for the power plan with due consideration to protecting, mitigation, and enhancing fish and wildlife does not mean that the Council, in the power plan, is to revisit or make new decisions on flow or other measures to protect, mitigate, and enhance fish and wildlife that were the subject of the Council's decisions in its fish and wildlife program. The development of the fish and wildlife program with its measures and objectives to protect, mitigate, and enhance fish and wildlife comes from a separate process the Council is to follow, set forth in Section 4(h) of the Act. The Act requires the Council to develop the fish and wildlife program *prior* to the review of the power plan. And the procedures and standards in Section 4(h) highly circumscribe the development of the fish and wildlife program by the Council, including provisions that require the Council to base the program's measures and objectives largely on the recommendations from state and federal fish and wildlife agencies and the region's Indian tribes that begin the program amendment process. See Chapter 20. Thus subsequently crafting a new resource strategy for the power plan under Sections 4(d-g) of the Act while giving due consideration to fish and wildlife does not allow or require the Council to revisit what the measures and objectives for fish and wildlife should be.

Similarly, the "due consideration" factors in Section 4(e)(2) do not authorize or allow the Council to make decisions in the power plan to change, shut down, or remove existing power system resources. The Council does not have the authority or the direction from Congress to make decisions on whether existing resources are removed or shut down. Moreover, the legal implications of the power plan for Bonneville are in guiding Bonneville's acquisitions of new resources under Section 6 of the Act. The power plan does not guide decisions Bonneville might make with regard to investments in maintenance, operation, or upgrades to existing resources. To the contrary, one of the due considerations for the Council in developing the plan's resource strategy is, as noted above, how compatible that resource scheme is with the existing regional power system.

Within that context, the following examples illustrate how the Council gave due consideration for environmental quality, fish and wildlife, and compatibility with the existing system in developing the resource strategy for the Seventh Power Plan:

The Council analyzed and documented the effects of new and existing resources on the environment and fish and wildlife. The generating resource chapters (Chapters 9 and 13, together with Appendix I) provide significant detail on what is known about the effects of both new and existing generating resources and the region's associated transmission system on the environment and fish and wildlife. These chapters (and Chapter 20) and the appendix also describe the environment regulations and protection and mitigation efforts already in place to address these effects; the particular current environmental concerns and conflicts specific to the regional power system; and proposed and prospective regulations and policies being advanced by some to address these concerns. The estimated costs of compliance with environmental regulations have been included in the new resource costs, as described in the first part of this chapter. But the Council's analysis and considerations of power resource effects on environmental quality have gone well beyond what can be quantified in resource costs, and the Council duly weighed these considerations as it developed the resource strategy for the plan.

The Council developed estimates of the costs that existing system resources must bear to comply with environmental regulations, including significant new regulations that have been adopted since the last power plan. The Council went beyond just describing the effects of existing system resources on environmental quality and fish and wildlife and developed estimates of costs that existing system resources must bear to comply with environmental regulations, including significant new regulations that have come into effect since the last power plan. Many, but not all, of these new regulations affect coal-fired power plants, as described in Chapter 9 and Appendix I. The main reason the Council did so is based on the fact that whether existing plants are used (or dispatched) at any particular time and to what extent depends to a significant extent on their operating costs, as compared to operating costs that other plants bear and costs of buying power on the market. For the Council to be able to estimate what the region might expect in the future as output from the existing system resources, the Council needs to estimate these future operating costs, including estimates of the future operation and maintenance costs of compliance with environmental regulations. Including these costs in the analyses helps the Council understand under what conditions, to what extent, at what costs, and with what effects will the existing plants run. Understanding how much energy and capacity the existing system might produce and at what costs is important to know in order to assess the effects and costs of new resources that might be used to meet or reduce load not met by the output of the existing system and that may have less adverse environmental effects at the same time.

The owners and operators of existing plants may also incur future capital investments or may have to make significant structural and operational changes in order to comply with new environmental regulations. The Council developed estimates for these capital investments and effects as well. Assuming that plant owners make the capital investments necessary for compliance, then only ongoing operating costs and not capital investments affect in any substantial way whether plants dispatch and produce power at any particular time. For that reason these capital costs have not been entered into the regional portfolio model as relevant to whether the model (or the region) will operate these plants to produce power through the planning study. Even so, the owners of these plants will have to decide in the future if these capital investments for environmental compliance are worth making, or whether to cease or reduce or significantly alter operations and avoid these needed investments. Those business decisions are not for the Council, and so the Council assumes in the baseline analysis that the plants will continue to run and that the necessary capital investments will be made to comply with all new environmental regulations, unless the owners or regulators of the plants have scheduled their shutdown (as with the Boardman, Centralia, and North Valmy coal plants) or conversion to a fuel other than coal. The estimates of future capital costs for environmental compliance are then also part of total projected system costs, except in modeling scenarios in which plants have been removed from the system in order to analyze the effects on the new resource strategy and its costs (see Chapters 9 and 15 and below).

The Council considered the impacts of greenhouse gas emissions and climate change with regard to the existing power system in particular, as part of evaluating and developing resource strategies for the next 20 years that may reduce carbon emissions and help the system adapt to climate change. The environmental quality topics of primary interest in the Seventh Power Plan, as it was in the Sixth, have been carbon emissions from the power system and climate change. The description in the first part of this chapter of the methodology for quantifying environmental costs discussed this issue with regard to *new* resources. But most of the attention in the power plan process has been focused on the system's *existing* resources, especially the region's existing coal plants. Greenhouse gas emissions from the existing system and various policies in place or proposed to deal with them are described in Chapter 9 and Appendix I. Chapter 15 describes a set of scenarios that the Council ran to assess the implications for the power system of various ways to address and reduce greenhouse gas emissions from the existing system, including analyzing the effects of a range of carbon costs as a risk factor; adding in just one set cost for carbon emissions, based on the social cost of carbon work done by the federal Interagency Work Group; and reducing the emissions by reducing the output from the region's coal plants. The Council also assessed those and other scenarios for their effects on the ability of the region as a whole (not as individual states) to comply with the emissions standards for existing plants proposed and recently finalized by EPA under §111(d) of the Clean Air Act.[11] These scenarios analyses are intended to inform the region about the nature and costs of resource strategies that can reduce carbon emissions.

The Council is also assessing the effects of climate change itself on system resources and resource needs. This includes assessing the effects of a rise in winter and summer temperatures and thus changes in temperature-dependent loads, as well as changes in the output of the hydro system resulting from possible changes in runoff patterns and flows. *See* Appendix M in particular for details. The Council considered modeling in the Regional Portfolio Model scenarios based on these effects. Preliminary modeling indicated that the possible changes in load shape (i.e., lower winter loads and higher summer loads) are limited in the near-term, and thus would not alter resource decisions required within the period covered by the action plan. Long-term impacts are subject to too wide a range of uncertainty to make the modeling useful at this time. The Council concluded that it would be best to delay these scenarios until after the release of an updated set of forecasts for climate-impacted stream flows based on the IPPC-5 climate change analysis. The Council did use its GENESYS model to estimate hydrosystem resource impacts based on the state of the data to date, as described in Appendix M.

[11] EPA issued a final rule under Section 111(d) on August 3, 2015, and published the rule in the Federal Register in October 2015. U.S. Environmental Protection Agency, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," 80 Fed. Reg. 64,662 (October 23, 2015). http://www2.epa.gov/sites/production/files/2015-08/documents/cpp-final-rule.pdf. A coalition of states, utilities, utility organizations and others challenged the rule in the federal D.C. Circuit Court of Appeals. The U.S. Supreme Court stayed the effectiveness of the rule that applies to existing sources in an order issued February 9, 2016, pending not just review on the merits by the court of appeals but also the resolution of any petition for further review in the Supreme Court following whatever decision is issued by the court of appeals. The litigation is ongoing as the Council completed the Seventh Power Plan.

The Seventh Power Plan's overall resource strategy seeks to minimize the need to develop new gas generation by meeting most future energy and capacity needs with energy efficiency and demand response. Successful implementation of this strategy provides time to take actions to reduce current fugitive methane emissions and minimize new methane emissions, so that the use of natural gas does produce a reduction in climate change impacts.

The Council analyzed the effects on the system and on the new resource strategy of removing or reducing the output of existing resources, in response to regional interest. There are interest groups and individuals interested in seeing certain existing system resources shut down, reduced in output, or removed for environmental and cost reasons. This includes the coal plants, the nuclear Columbia Generating Station, or the lower Snake River dams. They do not necessarily ask the Council to include the removal of these existing plants in the Seventh Power Plan resource strategy, as that is not the Council's power plan task under the Northwest Power Act. They have been interested instead in whether and how the Council might analyze the economic viability and environmental effects of these existing plants, and in understanding how the plan's new resource strategy might react to regulatory and economic developments affecting the output of the existing system. Thus in the power plan the Council is not analyzing, deciding, or recommending whether the existing plants remain viable or should close or change operations. But to the extent the Council has information indicating that existing plants may or will shut down, reduce output, or change operations in the future, for whatever reason, the Council has included those considerations in developing a new resource strategy, so that the region is able to maintain an adequate, economical, and reliable power supply. Moreover, as it has done in the past, the Council is again analyzing scenarios that inform the public of the system implications *if* resources were to be removed or their operations altered. The focus of the analysis is on assessing what new resources would fill in the gaps in a least-cost manner, estimating the total costs, and considering the comparative economic and environmental implications. *See* Chapters 3 and 15 for the analysis of these scenarios. Scenarios analyzed for this plan include a scenario removing coal-fired carbon emissions from the system, and two scenarios reflecting a planned and unplanned shut down of a major generating resource of 1,000 megawatts. This is roughly comparable to the size of either the Columbia Generating Station or the lower Snake River dams, although neither resource is specifically modeled for shutdown. As discussed in Chapter 3, the scenario analyzing the planned shutdown of a non-carbon emitting major resource can be used, along with other information provided, to understand the resource impacts that would occur if the lower Snake River dams were removed comparable to the more specific scenario analyzed for the Sixth Power Plan.

The Council considered non-quantifiable environmental benefits and residual environmental effects in analyzing resources and developing the new resource strategy. As discussed in the first part of this chapter, there are, in concept, environmental effects from the use of various resources that are as yet unregulated or that are residual after regulations. There are also benefits to the broader environment that result from implementation of new resources that allow for a reduction in an existing activity that causes environmental damage. The Council could not and did not quantify in dollars the environmental damage or benefits of this nature. The Council does, however, give them consideration in developing the resource strategy. In many ways, it is an additional consideration for aggressive implementation of energy efficiency and demand response measures. One issue raised in the power plan discussions has been the potential opportunity the region has to reduce carbon emissions from existing sources by implementing new non-carbon emitting resources and conservation measures. The Council has addressed this opportunity largely through the scenario analyses described above. Methane emissions associated with natural gas production has been another area of consideration, discussed in Chapters 3, 9, and 13 and Appendix I.

In the power plan and its resource strategy the Council continues to endorse and implement "Protected Areas" throughout the Pacific Northwest, areas that the Council recommends be off limits to new hydroelectric development to protect fish and wildlife. Beginning in 1988, the Council adopted what are called the "protected areas" as an element of the Council's fish and wildlife program and power plans. In these provisions, the Council calls on the Federal Energy Regulatory Commission (FERC) not to license a new hydroelectric project in river reaches with valuable fish or wildlife resources that the Council identified and mapped in a "protected areas" database by the Council. The protected areas provisions also call on Bonneville not to provide transmission support if such a project were to receive a license. To date, FERC has not licensed a new hydroelectric project in a protected area identified by the Council.

In the power plan context, protected areas represent a judgment by the Council that due to potential effects on habitat, flows, and passage, the adverse effects on and environmental costs to important fish and wildlife resources are too great to justify including new hydroelectric projects in these areas except under certain limited conditions.[12] This is particularly important because the existing power system is already bearing substantial costs to protect and mitigate for its impacts on fish and wildlife resources. The power plan context is also important in that the protected areas designations extend throughout the entire Northwest (essentially the same as the Bonneville service territory), not just within the Columbia River Basin, representing a part of the resource strategy for the region's power system as well as comprehensive plan for the region's waterways and new hydroelectric development. As the Council evaluates the potential and cost-effectiveness for new hydroelectric development in each power plan, it includes the effects of protected areas in limiting the extent of that potential. The Council also gives due consideration to fish and wildlife and the quality of their environment by including a set of development conditions to protect fish and wildlife as new hydroelectric projects are licensed and developed in areas outside of the protected areas designated by the Council.

The Council analyzed and developed a resource strategy that assures that Bonneville and the regional power system may reliably deliver the flows and other passage measures and implement other measures beneficial to fish in the Council's fish and wildlife program or otherwise required in some way. As described above, due consideration for fish and wildlife in developing the new resource strategy involves (1) assessing the effects of new resources on fish and wildlife and estimating the costs of compliance with regulations intended to address those effects, as part of the total resource costs for new resources, and (2) limiting the potential of new hydroelectric resource development itself to protect fish and wildlife. This has also meant, as noted above, that when there is an interest expressed by regional participants as to what would be the

[12] The protected areas provisions allow the Council to make an exception if a proposed hydropower project will provide "exceptional survival benefits" to fish and wildlife resources as determined by the relevant fish and wildlife agencies and tribes.

power system implications of a decision to shut down or remove an existing resource that affects fish and wildlife, the Council has been willing to provide that analysis in the power plan, even as the decision or even the question of whether to remove an existing resource is not for the Council in crafting a new resource strategy aimed at resource acquisitions by Bonneville and others.

Just as important as these, however, and at the core of how the power plan relates to protecting fish and wildlife, is the work the Council does to develop the lowest-cost new resource strategy that helps ensure Bonneville is able to implement the flow and other measures in the fish and wildlife program (and elsewhere) and yet assure for the region an adequate, efficient, economical, and reliable power supply. This is primarily described in Chapter 20, and in the assessment of the output of the hydroelectric system in Chapter 9. The plan's resource strategy has to make sure that Bonneville and the regional power system have adequate and reliable resources so as to be able to deliver reliably the flows and other measures called for in the fish and wildlife program (and elsewhere, such as in the court-ordered spill requirements of past years) to protect fish and wildlife.

In addition, the Council has been willing in the past, if regional participants are interested, in assessing the power system implications (and the resulting effects on the new resource strategy) of one or more scenarios that include system operations for fish and wildlife different or greater than those currently in the fish and wildlife program. This is comparable to the Council analyzing the power system implications of decisions to shut down or remove an existing resource (as described above), even as the decision the Council makes in the power plan's resource strategy does not relate to or affect decisions about the existing resource – or, in this case, have any relation to changing system flows for fish and wildlife. The Council's engagement with the region in the development of scenarios for analysis in the Seventh Power Plan did not identify any scenarios of this type.

The Council considered the effects of new renewable resource development, especially cumulative impacts, and associated transmission development on the environment and fish and wildlife. The generating resource Chapters 9 and 13 and Appendix I describe effects on the environment and fish and wildlife from renewable resources, including new wind towers and solar energy installations. This includes describing the environmental and land use regulations that address those effects, and the costs of compliance as part of new resource costs.

Some participants sought additional considerations. In the 2013-14 process to amend its fish and wildlife program, the Council received recommendations and comments from the Washington Department of Fish and Wildlife, a number the region's Indian tribes and the US. Fish and Wildlife Service concerned about the adverse effects on fish and wildlife from the construction and operation of renewable generating plants and accompanying transmission. They recommended that the Council address these effects in its program and power plan, including:

> "The NPCC should develop programs and processes to evaluate the impacts on fish and wildlife resources of all new energy sources (past, proposed, and potential) and associated transmission infrastructure. The NPCC should support a region-wide assessment of suitability for siting terrestrial and aquatic energy projects, prioritize possible sites, and examine potential site-specific and system-wide impacts to fish and wildlife. The outputs from this analysis should include a map of priority power generation development sites and power generation exclusion zones or protected areas, as was done for hydropower. The NPCC, as part of the program,

should provide an explicit evaluation of transmission system expansion and its potential to impact fish and wildlife as part of development scenarios and assessments and assess, analyze, and identify appropriate mitigation measures."

For reasons explained in the 2014 Fish and Wildlife Program itself, the program was not an appropriate venue to consider and address the effects on the environment and on fish and wildlife associated with the region's boom in renewable resource development.[13] To a certain extent these effects are within the considerations required of the Council in the power plan, as described above. The issue is whether there is more that the Council can do in the power plan to assess and address these effects other than to quantify the environmental compliance resource costs for an appropriate cost-effectiveness comparison in shaping the resource strategy. Commenters on this topic from state and federal energy agencies, utilities, and energy conservation groups took a stance opposite to the fish and wildlife agencies and tribes, recommending the Council not get involved and commenting that existing siting agencies, laws, regulations, and procedures are sufficient to address these effects. In this context, the Council considered the effects of renewable energy and transmission development on fish and wildlife and habitat in this power plan by:

- Describing in as comprehensive detail as possible in the generating resource chapters (9 and 13 and Appendix I) the environmental and fish and wildlife effects of renewable resource development, what environmental and land use regulations address those effects and at what cost, and what issues remain that spark the concerns of the fish and wildlife agencies and tribes with these resource developments.

- Identifying, highlighting and considering the transmission system's effects on the environment and fish and wildlife, including a discussion as to how those environmental effects have been addressed and how effectively. See Appendix I in particular. The Council is not a transmission planner and does not make recommendations and decisions on transmission, other than to recognize it as a cost and an issue in generating resource development.

- Inclusion of Action Plan item that calls on those who do have decision-making power over the siting of renewable resources and transmission – largely, state energy facility siting agencies, utilities that provide transmission services, and federal agencies managing public lands – to investigate further, take those concerns seriously, and address them to the extent possible. The Council staff will assist in this regard to the extent the Council has resources and expertise.

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[13] For further explanation, *see* "(21) Renewable energy development and the effects on wildlife and fish," at pp. 329-30 of Appendix S to the 2014 Fish and Wildlife Program. http://www.nwcouncil.org/fw/program/2014-12/program/. See also the discussion of transmission effects on wildlife on p. 283 of the same document.

CHAPTER 20: FISH AND WILDLIFE PROGRAM

One of the required elements of the Council's power plan, per the Northwest Power Act, is the Council's own fish and wildlife program, reviewed and amended by the Council prior to the development of the power plan under a separate provision of the Act. This chapter is the vehicle by which the Council incorporates into the Seventh Power Plan its *2014 Columbia River Basin Fish and Wildlife Program*. The full text of the 2014 Fish and Wildlife Program is found on the Council's website at http://www.nwcouncil.org/fw/program/2014-12/program/. This chapter also explains briefly how the Council, following the Act, integrates the fish and wildlife program into the development of the power plan's new resource strategy, especially so as to guide Bonneville's acquisition of resources to assist in the implementation of the measures in the fish and wildlife program.

The Council developed the 2014 Fish and Wildlife Program following the procedures and standards in Section 4(h) of the Northwest Power Act. That section instructs the Council to call for recommendations and amend the fish and wildlife program "prior to the development or review of the [power] plan." The Council develops the fish and wildlife program based on a set of recommendations from state and federal fish and wildlife agencies and the region's Indian tribes in particular, and from others as well, and after following a lengthy public process involving comments and consultations on those recommendations and on draft program amendments. The resulting final revised fish and wildlife program contains a set of measures and objectives intended to protect, mitigate and enhance fish and wildlife affected by the development and operation of the hydroelectric facilities on the Columbia River and its tributaries while assuring the Pacific Northwest an adequate, efficient, economical and reliable power supply. The Bonneville Power Administration has an obligation, set forth in Section 4(h)(10) of the Act, to protect, mitigate and enhance fish and wildlife affected by the Columbia River hydroelectric facilities "in a manner consistent with" the Council's fish and wildlife program, power plan, and the purposes of the Act. All of the federal agencies responsible for managing, operating and regulating the hydroelectric facilities also have an obligation, in Section 4(h)(11) of the Act, to exercise their statutory responsibilities while taking the Council's fish and wildlife program into account at each relevant stage of decisionmaking processes to the fullest extent practicable.

The Act then also provides, in Section 4(e)(3)(F), that the fish and wildlife program is one element in the power plan, a power plan to be reviewed and developed by the Council in a power planning effort that follows the completion of the fish and wildlife program. The Act itself does not explain what it means for the Council to include the fish and wildlife program in the power plan. But the meaning becomes clear from other power plan provisions, the purposes of the Act, and the inherent nature of crafting a new conservation and generating resource strategy for the region's power system.

Congress, in passing the Northwest Power Act in 1980, anticipated and expected that the Council's fish and wildlife program would contain flow and passage measures that derate the optimal generating capability of the hydroelectric system for the production of electricity, and that such measures were necessary in order to improve survival for salmon, steelhead and other fish and wildlife affected by the system. The Council's fish and wildlife program does contain, among other measures, mainstem flow and passage measures (including bypass spill for juvenile salmon and steelhead) to benefit fish and wildlife, measures that affect hydroelectric system operations. These flow and passage measures alter power generation at the mainstem dams, shifting flows and generation from winter to spring and summer as reservoir storage operations have changed to benefit fish and wildlife, and reducing potential generation in spring and summer by increasing bypass spill at run-of-the-river mainstem dams to improve fish passage survival. Since 1980, implementation of operations to benefit fish and wildlife has reduced firm hydroelectric generation on average by about 1,100 average megawatts. For perspective, this loss represents almost 10 percent of the hydroelectric system's firm energy generating capability (that is, the amount of energy the system can be expected to generate under the lowest runoff conditions). During that same period, the hydroelectric system's capacity for meeting peak hour demands has decreased by more than 5,000 megawatts. This represents about 20 percent of the hydroelectric system's 4-hour sustained peaking capability. Most of the energy and capacity reductions in the hydroelectric system have occurred gradually over a 30-year period, and the system operations and the regional power system have had ample time to adjust.

Each time the Council considers and adopts a revised fish and wildlife program, it must also assess how the program measures will affect the region's power supply, and then evaluate if it will be possible to accommodate these changes while assuring the region an adequate, efficient, economical, and reliable power supply (AEERPS). The Council's AEERPS conclusion in the fish and wildlife program decision recognizes and assumes that the Council will follow the requirements of the Act in subsequently developing the regional power plan. The power plan is to set forth a scheme for implementing conservation measures and adding generating resources that will guide Bonneville and the region in acquiring the least-cost resources necessary to maintain an adequate, efficient, economical and reliable power supply while also allowing the system operators to reliably deliver the system operations to benefit fish and wildlife. The critical link is that Bonneville has a legal obligation to acquire resources consistent with the Council's power plan not just to meet or reduce its obligations to sell power but also (per Section 6(a)(2)9B) of the Act) "to assist [Bonneville] in meeting the requirements of section 4(h) of this [Act]," that is, to be able to implement the operational and other measures to protect, mitigate and enhance fish and wildlife in a manner consistent with the Council's fish and wildlife program. This is the Council's central responsibility in integrating fish and wildlife and power planning under the Northwest Power Act – assessing the existing system capabilities and then crafting a resource strategy to add least-cost resources over time to keep the electricity supply adequate, efficient, economic and reliable while accommodating a wide range of possible future demand growth scenarios and including the effects of fish and wildlife operations.

How this works in the power planning process following the adoption of the fish and wildlife program is summarized here: As described in the resource chapters above, the Council projects a range of electricity demand scenarios over the next 20 years, and also assesses the amount and status of current electric power resources in the region. The Council then develops a plan for adding the lowest-cost new resources to the regional system, including (as a first priority) cost-effective conservation, and evaluates how well that plan will accommodate projected demand and other effects on the region's power supply and still maintain an adequate and reliable system. The Act also calls for the plan to include a forecast of the resources required to meet Bonneville's load obligations and the portion of such obligations the Council determines can be met by conservation and by various categories of generating resources.

Consistent with the Act, the Council develops the fish and wildlife program before engaging in this resource assessment because knowing the latest flow and passage operations to benefit fish and wildlife is necessary for the Council to assess the current generating capability of the hydroelectric system at different periods in the year. The amount of hydroelectric generation available is then one factor in assessing the total generating capability of current regional power resources. A change in hydroelectric generation due to a change in operations for fish and wildlife is conceptually similar, in terms of the Council's power planning responsibilities under the Power Act, as any other change that will or might affect the load-resource balance and thus need to be accommodated in the resource plan, including an increase in demand for electricity. The actual assessment of the hydroelectric generating capability for the Seventh Power Plan is described in Chapter 9.

Assessing how fish and wildlife operations (and other factors) affect hydroelectric generation is only part of the Council's considerations in this regard. The Council has to develop the least-cost resource strategy that will not only allow Bonneville and the region to meet or reduce demand for electricity, but also to accommodate and reliably deliver these current system operations, including the operations to benefit fish and wildlife as well as to meet other system needs. New or revised fish and wildlife operations alter the amount of overall energy that the hydropower system can produce, alter the peaking capability of the hydroelectric system, and reduce the flexibility of the system to follow load and balance the output of variable resources, such as wind and solar. The Council's resource strategy looks at resource needs in all these categories -- energy, capacity, and flexibility – not only to make sure the resources are there to meet demand and ensure reliability but also to make sure the needs for electricity do not impinge on the operations to benefit fish and wildlife.

As guided in large part by the Council's power plans, Bonneville and the other responsible entities have taken the necessary actions since 1980 to accommodate the impacts on the regional power supply of system operations to benefit fish and wildlife. They have done so primarily by implementing conservation measures, and also by developing new generating resources, developing resource adequacy standards, implementing demand response measures to help reduce capacity resource needs and provide reserves, and implementing strategies to minimize power system emergencies and events that might compromise fish operations. The resource acquisitions, especially the conservation measures, have allowed system operators over time to embed reliable fish and wildlife operations into core system operations while maintaining a power supply that is adequate, reliable and affordable.

Another of the expectations of the Power Act is that the power system is to bear the cost of managing and operating the hydroelectric system to improve conditions for fish and wildlife affected by the development and operation of the hydroelectric facilities on the Columbia River and its tributaries. Consistent with the Act, Bonneville and the other regional power system operators implement the fish and wildlife program and protect, mitigate and enhance fish and wildlife by using revenues generated by the hydroelectric system to cover the major portion of the costs of the fish and wildlife program. The regional power system absorbs both the financial effects of fish and wildlife operations that reduce the output and revenue of the system as well as the expenditures on other measures to implement the fish and wildlife protection and mitigation program. In order to do so, the power system must generate sufficient revenue to cover these financial requirements. This necessarily makes the region's power supply more expensive, as also anticipated by Congress when it passed the Northwest Power Act. The Council's power planning effort under the Act helps again by focusing on the least-cost resources, especially conservation, when deciding what resources must be added to the regional power system not just to meet load but to reliably implement the fish and wildlife program. Due to the power planning work of the Council, system operators have been able to reliably provide the actions specified to benefit fish and wildlife (and absorbed the cost of those actions) while they and others have been able to maintain for the Pacific Northwest an adequate, efficient, economic and reliable electrical energy supply.

ACEEE Policy Brief

American Council for an Energy-Efficient Economy

State Energy Efficiency Resource Standards (EERS)
January 2017

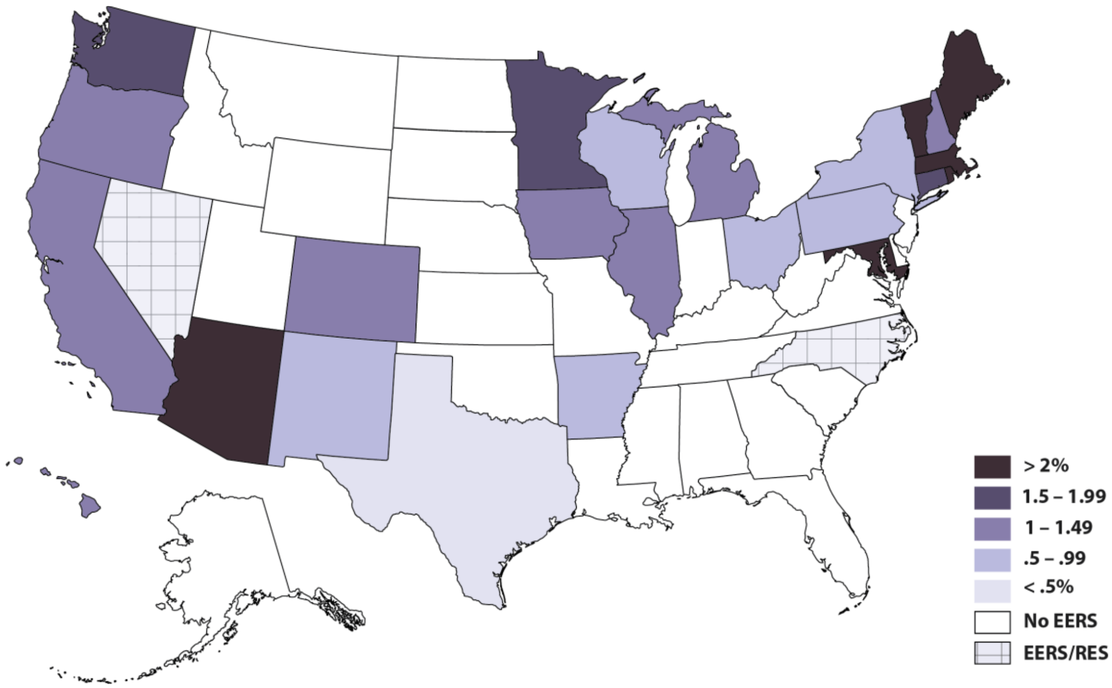

Figure 1. States with electric EERS policies in place (as of January 2017).

An energy efficiency resource standard (EERS) is a long-term (3+ years), binding energy savings target for utilities or third-party program administrators. Savings are achieved through energy efficiency programs for customers. An EERS is one of the most effective ways for a state to guarantee long-term energy savings. In 2015, states with an EERS achieved incremental electricity savings of 1.2% of retail sales on average, compared to average savings of 0.3% in states without an EERS.

Twenty-six states are currently implementing EERS policies requiring electricity savings (Figure 1).[1] Of these states, 16 also have EERS policies in place for natural gas. Seven of the 26 states have requirements that utilities or third-party administrators achieve all cost-effective energy efficiency.[2]

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[1] This count includes 24 states with a standalone EERS policy and two states that allow energy efficiency to count toward renewable energy standards (RES). This count does not include Indiana, where EERS guidelines have been rolled back. Additional states have some form of targets, but for the following reasons we do not consider them to have an EERS: Florida (previous targets were underfunded, and recent targets are so low as to be negligible); Utah, Missouri, and Virginia (voluntary standards with no binding requirement). It should also be noted that as of the time of publication, EERS policies are pending in Delaware but final targets have not yet been approved.

[2] The seven states that have chosen to enforce all cost-effective efficiency requirements are California, Connecticut, Maine, Massachusetts, Rhode Island, Vermont, and Washington. In addition, New Hampshire's EERS has set forth a

Texas adopted the nation's first EERS in 1999, and many states followed suit in the mid-2000s. These policies have contributed to notable energy and bill savings in many states. All of the top fifteen energy-saving states in 2015 had an EERS policy in place.[3] Furthermore, nearly every state with an EERS has met or surpassed their targets in recent years.[4] This policy brief summarizes each state electricity and natural gas EERS policy currently in place. Table 1 outlines current policy approaches for electricity EERS policies. Table 2 describes natural gas EERS policies. For a more in-depth look at individual state EERS policies, visit ACEEE's State and Local Policy Database.[5]

Table 1. Electricity EERS policy status by state

	· State · Year enacted · Authority · Applicability (% sales affected)[6]	Electricity energy efficiency resource standard	Reference
1	Arizona 2010 Regulatory[7] IOUs, Co-ops (~59%)	Incremental savings targets began at 1.25% of sales in 2011, ramping up to 2.5% in 2016 through 2020 for cumulative electricity savings of 22% of retail sales, of which 2% may come from peak demand reductions.[8] Co-ops must meet 75% of targets.	Docket No. RE-00000C-09-0427, Decision 71436 Docket No. RE-00000C-09-0427, Decision 71819
2	Arkansas 2010 Regulatory IOUs (~53%)	Incremental savings targets began at 0.25% in 2011, ramping up to 0.9% annually for 2015 – 2018 and 1.00% for 2019.	Order No. 15, Docket No. 08-137-U Order No. 17, Docket No. 08-144-U Order No. 1, Docket No. 13-002-U Order No. 7, Docket No. 13-002-U Order No. 31, Docket No. 13-002-U

long-term goal of achieving all cost-effective efficiency, which is anticipated to be met through planning and goal-setting in future implementation cycles.

[3] 2015 is the most recent year for which complete data is available. See *The 2016 State Energy Efficiency Scorecard* (Berg et. al, 2016) for more details. http://aceee.org/research-report/u1606

[4] See *Energy Efficiency Resource Standards: A New Progress Report on State Experience* (Downs and Cui, 2014) for more details: http://aceee.org/research-report/u1403

[5] http://database.aceee.org/

[6] This does not take into account whether large customers are eligible to opt-out of programs. For more information on large customer opt-out, see *The 2016 State Energy Efficiency Scorecard* (Berg et. al, 2016). http://aceee.org/research-report/u1606

[7] EERS policies can either be established through legislation or regulatory action. EERS policies under regulatory authority were set without legislation requiring specific savings levels or calling upon the state public utility commission to set savings targets. Thus far, a total of 21 states have legislatively established EERS policies, while five states have done so solely through regulatory orders.

[8] Incremental savings are one year of energy savings from measures implemented under programs in a given year. Cumulative savings are the savings in a given year from all the measures that have been implemented under the programs in that year and in prior years that are still saving energy.

	· State · Year enacted · Authority · Applicability (% sales affected)[6]	Electricity energy efficiency resource standard	Reference
3	California 2004, 2009, and 2015 Legislative[9] IOUs (~78%)	Average incremental savings targets average about 1.15% of retail sales electricity. In October 2015, California enacted SB 350, calling on state agencies and utilities to work together to double cumulative efficiency savings achieved by 2030. The CEC's SB 350 energy efficiency target setting efforts are anticipated to be completed in late 2017. Utilities must pursue all cost-effective efficiency resources.	CPUC Decision 04-09-060 CPUC Decision 08-07-047 CPUC Decision 14-10-046 CPUC Decision 15-10-028 AB 995 SB 350 (10/7/15) AB 802 (10/8/15)
4	Colorado 2007 Legislative IOUs (~57%)	Black Hills follows PSCo incremental savings targets of 0.8% of sales in 2011, increasing to 1.35% of sales in 2015. For the period 2015-2020, PSCo must achieve incremental savings of at least 400 GWh per year.	Colorado Revised Statutes 40-3.2-101, et seq. ; Docket No. 12A-100E Dec. R12-0900; Docket 10A-554EG Docket No. 13A-0686EG Dec. C14-0731
5	Connecticut 2007 & 2013 Legislative IOUs (~94%)	Average incremental savings of 1.51% of sales from 2016 through 2018. Utilities must pursue all cost-effective efficiency resources.	Public Act No. 07-242 Public Act No. 13-298 2016-2018 Electric and Natural Gas Conservation and Load Management Plan
6	Hawaii 2004 and 2009 Legislative Statewide goal (100%)	In 2009, Hawaii transitioned away from a combined RPS-EERS to a standalone EEPS goal to reduce electricity consumption by 4,300 GWh by 2030 (equal to ~30% of forecast electricity sales, or 1.4% incremental savings per year).	HRS §269-91, 92, 96 HI PUC Order, Docket 2010-0037
7	Illinois 2007 and 2016 Legislative Utilities with over 100,000 customers, Illinois DCEO (~88%)	Incremental savings targets vary by utility, averaging 1.77% of sales from 2018 to 2021, 2.08% from 2022 to 2025, and 2.05% from 2026 to 2030. SB 2814 also sets a rate cap of 4%, allowing targets to be adjusted downward should utilities reach spending limits.	S.B. 1918 Public Act 96-0033 § 220 ILCS 5/8-103 Case No. 13-0495 Case No. 13-0498 S.B. 2814
8	Iowa 2009 Legislative IOUs (75%)	Incremental savings targets vary by utility from ~1.1-1.2% annually through 2018.	Senate Bill 2386 Iowa Code § 476 Docket EEP-2012-0001

[9] Legislation governing EERS policies may not include specific targets. In many cases, referenced legislation requires or explicitly enables the state public utility commission to set targets.

	· State · Year enacted · Authority · Applicability (% sales affected)[6]	Electricity energy efficiency resource standard	Reference
9	Maine 2009 Legislative Statewide goal (100%)	Electric savings of 20% by 2020, with incremental savings targets of ~ 1.6% per year for 2014-2016 and ~2.4% per year for 2017-2019. Efficiency Maine operates under an all cost-effective mandate.	Efficiency Maine Triennial Plan (2014-2016) Efficiency Maine Triennial Plan (2017-2019) H.P. 1128 – L.D. 1559
10	Maryland 2008; 2015 Legislative through 2015, regulatory thereafter Electric IOUs (99%)	15% per-capita electricity use reduction goal by 2015 (10% by utilities, 5% achieved independently). 15% reduction in per capita peak demand by 2015, compared to 2007. After 2015, targets vary by utility, ramping up by 0.2% per year to reach 2% incremental savings.	Md. Public Utility Companies Code § 7-211 MD PSC Dockets 9153-9157 Order No. 87082
11	Massachusetts 2009 Legislative IOUs, Co-ops, Muni's, Cape Light Compact (~86%)	Average incremental savings of 2.93% percent of electric sales for 2016-2018. All cost-effective efficiency requirement.	D.P.U. 15-160 through D.P.U. 15-169 (MA Joint Statewide Three-Year Electric and Gas Energy Efficiency Plan 2016-2018) M.G.L. ch. 25, § 21;
12	Michigan 2008 and 2016 Legislative Statewide Goal (100%)	1.0% incremental savings through 2021.	Act 295 of 2008 S.B. 438
13	Minnesota 2007 Legislative Statewide Goal (100%)	1.5% incremental savings in 2010 and each year thereafter.	Minn. Stat. § 216B.241
14	Nevada 2005 and 2009 Legislative IOUs (~62%)	20% of retail electricity sales to be met by renewables and energy efficiency by 2015, and 25% by 2025. Energy efficiency may meet a quarter of the standard through 2014, but is phased out of the RPS by 2025.	NRS 704.7801 et seq. NRS 704.7801 as amended
15	New Hampshire 2016 Regulatory Statewide goal (100%)	0.8% incremental savings in 2018, ramping up to 1.0% in 2019 and 1.3% in 2020.	NH PUC Order No. 25932, Docket DE 15-137

	· State · Year enacted · Authority · Applicability (% sales affected)[6]	Electricity energy efficiency resource standard	Reference
16	New Mexico 2008 and 2013 Legislative IOUs (68%)	5% reduction from 2005 total retail electricity sales by 2014, and an 8% reduction by 2020.	N.M. Stat. § 62-17-1 et seq.
17	New York 2008, 2016 Regulatory Statewide Goal (100%)	Under current Reforming the Energy Vision (REV) proceedings, utilities have filed efficiency transition implementation plans (ETIPS) with incremental targets varying from 0.4% to 0.9% for the period 2016–2018. In January, the PSC authorized NYSERDA's Clean Energy Fund (CEF) framework, which outlines a minimum 10-year energy efficiency goal of 10.6 million MWh measured in cumulative first year savings. The PSC issued a REV II Track Order in May prescribing that the Clean Energy Advisory Council also propose utility targets supplemental to ETIPS by October 2016. In response, the Council generated a report in November describing options for energy efficiency target setting, but did not yet offer a consensus recommendation. Some degree of overlap of program savings is anticipated between utility targets and NYSERDA CEF goals.	NY PSC Order, Case 07-M-0548 NY PSC Case 14-M-0101 NY PSC Case 14-M-0252 2015 New York State Energy Plan NY PSC Order Authorizing the Clean Energy Fund Framework Energy Efficiency Metrics and Target Options Report (November 2016)
18	North Carolina 2007 Legislative Statewide Goal (100%)	Renewable Energy and Energy Efficiency Portfolio Standard (REPS) requires renewable generation and/or energy savings of 6% by 2015, 10% by 2018, and 12.5% by 2021 and thereafter. Energy efficiency is capped at 25% of target, increasing to 40% in 2021 and thereafter.	N.C. Gen. Stat. § 62-133.8 04 NCAC 11 R08-64, et seq.
19	Ohio 2008, 2014 Legislative IOUs (~89%)	Beginning in 2009, incremental savings of 0.3% per year, ramping up to 1% in 2014 and 2% in 2021. Savings targets resumed in 2017 following a “freeze” (S.B. 310) in 2015-2016 that allowed utilities that had achieved 4.2% cumulative savings to reduce or eliminate program offerings.	ORC 4928.66 et seq. S.B. 221 S.B. 310
20	Oregon 2010 Regulatory Energy Trust of Oregon (~70%)	Incremental targets average ~1.3% of sales annually for the period 2015-2019.	Energy Trust of Oregon 2015-2019 Strategic Plan Grant Agreement between Energy Trust of Oregon and OR PUC

	· State · Year enacted · Authority · Applicability (% sales affected)[6]	Electricity energy efficiency resource standard	Reference
21	Pennsylvania 2004 and 2008 Legislative Utilities with over 100,000 customers (~93%)	Varying targets have been set for IOUs amounting to yearly statewide incremental savings of 0.8% savings for 2016-2020. EERS includes peak demand targets. Energy efficiency measures may not exceed an established cost-cap.	66 Pa C.S. § 2806.1; PUC Order Docket No. M-2008-2069887; PUC Implementation Order Docket M-2012-2289411 PUC Final Implementation Order Docket M-2014-2424864
22	Rhode Island 2006 Legislative IOUs, Muni's (~99%)	Incremental savings of 2.5% in 2015 2.55% in 2016, and 2.6% in 2017. EERS includes demand response targets. Utilities must acquire all cost-effective energy efficiency.	R.I.G.L § 39-1-27.7 Docket No. 4443
23	Texas 1999 and 2007 Legislative IOUs (~73%)	20% incremental load growth in 2011 (equivalent to ~0.10% annual savings); 25% in 2012, 30% in 2013 onward. Peak demand reduction targets of 0.4% compared to previous year. Energy efficiency measures may not exceed an established cost cap.	Senate Bill 7; House Bill 3693; Substantive Rule § 25.181 Senate Bill 1125
24	Vermont 2000 Legislative Efficiency Vermont, Burlington Electric (100%)	Average incremental electricity savings of about 2.1% per year from 2015 – 2017. EERS includes demand response targets. Energy efficiency utilities must set budgets at a level that would realize all cost-effective energy efficiency.	30 V.S.A. § 209; VT PSB Docket EEU-2010-06 Efficiency Vermont Triennial Plan 2015-17 (2016 Update)
25	Washington 2006 Legislative IOUs, Co-ops, Muni's (~81%)	Biennial and Ten-Year Goals vary by utility. Law requires savings targets to be based on the Northwest Power Plan, which estimates potential incremental savings of about 1.5% per year through 2030 for Washington utilities. All cost-effective conservation requirement.	Ballot Initiative I-937 Energy Independence Act, Chapter 19.285.040 WAC 480-109-100 WAC 194-37 Seventh Northwest Power Plan (adopted 2/10/16)
26	Wisconsin 2011 Legislative Statewide Goal (100%)	Focus on Energy targets include incremental electricity savings of ~0.81% of sales per year in 2015-2018. Energy efficiency measures may not exceed an established cost-cap.	Order, Docket 5-FE-100: Focus on Energy Revised Goals and Renewable Loan Fund (10/15) Program Administrator Contract, Docket 9501-FE-120, Amendment 2 (3/16) 2005 Wisconsin Act 141

Table 2. Natural gas EERS policy status by state

	· State · Year enacted · Authority · Applicability (% sales affected)	Natural gas energy efficiency resource standard	Reference
1	Arizona 2010 Regulatory IOUs (~85%)	~0.6% incremental savings per year (for cumulative savings of 6% by 2020).	Docket No. RG-00000B-09-0428 Dec. No. 71855
2	Arkansas 2010 Regulatory IOUs (~60%)	Annual incremental reduction target of 0.50% for 2017-2019 for natural gas IOUs.	Order No. 15, Docket No. 08-137-U Order No. 1, Docket No. 13-002-U Order No. 7, Docket No. 13-002-U Order No. 31, Docket No. 13-002-U
3	California 2004 and 2009 Legislative IOUs (~82%)	Incremental savings target of 0.42% for natural gas. Utilities must pursue all cost-effective efficiency resources. In October 2015, California enacted SB 350, calling on the California Energy Commission, California Public Utilities Commission, and publicly owned utilities to work together to double cumulative efficiency savings achieved by 2030.	CPUC Decision 04-09-060 CPUC Decision 08-07-047 CPUC Decision 14-10-046 CPUC Decision 15-10-028 AB 995 SB 350 (10/7/15)
4	Colorado 2007 Legislative IOUs (~72%)	Savings targets commensurate with spending targets (at least 0.5% of prior year's revenue).	Colorado Revised Statutes 40-3.2-101, et seq. Docket 10A-554EG Docket No. 13A-0686EG Dec. C14-0731
5	Connecticut 2007 & 2013 Legislative IOUs (100%)	Average incremental savings of 0.61% per year from 2016 through 2018. Utilities must pursue all cost-effective efficiency resources.	Public Act No. 13-298 2016-2018 Electric and Natural Gas Conservation and Load Management Plan
6	Illinois 2007 Legislative Utilities with over 100,000 customers, Illinois DCEO (~88%)	8.5% cumulative savings by 2020 (0.2% incremental savings in 2012, ramping up to 1.5% in 2019).	S.B. 1918 Public Act 96-0033 § 220 ILCS 5/8-103 Case No. 13-0495 Case No. 13-0498 S.B. 2814
7	Iowa 2009 Legislative IOUs (100%)	Incremental savings targets vary by utility, ~0.66% -1.2% annually through 2018.	Senate Bill 2386 Iowa Code § 476 Docket EEP-2012-0001

	· State · Year enacted · Authority · Applicability (% sales affected)	Natural gas energy efficiency resource standard	Reference
8	Maine 2009 Legislative Efficiency Maine (100%)	Incremental savings of ~0.2% per year for 2017-2019. Efficiency Maine operates under an all cost-effective mandate.	Efficiency Maine Triennial Plan (2014-2016) Efficiency Maine Triennial Plan (2017-2019) H.P. 1128 – L.D. 1559
9	Massachusetts 2009 Legislative IOUs, Co-ops, Muni's (100%)	Average incremental savings of 1.24% per year for 2016-2018. All cost-effective efficiency requirement.	D.P.U. Order 09-121 through 09-128 D.P.U. Order 12-100 through 12-111 M.G.L. ch. 25, § 21;
10	Michigan 2016 Legislative Statewide Goal (100%)	Incremental savings of 0.75% through 2021.	Act 295 of 2008 S.B. 438
11	Minnesota 2007 Legislative Statewide Goal (100%)	0.75% incremental savings per year in 2010-2012; 1% incremental savings in 2013 and each year thereafter.	Minn. Stat. § 216B.241
12	New Hampshire 2016 Regulatory Statewide Goal (100%)	0.7% incremental savings in 2018; 0.75% in 2019; and 0.8% in 2020.	NH PUC Order No. 25932, Docket DE 15-137
13	New York 2008, 2016 Regulatory Companies with 14,000+ customers (~100%)	Under current Reforming the Energy Vision (REV) proceedings, utilities have filed efficiency transition implementation plans (ETIPS) with incremental targets averaging 0.28% for the period 2016–2018. In January, the PSC authorized NYSERDA's Clean Energy Fund (CEF) framework, which outlines a minimum 10-year energy efficiency goal of 13.4 million MMBtus measured in cumulative first year savings. The PSC issued a REV II Track Order in May prescribing that the Clean Energy Advisory Council also propose utility targets supplemental to ETIPS by October 2016. In response, the Council generated a report in November describing options for energy efficiency target setting for electricity. The	NY PSC Order, Case 07-M-0548 NY PSC Case 14-M-0101 NY PSC Case 14-M-0252 2015 New York State Energy Plan NY PSC Order Authorizing the Clean Energy Fund Framework Energy Efficiency Metrics and Target Options Report (November 2016)

	· State · Year enacted · Authority · Applicability (% sales affected)	Natural gas energy efficiency resource standard	Reference
		report did not consider natural gas efficiency, although it noted that gas efficiency targets should exist and should be developed after electricity targets are determined.	
14	Oregon 2010 Regulatory Energy Trust of Oregon (~89%)	Incremental savings of 0.3% of sales annually for the period 2015-2019.	Energy Trust of Oregon 2015-2019 Strategic Plan Grant Agreement between Energy Trust of Oregon and OR PUC
15	Rhode Island 2006 Legislative IOUs, Muni's (100%)	Incremental savings of 1% in 2015, 1.05% in 2016, and 1.1% in 2017. Utilities must acquire all cost-effective energy efficiency.	R.I.G.L § 39-1-27.7 Docket No. 4443
16	Wisconsin 2011 Legislative Statewide Goal (100%)	Focus on Energy targets include incremental natural gas savings of ~0.6% of sales per year in 2015-2018. Energy efficiency measures may not exceed an established cost-cap.	Order, Docket 5-FE-100: Focus on Energy Revised Goals and Renewable Loan Fund (10/15) Program Administrator Contract, Docket 9501-FE-120, Amendment 2 (3/16) 2005 Wisconsin Act 141

For more information on energy efficiency resource standards, please visit http://aceee.org/topics/energy-efficiency-resource-standard-eers

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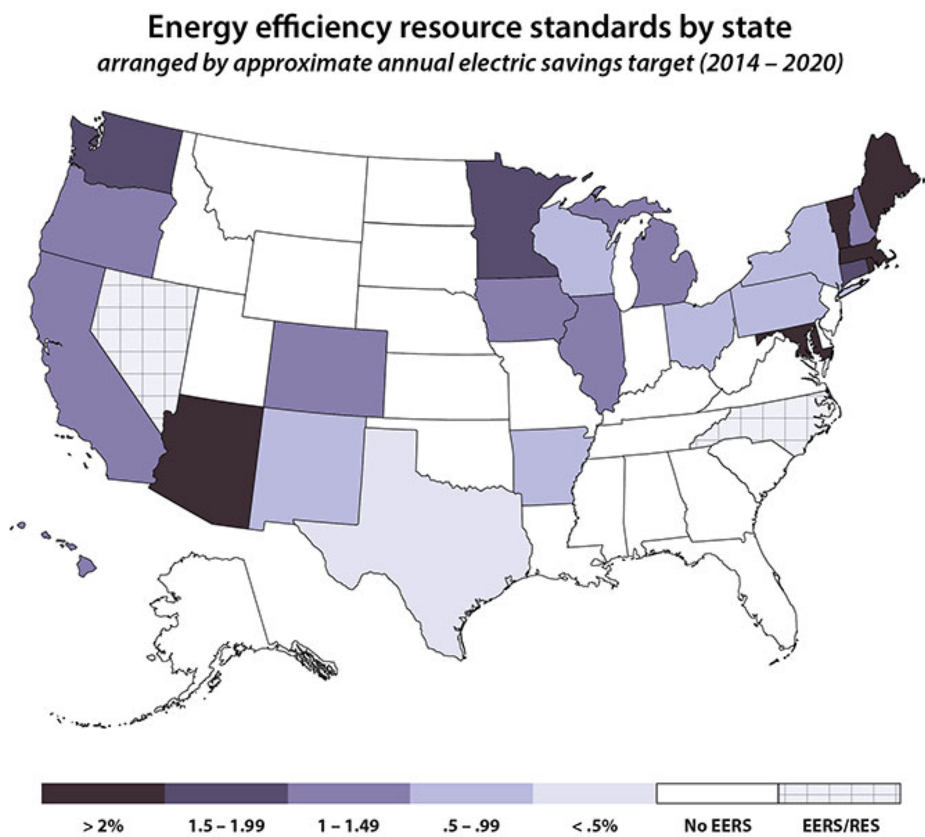
Energy Efficiency Resource Standard (EERS)



An Energy Efficiency Resource Standard (EERS) establishes specific, long-term targets for energy savings that utilities or non-utility program administrators must meet through customer energy efficiency programs. An EERS can apply to either electricity or natural gas utilities, or both, depending on the state, and can be adopted through either legislation or regulation. An EERS is similar in concept to a Renewable Energy Standard (RES) or Renewable Portfolio Standard (RPS). While an RES requires that electric utilities generate a certain percentage of electricity from renewable sources, an EERS requires that they achieve a percentage reduction in energy sales from energy efficiency measures.

As of January 2017, twenty-six states have fully-funded policies in place that establish specific energy savings targets that utilities or non-utility program administrators must meet through customer energy efficiency programs. Though Indiana had an EERS in place in the past, it was rolled back in 2014. The strongest EERS requirements exist in Massachusetts and Rhode Island, which require more than 2.5% new savings annually. For a complete summary of state-level EERS policies and impacts, see the State EERS Policy Brief (//aceee.org/policy-brief/state-energy-efficiency-resource-standard-activity).

A federal EERS would complement existing state-level energy efficiency standards by setting a national goal for energy savings with targets for utilities in every state. A modest EERS passed the House in 2009. More recently, the *American Energy Efficiency Act of 2015 (https://www.congress.gov/bill/114th-congress/senate-bill/1063)* was introduced in the Senate, and a similar provision in the House. It proposes a 20% electricity savings and 13% natural gas savings target by 2030 (with annual added savings rising to 1.75% for electricity and 1% for gas). ACEEE analyzed that meeting these targets would result in cumulative net savings of almost $150 billion by 2040. Read more about our analysis here (//aceee.org/white-paper/2015-ee-legislation).

At both the federal and state levels, an Energy Efficiency Resource Standard is a critical policy that lays the foundation for sustained investment in energy efficiency. The long-term goals associated with an EERS send a clear signal to market actors about the importance of energy efficiency in utility program planning, creating a level of certainty that encourages large-scale investment in cost-effective energy efficiency.

⇒ Find out which states have an EERS in place with ACEEE's State Energy Efficiency Policy Database (http://database.aceee.org/) and policy brief (//aceee.org/policy-brief/state-energy-efficiency-resource-standard-activity).

⇒ Read about our policy position on federal EERS here (//aceee.org/policy-brief/energy-efficiency-resource-standard-eers).

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Document - 1/9/2017

6560-50

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA-HQ-OAR-2013-0602; FRL-XXXX-XX-OAR]

RIN 2060-AR33

Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: In this action, the Environmental Protection Agency (EPA) is establishing final emission guidelines for states to follow in developing pans to reduce greenhouse gas (GHG) emissions from existing fossil fuel-fired electric generating units (EGUs). Specifically, the EPA is establishing: 1) carbon dioxide (CO_2) emission performance rates representing the best system of emission reduction (BSER) for two subcategories of existing fossil fuel-fired EGUs – fossil fuel-fired electric utility steam generating units and stationary combustion turbines, 2) state-specific CO_2 goals reflecting the CO_2 emission performance rates, and 3) guidelines for the development, submittal and implementation of state plans that establish emission standards or other measures to implement the CO_2 emission performance rates, which may be accomplished by meeting

the state goals. This final rule will continue progress already underway in the U.S. to reduce CO_2 emissions from the utility power sector.

DATES: The final rule is effective on **[INSERT THE DATE 60 DAYS AFTER PUBLICATION IN THE FEDERAL REGISTER].**

ADDRESSES:

Docket. The EPA has established a docket for this action under Docket No. EPA–HQ–OAR–2013-0602. All documents in the docket are listed in the http://www.regulations.gov index. Although listed in the index, some information is not publicly available (e.g., confidential business information (CBI) or other information for which disclosure is restricted by statute). Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in http://www.regulations.gov or in hard copy at the EPA Docket Center, EPA WJC West Building, Room 3334, 1301 Constitution Ave., NW, Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding federal holidays. The telephone number for the Public Reading Room is (202) 566-1744, and the telephone number for the Air Docket is (202) 566-1742. For additional information about the EPA's public docket, visit the EPA Docket Center homepage at http://www2.epa.gov/dockets.

World Wide Web. In addition to being available in the docket, an electronic copy of this final rule will be available on the World Wide Web (WWW). Following signature, a copy of this final rule will be posted at the following address: http://www.epa.gov/cleanpowerplan/. A number of documents relevant to this rulemaking, including technical support documents (TSDs), a legal memorandum, and the regulatory impact analysis (RIA), are also available at http://www.epa.gov/cleanpowerplan/. These and other related documents are also available for inspection and copying in the EPA docket for this rulemaking.

FOR FURTHER INFORMATION CONTACT: Ms. Amy Vasu, Sector Policies and Programs Division (D205-01), U.S. EPA, Research Triangle Park, NC 27711; telephone number (919) 541-0107, facsimile number (919) 541-4991; email address: vasu.amy@epa.gov or Mr. Colin Boswell, Measurements Policy Group (D243-05), Sector Policies and Programs Division, U.S. EPA, Research Triangle Park, NC 27711; telephone number (919) 541-2034, facsimile number (919) 541-4991; email address: boswell.colin@epa.gov.

SUPPLEMENTARY INFORMATION:

Acronyms. A number of acronyms and chemical symbols are used in this preamble. While this may not be an exhaustive list, to ease the reading of this preamble and for reference purposes, the following terms and acronyms are defined as follows:

ACEEE	American Council for an Energy-Efficient Economy
AEO	Annual Energy Outlook
AFL-CIO	American Federation of Labor and Congress of Industrial Organizations
ASTM	American Society for Testing and Materials
BSER	Best System of Emission Reduction
Btu/kWh	British Thermal Units per Kilowatt-hour
CAA	Clean Air Act
CBI	Confidential Business Information
CCS	Carbon Capture and Storage (or Sequestration)
CEIP	Clean Energy Incentive Program
CEMS	Continuous Emissions Monitoring System
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
DOE	U.S. Department of Energy
ECMPS	Emissions Collection and Monitoring Plan System
EE	Energy Efficiency
EERS	Energy Efficiency Resource Standard
EGU	Electric Generating Unit
EIA	Energy Information Administration
EM&V	Evaluation, Measurement and Verification
EO	Executive Order
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
ERC	Emission Rate Credit
FR	Federal Register
GHG	Greenhouse Gas
GW	Gigawatt
HAP	Hazardous Air Pollutant
HRSG	Heat Recovery Steam Generator
IGCC	Integrated Gasification Combined Cycle
IPCC	Intergovernmental Panel on Climate Change
IPM	Integrated Planning Model
IRP	Integrated Resource Plan
ISO	Independent System Operator
kW	Kilowatt
kWh	Kilowatt-hour
lb CO_2/MWh	Pounds of CO_2 per Megawatt-hour
LBNL	Lawrence Berkeley National Laboratory
MMBtu	Million British Thermal Units
MW	Megawatt
MWh	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NAICS	North American Industry Classification System
NAS	National Academy of Sciences
NGCC	Natural Gas Combined Cycle
NOx	Nitrogen Oxides

NRC	National Research Council
NSPS	New Source Performance Standard
NSR	New Source Review
NTTAA	National Technology Transfer and Advancement Act
OMB	Office of Management and Budget
PM	Particulate Matter
$PM_{2.5}$	Fine Particulate Matter
PRA	Paperwork Reduction Act
PSB	Public Service Board
PUC	Public Utilities Commission
RE	Renewable Energy
REC	Renewable Energy Credit
RES	Renewable Energy Standard
RFA	Regulatory Flexibility Act
RGGI	Regional Greenhouse Gas Initiative
RIA	Regulatory Impact Analysis
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
SBA	Small Business Administration
SBC	System Benefits Charge
SCC	Social Cost of Carbon
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
Tg	Teragram (one trillion (10^{12}) grams)
TSD	Technical Support Document
TTN	Technology Transfer Network
UMRA	Unfunded Mandates Reform Act of 1995
UNFCCC	United Nations Framework Convention on Climate Change
USGCRP	U.S. Global Change Research Program
VCS	Voluntary Consensus Standard

Organization of This Document. The information presented in this preamble is organized as follows:

I. General Information

A. Executive Summary

1. Introduction

This final rule is a significant step forward in reducing greenhouse gas (GHG) emissions in the U.S. In this action, the EPA is establishing for the first time GHG emission guidelines for existing power plants. These final emission guidelines, which rely in large part on already clearly emerging growth in clean energy innovation, development and deployment, will lead to significant carbon dioxide (CO_2) emission reductions from the utility power sector that will help protect human health and the environment from the impacts of climate change. This rule establishes, at the same time, the foundation for longer term GHG emission reduction strategies necessary to address climate change and, in so doing, confirms the international leadership of the U.S. in the global effort to address climate change. In this final rule, we have taken care to ensure that achievement of the required emission reductions will not compromise the reliability of our electric system, or the affordability of electricity for consumers. This final rule is the result of unprecedented outreach and engagement with states, tribes, utilities, and other stakeholders, with stakeholders providing more than 4.3 million comments on the proposed rule. In this final rule, we have addressed the comments and concerns of states and other stakeholders while staying consistent with the law. As a result, we have followed through on our commitment to issue a plan that is fair, flexible and relies on the accelerating transition to cleaner power generation that is already well underway in the utility power sector.

Under the authority of Clean Air Act (CAA) section 111(d), the EPA is establishing CO_2 emission guidelines for existing fossil fuel-fired electric generating units (EGUs) – the Clean Power Plan. These final guidelines, when fully implemented, will achieve significant reductions in CO_2 emissions by 2030, while offering states and utilities substantial flexibility and latitude in achieving these reductions. In this final rule, the EPA is establishing a CO_2 emission performance rate for each of two subcategories of fossil fuel-fired EGUs -- fossil fuel-fired electric steam generating units and stationary combustion turbines – that expresses the "best system of emissions reduction… adequately demonstrated" (BSER) for CO_2 from the power sector.[1] The EPA is also establishing state-specific rate-based

[1] Under CAA section 111(d), pursuant to 40 CFR 60. 22(b)(5), states must establish, in their state plans, emission standards that reflect the degree of emission limitation achievable

and mass-based goals that reflect the subcategory-specific CO_2 emission performance rates and each state's mix of affected EGUs. The guidelines also provide for the development, submittal and implementation of state plans that implement the BSER – again, expressed as CO_2 emission performance rates – either directly by means of source-specific emission standards or other requirements, or through measures that achieve equivalent CO_2 reductions from the same group of EGUs.

States with one or more affected EGUs will be required to develop and implement plans that set emission standards for affected EGUs. The CAA section 111(d) emission guidelines that the EPA is promulgating in this action apply to only the 48 contiguous states and any Indian tribe that has been approved by the EPA pursuant to 40 CFR 49.9 as eligible to develop and implement a CAA section 111(d) plan.[2] Because Vermont and the

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through the application of the "best system of emission reduction" that, taking into account the cost of achieving such reduction and any non-air quality health and environmental impacts and energy requirements, the Administrator determines has been adequately demonstrated (i.e., the BSER). Under CAA section 111(a)(1) and (d), the EPA is authorized to determine the BSER and to calculate the amount of emission reduction achievable through applying the BSER. The state is authorized to identify the emission standard or standards that reflect that amount of emission reduction.

[2] In the case of a tribe that has one or more affected EGUs in its area of Indian country, the tribe has the opportunity, but not the obligation, to establish a CO_2 emission standard for each affected EGU located in its area of Indian country and a CAA section 111(d) plan for its area of Indian country. If the tribe

District of Columbia do not have affected EGUs, they will not be required to submit a state plan. Because the EPA does not possess all of the information or analytical tools needed to quantify the BSER for the two non-contiguous states with otherwise affected EGUs (Alaska and Hawaii) and the two U.S. territories with otherwise affected EGUs (Guam and Puerto Rico), these emission guidelines do not apply to those areas, and those areas will not be required to submit state plans on the schedule required by this final action.

The emission standards in a state's plan may incorporate the subcategory-specific CO_2 emission performance rates set by the EPA or, in the alternative, may be set at levels that ensure that the state's affected EGUs, individually, in aggregate, or in combination with other measures undertaken by the state achieve the equivalent of the interim and final CO_2 emission performance rates between 2022 and 2029 and by 2030, respectively. State plans must also: 1) ensure that the period for emission reductions from the affected EGUs begin no later than 2022, 2) show how goals for the interim and final periods

chooses to establish its own plan, it must seek and obtain authority from the EPA to do so pursuant to 40 CFR 49.9. If it chooses not to seek this authority, the EPA has the responsibility to determine whether it is necessary or appropriate, in order to protect air quality, to establish a CAA section 111(d) plan for an area of Indian country where affected EGUs are located.

will be met, 3) ensure that, during the period from 2022 to 2029, affected EGUs in the state collectively meet the equivalent of the interim subcategory-specific CO_2 emission performance rates, and 4) provide for periodic state-level demonstrations prior to and during the 2022-2029 period that will ensure required CO_2 emission reductions are being accomplished and no increases in emissions relative to each state's planned emission reduction trajectory are occurring. A Clean Energy Incentive Program (CEIP) will provide opportunities for investments in renewable energy (RE) and demand-side energy efficiency (EE) that deliver results in 2020 and/or 2021. The plans must be submitted to the EPA in 2016, though an extension to 2018 is available to allow for the completion of stakeholder and administrative processes.

The EPA is promulgating: 1) subcategory-specific CO_2 emission performance rates, 2) state rate-based goals, and 3) state mass-based CO_2 goals that represent the equivalent of each state's rate-based goal. This will facilitate states' choices in developing their plans, particularly for those seeking to adopt mass-based allowance trading programs or other statewide policy measures as well as, or instead of, source-specific requirements. The EPA received significant comment to the effect that mass-based allowance trading was not only highly familiar to states and EGUs, but that it could be more readily applied than rate-based trading for achieving emission reductions in ways that optimize affordability and electric system reliability.

In this summary, we discuss the purpose of this rule, the major provisions of the final rule, the context for the rulemaking, key changes from the proposal, the estimated CO_2 emission reductions, and the costs and benefits expected to result from full implementation of this final action. Greater detail is provided in the body of this preamble, the RIA, the response to comments (RTC) documents, and various TSDs and memoranda addressing specific topics.

2. Purpose of this rule

The purpose of this rule is to protect human health and the environment by reducing CO_2 emissions from fossil fuel-fired power plants in the U.S. These plants are by far the largest domestic stationary source of emissions of CO_2, the most prevalent of the group of air pollutant GHGs that the EPA has determined endangers public health and welfare through its contribution to climate change. This rule establishes for the first time emission guidelines for existing power plants. These guidelines will lead to significant reductions in CO_2 emissions, result in cleaner generation from the existing power plant fleet, and support continued investments by the industry in cleaner power generation to ensure reliable, affordable electricity now and into the future.

Concurrent with this action, the EPA is also issuing a final rule that establishes CO_2 emission standards of performance for new, modified, and reconstructed power plants. Together, these rules will reduce CO_2 emissions by a substantial amount while ensuring that the utility power sector in the U.S. can continue to supply reliable and affordable electricity to all Americans using a diverse fuel supply. As with past EPA rules addressing air pollution from the utility power sector, these guidelines have been designed with a clear recognition of the unique features of this sector. Specifically, the agency recognizes that utilities provide an essential public service and are regulated and managed in ways unlike any other industrial activity. In providing assurances that the emission reductions required by this rule can be achieved without compromising continued reliable, affordable electricity, this final rule fully accounts for the critical service utilities provide.

As with past rules under CAA section 111, this rule relies on proven technologies and measures to set achievable emission performance rates that will lead to cost-effective pollutant emission reductions, in this case CO_2 emission reductions at power plants, across the country. In fact, the emission guidelines reflect strategies, technologies and approaches already in widespread use by power companies and states. The vast preponderance of the input we received from stakeholders is supportive of this conclusion.

States will play a key role in ensuring that emission reductions are achieved at a reasonable cost. The experience of states in this regard is especially important because CAA section 111(d) relies on the well-established state-EPA partnership to accomplish the required CO_2 emission reductions. States will have the flexibility to choose from a range of plan approaches and measures, including numerous measures beyond those considered in setting the CO_2 emission performance rates, and this final rule allows and encourages states to adopt the most effective set of solutions for their circumstances, taking account of cost and other considerations. This rulemaking, which will be implemented through the state-EPA partnership, is a significant step that will reduce air pollution, in this case GHG emissions, in the U.S. At the same time, the final rule greatly facilitates flexibility for EGUs by establishing a basis for states to set trading-based emission standards and compliance strategies. The rule establishes this basis by including both uniform emission performance rates for the two subcategories of sources and also state-specific rate- and mass-based goals.

This final rule is a significant step forward in implementing the President's Climate Action Plan.[3] To address the far-reaching harmful consequences and real economic costs of climate change, the President's Climate Action Plan details a broad array of actions to reduce GHG emissions that contribute to climate change and its harmful impacts on public health and the environment. Climate change is already occurring in this country, affecting the health, economic well-being and quality of life of Americans across the country, and especially those in the most vulnerable communities. This CAA section 111(d) rulemaking to reduce GHG emissions from existing power plants, and the concurrent CAA section 111(b) rulemaking to reduce GHG emissions from new, modified, and reconstructed power plants, implement one of the strategies of the Climate Action Plan.

Nationwide, by 2030, this final CAA section 111(d) existing source rule will achieve CO_2 emission reductions from the utility power sector of approximately 32 percent from CO_2 emission levels in 2005.

The EPA projects that these reductions, along with reductions in other air pollutants resulting directly from this rule, will result in net climate and health benefits of $25 billion to $45 billion in 2030. At the same time, coal and

[3] The President's Climate Action Plan, June 2013. http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf.

natural gas will remain the two leading sources of electricity generation in the U.S., with coal providing about 27 percent of the projected generation and natural gas providing about 33 percent of the projected generation.

3. Summary of major provisions

a. Overview. The fundamental goal of this rule is to reduce harmful emissions of CO_2 from fossil fuel-fired EGUs in accordance with the requirements of the CAA. The June 2014 proposal for this rule was designed to meet this overarching goal while accommodating two important objectives. The first was to establish guidelines that reflect both the unique interconnected and interdependent manner in which the power system operates and the actions, strategies, and policies states and utilities have already been undertaking that are resulting in CO_2 emission reductions. The second objective was to provide states and utilities with broad flexibility and choice in meeting those requirements in order to minimize costs to ratepayers and to ensure the reliability of electricity supply. In this final rule, the EPA has focused on changes that, in addition to being responsive to the critical concerns and priorities of stakeholders, more fully accomplish these objectives.

While our consideration of public input and additional information has led to notable revisions from the emission guidelines we proposed in June 2014, the proposed guidelines remain the foundation of this final rule. These final guidelines build on the progress already underway to reduce the carbon intensity of power generation in the U.S., especially through the lowest carbon-intensive technologies, while reflecting the unique interconnected and interdependent system within which EGUs operate. Thus, the BSER, as determined in these guidelines, incorporates a range of CO_2-reducing actions, while at the same time adhering to the fundamental approach the EPA has relied on for decades in implementing section 111 of the CAA. Specifically, in making its BSER determination, the EPA examined not only actions, technologies and measures already in use by EGUs and states, but also deliberately incorporated in its identification of the BSER the unique way in which affected EGUs actually operate in providing electricity services. This latter feature of the BSER mirrors Congress' approach to regulating air pollution in this sector, as exemplified by Title IV of the CAA. There, Congress established a pollution reduction program specifically for fossil fuel-fired EGUs and designed the sulfur dioxide (SO_2) portion of that program with express recognition of the utility power sector's ability to shift generation among various EGUs, which enabled pollution reduction by increasing reliance on RE and even on demand-side EE. The result of our following Congress' recognition of the interdependent operation of EGUs within an interconnected grid is the incorporation in the BSER of measures, such as shifting generation to lower-emitting NGCC units and increased use of RE, that rely on the current interdependent operation of EGUs. As we noted in the proposal and note here as well, the EPA undertook an unprecedented and sustained process of engagement with the public and stakeholders. It is, in many ways, as a direct result of public discussion and input that the EPA came to recognize the substantial extent to which the BSER needed to account for the unique interconnected and interdependent operations of EGUs if it was to meet the criteria on which the EPA has long relied in making BSER determinations.

Equally important, these guidelines offer states and owners and operators of EGUs broad flexibility and latitude in complying with their obligations. Because affordability and electricity system reliability are of paramount importance, the rule provides states and utilities with time for planning and investment, which is instrumental to ensuring both manageable costs and system reliability, as well as to facilitating clean energy innovation. The final rule continues to express the CO_2 emission reduction requirements in terms of state goals, as well as in terms of emission performance rates for the two subcategories of affected EGUs, reflecting the particular mix of power generation in each state, and it continues to provide until 2030, fifteen years from the date of this final rule, for states and sources to achieve the CO_2 reductions. Numerous commenters, including most sources, states and energy agencies, indicated that this was a reasonable timeframe. The final guidelines also continue to provide an option where programs beyond those directly limiting power plant emission rates can be used for compliance (i.e., policies, programs and other measures). The final rule also continues to allow, but not require, multi-state approaches. Finally, EPA took care to ensure that states could craft their own emissions reduction trajectories in meeting the interim goals included in this final rule.

b. Opportunities for states. As stated above, the final guidelines are designed to build on and reinforce progress by states, cities and towns, and companies on a growing variety of sustainable strategies to reduce power sector CO_2 emissions. States, in their CAA section 111(d) plans, will be able to rely on, and extend, programs they may already have created to address emissions of air pollutants, and in particular CO_2, from the utility power sector or to address the sector from an overall perspective. Those states committed to Integrated Resource Planning (IRP) will be able to establish their CO_2 reduction plans within that framework, while states with a more deregulated power sector system will be able to develop CO_2

reduction plans within that specific framework. Each state will have the opportunity to take advantage of a wide variety of strategies for reducing CO_2 emissions from affected EGUs, including demand-side EE programs and mass-based trading, which some suggested in their comments. The EPA and other federal entities, including the U.S. Department of Energy (DOE), the Federal Energy Regulatory Commission (FERC) and the U.S. Department of Agriculture (USDA), among others, are committed to sharing expertise with interested states as they develop and implement their plans.

States will be able to address the economic interests of their utilities and ratepayers by using the flexibilities in this final action to reduce costs to consumers, minimize stranded assets, and spur private investments in RE and EE technologies and businesses. They may also, if they choose, work with other states on multi-state approaches that reflect the regional structure of electricity operating systems that exists in most parts of the country and is critical to ensuring a reliable supply of affordable energy. The final rule gives states the flexibility to implement a broad range of approaches that recognize that the utility power sector is made up of a diverse range of companies of various sizes that own and operate fossil fuel-fired EGUs, including vertically integrated companies in regulated markets, independent power producers, rural cooperatives and municipally-owned utilities, some of which are likely to have more direct access than others to certain types of GHG emission reduction opportunities, but all of which have a wide range of opportunities to achieve reductions or acquire clean generation.

Again, with features that facilitate mass-based and/or interstate trading, the final guidelines also empower affected EGUs to pursue a broad range of choices for compliance and for integrating compliance action with the full range of their investments and operations.

c. Main elements. This final rule comprises three main elements: 1) two subcategory-specific CO_2 emission performance rates resulting from application of the BSER to the two subcategories of affected EGUs; 2) state-specific CO_2 goals, expressed as both emission rates and as mass, that reflect the subcategory-specific CO_2 emission performance rates and each state's mix of affected EGUsthe two performance rates; and 3) guidelines for the development, submittal and implementation of state plans that implement those BSER emission performance rates either through emission standards for affected EGUs, or through measures that achieve the equivalent, in aggregate, of those rates as defined and expressed in the form of the state goals.

In this final action, the EPA is setting emission performance rates, phased in over the period from 2022 through 2030, for two subcategories of affected fossil fuel-fired EGUs – fossil fuel-fired electric utility steam-generating units and stationary combustion turbines. These rates, applied to each state's particular mix of fossil fuel-fired EGUs, generate the state's carbon intensity goal for 2030 (and interim rates for the period 2022-2029). Each state will determine whether to apply these to each affected EGU or to take an alternative approach and meet either an equivalent statewide rate-based goal or statewide mass-based goal. The EPA does not prescribe how a state must meet the emission guidelines, but, if a state chooses to take the path of meeting a state goal, these final guidelines identify the methods that a state can or, in some cases, must use to demonstrate that the combination of measures and standards that the state adopts meets its state-level CO_2 goals. While the EPA accomplishes the phase-in of the interim goal by way of annual emission performance rates, states and EGUs may meet their respective emission reduction obligations "on average" over that period following whatever emission reduction trajectory they determine to pursue over that period.

CAA section 111(d) creates a partnership between the EPA and the states under which the EPA establishes emission guidelines and the states take the lead on implementing them by establishing emission standards or creating plans that are consistent with the EPA emission guidelines. The EPA recognizes that each state has differing policy considerations – including varying regional emission reduction opportunities and existing state programs and measures – and that the characteristics of the electricity system in each state (e.g., utility regulatory structure and generation mix) also differ. Therefore, as in the proposal, each state will have the latitude to design a program to meet source-category specific emission performance rates or the equivalent statewide rate- or mass-based goal in a manner that reflects its particular circumstances and energy and environmental policy objectives. Each state can do so on its own, or a state can collaborate with other states and/or tribal governments on multi-state plans, or states can include in their plans the trading tools that EGUs can use to realize additional opportunities for cost savings while continuing to operate across the interstate system through which electricity is produced. A state would also have the option of adopting the model rules for either a rate- or a mass-based program that the EPA is proposing concurrently with this action.[4]

To facilitate the state planning process, this final rule establishes guidelines for the development, submittal, and implementation of state plans. The final rule describes the components of a state plan, the additional latitude states have in developing strategies to meet the emission guidelines, and the options they have in the timing of submittal of their plans. This final rule also gives states considerable flexibility with respect to the timeframes for plan development and implementation, as well as the choice of emission reduction measures. The final rule provides up to fifteen years for full implementation of all emission reduction measures, with incremental steps for planning and then for demonstration of CO_2 reductions that will ensure that progress is being made in achieving CO_2 emission reductions. States will be able to choose from a wide range of emission reduction measures, including measures that are not part of the BSER, as discussed in detail in section VIII.G of this preamble.

[4] The EPA's proposed CAA section 111(d) federal plan and model rules for existing fossil fuel-fired EGUs are being published concurrently with this final rule.

d. Determining the BSER. In issuing this final rulemaking, the EPA is implementing statutory provisions that have been in place since Congress first enacted the CAA in 1970 and that have been implemented pursuant to regulations promulgated in 1975 and followed in numerous subsequent CAA section 111 rulemakings. These requirements call on the EPA to develop emission guidelines that reflect the EPA's determination of the "best system of emission reduction... adequately demonstrated"for states to follow in formulating plans to establish emission standards to implement the BSER.

As the EPA has done in making BSER determinations in previous CAA section 111 rulemakings, for this final BSER determination, the agency considered the types of strategies that states and owners and operators of EGUs are already employing to reduce the covered pollutant (in this case, CO_2) from affected sources (in this case, fossil fuel-fired EGUs).[5]

In so doing, as has always been the case, our considerations were not limited solely to specific technologies

[5] The final emission guidelines for landfill gas emissions from municipal solid waste landfills, published on March 12, 1996, and amended on June 16, 1998 (61 FR 9905 and 63 FR 32743, respectively), provide an example, as the guidelines allow either of two approaches for controlling landfill gas – by recovering the gas as a fuel, for sale, and removing from the premises, or by destroying the organic content of the gas on the premises using a control device. Recovering the gas as a fuel source was a practice already being used by some affected sources prior to promulgation of the rulemaking.

or equipment in hypothetical operation; rather, our analysis encompassed the full range of operational practices, limitations, constraints and opportunities that bear upon EGUs' emission performance, and which reflect the unique interconnected and interdependent operations of EGUs and the overall electricity grid.

In this final action, the agency has determined that the BSER comprises the first three of the four proposed "building blocks," with certain refinements to the three building blocks. The three building blocks are:

1. Improving heat rate at affected coal-fired steam EGUs.
2. Substituting increased generation from lower-emitting existing natural gas combined cycle units for reduced generation from higher-emitting affected steam generating units.
3. Substituting increased generation from new zero-emitting renewable energy generating capacity for reduced generation from affected fossil fuel-fired generating units.

These three building blocks are approaches that are available to all affected EGUs, either through direct investment or operational shifts or through emissions trading where states, which must establish emission standards for affected EGUs, do so by incorporating emissions trading.[6] At the same time, and as we noted in the proposal, there are numerous other measures available to reduce CO_2 emissions from affected EGUs, and our determination of the BSER does not necessitate the use of the three building blocks to their maximum extent, or even at all. The building blocks and the BSER determination are described in detail in section V of this preamble.

e. CO_2 state-level goals and subcategory-specific emission performance rates.

(1) Final CO_2 goals and emission performance rates.

In this action, the EPA is establishing CO_2 emission performance rates for two subcategories of affected EGUs -- fossil fuel-fired electric utility steam generating units and stationary combustion turbines. For fossil fuel-fired steam generating units, we are finalizing an emission performance rate of 1,305 lb CO_2/MWh. For stationary combustion turbines, we are finalizing an emission performance rate of 771 lb CO_2/MWh. As we did at proposal, for each state, we are also promulgating rate-

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[6] The EPA notes that, in quantifying the emission reductions that are achievable through application of the BSER, some building blocks will apply to some, but not all, affected EGUs. Specifically, building block 1 will apply to affected coal-fired steam EGUs, building block 2 will apply to all affected steam EGUs (both coal-fired and oil/gas-fired), and building block 3 will apply to all affected EGUs.

based CO_2 goals that are the weighted aggregate of the emission performance rates for the state's EGUs. To ensure that states and sources can choose additional alternatives in meeting their obligations, the EPA is also promulgating each state's goal expressed as a CO_2 mass goal. The inclusion of mass-based goals, along with information provided in the proposed federal plan and model rules that are being issued concurrently with this rule, paves the way for states to implement mass-based trading, as some states have requested, reflecting their view that mass-based trading provides significant advantages over rate-based trading.

Affected EGUs, individually, in aggregate, or in combination with other measures undertaken by the state, must achieve the equivalent of the CO_2 emission performance rates, expressed via the state-specific rate- and mass-based goals, by 2030.

(2) Interim CO_2 emission performance rates and state-specific goals.

The best system of emission reduction includes both the measures for reducing CO_2 emissions and the timeframe over which they can be implemented. In this final action, the EPA is establishing an eight-year interim period, beginning in 2022 instead of 2020, over which to achieve the full required reductions to meet the CO_2 performance rates, a commencement date more than six years from **[INSERT THE DATE OF PUBLICATION IN THE FEDERAL REGISTER]**, the date of this rulemaking. This eight-year interim period from 2022 through 2029 is separated into three steps, 2022-2024, 2025-2027, and 2028-2029, each associated with its own interim CO_2 emission performance rates. The interim steps are presented both in terms of emission performance rates for the two subcategories of affected EGUs and in terms of state goals, expressed both as a rate and as a mass. A state may adopt emission standards for its sources that are identical to these interim emission performance rates or, alternatively, adapt these steps to accommodate the timing of expected reductions, as long as the state's interim goal is met over the eight-year period.

f. State plans.[7]

[7] The CAA section 111(d) emission guidelines apply to the 50 states, the District of Columbia, U.S. territories, and any Indian tribe that has been approved by the EPA pursuant to 40 CFR 49.9 as eligible to develop and implement a CAA section 111(d) plan. In this preamble, in instances where these governments are not specifically listed, the term "state" is used to represent them. Because Vermont and the District of Columbia do not have affected EGUs, they will not be required to submit a state plan. Because the EPA lacks appropriate information to quantify the BSER for the two non-contiguous states with affected EGUs (Alaska and Hawaii) and the two U.S. territories with affected EGUs (Guam and Puerto Rico), we are not finalizing emission performance rates in those areas at this time, and those areas will not be required to submit state plans until we do.

In this action, the EPA is establishing final guidelines for states to follow in developing, submitting and implementing their plans. In developing plans, states will need to choose the type of plan they will develop. They will also need to include required plan components in their plan submittals, meet plan submittal deadlines, achieve the required CO_2 emission reductions over time, and provide for monitoring and periodic reporting of progress. As with the BSER determination, stakeholder comments have provided both data and recommendations to which these final guidelines are responsive.

(1) Plan approaches.

To comply with these emission guidelines, a state will have to ensure, through its plan, that the emission standards it establishes for its sources individually, in aggregate, or in combination with other measures undertaken by the state, represent the equivalent of the subcategory-specific CO_2 emission performance rates. This final rule includes several options for state plans, as discussed in the proposal and in many of the comments we received.

First, in the final rule, states may establish emission standards for their affected EGUs that mirror the uniform emission performance rates for the two subcategories of sources included in this final rule. They may also pursue alternative approaches that adopt emission standards that meet the uniform emission performance rates, or emission standards that meet either the rate-based goal promulgated for the state or the alternative mass-based goal promulgated for the state. It is for the purpose of providing states with these choices that the EPA is providing state-specific rate-based and mass-based goals equivalent to the emission performance rates that the EPA is establishing for the two subcategories of fossil fuel-fired EGUs. A detailed explanation of rate- and mass-based goals is provided in section VII of this preamble and in a TSD.[8] In developing its plan, each state and eligible tribe electing to submit a plan will need to choose whether its plan will result in the achievement of the CO_2 emission performance rates, statewide rate-based goals, or statewide mass-based goals by the affected EGUs.

The second major set of options provided in the final rule includes the types of measures states may rely on through the state plans. A state will be able to choose to establish emission standards for its affected EGUs sufficient to meet the requisite performance rates or state goal, thus placing all of the requirements directly on its affected EGUs, which we refer to as the "emission standards approach." Alternatively, a state

[8] The CO_2 Emission Performance Rate and Goal Computation TSD for the CPP Final Rule, available in the docket for this rulemaking.

can adopt a "state measures approach," which would result in the affected EGUs meeting the statewide mass-based goal by allowing a state to rely upon state-enforceable measures on entities other than affected EGUs, in conjunction with any federally enforceable emission standards the state chooses to impose on affected EGUs. With a state measures approach, the plan must also include a contingent backstop of federally enforceable emission standards for affected EGUs that fully meet the emission guidelines and that would be triggered if the plan failed to achieve the required emission reductions on schedule. A state would have the option of basing its backstop emission standards on the model rule, which focuses on the use of emissions trading as the core mechanism, that the EPA is proposing today. A state that adopts a state measures approach must use its mass CO_2 emission goal as the metric for demonstrating plan performance.

The final rule requires that the state plan submittal include a timeline with all of the programmatic milestone steps the state will take between the time of the state plan submittal and the year 2022 to ensure that the plan is effective as of 2022. States must submit a report to the EPA in 2021 that demonstrates that the state has met the programmatic milestone steps that the state indicated it would take during the period from the submittal of the final plan through the end of 2020, and that the state is on track to implement the approved state plan as of January 1, 2022.

The plan must also include a process for reporting on plan implementation, progress toward achieving CO_2 emission reductions, and implementation of corrective actions, in the event that the state fails to achieve required emission levels in a timely fashion. Beginning January 1, 2025, and then January 1, 2028, January 1, 2030, and then every two calendar years thereafter, the state will be required to compare emission levels achieved by affected EGUs in the state with the emission levels projected in the state plan and report the results of that comparison to the EPA by July 1 of those calendar years.

Existing state programs can be aligned with the various state plan options further described in Section VIII. A state plan that uses one of the finalized model rules, which the EPA is proposing concurrently with this action, could be presumptively approvable if the state plan meets all applicable requirements.[9] The plan guidelines provide the states with the ability to achieve the full reductions over a multi-year period, through a variety of reduction strategies, using state-specific or multi-state approaches that can be achieved on either a rate or mass

[9] The EPA would take action on such a state plan through independent notice and comment rulemaking.

basis. They also address several key policy considerations that states can be expected to contemplate in developing their plans.

State plan approaches and plan guidelines are explained further in section VIII of this preamble.

(2) State plan components and approvability criteria.

The EPA's implementing regulations provide certain basic elements required for state plans submitted pursuant to CAA section 111(d).[10] In the proposal, the EPA identified certain additional elements that should be contained in state plans. In this final action, in response to comments, the EPA is making several revisions to the components required in a state plan submittal and is also incorporating the approvability criteria into the final list of components required in a state plan submittal. In addition, we have organized the state plan components to reflect: 1) components required for all state plan submittals; 2) additional components required for the emission standards approach; and 3) additional components required for the state measures approach.

All state plans must include the following components:

- Description of the plan
- Applicability of state plans to affected EGUs

[10] 40 CFR 60.23.

- Demonstration that the plan submittal is projected to achieve the state's CO_2 emission performance rates or state CO_2 goal[11]
- Monitoring, reporting and recordkeeping requirements for affected EGUs
- State recordkeeping and reporting requirements
- Public participation and certification of hearing on state plan
- Supporting documentation

Also, in submitting state plans, states must provide documentation demonstrating that they have considered electric system reliability in developing their plans.

Further, in this final rule, the EPA is requiring states to demonstrate how they are meaningfully engaging all stakeholders, including workers and low-income communities, communities of color, and indigenous populations living near power plants and otherwise potentially affected by the state's plan. In their plan submittals, states must describe their engagement with their stakeholders, including their most vulnerable communities. The participation of these communities, along with that of ratepayers and the public, can be expected to help states ensure that state plans maintain the affordability of electricity for all and preserve and expand jobs and job opportunities as they move forward to develop and implement their plans.

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[11] A state that chooses to set emission standards that are identical to the emission performance rates for both the interim period and in 2030 and beyond need not identify interim state goals nor include a separate demonstration that its plan will achieve the state goals.

State plan submittals using the emission standards approach must also include:

- Identification of each affected EGU; identification of federally enforceable emission standards for the affected EGUs; and monitoring, recordkeeping and reporting requirements.
- Demonstrations that each emission standard will result in reductions that are quantifiable, non-duplicative, permanent, verifiable, and enforceable.

State plan submittals using the state measures approach must also include:

- Identification of each affected EGU; identification of federally enforceable emission standards for affected EGUs (if applicable); identification of backstop of federally enforceable emission standards; and monitoring, recordkeeping and reporting requirements.
- Identification of each state measure and demonstration that each state measure will result in reductions that are quantifiable, non-duplicative, permanent, verifiable, and enforceable.

In addition to these requirements, each state plan must follow the EPA implementing regulations at 40 CFR 60.23.

(3) Timing and process for state plan submittal and review.

Because of the compelling need for actions to begin the steps necessary to reduce GHG emissions from EGUs, the EPA proposed that states submit their plans within 13 months of the date of this final rule and that reductions begin in 2020. In light of the comments received and in order to provide maximum flexibility to states while still taking timely action to reduce

CO_2 emissions, in this final rule the EPA is allowing for a 2-year extension until September 6, 2018, for both individual and multi-state plans, to provide a total of 3 years for states to submit a final plan if an extension is received. Specifically, the final rule requires each state to submit a final plan by September 6, 2016. Since some states may need more than one year to complete all of the actions needed for their final state plans, including technical work, state legislative and rulemaking activities, a robust public participation process, coordination with third parties, coordination among states involved in multi-state plans, and consultation with reliability entities, the EPA is allowing an optional two-phased submittal process for state plans. If a state needs additional time to submit a final plan, then the state may request an extension by submitting an initial submittal by September 6, 2016. For the extension to be granted, the initial submittal must address three required components sufficiently to demonstrate that a state is able to undertake steps and processes necessary to timely submit a final plan by the extended date of September 6, 2018. These components are: an identification of final plan approach or approaches under consideraton, including a description of progress made to date; an appropriate explanation for why the state needs additional time to submit a final plan beyond September 6, 2016; and a demonstration of how they have been engaging with the public, including vulnerable communities, and a description of how they intend to meaningfully engage with community stakeholders during the additonal time (if an extension is granted) for development of the final plan, as described in section VIII.E of this preamble. As further described in section VIII.B of this preamble, the EPA is establishing a CEIP in order to promote early action. States' participation in the CEIP is optional. In order for a state to participate in the program, it must include in its initial submittal, if applicable, a non-binding statement of intent to participate in the CEIP; if a state is submitting a final plan by September 6, 2016, it must include such a statement of intent as part of its supporting documentation for the plan.

If the initial submittal includes those components and if the EPA does not notify the state that the initial submittal does not contain the required components, then, within 90 days of the submittal, the extension of time to submit a final plan will be deemed granted. A state will then have until no later than September 6, 2018, to submit a final plan. The EPA will also be working with states during the period after they make their initial submittals and provide states with any necessary information and assistance during the 90-day period. Further, states participating in a multi-state plan may submit a single joint plan on behalf of all of the participating states.

States and tribes that do not have any affected EGUs in their jurisdictional boundaries may provide emission rate credits (ERCs) to adjust CO_2 emissions, provided they are connected to the contiguous U.S. grid and meet other requirements for eligibility. There are certain limitations and restrictions for generating ERCs, and these, as well as associated requirements, are explained in section VIII of this preamble.

Following submission of final plans, the EPA will review plan submittals for approvability. Given a similar timeline accorded under section 110 of the CAA, and the diverse approaches states may take to meet the CO_2 emission performance rates or equivalent statewide goals in the emission guidelines, the EPA is extending the period for EPA review and approval or disapproval of plans from the four-month period provided in the EPA implementing regulations to a twelve-month period. This timeline will provide adequate time for the EPA to review plans and follow notice-and-comment rulemaking procedures to ensure an opportunity for public comment. The EPA, especially through our regional offices, will be available to work with states as they develop their plans, in order to make review of submitted plans more straightforward and to minimize the chances of unexpected issues that could slow down approval of state plans.

(4) <u>Timing for implementing the CO_2 emission guidelines</u>.

The EPA recognizes that the measures states and utilities have been and will be taking to reduce CO_2 emissions from existing EGUs can take time to implement. We also recognize that investments in low-carbon intensity and RE and in EE strategies are currently underway and in various stages of planning and implementation widely across the country. We carefully reviewed information submitted to us regarding the feasible timing of various measures and identifying concerns that the required CO_2 emission reductions could not be achieved as early as 2020 without compromising electric system reliability, imposing unnecessary costs on ratepayers, and requiring investments in more carbon-intensive generation, while diverting investment in cleaner technologies. The record is compelling. To respond to these concerns and to reflect the period of time required for state plan development and submittal by states, review and approval by the EPA, and implementation of approved plans by states and affected EGUs, the EPA is determining in this final rule that affected EGUs will be required to begin to make reductions by 2022, instead of 2020, as proposed, and meet the final CO_2 emission performance rates or equivalent statewide goals by no later than 2030. The EPA is establishing an 8-year interim period that begins in 2022 and goes through 2029, and which is separated into three steps, 2022-2024, 2025-2027, and 2028-2029, each associated with its own interim goal. Affected EGUs must meet each of the interim period step 1, 2, and 3 CO_2 emission performance rates, or, following the emissions reduction trajectory designed by the state itself, must meet the equivalent statewide interim period goals, on average, that a state may establish over the 8-year period from 2022-2029. The CAA section 111(d) plan must include those specific requirements. Affected EGUs must also achieve the final CO_2 performance rates or the equivalent statewide goal by 2030 and maintain that level subsequently. This approach reflects adjustments to the timeframe over which reductions must be achieved that mirror the determination of the final BSER, which incorporates the phasing in of the BSER measures in keeping with the achievability of those measures. The agency believes that this approach to timing is reasonable and appropriate, is consistent with many of the comments we received, and will best support the optimization of overall CO_2 reductions, ratepayer affordability and electricity system reliability.

The EPA recognizes that successfully achieving reductions by 2022 will be facilitated by actions and investments that yield CO_2 emission reductions prior to 2022. The final guidelines include provisions to encourage early actions. States will be able to take advantage of the impacts of early investments that occur prior to the beginning of a plan performance period. Under a mass-based plan, those impacts will be reflected in reductions in the reported CO_2 emissions of affected EGUs during the plan performance period. Under a rate-based plan, states may recognize early actions implemented after 2012 by crediting MWh of electricity generation and savings that are achieved by those measures during the interim and final plan performance periods. This provision is discussed in section VIII.K of the preamble.

In addition, to encourage early investments in RE and demand-side EE, the EPA is establishing the CEIP. Through this program, detailed in section VIII.B of this preamble, states will have the opportunity to award allowances and ERCs to qualified providers that make early investments in RE, as well as in demand-side EE programs implemented in low-income communities. Those states that take advantage of this option will be eligible to receive from the EPA matching allowances or ERCs, up to a total for all states that represents the equivalent of 300 million short tons of CO_2 emissions.

The EPA will address design and implementation details of the CEIP in a subsequent action. Prior to doing so, the EPA will engage with states, utilities and other stakeholders to gather information regarding their interests and priorities with regard to implementation of the CEIP.

The CEIP can play an important role in supporting one of the critical policy benefits of this rule. The incentives and market signal generated by the CEIP can help sustain the momentum toward greater RE investment in the period between now and 2022 so as to offset any dampening effects that might be created by setting the period for mandatory reductions to begin to 2022, two years later than at proposal.

(5) Community and environmental justice considerations.

Climate change is an environmental justice issue. Low-income communities and communities of color already overburdened by pollution are disproportionately affected by climate change and are less resilient than others to adapt to or recover from climate-change impacts. While this rule will provide broad benefits to communities across the nation by reducing GHG emissions, it will be particularly beneficial to populations that are disproportionately vulnerable to the impacts of climate change and air pollution.

Conventional pollutants emitted by power plants, such as particulate matter (PM), SO_2, hazardous air pollutants (HAP), and nitrogen oxides (NOx), will also be reduced as the plants reduce their carbon emissions. These pollutants can have significant adverse local and regional health impacts. The EPA analyzed the communities in closest proximity to power plants and found that they include a higher percentage of communities of color and low-income communities than national averages. We thus expect an important co-benefit of this rule to be a reduction in the adverse health impacts of air pollution on these low-income communities and communities of color. We refer to these communities generally as "vulnerable" or "overburdened," to denote those communities least resilient to the impacts of climate change and central to environmental justice considerations.

While pollution will be cut from power plants overall, there may be some relatively small number of plants whose operation and corresponding emissions increase, as energy providers balance energy production across their fleets to comply with state plans. These plants are likely to be the highest-efficiency natural gas-fired units, which have correspondingly low carbon emissions and are also characterized by low emissions of the conventional pollutants that contribute to adverse health effects in nearby communities and regionally. The EPA strongly encourages states to evaluate the effects of their plans on vulnerable communities and to take the steps necessary to ensure that all communities benefit from the implementation of this rule. In order to identify whether state plans are causing any adverse impacts on overburdened communities, mindful that substantial overall reductions, nevertheless, may be accompanied by potential localized increases, the EPA intends to perform an assessment of the implementation of this rule to determine whether it and other air quality rules are leading to improved air quality in all areas or whether there are localized impacts that need to be addressed.

Effective engagement between states and affected communities is critical to the development of state plans. The EPA encourages states to identify communities that may be currently experiencing adverse, disproportionate impacts of climate change and air pollution, how state plan designs may affect them, and how to most effectively reach out to them. This final rule requires that states include in their initial submittals a description of how they engaged with vulnerable communities as they developed their initial submittals, as well as the means by which they intend to involve communities and other stakeholders as they develop their final plans. The EPA will provide training and other resources for states and communities to facilitate meaningful engagement.

In addition to the benefits for vulnerable communities from reducing climate change impacts and effects of conventional pollutant emissions, this rule will also help communities by moving the utility industry toward cleaner generation and greater EE. The federal government is committed to ensuring that all communities share in these benefits.

The EPA also encourages states to consider how they may incorporate approaches already used by other states to help low-income communities share in the investments in infrastructure, job creation, and other benefits that RE and demand-side EEprograms provide, have access to financial assistance programs, and minimize any adverse impacts that their plans could have on communities. To help support states in taking concrete actions that provide economic development, job and electricity bill-cutting benefits to low-income communities directly, the EPA has designed the CEIP specifically to target the incentives it creates on investments that benefit low-income communities.

Community and environmental justice considerations are discussed further in section IX of this preamble.

(6) Addressing employment concerns.

In addition, the EPA encourages states in designing their state plans to consider the effects of their plans on employment and overall economic development to assure that the opportunities for economic growth and jobs that the plans offer are realized. To the extent possible, states should try to assure that communities that can be expected to experience job losses can also take advantage of the opportunities for job growth or otherwise transition to healthy, sustainable economic growth. The President has proposed the POWER+ Plan to help communities impacted by power sector transition. The POWER+ planinvests in workers and jobs, addresses important legacy costs in coal country, and drives development of coal technology.[12] Implementation of one key part of the POWER+ Plan, the Partnerships for Opportunity and Workforce and Economic Revitalization (POWER) initiative, has already begun. The POWER initiative specifically targets economic and workforce development assistance to communities affected by ongoing changes in the coal industry and the utility power sector.[13]

(7) Electric system reliability.

In no small part thanks to the comments we received and our extensive consultation with key agencies responsible for reliability, including FERC and DOE, among others, along with EPA's longstanding principles in setting emission standards for the utility power sector, these guidelines reflect the paramount importance of ensuring electric system reliability. The input we received on this issue focused heavily on the extent of the reductions required at the beginning of the interim period, proposed as 2020. We are addressing these concerns in large part by moving the beginning of the period for mandatory reductions under the program from 2020 to 2022 and significantly adjusting

[12] https://www.whitehouse.gov/the-press-office/2015/03/27/fact-sheet-partnerships-opportunity-and-workforce-and-economic-revitaliz.

[13] http://www.eda.gov/power/.

the interim goals so that they provide a less abrupt initial reduction expectation. This, in turn, will provide states and utilities with a great deal more latitude in determining their emission reduction trajectories over the interim period. As a result, there will be more time for planning, consultation and decision making in the formulation of state plans and in EGUs' choice of compliance strategies, all within the existing extensive structure of energy planning at the state and regional levels. These adjustments in the interim goals are supported by the information in the record concerning the time needed to develop and implement reductions under the BSER. In addition, the various forms of flexibility retained and enhanced in this final rule, including opportunities for trading within and between states, and other multi-state compliance approaches, will further support electric system reliability.

The final guidelines address electric system reliability in several additional important ways. Numerous commenters urged us to include, as part of the plan development or approval process, input from review by energy regulatory agencies and reliability entities. In the final rule, we are requiring that each state demonstrate in its final state plan submittal that it has considered reliability issues in developing its plan. Second, we recognize that issues may arise during the implementation of the guidelines that may warrant adjustments to a state's plan in order to maintain electric system reliability. The final guidelines make clear that states have the ability to propose amendments to approved plans in the event that unanticipated and significant electric system reliability challenges arise and compel affected EGUs to generate at levels that conflict with their compliance obligations under those plans.

As a final element of reliability assurance, the rule also provides for a reliability safety valve for individual sources where there is a conflict between the requirements the state plan imposes on a specific affected EGU and the maintenance of electric system reliability in the face of an extraordinary and unanticipated event that presents substantial reliability concerns.

We anticipate that these situations will be extremely rare because the states have the flexibility to craft requirements for their EGUs that will provide long averaging periods and/or compliance mechanisms, such as trading, whose inherent flexibility will make it unlikely that an individual unit will find itself in this kind of situation. As one example, under compliance regimes that allow individual EGUs to establish compliance through the acquisition and holding of allowances or ERCs equal to their emissions, an EGU’s need to continue to operate – and emit – for the purposes of ensuring system reliability will not put the EGU into non-compliance, provided, of course, it obtains the needed allowances or credits in a timely fashion. We, nevertheless, agree with many commenters that it is prudent to provide an electric system reliability safety valve as a precaution.

Finally, the EPA, DOE and FERC have agreed to coordinate their efforts, at the federal level, to help ensure continued reliable electricity generation and transmission during the implementation of the final rule. The three agencies have set out a memorandum that reflects their joint understanding of how they will work together to monitor implementation, share information, and to resolve any difficulties that may be encountered.

As a result of the many features of this final rule that provide states and affected EGUs with meaningful time and decision making latitude, we believe that the comprehensive safeguards already in place in the U.S. to ensure electric system reliability will continue to operate effectively as affected EGUs reduce their CO_2 emissions under this program.

(8) Outreach and resources for stakeholders.

To provide states, U.S. territories, tribes, utilities, communities, and other interested stakeholders with understanding about the rule requirements, and to provide efficiencies where possible and reduce the cost and administrative burden, the EPA will continue to work with states, tribes, territories, and stakeholders to provide information and address questions about the final rule. Outreach will include opportunities for states and tribes to participate in briefings, teleconferences, and meetings about the final rule. The EPA's ten regional offices will continue to be the entry point for states, tribes and territories to ask technical and policy questions. The agency will host (or partner with appropriate groups to co-host) a number of webinars about various components of the final rule; these webinars are planned for the first two months after the final rule is issued. The EPA will also offer consultations with tribal governments. The EPA will continue outreach throughout the plan development and submittal process. The EPA will use information from this outreach process to inform the training and other tools that will be of most use to the state, tribes, and territories that are implementing the final rule.

The EPA has worked with communities, states, tribes and relevant associations to develop an extensive training plan that will continue in the months after the Clean Power Plan is finalized. The EPA has assembled resources from a variety of sources to create a comprehensive training curriculum for those implementing this rule. Recorded presentations from the EPA, DOE and other federal entities will be available for communities, states, and others involved in composing and participating in the development of state plans. This curriculum is available online at EPA's Air Pollution Training Institute.

The EPA also expects to issue guidance on specific topics. As guidance documents, tools, templates and other resources become available, the EPA, in consultation with DOE and other federal agencies, will continue to make these resources available via a dedicated website.[14]

We intend to continue to work actively with states and tribes, as appropriate, to provide information and technical support that will be helpful to them in developing and implementing their plans. The EPA will engage in formal consultations with tribal governments and provide training tailored to the needs of tribes and tribal governments.

Additional detail on aspects of the final rule is included in several technical support documents (TSDs) and memoranda that are available in the rulemaking docket.

4. Key changes from proposal

a. Overview and highlights. As noted earlier in this overview, the June 2014 proposal for the rule was designed to meet the fundamental goal of reducing harmful emissions of CO_2 from fossil fuel-fired EGUs in a manner consistent with the CAA requirements, while accommodating two important objectives. The

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[14] www.epa.gov/cleanpowerplantoolbox.

first objective was to establish guidelines that reflect both the manner in which the power system operates and the actions and measures already underway across states and the utility power sector that are resulting in CO_2 emission reductions. The second objective was to provide states and utilities maximum flexibility, control and choice in meeting their compliance obligations. In this final rule, the EPA has focused on changes that, in addition to being responsive to the critical concerns and priorities of stakeholders, more fully accomplish these two crucial objectives.

To achieve these objectives, the June 2014 proposal featured several important elements: the building block approach for the BSER; state-specific, rather than source-specific, goals; a 10-year interim goal that could be met "on average" over the 10-year period between 2020 and 2029; and a "portfolio" option for state plans. These features were intended either to capture, in the emission guidelines, emission reduction measures already in widespread use or to maximize the range of choices that states and utilities could select in order to achieve their emission limitations at low cost while ensuring electric system reliability. In this final rule, we are retaining the key design elements of the proposal and making certain adjustments to respond to a variety of very constructive comments on ways that will implement the CAA section 111(d) requirements efficiently and effectively.

The building block approach is a key feature of the proposal that we are retaining in the final rule, but have refined to include only the first three building blocks and to reflect implementation of the measures encompassed in the building blocks on a broad regional grid-level. In the proposal, we expressed the emission limitation requirements reflecting the BSER in terms of the state goals in order to provide states with maximum flexibility and latitude. We viewed this as an important feature because each state has its own energy profile and state-specific policies and needs relative to the production and use of electricity. In the final rule, we extend that flexibility significantly in direct response to comments from states and utilities. The final rule establishes source-level emission performance rates for the source subcategories, while retaining state-level rate- and mass-based goals. One of the key messages conveyed by state and utility commenters was that the final rule should make it easier for states to adopt mass-based programs and for utilities accustomed to operating across broad multi-state grids to be able to avail themselves of more "ready-made" emissions trading regimes. The inclusion of both of these new features – mass-based state goals in addition to rate-based goals, and source-level emission performance rates for the two subcategories of sources – is intended to make it easier for states and utilities to achieve these outcomes. In fact, these additions, together with the model rules and federal plan being proposed concurrently with this rule, should demonstrate the relative ease with which states can adopt mass-based trading programs, including interstate mass-based programs that lend themselves to the kind of interstate compliance strategies so well suited for integration with the current interstate operations of the overall utility grid.

Many stakeholders conveyed to the EPA that the proposal's interim goals for the 2020-2029 period were designed in a way that defeated the EPA's objective of allowing states and utilities to shape their emission reduction trajectories. They pointed out that, in many cases, the timing and stringency of the states' interim goals could require actions that could result in high costs, threaten electric system reliability or hinder the deployment of renewable technology. In response, the EPA has revised the interim goals in two critical ways. First, the period for mandatory reductions begin in 2022 rather than 2020; second, in keeping with the BSER, emission reduction requirements are phased in more gradually over the interim period. These changes will allow states and utilities to delineate their own emission reduction trajectories so as to minimize costs and foster broader deployment of RE technologies.

The value of these changes is demonstrated by our analysis of the final rule, which shows lower program costs, especially in the early years of the interim period, and greater RE deployment, relative to the analysis of the proposed rule. At the same time, this re-design of the interim goals, together with refinements we have made to state plan requirements and the inclusion of a reliability safety valve, provide states, utilities and other entities with the ability to continue to guarantee system reliability.

b. Outreach, engagement and comment record. This final rule is the product of one of the most extensive and long-running public engagement processes the EPA has ever conducted, starting in the summer of 2013, prior to proposal, and continuing through December 2014, when the public comment period ended, and continuing beyond that with consultations and meetings with stakeholders. The result of this extensive consultation was millions of comments from stakeholders, which we have carefully considered over the past several months. The EPA gained crucial insights from the more than 4 million comments that the agency received on the proposal and on notices leading to this final rulemaking. Comments were provided by stakeholders that include state environmental and energy officials, tribal officials, public utility commissioners, system operators, owners and operators of every type of power generating facility, other industry representatives, labor leaders, public health leaders, public interest advocates, community and faith leaders, and members of the public.

The insights gained from public comments contributed to the development of final emission guidelines that build on the proposal and the alternatives on which we sought comment. The modifications incorporated in the final guidelines are directly responsive to the comments we received from the many and diverse stakeholders. The improved guidelines reflect information and ideas that states and utilities provided to us about both the best approach to establishing CO_2 emission reduction requirements for EGUs and the most effective ways to create true flexibility for states and utilities in meeting these requirements. These final rules also reflect the results of EPA's robust consultation with federal, state and regional energy agencies and authorities, to ensure that the actions sources will take to reduce GHG emissions will not compromise electric system reliability or affordability of the U.S. electricity supply. Input and assistance from FERC and DOE have been particularly important in shaping some provisions in these final guidelines. At the same time, input from faith-based, community-based and environmental justice organizations, who provided thoughtful comments about the potential impacts of this rule on pollution levels in overburdened communities and economic impacts, including utility rates in low-income communities, is also reflected in this rule. The final rule also reflects our response to concerns raised by labor leaders regarding the potential effects on workers and communities of the transition away from higher-emitting power generation to lower- and zero-emitting power generation.

c. Key changes. The most significant changes in these final guidelines are: 1) the period for mandatory emission reductions beginning in 2022 instead of 2020 and a gradual application of the BSER over the 2022-2029 interim period, such that a state has substantial latitude in selecting its own emission reduction trajectory or "glide path" over that period, 2) a revised BSER determination that focuses on narrower generation options that do not include demand-side EE measures and that includes refinements to the building blocks, more complete incorporation in the BSER of the realities of electricity operations over the three regional interconnections, and up-to-date information about the cost and availability of clean generation options, 3) establishment of source-specific CO_2 emission performance rates that are uniform across the two fossil fuel-fired subcategories covered in these guidelines, as well as rate- and mass-based state goals, to facilitate emission trading, including interstate trading and, in particular, mass-based trading, 4) a variation on the proposal's "portfolio" option for state plans –

called here the “state measures” approach - that continues to provide states flexibility while ensuring that all state plans have federally enforceable measures as a backstop, 5) additional, more flexible options for states and utilities to adopt multi-state compliance strategies, 6) an extension of up to two years available to all states for submittal of their final compliance plans following making initial submittals in 2016, 7) provisions to encourage actions that achieve early reductions, including a Clean Energy Incentive Program (CEIP), 8) a combination of provisions expressly designed to ensure electric system reliability, 9) the addition of employment considerations for states in plan development, and 10) the expansion of considerations and programs for low-income and vulnerable communities.

We provide summary explanations in the following paragraphs and more detailed explanations of all of these changes in later sections of this preamble and associated documents.

(1) Mandatory reduction period beginning in 2022 and a gradual glide path.

The proposal’s mandatory emission reduction period beginning in 2020 and the trajectory of emission reduction requirements in the interim period were both the subjects of significant comment. Earlier this year, FERC conducted a series of technical conferences comprising one national session and three regional sessions. The information provided by workshop participants echoed much of the material that had been submitted to the comment record for this rulemaking. On May 15, 2015, the FERC Commissioners, drawing upon information highlighted at the technical conferences, transmitted to the EPA some suggestions for the final rule. In addition, via comments, states, utilities, and reliability entities asked us to ensure adequate time for them to implement strategies to achieve CO_2 reductions. They expressed concern that, in the proposal, at least some states would be required to reduce emissions in 2020 to levels that would require abrupt shifts in generation in ways that raised concerns about impacts to electric system reliability and ratepayer bills, as well as about stranded assets. To many commenters, the proposal's requirement for CO_2 emission reductions beginning in 2020, together with the stringency of the interim CO_2 goal, posed significant reliability implications, in particular. In this final rule, the agency is addressing these concerns, in part, by adjusting the compliance timeframe from a 10-year interim period that begins in 2020 to an 8-year interim period that begins in 2022, and by refining the approach for meeting interim CO_2 emission performance rates to be a gradual glide path separated into three steps, 2022-2024, 2025-2027, and 2028-2029, that is also achievable "on average" over the 8-year interim period. In response to the concerns of commenters that the proposal's 10-year interim target failed to afford sufficient flexibility, the final guidelines' approach will provide states with realistic options for customizing their emission reduction trajectories. Of equal importance, the approach provides more time for planning, consultation and decision making in the formulation of state plans and in EGUs' choices of compliance strategies. Both FERC's May 15, 2015 letter and the comment record, as well as other information sources, made it clear that providing sufficient time for planning and implementation was essential to ensuring electric system reliability.

The final guidelines' approach to the interim emission performance rates is the result of the application of the measures constituting the BSER in a more gradual way, reflecting stakeholder comments and information about the appropriate period of time over which those measures can be deployed consistent with the BSER factors of cost and feasibility. In addition to facilitating reliable system operations, these changes provide states and utilities with the latitude to consider a broader range of options to achieve the required reductions while addressing concerns about ratepayer impacts and stranded assets.

(2) Revised BSER determination.

Commenters urged the EPA to confine its BSER determination to actions that involve what they characterized as more "traditional" generation. While some stakeholders recognized demand-side EE as being an integral part of the electricity system, with many of the characteristics of more traditional generating resources, other stakeholders did not. As explained in section V.B.3.c.(8) below, our traditional interpretation and implementation of CAA section 111 has allowed regulated entities to produce as much of a particular good as they desire, provided that they do so through an appropriately clean (or low-emitting) process. While building blocks 1, 2, and 3 fall squarely within this paradigm, the proposed building block 4 does not. In view of this, since the BSER must serve as the foundation of the emission guidelines, the EPA has not included demand-side EE as part of the final BSER determination. Thus, neither the final guidelines' BSER determination nor the emission performance rates for the two subcategories of affected EGUs take into account demand-side EE. However, many commenters also urged the EPA to allow states and sources to rely on demand-side EE as an element of their compliance strategies, as demand-side EE is treated as functionally interchangeable with other forms of generation for planning and operational purposes, as EE measures are in widespread use across the country and provide energy savings that reduce emissions, lower electric bills, and lead to positive investments and job creation. We agree, and the final guidelines provide ample latitude for states and utilities to rely on demand-side EE in meeting emission reduction requirements.

In response to stakeholder comments on the first three building blocks and considerable data in the record, the EPA has made refinements to the building blocks, and these are reflected in the final BSER. Refinements include adoption of a modified approach to quantification of the RE component, exclusion of the proposed nuclear generation components, and adoption of a consistent regionalized approach to quantification of all three building blocks. The agency also recognizes the important functional relationship between the period of time over which measures are deployed and the stringency of emission limitations those measures can achieve practically and at reasonable cost. Therefore, the final BSER also reflects adjustments to the stringency of the building blocks, after consideration of more and less stringent levels, and refinements to the timeframe over which reductions must be achieved. Sections V.C through V.E of this preamble provide further information on the refinements made to the building blocks and the rationale for doing so.

Commenters pointed out – and practical experience confirms – what is widely known: that the utility power sector operates over regional interconnections that are not constrained by state borders. Across a variety of issues raised in the proposal, many commenters urged that the EPA take that reality into account in developing this final rule. Consequently, the BSER determination itself (as well as a number of new compliance features included in this final rule) and the resulting subcategory-specific emission performance rates take into account the grid-level operations of the source category.

The final guidelines' BSER determination also takes into account recent reductions in the cost of clean energy technology, as well as projections of continuing cost reductions, and continuing increases in RE deployment. We also updated the underlying analysis with the most recent Energy Information Administration (EIA) projections that show lower growth in electricity demand between 2020 and 2030 than previously projected. In keeping with these recent EIA projections, we expect the final guidelines will be more conducive to compliance, consistent with a strategy that allows for the cleanest power generation and greater CO_2 reductions in 2030 than the proposal. With a date of 2022, instead of 2020, as proposed, for the mandatory CO_2 emission reduction period to begin, the final guidelines reflect that the additional time aligns with the adoption of lower-cost clean technology and, thus, its incorporation in the BSER at higher levels. At the same time, the 2022-2029 interim period will more easily allow for companies to take advantage of improved clean energy technologies as potential least cost options.

(3) Uniform emission performance rates.

Some stakeholders commented that the proposal's approach of expressing the BSER in terms of state-specific goals deviated from the requirements of CAA section 111 and from previous new source performance standards (NSPS). The effect, they stated, was that the proposal created de facto emission standards for all affected EGUs but that these de facto standards varied widely depending on the state in which a given EGU happened to be located. Instead, these and other commenters stated, section 111 requires that EPA establish the BSER specifically for affected sources, rather than by means of merely setting state-specific goals, and that these standards be uniform. Still other commenters observed that the effect of the approach taken in the proposal of applying the BSER to each state's fleet was to put a greater burden of reductions on lower-emitting or less carbon-intensive states and a lesser emission reduction burden on sources and states that were higher-emitting or more carbon-intensive. This, they argued, was both inequitable and at odds with the way in which NSPS have been applied in the past, where the higher-emitting sources have made the greater and more cost-effective reductions, while lower-emitting sources, whose reduction opportunities tend to be less cost-effective, have been required to make fewer reductions to meet the applicable standard.

At the same time, state and utility commenters expressed concern that relying on state-specific goals and state-by-state planning could introduce complexity into the otherwise seamless integrated operation of affected EGUs across the multi-state grids on which system operators, states and utilities currently rely and intend to continue to rely. Accordingly, they recommended that the final guidelines facilitate emissions trading, in particular interstate trading, which would enable EGU operators to integrate compliance with CO_2 emissions limitations with facility and grid-level operations. These sets of comments intersected at the point at which they focused on the fact that it is at the source level at which the standard is set for NSPS and at the source level at which compliance must be achieved.

The EPA carefully considered these comments and while we believe that the approach we took at proposal was well-founded and reflected a number of important considerations, we have concluded that there is a way to address these concerns while expanding upon the advantages offered by the proposal. Accordingly, the final guidelines establish uniform rates for the two subcategories of sources – an approach that is valuable for creating greater equity between and among utilities and states with widely varying emission levels and for expanding the flexibility of the program, especially in ways that have been identified as important to utilities and states. Specifically, the final guidelines express the BSER by means of performance-based CO_2 emission rates that are uniform across each of two subcategories – fossil fuel-fired electric steam generating units and stationary combustion turbines – for the affected EGUs covered by the guidelines. The rates are determined, in part, by applying the methodology identified in the Notice of Data Availability published on October 30, 2014, which was based on the proposal's building block approach. The final guidelines also maintain the approach adopted in the proposal of establishing state-level goals; in the final rule, those goals are equal to the weighted aggregate of the two emission performance rates as applied to the EGUs in each state.

This approach rectifies what would have been an inefficient, unintended outcome of putting the greater reduction burden on lower-emitting sources and states while exempting higher-emitting sources and states. Expressing the BSER by means of these rates also augments the range of options for both states and EGUs for securing needed flexibility. Inclusion of state goals creates latitude for states as to how they will meet the guidelines. States also may meet the guideline requirements by adopting the CO_2 emission performance rates as emission standards that apply to the affected EGUs in their jurisdiction. Such an approach would lend itself to the ready establishment of intra-state and interstate trading, with the uniform rate-based standards of performance established for each EGU as the basis for such trading. At the same time, as at proposal, each state also has the option of complying with these guidelines by adopting a plan that takes a different approach to setting standards of performance for its EGUs and/or by applying complementary or alternative measures to meet the state goal set by these guidelines – as either a rate or a mass total.

During the outreach process and through comments, a number of state officials and other stakeholders expressed concern that the EPA's approach at proposal necessitated or represented a significant intrusion into state-level energy policy-making, drawing the EPA well beyond the bounds of its CAA authority and expertise. In fact, these final guidelines are entirely respectful of the EPA's responsibility and authority to regulate sources of air pollution. Instead, by establishing and operating through uniform performance rates for the two subcategories of sources that can be applied by states at the individual source level and that can readily be implemented through emission standards that incorporate emissions trading, these final guidelines align with the approach Congress and the EPA have consistently taken to regulating emissions from this and other industrial sectors, namely setting source-level, source category-wide standards that individual sources can meet through a variety of technologies and measures.

We emphasize, at the same time, that while the final guidelines express the BSER by means of source-level CO_2 emission performance rates, as well as state-level goals, as at proposal, each state will have a goal reflecting its particular mix of sources, and the final guidelines retain the flexibility inherent in the proposal's state-specific goals approach (and, as discussed in section VIII of this preamble, enhanced in various ways). Thus, in keeping with the proposal's flexibility, states may choose to adopt either the emission performance rates as emission standards for their sources, set different but, in the aggregate, equivalent rates, or fulfill their obligations by meeting their respective individual state goals.

(4) State plan approaches.

Commenters expressed support for the objectives served by the "portfolio" option in the state plan approaches included at proposal, but many raised concerns about its legality, with respect, in particular, to the CAA's enforceability requirements. Some of these commenters identified a "state commitment approach" with backstop measures as a variation of the "portfolio" approach that would retain the benefits of the "portfolio" approach while resolving legal and enforceability concerns. In this final rule, in response to stakeholder comments on the portfolio approach and alternative approaches, the EPA is finalizing two approaches: a source-based "emission standards" approach, and a "state measures" approach. Through the latter, states may adopt a set of policies and programs, which would not be federally enforceable, except that any standards imposed on affected EGUs would be federally enforceable. In addition, states would be required to include federally enforceable backstop measures applicable to each affected EGU in the event that the measures included in the state plan failed to achieve the state plan's emissions reduction trajectory. Under these guidelines, states can implement the BSER through standards of performance incorporating the uniform performance rates or alternative but in the aggregate equivalent rates, or they can adopt plans that achieve in aggregate the equivalent of the subcategory-specific CO_2 emission performance rates by relying on other measures undertaken by the state that complement source-specific requirements or, save for the contingent backstop requirement, supplant them entirely. This revision provides consistency in the treatment of sources while still providing maximum flexibility for states to design their plans around reduction approaches that best suit their policy objectives.

(5) Emission trading programs.

Many state and utility commenters supported the use of mass-based and rate-based emission trading programs in state plans, including interstate emission trading programs, and either pointed out obstacles to establishing such programs or suggested approaches that would enhance states’ and utilities’ ability to create and participate in such programs.

Through a combination of features retained from the proposal and changes made to the proposal, these final guidelines provide states and utilities with a panoply of tools that greatly facilitate their putting in place and participating in emissions trading programs. These include: 1) expressing BSER in uniform emission performance rates that states may rely on in setting emission standards for affected EGUs such that EGUs operating under such standards readily qualify to trade with affected EGUs in states that adopt the same approach, 2) promulgating state mass goals so that states can move quickly to establish mass-based programs such that their affected EGUs readily qualify to trade with affected EGUs in states that adopt the same approach, and 3) providing EPA resources and capacity to create a tracking system to support state emissions trading programs.

(6) Extension of plan submittal date.

Stakeholders, particularly states, provided compelling information establishing that it could take longer than the agency initially anticipated for the states to develop and submit their required plans. While the approach at proposal reflected the EPA's conclusion that it was essential to the environmental and economic purposes of this rulemaking that utilities and states establish the path towards emissions reductions as early as possible, we recognize commenters' concerns. To strike the proper balance, the EPA has developed a revised state plan submittal schedule. For states that cannot submit a final plan by September 6, 2016, the EPA is requiring those states to make an initial submittal by that date to assure that states begin to address the urgent needs for reductions quickly, and is providing until September 6, 2018, for states to submit a final plan, if an extension until that date is justified, to address the concern that a submitting state needs more time to develop comprehensive plans that reflect the full range of the state's and its stakeholders' interests.

(7) Provisions to encourage early action.

Many commenters supported providing incentives for states and utilities to deploy CO_2-reducing investments, such as RE and demand-side EE measures, as early as possible. We also received comments from stakeholders regarding the disproportionate burdens that some communities already bear, and stating that all communities should have equal access to the benefits of clean and affordable energy. The EPA recognizes the validity and importance of these perspectives, and as a result has determined to provide a program – called the CEIP – in which states may choose to participate.

The CEIP is designed to incentivize investment in certain RE and demand-side EE projects that commence construction, in the case of RE, or commence construction, in the case of demand-side EE, following the submission of a final state plan to the EPA, or after September 6, 2018, for states that choose not to submit a final state plan by that date, and that generate MWh (RE) or reduce end-use energy demand (EE) during 2020 and/or 2021. State participation in the program is optional.

Under the CEIP, a state may set aside allowances from the CO_2 emission budget it establishes for the interim plan performance period or may generate early action ERCs (ERCs are discussed in more detail in section VIII.K.2), and allocate these allowances or ERCs to eligible projects for the MWh those projects generate or the end-use energy savings they achieve in 2020 and/or 2021. For each early action allowance or ERC a state allocates to such projects, the EPA will provide the state with an appropriate number of matching allowances or ERCs for the state to allocate to the project. The EPA will match state-issued early action ERCs and allowances up to an amount that represents the equivalent of 300 million short tons of CO_2 emissions.

For a state to be eligible for a matching award of allowances or ERCs from the EPA, it must demonstrate that it will award allowances or ERCs only to “eligible” projects. These are projects that:

- Are located in or benefit a state that has submitted a final state plan that includes requirements establishing its participation in the CEIP;
- Are implemented following the submission of a final state plan to the EPA, or after September 6, 2018, for a state that chooses not to submit a complete state plan by that date;
- For RE: Generate metered MWh from any type of wind or solar resources;
- For EE: Result in quantified and verified electricity savings (MWh) through demand-side EE implemented in low-income communities; and
- Generate or save MWh in 2020 and/or 2021.

The following provisions outline how a state may award early action ERCs and allowances to eligible projects, and how the EPA will provide matching ERCs or allowances to states.

- For RE projects that generate metered MWh from any type of wind or solar resources: for every two MWh generated, the project will receive one early action ERC (or the equivalent number of allowances) from the state, and the EPA will provide one matching ERC (or the equivalent number of allowances) to the state to award to the project.

- For EE projects implemented low-income communities: for every two MWh in end-use demand savings achieved, the project will receive two early action ERCs (or the equivalent number of allowances) from the state, and the EPA will provide two matching ERCs (or the equivalent number of allowances) to the state to award to the project.

Early action allowances or ERCs awarded by the state, and matching allowances or ERCs awarded by the EPA pursuant to the CEIP, may be used for compliance by an affected EGU with its emission standards and are fully transferrable prior to such use.

The EPA discusses the CEIP in the proposed federal plan rule and will address design and implementation details of the CEIP in a subsequent action. Prior to doing so, the EPA will engage with states, utilities and other stakeholders to gather information regarding their interests and priorities with regard to implementation of the CEIP.

(8) Provisions for electric system reliability.

A number of commenters stressed the importance of final guidelines that addressed the need to ensure that EGUs could meet their emission reduction requirements without being compelled to take actions that would undermine electric system reliability. As noted above, the EPA has consulted extensively with federal, regional and state energy agencies, utilities and many others about reliability concerns and ways to address them. The final guidelines support electric system reliability in a number of ways, some inherent in the improvements made in the program's design and some through specific provisions we have included in the final rule. Most important are the two key changes we made to the interim goal: establishing 2022, instead of 2020, as the period for mandatory emission reductions begin and phasing in, over the 8-year period, emission performance rates such that the level of stringency of the emission performance rates in 2022-2024 is significantly less than that for the years 2028 and 2029. Since states and utilities need only to meet their interim goal "on average" over the 8-year period, these changes provide them with a great deal of latitude in determining for themselves their emission reduction trajectory – and they have additional time to do so. As a result, the final guidelines provide the ingredients that commenters, reliability entities and expert agencies told the EPA were essential to ensuring electric system reliability: time and flexibility sufficient to allow for planning, implementation and the integration of actions needed to address reliability while achieving the required emissions reductions.

In addition, the final guidelines add a requirement, based on substantial input from experts in the energy field, for states to demonstrate that they have considered electric system reliability in developing their state plans. The final rule also offers additional opportunities that support electric system reliability, including opportunities for trading within and between states. The final guidelines also make clear that states can adjust their plans in the event that reliability challenges arise that need to be remedied by amending the state plan. In addition, the final rule includes a reliability safety valve to address situations where, because of an unanticipated catastrophic event, there is a conflict between the requirements imposed on an affected unit and the maintenance of reliability.

(9) Approaches for addressing employment concerns.

Some commenters brought to our attention the concerns of workers, their families and communities, particularly in coal-producing regions and states, that the ongoing shift toward lower-carbon electricity generation that the final rule reflects will cause harm to communities that are dependent on coal. Others had concerns about whether new jobs created as a result of actions taken pursuant to the final rule will allow for overall economic development. In the final rule, the EPA encourages states, in designing their state plans, to consider the effects of their plans on employment and overall economic development to assure that the opportunities for economic growth and jobs that the plans offer are manifest. We also identify federal programs, including the multi-agency Partnerships for Opportunity and Workforce and Economic Revitalization (POWER) Initiative.[15] The POWER Initiative is competitively awarding planning assistance and implementation grants with funding from the Department of Commerce, Department of Labor (DOL), Small Business Administration, and the Appalachian Regional Commission,[16] whose mission is to assist communities affected by changes in the coal industry and the utility power sector.

(10) Community and environmental justice considerations.

Many community leaders, environmental justice advocates, faith-based organizations and others commented that the benefits of this rule must be shared broadly across society and that undue burdens should not be imposed on low-income ratepayers. We agree. The federal government is taking significant steps to help low-income families and individuals gain access to RE and demand-side EE through new initiatives involving, for example, increasing solar energy systems in federally subsidized homes and supporting solar systems for others with low incomes. The final rule ensures that bill-lowering measures such as demand-

[15] http://www.eda.gov/power/.

[16] https://www.whitehouse.gov/the-press-office/2015/03/27/fact-sheet-partnerships-opportunity-and-workforce-and-economic-revitaliz.

side EE continue to be a major compliance option. The CEIP will encourage early investment in these types of projects as well. In addition to carbon reduction benefits, we expect significant near- and long-term public health benefits in communities as conventional air pollutants are reduced along with GHGs. However, some stakeholders expressed concerns about the possibility of localized increases in emissions from some power plants as the utility industry complies with state plans, in particular in communities already disproportionately affected by air pollution. This rule sets expectations for states to engage with vulnerable communities as they develop their plans, so that impacts on these communities are considered as plans are designed. The EPA also encourages states to engage with workers in the utility power and related sectors, as well as their worker representatives, so that impacts on their communities may be considered. The EPA commits, once implementation is under way, to assess the impacts of this rule. Likewise, we encourage states to evaluate the effects of their plans to ensure that there are no disproportionate adverse impacts on their communities.

5. Additional context for this final rule

a. Climate change impacts. This final rule is an important step in an essential series of long-term actions that are achieving and must continue to achieve the GHG emission reductions needed to address the serious threat of climate change, and constitutes a major commitment – and international leadership-by-doing – on the part of the U.S., one of the world's largest GHG emitters. GHG pollution threatens the American public by leading to damaging and long-lasting changes in our climate that can have a range of severe negative effects on human health and the environment. CO_2 is the primary GHG pollutant, accounting for nearly three-quarters of global GHG emissions[17] and 82 percent of U.S. GHG emissions.[18] The May 2014 report of the National Climate Assessment[19] concluded that climate change impacts are already manifesting themselves and imposing losses and costs. The report documents increases in extreme weather and climate events in recent decades, with resulting damage and disruption to human well-being, infrastructure, ecosystems, and agriculture, and projects continued increases in impacts across a wide range of communities, sectors, and ecosystems. New scientific assessments since 2009, when the EPA determined that GHGs pose a threat to

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[17] Intergovernmental Panel on Climate Change (IPCC) report, "Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change," 2007. Available at http://epa.gov/climatechange/ghgemissions/global.html.

[18] From Table ES-2 "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2013", Report EPA 430-R-15-004, United States Environmental Protection Agency, April 15, 2015.

[19] U.S. Global Change Research Program, Climate Change Impacts in the United States: The Third National Climate Assessment, May 2014. Available at http://nca2014.globalchange.gov/.

human health and the environment (the "Endangerment Finding"), highlight the urgency of addressing the rising concentration of CO_2 in the atmosphere. Certain groups, including children, the elderly, and the poor, are most vulnerable to climate-related effects. Recent studies also find that certain communities, including low-income communities and some communities of color (more specifically, populations defined jointly by ethnic/racial characteristics and geographic location), are disproportionately affected by certain climate change related impacts — including heat waves, degraded air quality, and extreme weather events – which are associated with increased deaths, illnesses, and economic challenges. Studies also find that climate change poses particular threats to the health, well-being, and ways of life of indigenous peoples in the U.S.

b. <u>The utility power sector</u>. One of the strategies of the President's Climate Action Plan is to reduce CO_2 emissions from power plants.[20] This is because fossil fuel-fired EGUs are by far the largest emitters of GHGs, primarily in the form of CO_2. Among stationary sources in the U.S. and among fossil fuel-fired EGUs, coal-fired units are by far the largest emitters of GHGs. To accomplish the goal of reducing CO_2 emissions from power plants,

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[20] The President's Climate Action Plan, June 2013. http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf.

President Obama issued a Presidential Memorandum[21] that recognized the importance of significant and prompt action. The Memorandum directed the EPA to complete carbon pollution standards, regulations or guidelines, as appropriate, for new, modified, reconstructed and existing power plants, and in doing so to build on state leadership in moving toward a cleaner power sector. In this action and the concurrent CAA section 111(b) rule, the EPA is finalizing regulations to reduce GHG emissions from fossil fuel-fired EGUs. This CAA section 111(d) action builds on actions states and utilities are already taking to move toward cleaner generation of electric power.

The utility power sector is unlike other industrial sectors. In other sectors, sources effectively operate independently and on a local-site scale, with control of their physical operations resting in the hands of their respective owners and operators. Pollution control standards, which focus on each source in a non-utility industrial source category, have reflected the standalone character of individual source investment decision-making and operations.

In stark contrast, the utility power sector comprises a unique system of electricity resources, including the EGUs

[21] Presidential Memorandum – Power Sector Carbon Pollution Standards, June 25, 2013. http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.

affected under these guidelines, that operate in a complex and interconnected grid where electricity generally flows freely (e.g., portions of the system cannot be easily isolated through the use of switches or valves as can be done in other networked systems like trains and pipeline systems). That grid is physically interconnected and operated on an integrated basis across large regions. In this interconnected system, system operators, whose decisions, protocols, and actions, to a significant extent, dictate the operations of individual EGUs and large ensembles of EGUs, must reliably balance supply and demand using available generation and demand-side resources, including EE, demand response and a wide range of low- and zero-emitting sources. These resources are managed to meet the system needs in a reliable and efficient manner. Each aspect of this interconnected system is highly regulated and coordinated, with supply and demand constantly being balanced to meet system needs. Each step of the process from the electric generator to the end user is highly regulated by multiple entities working in coordination and considering overall system reliability. For example, in an independent system operator (ISO) or regional transmission organization (RTO) with a centralized, organized capacity market, electric generators are paid to be available to run when needed, must bid into energy markets, must respond to dispatch instructions, and must have permission to schedule maintenance. The ISO/RTO dispatches resources in a way that maintains electric system reliability.

The approach we take in the final guidelines – both in the way we defined the BSER and established the resulting emission performance rates, and in the ranges of options we created for states and affected EGUs – is consistent with, and in some ways mirrors, the interconnected, interdependent and highly regulated nature of the utility power sector, the daily operation of affected EGUs within this framework, and the critical role of utilities in providing reliable, affordable electricity at all times and in all places within this complex, regulated system. Thus, not only do these guidelines put a premium on providing as much flexibility and latitude as possible for states and utilities, they also recognize that a given EGU's operations are determined by the availability and use of other generation resources to which it is physically connected and by the collective operating regime that integrates that individual EGU's activity with other resources across the grid.

In this integrated system, numerous entities have both the capability and the responsibility to maintain a reliable electric system. FERC, DOE, state public utility commissions, ISOs, RTOs, other planning authorities, and the North American Electric Reliability Corporation (NERC), all contribute to ensuring the reliability of the electric system in the U.S.

Critical to this function are dispatch tools, applied primarily by RTOs, ISOs, and balancing authorities, that operate such that actions taken or costs incurred at one source directly affect or cause actions to occur at other sources. Generation, outages, and transmission changes in one part of the synchronous grid can affect the entire interconnected grid.[22] The interconnection is such that "[i]f a generator is lost in New York City, its effect is felt in Georgia, Florida, Minneapolis, St. Louis, and New Orleans."[23] The U.S. Supreme Court has explicitly recognized the interconnected nature of the electricity grid.[24]

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[22] Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 159 (2d ed. 2010).
[23] Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 160 (2d ed. 2010).
[24] *Federal Power Comm'n v. Florida Power & Light Co.*, 404 U.S. 453, at 460 (1972) (quoting a Federal Power Commission hearing examiner, "`If a housewife in Atlanta on the Georgia system turns on a light, every generator on Florida's system almost instantly is caused to produce some quantity of additional electric energy which serves to maintain the balance in the interconnected system between generation and load.'") (citation omitted). *See also New York v. FERC*, 535 U.S. 1, at 7-8 (2002) (stating that "any electricity that enters the grid immediately becomes a part of a vast pool of energy that is constantly moving in interstate commerce.") (citation omitted). In *Federal Power Comm'n v. Southern California Edison Co.*, 376 U.S. 205 (1964), the Supreme Court found that a sale for resale of electricity from Southern California Edison to the City of Colton, which took place solely in California, was under Federal Power Commission jurisdiction because some of the electricity that Southern California Edison marketed came from out of state. The Supreme Court stated that, "`federal jurisdiction was to follow the flow of electric energy, an engineering and scientific, rather than a legalistic or governmental, test.'" *Id.* at 210, *quoting Connecticut Light & Power Co. v. Federal Power Commission*, 324 U.S. 515, 529 (1945) (emphasis omitted).

The uniqueness of the utility power sector inevitably affects the way in which environmental regulations are designed. When the EPA promulgates environmental regulations that affect the utility power sector, as we have done numerous times over the past four decades, we do so with the awareness of the importance of the efficient and continuous, uninterrupted operation of the interconnected electricity system in which EGUs participate. We also keep in mind the unique product that this interconnected system provides – electricity services – and the critical role of this sector to the U.S. economy and to the fundamental well-being of all Americans.

In the context of environmental regulation, Congress, the EPA and the states all have recognized – as we do in these final guidelines – that electricity production takes place, at least to some extent, interchangeably between and among multiple generation facilities and different types of generation. This is evidenced in the enactment or promulgation of pollution reduction programs, such as Title IV of the CAA, the NOx state implementation plan (SIP) Call, the Cross-State Air Pollution Rule (CSAPR), and the Regional Greenhouse Gas Initiative (RGGI). As these actions show, both Congress and the EPA have consistently tailored legislation and regulations affecting the utility power sector to its unique characteristics. For example, in Title IV of the Clean Air Act Amendments of 1990, Congress established a pollution reduction program specifically for fossil fuel-fired EGUs and designed the SO_2 portion of that program with express recognition of the sector's ability to shift generation among various EGUs, which enabled pollution reduction by increasing reliance on RE and demand-side EE. Similarly, in the NO_X SIP Call, the Clean Air Interstate Rule (CAIR), and CSAPR, the EPA established pollution reduction programs focused on fossil fuel-fired EGUs and designed those programs with express recognition of the sector's ability to shift generation among various EGUs. In this action, we continue that approach. Both the subcategory-specific emission performance rates, and the pathways offered to achieve them, reflect and are tailored to the unique characteristics of the utility power sector.

The way that power is produced, distributed and used in the U.S. is already changing as a result of advancements in innovative power sector technologies and in the availability and cost of low-carbon fuel, RE and demand-side EE technologies, as well as economic conditions. These changes are taking place at a time when the average age of the coal-fired generating fleet is approaching that at which utilities and states undertake significant new investments to address aging assets. In 2025, the average age of the coal-fired generating fleet is projected to be 49 years old, and 20 percent of those units would be more than 60 years old if they remain in operation at that time. Therefore, even in the absence of additional environmental regulation, states and utilities can be expected to be, and already are, making plans for and investing in the next generation of power production, simply because of the need to take account of the age of current assets and infrastructure. Historically, the industry has invested about $100 billion a year in capital improvements. These guidelines will help ensure that, as those necessary investments are being made, they are integrated with the need to address GHG pollution from the sector.

At the same time, owners/operators of affected EGUs are already pursuing the types of measures contemplated in this rule. Out of 404 entities identified as owners or operators of affected EGUs, representing ownership of 82 percent of the total capacity of the affected EGUs, 178 already own RE generating capacity in addition to fossil fuel-fired generating capacity. In fact, these entities already own aggregate amounts of RE generating capacity equal to 25 percent of the aggregate amounts of their affected EGU capacity.[25] In addition, funding for utility EE programs has been growing rapidly, increasing from $1.6 billion in 2006 to $6.3 billion in 2013.

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[25] SNL Energy. Data used with permission. Accessed on June 9, 2015.

The final guidelines are based on, and reinforce, the actions already being taken by states and utilities to upgrade aging electricity infrastructure with 21st century technologies. The guidelines will ensure that these trends continue in ways that are consistent with the long-term planning and investment processes already used in the utility power sector. This final rule provides flexibility for states to build upon their progress, and the progress of cities and towns, in addressing GHGs, and minimizes additional requirements for existing programs where possible. It also allows states to pursue policies to reduce carbon pollution that: 1) continue to rely on a diverse set of energy resources; 2) ensure electric system reliability; 3) provide affordable electricity; 4) recognize investments that states and power companies are already making; and 5) tailor plans to meet their respective energy, environmental and economic needs and goals, and those of their local communities. Thus, the final guidelines will achieve meaningful CO_2 emission reductions while maintaining the reliability and affordability of electricity in the U.S.

6. Projected national-level emission reductions

Under the final guidelines, the EPA projects annual CO_2 reductions of 22 to 23 percent below 2005 levels in 2020, 28 to 29 percent below 2005 levels in 2025, and 32 percent below 2005 levels in 2030. These guidelines will also result in important reductions in emissions of criteria air pollutants, including SO_2, NO_X, and directly-emitted fine particulate matter ($PM_{2.5}$). A thorough discussion of the EPA's analysis is presented in Section XI.A of this preamble and in Chapter 3 of the Regulatory Impact Analysis (RIA) included in the docket for this rulemaking.

7. Costs and benefits

Actions taken to comply with the final guidelines will reduce emissions of CO_2 and other air pollutants, including SO_2, NO_X, and directly emitted $PM_{2.5}$ from the utility power sector. States will make the ultimate determination as to how the emission guidelines are implemented. Thus, all costs and benefits reported for this action are illustrative estimates. The illustrative costs and benefits are based upon compliance approaches that reflect a range of measures consisting of improved operations at EGUs, dispatching lower-emitting EGUs and zero-emitting energy sources, and increasing levels of end-use EE.

Because of the range of choices available to states and the lack of *a priori* knowledge about the specific choices states will make in response to the final goals, the RIA for this final action presents two scenarios designed to achieve these goals, which we term the "rate-based" illustrative plan approach and the "mass-based" illustrative plan approach.

In summary, we estimate the total combined climate benefits and health co-benefits for the rate-based approach to be $3.5 to $4.6 billion in 2020, $18 to $28 billion in 2025, and $34 to $54 billion in 2030 (3 percent discount rate, 2011$). Total combined climate benefits and health co-benefits for the mass-based approach are estimated to be $5.3 to $8.1 billion in 2020, $19 to $29 billion in 2025, and $32 to $48 billion in 2030 (3 percent discount rate, 2011$). A summary of the emission reductions and monetized benefits estimated for this rule at all discount rates is provided in Tables 15 through 22 of this preamble.

The annual compliance costs are estimated using the Integrated Planning Model (IPM) and include demand-side EE program and participant costs as well as monitoring, reporting and recordkeeping costs. In 2020, total compliance costs of the final guidelines are approximately $2.5 billion (2011$) under the rate-based approach and $1.4 billion (2011$) under the mass-based approach. In 2025, total compliance costs of the final guidelines are approximately $1.0 billion (2011$) under the rate-based approach and $3.0 billion (2011$) under the mass-based approach. In 2030, total compliance costs of the final guidelines are approximately $8.4 billion (2011$) under the rate-based approach and $5.1 billion (2011$) under the mass-based approach.

The quantified net benefits (the difference between monetized benefits and compliance costs) in 2020 are estimated to range from $1.0 billion to $2.1 billion (2011$) using a 3 percent discount rate (model average) under the rate-based approach and from $3.9 billion to $6.7 billion (2011$) using a 3 percent discount rate (model average) under the mass-based approach. In 2025, the quantified net benefits (the difference between monetized benefits and compliance costs) in 2025 are estimated to range from $17 billion to $27 billion (2011$) using a 3 percent discount rate (model average) under the rate-based approach and from $16 billion to $26 billion (2011$) using a 3 percent discount rate (model average) under the mass-based approach. In 2030, the quantified net benefits (the difference between monetized benefits and compliance costs) in 2030 are estimated to range from $26 billion to $45 billion (2011$) using a 3 percent discount rate (model average) under the rate-based approach and from $26 billion to $43 billion (2011$) using a 3 percent discount rate (model average) under the mass-based approach.

Table 1. Summary of the Monetized Benefits, Compliance Costs, and Net Benefits for the Final Guidelines in 2020, 2025, and

2030[a] Under the Rate-Based Illustrative Plan Approach [Billions of 2011$]

Rate-based Approach, 2020		
	3% Discount Rate	**7% Discount rate**
Climate benefits [b]	$2.8	
Air pollution health co-benefits [c]	$0.70 to $1.8	$0.64 to $1.7
Total Compliance Costs [d]	$2.5	$2.5
Net Monetized Benefits [e]	$1.0 to $2.1	$1.0 to $2.0
Non-monetized Benefits	Non-monetized climate benefits Reductions in exposure to ambient NO_2 and SO_2 Reductions in mercury deposition Ecosystem benefits associated with reductions in emissions of NO_X, SO_2, PM, and mercury Visibility impairment	
Rate-based Approach, 2025		
	3% Discount rate	**7% Discount rate**
Climate benefits [b]	$10	
Air pollution health co-benefits [c]	$7.4 to $18	$6.7 to $16
Total Compliance Costs [d]	$1.0	$1.0
Net Monetized Benefits [e]	$17 to $27	$16 to $25
Non-monetized Benefits	Non-monetized climate benefits Reductions in exposure to ambient NO_2 and SO_2 Reductions in mercury deposition Ecosystem benefits associated with reductions in emissions of NO_X, SO_2, PM, and mercury Visibility impairment	
Rate-based Approach, 2030		
Climate benefits [b]	$20	

Air pollution health co-benefits [c]	\$14 to \$34	\$13 to \$31
Total Compliance Costs [d]	\$8.4	\$8.4
Net Monetized Benefits [e]	\$26 to \$45	\$25 to \$43
Non-monetized Benefits	Non-monetized climate benefits Reductions in exposure to ambient NO_2 and SO_2 Reductions in mercury deposition Ecosystem benefits associated with reductions in emissions of NO_X, SO_2, PM, and mercury Visibility impairment	

[a] All are rounded to two significant figures, so figures may not sum.

[b] The climate benefit estimate in this summary table reflects global impacts from CO_2 emission changes and does not account for changes in non-CO_2 GHG emissions. Also, different discount rates are applied to SC-CO_2 than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SCC estimated for a 3 percent discount rate, however we emphasize the importance and value of considering the full range of SC-CO_2 values. As shown in the RIA, climate benefits are also estimated using the other three SC-CO_2 estimates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). The SC-CO_2 estimates are year-specific and increase over time.

[c] The air pollution health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of directly emitted $PM_{2.5}$, SO_2 and NO_X. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in premature fatalities each year accounts for over 98 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[d] Total costs are approximated by the illustrative compliance costs estimated using the Integrated Planning Model for the final guidelines and a discount rate of approximately 5%. This estimate includes monitoring, recordkeeping, and reporting costs and demand-side EE program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global SC-CO_2 at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on additional discount rates.

Table 2. Summary of the Monetized Benefits, Compliance Costs, and Net Benefits for the Final Guidelines in 2020, 2025 and 2030[a] Under the Mass-Based Illustrative Plan Approach [Billions of 2011$]

Mass-based Approach, 2020		
	3% Discount Rate	**7% Discount rate**
Climate benefits [b]	$3.3	
Air pollution health co-benefits [c]	$2.0 to $4.8	$1.8 to $4.4
Total Compliance Costs [d]	$1.4	$1.4
Net Monetized Benefits [e]	$3.9 to $6.7	$3.7 to $6.3
Non-monetized Benefits	Non-monetized climate benefits Reductions in exposure to ambient NO_2 and SO_2 Reductions in mercury deposition Ecosystem benefits associated with reductions in emissions of NO_X, SO_2, PM, and mercury Visibility impairment	
Mass-based Approach, 2025		
	3% Discount rate	**7% Discount rate**
Climate benefits [b]	$12	
Air pollution health co-benefits [c]	$7.1 to $17	$6.5 to $16
Total Compliance Costs [d]	$3.0	$3.0
Net Monetized Benefits [e]	$16 to $26	$15 to $24
Non-monetized Benefits	Non-monetized climate benefits Reductions in exposure to ambient NO_2 and SO_2	

	Reductions in mercury deposition Ecosystem benefits associated with reductions in emissions of NO_X, SO_2, PM, and mercury Visibility impairment	
Mass-based Approach, 2030		
Climate benefits [b]	$20	
Air pollution health co-benefits [c]	$12 to $28	$11 to $26
Total Compliance Costs [d]	$5.1	$5.1
Net Monetized Benefits [e]	$26 to $43	$25 to $40
Non-monetized Benefits	Non-monetized climate benefits Reductions in exposure to ambient NO_2 and SO_2 Reductions in mercury deposition Ecosystem benefits associated with reductions in emissions of NO_X, SO_2, PM, and mercury Visibility impairment	

[a] All are rounded to two significant figures, so figures may not sum.

[b] The climate benefit estimate in this summary table reflects global impacts from CO_2 emission changes and does not account for changes in non-CO_2 GHG emissions. Also, different discount rates are applied to SC-CO_2 than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SC-CO_2 estimated for a 3 percent discount rate, however we emphasize the importance and value of considering the full range of SC-CO_2 values. As shown in the RIA, climate benefits are also estimated using the other three SC-CO_2 estimates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). The SC-CO_2 estimates are year-specific and increase over time.

[c] The air pollution health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of directly emitted $PM_{2.5}$, SO_2 and NO_X. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in premature fatalities each year accounts for over 98 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume that all fine particles, regardless of their chemical composition, are equally potent in

causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.
[d] Total costs are approximated by the illustrative compliance costs estimated using the Integrated Planning Model for the final guidelines and a discount rate of approximately 5 percent. This estimate includes monitoring, recordkeeping, and reporting costs and demand-side EE program and participant costs.
[e] The estimates of net benefits in this summary table are calculated using the global SC-CO_2 at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on additional discount rates.

There are additional important benefits that the EPA could not monetize. Due to current data and modeling limitations, our estimates of the benefits from reducing CO_2 emissions do not include important impacts like ocean acidification or potential tipping points in natural or managed ecosystems. The unquantified benefits also include climate benefits from reducing emissions of non-CO_2 GHGs (e.g., nitrous oxide and methane)[26] and co-benefits from reducing direct exposure to SO_2, NO_X, and HAP (e.g., mercury and hydrogen chloride), as well as from reducing ecosystem effects and visibility impairment.

We project employment gains and losses relative to base case for different types of labor, including

[26] Although CO_2 is the predominant greenhouse gas released by the power sector, electricity generating units also emit small amounts of nitrous oxide and methane. For more detail about power sector emissions, see RIA Chapter 2 and the U.S. Greenhouse Gas Reporting Program's power sector summary, http://www.epa.gov/ghgreporting/ghgdata/reported/powerplants.html.

construction, plant operation and maintenance, coal and natural gas production, and demand-side EE. In 2030, we project a net decrease in job-years of about 31,000 under the rate-based approach and 34,000 under the mass-based approach[27] for construction, plant operation and maintenance, and coal and natural gas and a gain of 52,000 to 83,000 jobs in the demand-side EE sector under either approach. Actual employment impacts will depend upon measures taken by states in their state plans and the specific actions sources take to comply.

Based upon the foregoing, it is clear that the monetized benefits of this rule are substantial and far outweigh the costs.

B. Organization and Approach for this Rule

This final rule establishes the EPA's emission guidelines for states to follow in developing plans to reduce CO2 emissions from the utility power sector. Section II of this preamble provides background information on climate change impacts from GHG emissions, GHG emissions from fossil fuel-fired EGUs, the utility power sector, the CAA section 111(d) requirements, EPA actions prior to this final action, outreach and consultations,

[27] A job-year is not an individual job; rather, a job-year is the amount of work performed by the equivalent of one full-time individual for one year. For example, 20 job-years in 2025 may represent 20 full-time jobs or 40 half-time jobs.

and the number and extent of comments received. In section III of the preamble, we present a summary of the rule requirements and the legal basis for these. Section IV explains the EPA authority to regulate CO2 and EGUs, identifies affected EGUs, and describes the proposed treatment of source categories. Section V describes the agency's determination of the BSER using three building blocks and our key considerations in making the determination. Section VI provides the subcategory-specific emission performance rates, and section VII provides equivalent statewide rate-based and mass-based goals. Section VIII then describes state plan approaches and the requirements, and flexibilities, for state plans, followed by section IX, in which considerations for communities are described. Interactions between this final rule and other EPA programs and rules are discussed in section X. Impacts of the proposed action are then described in section XI, followed by a discussion of statutory and executive order reviews in section XII and the statutory authority for this action in section XIII.

We note that this rulemaking is being promulgated concurrently with two related rulemakings: the final NSPS for CO_2 emissions from newly constructed, modified, and reconstructed EGUs **[INSERT THE FEDERAL REGISTER REFERENCE FOR THE FINAL GHG NEW SOURCE RULE]**, which is being promulgated under CAA section 111(b), and the proposed federal plan and model rules **[INSERT**

THE FEDERAL REGISTER REFERENCE FOR THE FEDERAL PLAN PROPOSAL]. These rulemakings have their own rulemaking dockets.

II. Background

In this section, we discuss climate change impacts from GHG emissions, both on public health and public welfare. We also present information about GHG emissions from fossil fuel-fired EGUs, the challenges associated with controlling carbon dioxide emisions, the uniqueness of the utility power sector, and drecent and continuing trends and transitions in the utility power sector. In addition, we briefly describe CAA regulations for power plants, provide highlights of Congressional awareness of climate change and international agreements and actions, and summarize statutory and regulatory requirements relevant to this rulemaking. In addition, we provide background information on the EPA's June 18, 2014 Clean Power Plan proposal, the November 4, 2014 supplemental proposal, and other actions associated with this rulemaking,[28] followed by information on stakeholder outreach and consultations and the comments that the EPA received prior to issuing this final rulemaking.

A. Climate Change Impacts from GHG Emissions

[28] The EPA also published in the *Federal Register* a notice of data availability (79 FR 64543; November 8, 2014) and a notice on the translation of emission rate-based CO_2 goals to mass-based equivalents (79 FR 67406; November 13, 2014).

According to the National Research Council, "Emissions of CO_2 from the burning of fossil fuels have ushered in a new epoch where human activities will largely determine the evolution of Earth's climate. Because CO_2 in the atmosphere is long lived, it can effectively lock Earth and future generations into a range of impacts, some of which could become very severe. Therefore, emission reduction choices made today matter in determining impacts experienced not just over the next few decades, but in the coming centuries and millennia."[29]

In 2009, based on a large body of robust and compelling scientific evidence, the EPA Administrator issued the Endangerment Finding under CAA section 202(a)(1).[30] In the Endangerment Finding, the Administrator found that the current, elevated concentrations of GHGs in the atmosphere—already at levels unprecedented in human history—may reasonably be anticipated to endanger public health and welfare of current and future generations in the U.S. We summarize these adverse effects on public health and welfare briefly here.

1. Public health impacts detailed in the 2009 Endangerment Finding

[29] National Research Council, Climate Stabilization Targets, p.3.

[30] "Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act," 74 FR 66496 (Dec. 15, 2009) ("Endangerment Finding").

Climate change caused by human emissions of GHGs threatens the health of Americans in multiple ways. By raising average temperatures, climate change increases the likelihood of heat waves, which are associated with increased deaths and illnesses. While climate change also increases the likelihood of reductions in cold-related mortality, evidence indicates that the increases in heat mortality will be larger than the decreases in cold mortality in the U.S. Compared to a future without climate change, climate change is expected to increase ozone pollution over broad areas of the U.S., especially on the highest ozone days and in the largest metropolitan areas with the worst ozone problems, and thereby increase the risk of morbidity and mortality. Climate change is also expected to cause more intense hurricanes and more frequent and intense storms and heavy precipitation, with impacts on other areas of public health, such as the potential for increased deaths, injuries, infectious and waterborne diseases, and stress-related disorders. Children, the elderly, and the poor are among the most vulnerable to these climate-related health effects.

2. Public welfare impacts detailed in the 2009 Endangerment Finding

Climate change impacts touch nearly every aspect of public welfare. Among the multiple threats caused by human emissions of GHGs, climate changes are expected to place large areas of the country at serious risk of reduced water supplies, increased water pollution, and increased occurrence of extreme events such as floods and droughts. Coastal areas are expected to face a multitude of increased risks, particularly from rising sea level and increases in the severity of storms. These communities face storm and flooding damage to property, or even loss of land due to inundation, erosion, wetland submergence and habitat loss.

Impacts of climate change on public welfare also include threats to social and ecosystem services. Climate change is expected to result in an increase in peak electricity demand. Extreme weather from climate change threatens energy, transportation, and water resource infrastructure. Climate change may also exacerbate ongoing environmental pressures in certain settlements, particularly in Alaskan indigenous communities, and is very likely to fundamentally rearrange U.S. ecosystems over the 21st century. Though some benefits may balance adverse effects on agriculture and forestry in the next few decades, the body of evidence points towards increasing risks of net adverse impacts on U.S. food production, agriculture and forest productivity as temperature continues to rise. These impacts are global and may exacerbate problems outside the U.S. that raise humanitarian, trade, and national security issues for the U.S.

3. New scientific assessments and observations

Since the administrative record concerning the Endangerment Finding closed following the EPA's 2010 Reconsideration Denial, the climate has continued to change, with new records being set for a number of climate indicators such as global average surface temperatures, Arctic sea ice retreat, CO_2 concentrations, and sea level rise. Additionally, a number of major scientific assessments have been released that improve understanding of the climate system and strengthen the case that GHGs endanger public health and welfare both for current and future generations. These assessments, from the Intergovernmental Panel on Climate Change (IPCC), the U.S. Global Change Research Program (USGCRP), and the National Research Council (NRC), include: IPCC's 2012 *Special Report on Managing the Risks of Extreme Events and Disasters to Advance Climate Change Adaptation* (SREX) and the 2013-2014 Fifth Assessment Report (AR5), the USGCRP's 2014 National Climate Assessment, *Climate Change Impacts in the United States* (NCA3), and the NRC's 2010 *Ocean Acidification: A National Strategy to Meet the Challenges of a Changing Ocean* (Ocean Acidification), 2011 *Report on Climate Stabilization Targets: Emissions, Concentrations, and Impacts over Decades to Millennia* (Climate Stabilization Targets), 2011 *National Security Implications for U.S. Naval Forces* (National Security Implications), 2011 *Understanding Earth's Deep Past: Lessons for Our Climate Future* (Understanding Earth's Deep Past), 2012 *Sea*

Level Rise for the Coasts of California, Oregon, and Washington: Past, Present, and Future, 2012 *Climate and Social Stress: Implications for Security Analysis* (Climate and Social Stress), and 2013 *Abrupt Impacts of Climate Change* (Abrupt Impacts) assessments.

The EPA has carefully reviewed these recent assessments in keeping with the same approach outlined in Section VIII.A of the 2009 Endangerment Finding, which was to rely primarily upon the major assessments by the USGCRP, the IPCC, and the NRC of the National Academies to provide the technical and scientific information to inform the Administrator's judgment regarding the question of whether GHGs endanger public health and welfare. These assessments addressed the scientific issues that the EPA was required to examine, were comprehensive in their coverage of the GHG and climate change issues, and underwent rigorous and exacting peer review by the expert community, as well as rigorous levels of U.S. government review.

The findings of the recent scientific assessments confirm and strengthen the conclusion that GHGs endanger public health, now and in the future. The NCA3 indicates that human health in the U.S. will be impacted by "increased extreme weather events, wildfire, decreased air quality, threats to mental health, and illnesses transmitted by food, water, and disease-carriers such as mosquitoes and ticks." The most recent assessments now have greater confidence that climate change will influence production of pollen that exacerbates asthma and other allergic respiratory diseases such as allergic rhinitis, as well as effects on conjunctivitis and dermatitis. Both the NCA3 and the IPCC AR5 found that increasing temperature has lengthened the allergenic pollen season for ragweed, and that increased CO_2 by itself can elevate production of plant-based allergens.

The NCA3 also finds that climate change, in addition to chronic stresses such as extreme poverty, is negatively affecting indigenous peoples' health in the U.S. through impacts such as reduced access to traditional foods, decreased water quality, and increasing exposure to health and safety hazards. The IPCC AR5 finds that climate change-induced warming in the Arctic and resultant changes in environment (e.g., permafrost thaw, effects on traditional food sources) have significant impacts, observed now and projected, on the health and well-being of Arctic residents, especially indigenous peoples. Small, remote, predominantly-indigenous communities are especially vulnerable given their "strong dependence on the environment for food, culture, and way of life; their political and economic marginalization; existing social, health, and poverty disparities; as well as their frequent close proximity to exposed locations along ocean, lake, or river shorelines."[31] In addition, increasing temperatures and loss of Arctic sea ice increases the risk of drowning for those engaged in traditional hunting and fishing.

The NCA3 concludes that children's unique physiology and developing bodies contribute to making them particularly vulnerable to climate change. Impacts on children are expected from heat waves, air pollution, infectious and waterborne illnesses, and mental health effects resulting from extreme weather events. The IPCC AR5 indicates that children are among those especially susceptible to most allergic diseases, as well as health effects associated with heat waves, storms, and floods. The IPCC finds that additional health concerns may arise in low income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity within households.

Both the NCA3 and IPCC AR5 conclude that climate change will increase health risks facing the elderly. Older people are at much higher risk of mortality during extreme heat events.

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[31] IPCC, 2014: *Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part B: Regional Aspects*. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Barros, V.R., C.B. Field, D.J. Dokken, M.D. Mastrandrea, K.J. Mach, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, Cambridge, p. 1581.

Pre-existing health conditions also make older adults susceptible to cardiac and respiratory impacts of air pollution and to more severe consequences from infectious and waterborne diseases. Limited mobility among older adults can also increase health risks associated with extreme weather and floods.

The new assessments also confirm and strengthen the conclusion that GHGs endanger public welfare, and emphasize the urgency of reducing GHG emissions due to their projections that show GHG concentrations climbing to ever-increasing levels in the absence of mitigation. The NRC assessment Understanding Earth's Deep Past projected that, without a reduction in emissions, CO_2 concentrations by the end of the century would increase to levels that the Earth has not experienced for more than 30 million years.[32] In fact, that assessment stated that "the magnitude and rate of the present GHG increase place the climate system in what could be one of the most severe increases in radiative forcing of the global climate system in Earth history."[33] Because of these unprecedented changes, several assessments state that we may be approaching critical, poorly understood thresholds. As stated in the assessment, "As Earth continues to warm, it may be approaching a critical climate

[32] National Research Council, Understanding Earth's Deep Past, p. 1.
[33] Id., p.138.

threshold beyond which rapid and potentially permanent—at least on a human timescale—changes not anticipated by climate models tuned to modern conditions may occur.” The NRC Abrupt Impacts report analyzed abrupt climate change in the physical climate system and abrupt impacts of ongoing changes that, when thresholds are crossed, can cause abrupt impacts for society and ecosystems. The report considered destabilization of the West Antarctic Ice Sheet (which could cause 3-4 m of potential sea level rise) as an abrupt climate impact with unknown but probably low probability of occurring this century. The report categorized a decrease in ocean oxygen content (with attendant threats to aerobic marine life); increase in intensity, frequency, and duration of heat waves; and increase in frequency and intensity of extreme precipitation events (droughts, floods, hurricanes, and major storms) as climate impacts with moderate risk of an abrupt change within this century. The NRC *Abrupt Impacts* report also analyzed the threat of rapid state changes in ecosystems and species extinctions as examples of an irreversible impact that is expected to be exacerbated by climate change. Species at most risk include those whose migration potential is limited, whether because they live on mountaintops or fragmented habitats with barriers to movement, or because climatic conditions are changing more rapidly than the species can move or adapt. While the NRC determined that it is not presently possible to place exact probabilities on the added contribution of climate change to extinction, they did find that there was substantial risk that impacts from climate change could, within a few decades, drop the populations in many species below sustainable levels thereby committing the species to extinction. Species within tropical and subtropical rainforests such as the Amazon and species living in coral reef ecosystems were identified by the NRC as being particularly vulnerable to extinction over the next 30 to 80 years, as were species in high latitude and high elevation regions. Moreover, due to the time lags inherent in the Earth's climate, the NRC Climate Stabilization Targets assessment notes that the full warming from any given concentration of CO_2 reached will not be fully realized for several centuries, underscoring that emission activities today carry with them climate commitments far into the future.

Future temperature changes will depend on what emission path the world follows. In its high emission scenario, the IPCC AR5 projects that global temperatures by the end of the century will likely be 2.6 °C to 4.8 °C (4.7 to 8.6 °F) warmer than today. Temperatures on land and in northern latitudes will likely warm even faster than the global average. However, according to the NCA3, significant reductions in emissions would lead to noticeably less future warming beyond mid-century, and therefore less impact to public health and welfare.

While rainfall may only see small globally and annually averaged changes, there are expected to be substantial shifts in where and when that precipitation falls. According to the NCA3, regions closer to the poles will see more precipitation, while the dry subtropics are expected to expand (colloquially, this has been summarized as wet areas getting wetter and dry regions getting drier). In particular, the NCA3 notes that the western U.S., and especially the Southwest, is expected to become drier. This projection is consistent with the recent observed drought trend in the West. At the time of publication of the NCA, even before the last 2 years of extreme drought in California, tree ring data was already indicating that the region might be experiencing its driest period in 800 years. Similarly, the NCA3 projects that heavy downpours are expected to increase in many regions, with precipitation events in general becoming less frequent but more intense. This trend has already been observed in regions such as the Midwest, Northeast, and upper Great Plains. Meanwhile, the NRC Climate Stabilization Targets assessment found that the area burned by wildfire is expected to grow by 2 to 4 times for 1 °C (1.8 °F) of warming. For 3 °C of warming, the assessment found that 9 out of 10 summers would be warmer than all but the 5 percent of warmest summers today, leading to increased frequency, duration, and intensity of heat waves. Extrapolations by the NCA also indicate that Arctic sea ice in summer may essentially disappear by mid-century. Retreating snow and ice, and emissions of carbon dioxide and methane released from thawing permafrost, will also amplify future warming.

Since the 2009 Endangerment Finding, the USGCRP NCA3, and multiple NRC assessments have projected future rates of sea level rise that are 40 percent larger to more than twice as large as the previous estimates from the 2007 IPCC 4th Assessment Report due in part to improved understanding of the future rate of melt of the Antarctic and Greenland Ice sheets. The NRC Sea Level Rise assessment projects a global sea level rise of 0.5 to 1.4 meters (1.6 to 4.6 feet) by 2100, the NRC National Security Implications assessment suggests that "the Department of the Navy should expect roughly 0.4 to 2 meters [1.3 to 6.6 feet] global average sea-level rise by 2100,"[34] and the NRC Climate Stabilization Targets assessment states that an increase of 3°C will lead to a sea level rise of 0.5 to 1 meter (1.6 to 3.3 feet) by 2100. These assessments continue to recognize that there is uncertainty inherent in accounting for ice sheet processes. Additionally, local sea level rise can differ from

[34] NRC, 2011: *National Security Implications of Climate Change for U.S. Naval Forces*. The National Academies Press, p. 28.

the global total depending on various factors: the east coast of the U.S. in particular is expected to see higher rates of sea level rise than the global average. For comparison, the NCA3 states that "five million Americans and hundreds of billions of dollars of property are located in areas that are less than four feet above the local high-tide level," and the NCA3 finds that "[c]oastal infrastructure, including roads, rail lines, energy infrastructure, airports, port facilities, and military bases, are increasingly at risk from sea level rise and damaging storm surges."[35] Also, because of the inertia of the oceans, sea level rise will continue for centuries after GHG concentrations have stabilized (though more slowly than it would have otherwise). Additionally, there is a threshold temperature above which the Greenland ice sheet will be committed to inevitable melting: according to the NCA, some recent research has suggested that even present day CO_2 levels could be sufficient to exceed that threshold.

In general, climate change impacts are expected to be unevenly distributed across different regions of the U.S. and have a greater impact on certain populations, such as indigenous peoples and the poor. The NCA3 finds climate change impacts such

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[35] Melillo, Jerry M., Terese (T.C.) Richmond, and Gary W. Yohe, Eds., 2014: *Climate Change Impacts in the United States: The Third National Climate Assessment.* U.S. Global Change Research Program, p. 9.

as the rapid pace of temperature rise, coastal erosion and inundation related to sea level rise and storms, ice and snow melt, and permafrost thaw are affecting indigenous people in the U.S. Particularly in Alaska, critical infrastructure and traditional livelihoods are threatened by climate change and, "[i]n parts of Alaska, Louisiana, the Pacific Islands, and other coastal locations, climate change impacts (through erosion and inundation) are so severe that some communities are already relocating from historical homelands to which their traditions and cultural identities are tied."[36] The IPCC AR5 notes, "Climate-related hazards exacerbate other stressors, often with negative outcomes for livelihoods, especially for people living in poverty (high confidence). Climate-related hazards affect poor people's lives directly through impacts on livelihoods, reductions in crop yields, or destruction of homes and indirectly through, for example, increased food prices and food insecurity."[37]

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[36] Melillo, Jerry M., Terese (T.C.) Richmond, and Gary W. Yohe, Eds., 2014: *Climate Change Impacts in the United States: The Third National Climate Assessment.* U.S. Global Change Research Program, p. 17.

[37] IPCC, 2014: *Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects.* Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, p. 796.

Carbon dioxide in particular has unique impacts on ocean ecosystems. The NRC Climate Stabilization Targets assessment found that coral bleaching will increase due both to warming and ocean acidification. Ocean surface waters have already become 30 percent more acidic over the past 250 years due to absorption of CO_2 from the atmosphere. According to the NCA3, this acidification will reduce the ability of organisms such as corals, krill, oysters, clams, and crabs to survive, grow, and reproduce. The NRC Understanding Earth's Deep Past assessment notes four of the five major coral reef crises of the past 500 million years were caused by acidification and warming that followed GHG increases of similar magnitude to the emissions increases expected over the next hundred years. The NRC Abrupt Impacts assessment specifically highlighted similarities between the projections for future acidification and warming and the extinction at the end of the Permian which resulted in the loss of an estimated 90 percent of known species. Similarly, the NRC Ocean Acidification assessment finds that "[t]he chemistry of the ocean is changing at an unprecedented rate and magnitude due to anthropogenic carbon dioxide emissions; the rate of change exceeds any known to have occurred for at least the past hundreds of thousands of years."[38] The assessment notes that the full range of consequences is still unknown, but the risks "threaten coral reefs, fisheries, protected species, and other natural resources of value to society."[39]

Events outside the U.S., as also pointed out in the 2009 Endangerment Finding, will also have relevant consequences. The NRC Climate and Social Stress assessment concluded that it is prudent to expect that some climate events "will produce consequences that exceed the capacity of the affected societies or global systems to manage and that have global security implications serious enough to compel international response." The NRC National Security Implications assessment recommends preparing for increased needs for humanitarian aid; responding to the effects of climate change in geopolitical hotspots, including possible mass migrations; and addressing changing security needs in the Arctic as sea ice retreats.

In addition to future impacts, the NCA3 emphasizes that climate change driven by human emissions of GHGs is already happening now and it is happening in the U.S. According to the IPCC AR5 and the NCA3, there are a number of climate-related changes that have been observed recently, and these changes are

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[38] NRC, 2010: *Ocean Acidification: A National Strategy to Meet the Challenges of a Changing Ocean*. The National Academies Press, p. 5.
[39] Ibid.

projected to accelerate in the future. The planet warmed about 0.85 °C (1.5 °F) from 1880 to 2012. It is extremely likely (>95 percent probability) that human influence was the dominant cause of the observed warming since the mid-20th century, and likely (>66 percent probability) that human influence has more than doubled the probability of occurrence of heat waves in some locations. In the Northern Hemisphere, the last 30 years were likely the warmest 30 year period of the last 1400 years. U.S. average temperatures have similarly increased by 1.3 to 1.9 degrees F since 1895, with most of that increase occurring since 1970. Global sea levels rose 0.19 m (7.5 inches) from 1901 to 2010. Contributing to this rise was the warming of the oceans and melting of land ice. It is likely that 275 gigatons per year of ice melted from land glaciers (not including ice sheets) since 1993, and that the rate of loss of ice from the Greenland and Antarctic ice sheets increased substantially in recent years, to 215 gigatons per year and 147 gigatons per year respectively since 2002. For context, 360 gigatons of ice melt is sufficient to cause global sea levels to rise 1 mm. Annual mean Arctic sea ice has been declining at 3.5 to 4.1 percent per decade, and Northern Hemisphere snow cover extent has decreased at about 1.6 percent per decade for March and 11.7 percent per decade for June. Permafrost temperatures have increased in most regions since the 1980s, by up to 3 °C (5.4 °F) in parts of

Northern Alaska. Winter storm frequency and intensity have both increased in the Northern Hemisphere. The NCA3 states that the increases in the severity or frequency of some types of extreme weather and climate events in recent decades can affect energy production and delivery, causing supply disruptions, and compromise other essential infrastructure such as water and transportation systems.

In addition to the changes documented in the assessment literature, there have been other climate milestones of note. In 2009, the year of the Endangerment Finding, the average concentration of CO_2 as measured on top of Mauna Loa was 387 parts per million, far above preindustrial concentrations of about 280 parts per million.[40] The average concentration in 2013, the last full year before this rule was proposed, was 396 parts per million. The average concentration in 2014 was 399 parts per million. And the monthly concentration in April of 2014 was 401 parts per million, the first time a monthly average has exceeded 400 parts per million since record keeping began at Mauna Loa in 1958, and for at least the past 800,000 years.[41] Arctic sea ice has continued to decline, with September of 2012 marking a new record low in terms of Arctic sea ice extent, 40 percent below

[40] ftp://aftp.cmdl.noaa.gov/products/trends/co2/co2_annmean_mlo.txt.
[41] http://www.esrl.noaa.gov/gmd/ccgg/trends/.

the 1979-2000 median. Sea level has continued to rise at a rate of 3.2 mm per year (1.3 inches/decade) since satellite observations started in 1993, more than twice the average rate of rise in the 20th century prior to 1993.[42] And 2014 was the warmest year globally in the modern global surface temperature record, going back to 1880; this now means 19 of the 20 warmest years have occurred in the past 20 years, and except for 1998, the ten warmest years on record have occurred since 2002.[43] The first months of 2015 have also been some of the warmest on record.

These assessments and observed changes make it clear that reducing emissions of GHGs across the globe is necessary in order to avoid the worst impacts of climate change, and underscore the urgency of reducing emissions now. The NRC Committee on America's Climate Choices listed a number of reasons "why it is imprudent to delay actions that at least begin the process of substantially reducing emissions."[44] For example:

- The faster emissions are reduced, the lower the risks posed by climate change. Delays in reducing emissions could commit the planet to a wide range of adverse impacts, especially if the sensitivity of the climate to GHGs is on the higher end of the estimated range.

[42] Blunden, J., and D. S. Arndt, Eds., 2014: State of the Climate in 2013. Bull. Amer. Meteor. Soc., 95 (7), S1-S238.
[43] http://www.ncdc.noaa.gov/sotc/global/2014/13.
[44] NRC, 2011: *America's Climate Choices*, The National Academies Press.

- Waiting for unacceptable impacts to occur before taking action is imprudent because the effects of GHG emissions do not fully manifest themselves for decades and, once manifest, many of these changes will persist for hundreds or even thousands of years.

- In the committee's judgment, the risks associated with doing business as usual are a much greater concern than the risks associated with engaging in strong response efforts.

4. Observed and Projected U.S. Regional Changes

The NCA3 assessed the climate impacts in 8 regions of the U.S., noting that changes in physical climate parameters such as temperatures, precipitation, and sea ice retreat were already having impacts on forests, water supplies, ecosystems, flooding, heat waves, and air quality. Moreover, the NCA3 found that future warming is projected to be much larger than recent observed variations in temperature, with precipitation likely to increase in the northern states, decrease in the southern states, and with the heaviest precipitation events projected to increase everywhere.

In the Northeast, temperatures increased almost 2 °F from 1895 to 2011, precipitation increased by about 5 inches (10 percent), and sea level rise of about a foot has led to an increase in coastal flooding. The 70 percent increase in the amount of rainfall falling in the 1 percent of the most intense events is a larger increase in extreme precipitation than experienced in any other U.S. region.

In the future, if emissions continue increasing, the Northeast is expected to experience 4.5 to 10 °F of warming by the 2080s. This will lead to more heat waves, coastal and river flooding, and intense precipitation events. The southern portion of the region is projected to see 60 additional days per year above 90 °F by mid-century. Sea levels in the Northeast are expected to increase faster than the global average because of subsidence, and changing ocean currents may further increase the rate of sea level rise. Specific vulnerabilities highlighted by the NCA include large urban populations particularly vulnerable to climate-related heat waves and poor air quality episodes, prevalence of climate sensitive vector-borne diseases like Lyme and West Nile Virus, usage of combined sewer systems that may lead to untreated water being released into local water bodies after climate-related heavy precipitation events, and 1.6 million people living within the 100-year coastal flood zone who are expected to experience more frequent floods due to sea level rise and tropical-storm induced storm-surge. The NCA also highlighted infrastructure vulnerable to inundation in coastal metropolitan areas, potential agricultural impacts from increased rain in the spring delaying planting or damaging crops or increased heat in the summer leading to decreased yields and increased water demand, and shifts in ecosystems leading to declines in iconic species in some regions, such as cod and lobster south of Cape Cod.

In the Southeast, average annual temperature during the last century cycled between warm and cool periods. A warm peak occurred during the 1930s and 1940s followed by a cool period and temperatures then increased again from 1970 to the present by an average of 2°F. There have been increasing numbers of days above 95°F and nights above 75°F, and decreasing numbers of extremely cold days since 1970. Daily and five-day rainfall intensities have also increased, and summers have been either increasingly dry or extremely wet. Louisiana has already lost 1,880 square miles of land in the last 80 years due to sea level rise and other contributing factors.

The Southeast is exceptionally vulnerable to sea level rise, extreme heat events, hurricanes, and decreased water availability. Major consequences of further warming include significant increases in the number of hot days (95°F or above) and decreases in freezing events, as well as exacerbated ground-level ozone in urban areas. Although projected warming for some parts of the region by the year 2100 are generally smaller than for other regions of the U.S., projected warming for interior states of the region are larger than coastal regions by 1°F to 2°F. Projections further suggest that globally there will be fewer tropical storms, but that they will be more intense, with more Category 4 and 5 storms. The NCA identified New Orleans, Miami, Tampa, Charleston, and Virginia Beach as being specific cities that are at risk due to sea level rise, with homes and infrastructure increasingly prone to flooding. Additional impacts of sea level rise are expected for coastal highways, wetlands, fresh water supplies, and energy infrastructure.

In the Northwest, temperatures increased by about 1.3°F between 1895 and 2011. A small average increase in precipitation was observed over this time period. However, warming temperatures have caused increased rainfall relative to snowfall, which has altered water availability from snowpack across parts of the region. Snowpack in the Northwest is an important freshwater source for the region. More precipitation falling as rain instead of snow has reduced the snowpack, and warmer springs have corresponded to earlier snowpack melting and reduced streamflows during summer months. Drier conditions have increased the extent of wildfires in the region.

Average annual temperatures are projected to increase by 3.3°F to 9.7°F by the end of the century (depending on future global GHG emissions), with the greatest warming is expected during the summer. Continued increases in global GHG emissions are projected to result in up to a 30 percent decrease in summer precipitation. Earlier snowpack melt and lower summer stream flows are expected by the end of the century and will affect drinking water supplies, agriculture, ecosystems, and hydropower production. Warmer waters are expected to increase disease and mortality in important fish species, including Chinook and sockeye salmon. Ocean acidification also threatens species such as oysters, with the Northwest coastal waters already being some of the most acidified worldwide due to coastal upwelling and other local factors. Forest pests are expected to spread and wildfires burn larger areas. Other high-elevation ecosystems are projected to be lost because they can no longer survive the climatic conditions. Low lying coastal areas, including the cities of Seattle and Olympia, will experience heightened risks of sea level rise, erosion, seawater inundation and damage to infrastructure and coastal ecosystems.

In Alaska, temperatures have changed faster than anywhere else in the U.S. Annual temperatures increased by about 3 °F in the past 60 years. Warming in the winter has been even greater, rising by an average of 6 °F. Arctic sea ice is thinning and shrinking in area, with the summer minimum ice extent now covering only half the area it did when satellite records began in 1979. Glaciers in Alaska are melting at some of the fastest rates on Earth. Permafrost soils are also warming and beginning to thaw. Drier conditions have contributed to more large wildfires in the last 10 years than in any previous decade since the 1940s, when recordkeeping began. Climate change impacts are harming the health, safety and livelihoods of Native Alaskan communities.

By the end of this century, continued increases in GHG emissions are expected to increase temperatures by 10 to 12 °F in the northernmost parts of Alaska, by 8 to 10 °F in the interior, and by 6 to 8 °F across the rest of the state. These increases will exacerbate ongoing arctic sea ice loss, glacial melt, permafrost thaw and increased wildfire, and threaten humans, ecosystems, and infrastructure. Precipitation is expected to increase to varying degrees across the state, however warmer air temperatures and a longer growing season are expected to result in drier conditions. Native Alaskans are expected to experience declines in economically, nutritionally, and culturally important wildlife and plant species. Health threats will also increase, including loss of clean water, saltwater intrusion, sewage contamination from thawing permafrost, and northward extension of diseases. Wildfires will increasingly pose threats to human health as a result of smoke and direct contact. Areas underlain by ice-rich permafrost across the state are likely to experience ground subsidence and extensive damage to infrastructure as the permafrost thaws. Important ecosystems will continue to be affected. Surface waters and wetlands that are drying provide breeding habitat for millions of waterfowl and shorebirds that winter in the lower 48 states. Warmer ocean temperatures, acidification, and declining sea ice will contribute to changes in the location and availability of commercially and culturally important marine fish.

In the Southwest, temperatures are now about 2 °F higher than the past century, and are already the warmest that region has experienced in at least 600 years. The NCA notes that there is evidence that climate-change induced warming on top of recent drought has influenced tree mortality, wildfire frequency and area, and forest insect outbreaks. Sea levels have risen about 7 or 8 inches in this region, contributing to inundation of Highway 101 and backup of seawater into sewage systems in the San Francisco area.

Projections indicate that the Southwest will warm an additional 5.5 to 9.5 °F over the next century if emissions continue to increase. Winter snowpack in the Southwest is projected to decline (consistent with the record lows from this past winter), reducing the reliability of surface water supplies for cities, agriculture, cooling for power plants, and ecosystems. Sea level rise along the California coast will worsen coastal erosion, increase flooding risk for coastal highways, bridges, and low-lying airports, pose a threat to groundwater supplies in coastal cities such as Los Angeles, and increase vulnerability to floods for hundreds of thousands of residents in coastal areas. Climate change will also have impacts on the high-value specialty crops grown in the region as a drier climate will increase demands for irrigation, more frequent heat waves will reduce yields, and decreased winter chills may impair fruit and nut production for trees in California. Increased drought, higher temperatures, and bark beetle outbreaks are likely to contribute to continued increases in wildfires. The highly urbanized population of the Southwest is vulnerable to heat waves and water supply disruptions, which can be exacerbated in cases where high use of air conditioning triggers energy system failures.

The rate of warming in the Midwest has markedly accelerated over the past few decades. Temperatures rose by more than 1.5 °F from 1900 to 2010, but between 1980 and 2010 the rate of warming was three times faster than from 1900 through 2010. Precipitation generally increased over the last century, with much of the increase driven by intensification of the heaviest rainfalls. Several types of extreme weather events in the Midwest (e.g., heat waves and flooding) have already increased in frequency and/or intensity due to climate change.

In the future, if emissions continue increasing, the Midwest is expected to experience 5.6 to 8.5 °F of warming by the 2080s, leading to more heat waves. Though projections of changes in total precipitation vary across the regions, more precipitation is expected to fall in the form of heavy downpours across the entire region, leading to an increase in flooding. Specific vulnerabilities highlighted by the NCA include long-term decreases in agricultural productivity, changes in the composition of the region's forests, increased public health threats from heat waves and degraded air and water quality, negative impacts on transportation and other infrastructure associated with extreme rainfall events and flooding, and risks to the Great Lakes including shifts in invasive species, increases in harmful algal blooms, and declining beach health.

High temperatures (more than 100 °F in the Southern Plains and more than 95 °F in the Northern Plains) are projected to occur much more frequently by mid-century. Increases in extreme heat will increase heat stress for residents, energy demand for air conditioning, and water losses. North Dakota's increase in annual temperatures over the past 130 years is the fastest in the contiguous U.S., mainly driven by warming winters. Specific vulnerabilities highlighted by the NCA include increased demand for water and energy, changes to crop growth cycles and agricultural practices, and negative impacts on local plant and animal species from habitat fragmentation, wildfires, and changes in the timing of flowering or pest patterns. Communities that are already the most vulnerable to weather and climate extremes will be stressed even further by more frequent extreme events occurring within an already highly variable climate system.

In Hawaii, other Pacific islands, and the Caribbean, rising air and ocean temperatures, shifting rainfall patterns, changing frequencies and intensities of storms and drought, decreasing baseflow in streams, rising sea levels, and changing ocean chemistry will affect ecosystems on land and in the oceans, as well as local communities, livelihoods, and cultures. Low islands are particularly at risk.

Rising sea levels, coupled with high water levels caused by tropical and extra-tropical storms, will incrementally increase coastal flooding and erosion, damaging coastal ecosystems, infrastructure, and agriculture, and negatively affecting tourism. Ocean temperatures in the Pacific region exhibit strong year-to-year and decadal fluctuations, but since the 1950s, they have exhibited a warming trend, with temperatures from the surface to a depth of 660 feet rising by as much as 3.6°F. As a result of current sea level rise, the coastline of Puerto Rico around Rincón is being eroded at a rate of 3.3 feet per year. Freshwater supplies are already constrained and will become more limited on many islands. Saltwater intrusion associated with sea level rise will reduce the quantity and quality of freshwater in coastal aquifers, especially on low islands. In areas where precipitation does not increase, freshwater supplies will be adversely affected as air temperature rises.

Warmer oceans are leading to increased coral bleaching events and disease outbreaks in coral reefs, as well as changed distribution patterns of tuna fisheries. Ocean acidification will reduce coral growth and health. Warming and acidification, combined with existing stresses, will strongly affect coral reef fish communities. For Hawaii and the Pacific islands, future sea surface temperatures are projected to increase 2.3°F by 2055 and 4.7°F by 2090 under a scenario that assumes continued increases in emissions. Ocean acidification is also taking place in the region, which adds to ecosystem stress from increasing temperatures. Ocean acidity has increased by about 30 percent since the pre-industrial era and is projected to further increase by 37 percent to 50 percent from present levels by 2100.

The NCA also discussed impacts that occur along the coasts and in the oceans adjacent to many regions, and noted that other impacts occur across regions and landscapes in ways that do not follow political boundaries.

B. GHG Emissions from Fossil Fuel-fired EGUs[45]

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[45] The emission data presented in this section of the preamble (Section II.B) are in metric tons, in keeping with reporting requirements for the GHGRP and the U.S. GHG Inventory. Note that

Fossil fuel-fired electric utility generating units (EGUs) are by far the largest emitters of GHGs among stationary sources in the U.S., primarily in the form of CO_2, and among fossil fuel-fired EGUs, coal-fired units are by far the largest emitters. This section describes the amounts of these emissions and places these amounts in the context of the U.S. Inventory of Greenhouse Gas Emissions and Sinks[46] (the U.S. GHG Inventory).

The EPA implements a separate program under 40 CFR Part 98 called the Greenhouse Gas Reporting Program[47] (GHGRP) that requires emitting facilities over threshold amounts of GHGs to report their emissions to the EPA annually. Using data from the GHGRP, this section also places emissions from fossil fuel-fired EGUs in the context of the total emissions reported to the GHGRP from facilities in the other largest-emitting industries.

The EPA prepares the official U.S. GHG Inventory to comply with commitments under the United Nations Framework Convention on Climate Change (UNFCCC). This inventory, which includes recent trends, is organized by industrial sectors. It provides

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the mass-based state goals presented in section VII of this preamble, and discussed elsewhere in this preamble, are presented in short tons.

[46] "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2013", Report EPA 430-R-15-004, United States Environmental Protection Agency, April 15, 2015. http://epa.gov/climatechange/ghgemissions/usinventoryreport.html

[47] U.S. EPA Greenhouse Gas Reporting Program Dataset, see http://www.epa.gov/ghgreporting/ghgdata/reportingdatasets.html.

the information in Table 3 below, which presents total U.S. anthropogenic emissions and sinks[48] of GHGs, including CO_2 emissions, for the years 1990, 2005 and 2013.

Table 3. U.S. GHG Emissions and Sinks by Sector (million metric tons carbon dioxide equivalent (MMT CO_2 Eq.))[49]

SECTOR	1990	2005	2013
Energy[50]	5,290.5	6,273.6	5,636.6
Industrial Processes and Product Use	342.1	367.4	359.1
Agriculture	448.7	494.5	515.7
Land Use, Land-Use Change and Forestry	13.8	25.5	23.3
Waste	206.0	189.2	138.3
Total Emissions	6,301.1	7,350.2	6,673.0
Land Use, Land-Use Change and Forestry (Sinks)	(775.8)	(911.9)	(881.7)
Net Emissions (Sources and Sinks)	5,525.2	6,438.3	5,791.2

[48] Sinks are a physical unit or process that stores GHGs, such as forests or underground or deep sea reservoirs of carbon dioxide.
[49] From Table ES-4 of "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2013", Report EPA 430-R-15-004, U.S. Environmental Protection Agency, April 15, 2015. http://epa.gov/climatechange/ghgemissions/usinventoryreport.html
[50] The energy sector includes all greenhouse gases resulting from stationary and mobile energy activities, including fuel combustion and fugitive fuel emissions.

Total fossil energy-related CO_2 emissions (including both stationary and mobile sources) are the largest contributor to total U.S. GHG emissions, representing 77.3 percent of total 2013 GHG emissions.[51] In 2013, fossil fuel combustion by the utility power sector -- entities that burn fossil fuel and whose primary business is the generation of electricity -- accounted for 38.3 percent of all energy-related CO_2 emissions.[52] Table 4 below presents total CO_2 emissions from fossil fuel-fired EGUs, for years 1990, 2005 and 2013.

Table 4. U.S. GHG Emissions from Generation of Electricity from Combustion of Fossil Fuels (MMT CO_2)[53]

GHG EMISSIONS	1990	2005	2013
Total CO_2 from fossil fuel-fired EGUs	1,820.8	2,400.9	2,039.8
- from coal	1,547.6	1,983.8	1,575.0
- from natural gas	175.3	318.8	441.9
- from petroleum	97.5	97.9	22.4

51 From Table ES-2 "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2013", Report EPA 430-R-15-004, United States Environmental Protection Agency, April 15, 2015. http://epa.gov/climatechange/ghgemissions/usinventoryreport.html.

52 From Table 3-1 "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2013", Report EPA 430-R-15-004, United States Environmental Protection Agency, April 15, 2015. http://epa.gov/climatechange/ghgemissions/usinventoryreport.html

53 From Table 3-5 "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2013", Report EPA 430-R-15-004, United States Environmental Protection Agency, April 15 2015. http://epa.gov/climatechange/ghgemissions/usinventoryreport.html.

In addition to preparing the official U.S. GHG Inventory to present comprehensive total U.S. GHG emissions and comply with commitments under the UNFCCC, the EPA collects detailed GHG emissions data from the largest emitting facilities in the U.S. through its Greenhouse Gas Reporting Program (GHGRP). Data collected by the GHGRP from large stationary sources in the industrial sector show that the utility power sector emits far greater CO_2 emissions than any other industrial sector. Table 5 below presents total GHG emissions in 2013 for the largest emitting industrial sectors as reported to the GHGRP. As shown in Table 4 and Table 5, respectively, CO_2 emissions from fossil fuel-fired EGUs are nearly three times as large as the total reported GHG emissions from the next ten largest emitting industrial sectors in the GHGRP database combined.

Table 5. Direct GHG Emissions Reported to GHGRP by Largest Emitting Industrial Sectors (MMT CO_2e)[54]

Industrial Sector	2013
Petroleum Refineries	176.7
Onshore Oil & Gas Production	94.8
Municipal Solid Waste Landfills	93.0
Iron & Steel Production	84.2
Cement Production	62.8
Natural Gas Processing Plants	59.0
Petrochemical Production	52.7
Hydrogen Production	41.9
Underground Coal Mines	39.8
Food Processing Facilities	30.8

[54] U.S. EPA Greenhouse Gas Reporting Program Dataset as of August 18, 2014. http://ghgdata.epa.gov/ghgp/main.do.

C. Challenges in Controlling Carbon Dioxide Emissions

Carbon dioxide is a unique air pollutant and controlling it presents unique challenges. CO_2 is emitted in enormous quantities, and those quantities, coupled with the fact that CO_2 is relatively unreactive, make it much more difficult to mitigate by measures or technologies that are typically utilized within an existing power plant. Measures that may be used to limit CO_2 emissions would include efficiency improvements, which have thermodynamic limitations and carbon capture and sequestration (CCS), which is energy resource intensive.

Unlike other air pollutants which are results of trace impurities in the fuel, products of incomplete or inefficient combustion, or combustion byproducts, CO_2 is an inherent product of clean, efficient combustion of fossil fuels, and therefore is an unavoidable product generated in enormous quantities, far greater than any other air pollutant.[55] In fact, CO_2 is emitted in far greater quantities than all other air pollutants *combined*. Total emissions of all non-GHG air pollutants in the U.S., from all sources, in 2013, were 121 million metric

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[55] Lackner et al., "Comparative Impacts of Fossil Fuels and Alternative Energy Sources", Issues in Environmental Science and Technology (2010).

tons.[56,57] As noted above, total emissions of CO_2 from coal-fired power plants alone – the largest stationary source emitter --

[56] This includes NAAQS and HAPs, based on the following table:

Pollutant	**2013 tons** (million short tons)	**Reference**
CO	69.758	Trends file (http://www.epa.gov/ttnchie1/trends/)
NO_X	13.072	"
PM_{10}	20.651	"
SO_2	5.098	"
VOC	17.471	"
NH_3	4.221	"
HAPS	3.641	2011 NEI version 2 (http://www.epa.gov/ttn/chief/net/2011inventory.html)
Total	133.912	

It should be noted that $PM_{2.5}$ is included in the amounts for PM_{10}. Lead, another NAAQS pollutant, is emitted in the amounts of approximately 1,000 tons per year, and, in light of that relatively small quantity, was excluded from this analysis. Ammonia (NH_3) is included because it is a precursor to $PM_{2.5}$ secondary formation. Note that one short ton is equivalent to 0.907185 metric ton.

[57] In addition, emissions of non-CO_2 GHGs totaled 1.168 billion metric tons of carbon-dioxide equivalents (CO_2e) in 2013. See Table ES-2, Executive Summary, 1990-2013 Inventory of U.S. Greenhouse Gas Emissions and Sinks. http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Chapter-Executive-Summary.pdf.
This includes emissions of methane, nitrous oxide, and fluorinated GHGs (hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride, and nitrogen trifluoride). In the total, the emissions of each non-CO_2 GHG have been translated from metric tons of that gas into metric tons of CO_2e by multiplying the metric tons of the gas by the global warming potential (GWP) of the gas. (The GWP of a gas is a measure of the ability of one kilogram of that gas to trap heat in earth's atmosphere compared to one kilogram of CO_2.)

were 1.575 billion metric tons in that year,[58] and total emissions of CO_2 from all sources were 5.5 billion metric tons.[59,60] Carbon makes up the majority of the mass of coal and other fossil fuels, and for every ton of carbon burned, more than 3 tons of CO_2 is produced.[61] In addition, unlike many of the other air pollutants that react with sunlight or chemicals in the atmosphere, or are rained out or deposited on surfaces, CO_2 is relatively unreactive and difficult to remove directly from the atmosphere.[62,63]

CO_2's huge quantities and lack of reactivity make it challenging to remove from the smokestack. Retrofitted equipment

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[58] From Table 3-5 "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2013", Report EPA 430-R-15-004, United States Environmental Protection Agency, April 15, 2015. http://epa.gov/climatechange/ghgemissions/usinventoryreport.html.

[59] U.S. EPA, *Greenhouse Gas Inventory Data Explorer*, http://www.epa.gov/climatechange/ghgemissions/inventoryexplorer/#allsectors/allgas/gas/current.

[60] As another point of comparison, except for carbon dioxide, SO_2 and NO_x are the largest air pollutant emissions from coal-fired power plants. Over the past decade, U.S. power plants have emitted more than 200 times as much CO_2 as they have emitted SO_2 and NO_x. *See* de Gouw et al., "Reduced emissions of CO_2, NOx, and SO_2 from U.S. power plants owing to switch from coal to natural gas with combined cycle technology," Earth's Future (2014).

[61] Each atom of carbon in the fuel combines with 2 atoms of oxygen in the air.

[62] Seinfeld J. and Pandis S., Atmospheric Chemistry and Physics: From Air Pollution to Climate Change (1998).

[63] The fact that CO_2 is unreactive means that it is primarily removed from the atmosphere by dissolving in oceans or by being converted into biomass by plants. Herzog, H., "Scaling up carbon dioxide capture and storage: From megatons to gigatons", Energy Economics (2011).

is required to capture the CO_2 before transporting it to a storage site. However, the scale of infrastructure required to directly mitigate CO_2 emissions from existing EGUs through CCS can be quite large and difficult to integrate into the existing fossil fuel infrastructure. These CCS techniques are discussed in more depth elsewhere in the preamble for this rule and for the section 111(b) rule for new sources that accompanies this rule.

The properties of CO_2 can be contrasted with those of a number of other pollutants which have more accessible mitigation options. For example, the NAAQS pollutants – which generally are emitted in the largest quantities of any of the other air pollutants, except for CO_2 – each have more accessible mitigation options. Sulfur dioxide (SO_2) is the result of a contaminant in the fuel, and, as a result, it can be reduced by using low-sulfur coal or by using flue-gas desulfurization (FGD) technologies. Emissions of NO_x can be mitigated relatively easily using combustion control techniques (e.g., low-NO_x burners) and by using downstream controls such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) technologies. PM can be effectively mitigated using fabric filters, PM scrubbers, or electrostatic precipitators. Lead is part of particulate matter emissions and is controlled through the same devices. Carbon monoxide and VOCs are the products of incomplete combustion and can therefore be abated by more efficient combustion conditions, and can also be destroyed in the smokestack by the use of oxidation catalysts which complete the combustion process. Many air toxics are VOCs, such as polyaromatic hydrocarbons, and therefore can be abated in the same ways just described. But in every case, these pollutants can be controlled at the source much more readily than CO_2 primarily because of the comparatively lower quantities that are produced, and also due to other attributes such as relatively greater reactivity and solubility.

D. The Utility Power Sector

1. A brief history

The modern American electricity system is one of the greatest engineering achievements of the past 100 years. Since the invention of the incandescent light bulb in the 1870s,[64] electricity has become one of the major foundations for modern American life. Beginning with the first power station in New York City in 1882, each power station initially served a discrete set of consumers, resulting in small and localized electricity systems.[65] During the early 1900s, smaller systems

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[64] Regulatory Assistance Project (RAP), *Electricity Regulation in the US: A Guide*, at 1 (2011), *available at* http://www.raponline.org/document/download/id/645.
[65] Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 2-4 (2d ed. 2010).

consolidated, allowing generation resources to be shared over larger areas. Interconnecting systems have reduced generation investment costs and improved reliability.[66] Local and state governments initially regulated these growing electricity systems with federal regulation coming later in response to public concerns about rising electricity costs.[67]

Initially, states had broad authority to regulate public utilities, but gradually federal regulation increased. In 1920, Congress passed the Federal Water Power Act, creating the Federal Power Commission (FPC) and providing for the licensing of hydroelectric facilities on U.S. government lands and navigable waters of the U.S.[68] During this time period, the U.S. Supreme Court found that state authority to regulate public utilities is limited, holding that the Commerce Clause does not

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[66] Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 5-6 (2d ed. 2010). Investment in electric generation is extremely capital intensive, with generation potentially accounting for 65 percent of customer costs. If these costs can be spread to more customers, then this can reduce the amount that each individual customer pays. Federal Energy Regulatory Commission, *Energy Primer: A Handbook of Energy Market Basics*, at 38 (2012), *available at* http://www.ferc.gov/market-oversight/guide/energy-primer.pdf.
[67] Burn, An Energy Journal, *The Electricity Grid: A History*, *available at* http://burnanenergyjournal.com/the-electric-grid-a-history/ (last visited Mar. 9, 2015).
[68] The FPC became an independent Commission in 1930. *United States Government Manual 1945: First Edition*, at 486, *available at* http://www.ibiblio.org/hyperwar/ATO/USGM/FPC.html.

allow state regulation to directly burden interstate commerce.[69] For example, in *Public Utilities Commission of Rhode Island v. Attleboro Steam & Electric Company*, Rhode Island sought to regulate the electricity rates that a Rhode Island generator was charging to a company in Massachusetts that resold the electricity to Attleboro, Massachusetts.[70] The Supreme Court found that Rhode Island's regulation was impermissible because it imposed a "direct burden upon interstate commerce."[71] The Supreme Court held that this kind of interstate transaction was not subject to state regulation. However, because Congress had not yet passed legislation to make these types of transactions subject to federal regulation, this became known as the "*Attleboro* gap" in regulation. In 1935, Congress passed the Federal Power Act (FPA), giving the FPC jurisdiction over "the transmission of electric energy in interstate commerce" and "the sale of electric energy at wholesale in interstate commerce."[72] Under FPA section 205, the FPC was tasked with ensuring that rates for jurisdictional services are just, reasonable, and not

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[69] *New York v. Federal Energy Regulatory Commission*, 535 U.S. 1, 5 (2002) (citation omitted).
[70] *Public Utils. Comm'n of Rhode Island v. Attleboro Steam & Elec. Co., 273 U.S. 83 (1927).*
[71] *Public Utils. Comm'n of Rhode Island v. Attleboro Steam & Elec. Co., 273 U.S. 83, 89 (1927).*
[72] 16 U.S.C. § 824(b)(1).

unduly discriminatory or preferential.[73] FPA section 206 authorized the FPC to determine, after a hearing upon its own motion or in response to a complaint filed at the Commission, whether jurisdictional rates are just, reasonable, and not unduly discriminatory or preferential.[74] In 1938, Congress passed the Natural Gas Act (NGA), giving the FPC jurisdiction over the transmission or sale of natural gas in interstate commerce.[75] The NGA also gave the FPC the jurisdiction to "grant certificates allowing construction and operation of facilities used in interstate gas transmission and authorizing the provision of services."[76] In 1977, the FPC became FERC after Congress passed the Department of Energy Organization Act.

By the 1930s, regulated electric utilities that provided the major components of the electrical system - generation, transmission, and distribution - were common.[77] These regulated monopolies are referred to as vertically-integrated utilities.

[73] 16 U.S.C. § 824d.
[74] 16 U.S.C. § 824e.
[75] Energy Information Administration, *Natural Gas Act of 1938*, *available at* http://www.eia.gov/oil_gas/natural_gas/analysis_publications/ngmajorleg/ngact1938.html.
[76] Energy Information Administration, *Natural Gas Act of 1938*, *available at* http://www.eia.gov/oil_gas/natural_gas/analysis_publications/ngmajorleg/ngact1938.html.
[77] Burn, An Energy Journal, *The Electricity Grid: A History*, *available at* http://burnanenergyjournal.com/the-electric-grid-a-history/(last visited Mar. 9, 2015).

As utilities built larger and larger electric generation plants, the cost per unit to generate electricity decreased.[78] However, these larger plants were extremely capital intensive for any one company to fund.[79] Some neighboring utilities solved this issue by agreeing to share electricity reserves when needed.[80] These utilities began building larger transmission lines to deliver power in times when large generators experienced outages.[81] Eventually, some utilities that were in reserve sharing agreements formed electric power pools to balance electric load over a larger area. Participating utilities gave control over scheduling and dispatch of their electric generation units to a system operator.[82] Some power pools evolved into today's RTOs and ISOs.

In the past, electric utilities generally operated as state regulated monopolies, supplying end-use customers with

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[78] Federal Energy Regulatory Commission, *Energy Primer: A Handbook of Energy Market Basics*, at 38 (2012), *available at* http://www.ferc.gov/market-oversight/guide/energy-primer.pdf.
[79] Federal Energy Regulatory Commission, *Energy Primer: A Handbook of Energy Market Basics*, at 38 (2012), *available at* http://www.ferc.gov/market-oversight/guide/energy-primer.pdf.
[80] Federal Energy Regulatory Commission, *Energy Primer: A Handbook of Energy Market Basics*, at 38 (2012), *available at* http://www.ferc.gov/market-oversight/guide/energy-primer.pdf.
[81] Federal Energy Regulatory Commission, *Energy Primer: A Handbook of Energy Market Basics*, at 38 (2012), *available at* http://www.ferc.gov/market-oversight/guide/energy-primer.pdf.
[82] Shively, B, Ferrare, J, *Understanding Today's Electricity Business*, Enerdynamics, at 94 (2012).

generation, distribution, and transmission service.[83] However, the ability of electric utilities to operate as natural monopolies came with consumer protection safeguards.[84] "In exchange for a franchised, monopoly service area, utilities accept an obligation to serve – meaning there must be adequate supply to meet customers' needs regardless of the cost."[85] Under this obligation to serve, the utility agreed to provide service to any customer located within its service jurisdiction.

On both a federal and state level, competition has entered the electricity sector to varying degrees in the last few decades.[86] In the early 1990s, some states began to consider

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[83] Maryland Department of Natural Resources, *Maryland Power Plants and the Environment: A Review of the Impacts of Power Plants and Transmission Lines on Maryland's Natural Resources*, at 2-5 (2006).

[84] Pacific Power, *Utility Regulation*, at 1, *available at* https://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Newsroom/Media_Resources/Regulation.PP.08.pdf.

[85] Pacific Power, *Utility Regulation*, at 1, *available at* https://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Newsroom/Media_Resources/Regulation.PP.08.pdf.

[86] For example, in 1978, Congress passed the Public Utilities Regulatory Policies Act (PURPA) which allowed non-utility owned power plants to sell electricity. Burn, An Energy Journal, *The Electricity Grid: A History*, *available at* http://burnanenergyjournal.com/the-electric-grid-a-history/ (last visited Mar. 9, 2015). PURPA, the Energy Policy Act of 1992 (EPAct 1992), and the Energy Policy Act of 2005 (EPAct 2005) "promoted competition by lowering entry barriers and increasing transmission access." The Electric Energy Market Competition Task Force, *Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy*, at 2, *available at* http://www.ferc.gov/legal/fed-sta/ene-pol-act/epact-final-rpt.pdf (last visited Mar. 20, 2015).

allowing competition to enter retail electric service.[87] Federal and state efforts to allow competition in the electric utility industry have resulted in independent power producers (IPPs)[88] producing approximately 37 percent of net generation in 2013.[89] Electric utilities in some states remain vertically integrated without retail competition from IPPs. Today, there are over 3,000 public, private, and cooperative utilities in the U.S.[90] These utilities include both investor-owned utilities[91] and consumer-owned utilities.[92]

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[87] The Electric Energy Market Competition Task Force, *Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy*, at 2, *available at* http://www.ferc.gov/legal/fed-sta/ene-pol-act/epact-final-rpt.pdf (last visited Mar. 20, 2015).

[88] These entities are also referred to as merchant generators.

[89] Energy Information Administration, *Electric Power Annual, Table 1.1 Total Electric Power Summary Statistics, 2013 and 2012* (2015), *available at* http://www.eia.gov/electricity/annual/html/epa_01_01.html.

[90] Regulatory Assistance Project (RAP), *Electricity Regulation in the US: A Guide*, at 9 (2011), *available at* http://www.raponline.org/document/download/id/645.

[91] Investor-owned utilities are private companies that are financed by a combination of shareholder equity and bondholder debt. Regulatory Assistance Project (RAP), *Electricity Regulation in the US: A Guide*, at 9 (2011), *available at* http://www.raponline.org/document/download/id/645.

[92] Consumer-owned utilities include municipal utilities, public utility districts, cooperatives, and a variety of other entities such as irrigation districts. Regulatory Assistance Project (RAP), *Electricity Regulation in the US: A Guide*, at 9-10 (2011), *available at* http://www.raponline.org/document/download/id/645.

Over time, the grid slowly evolved into a complex, interconnected transmission system that allows electric generators to produce electricity that is then fed onto transmission lines at high voltages.[93] These larger transmission lines are able to access generation that is located more remotely, with transmission lines crossing many miles, including state borders.[94] Closer to end users, electricity is transformed

[93] Peter Fox-Penner, *Electric Utility Restructuring: A Guide to the Competitive Era*, Public Utility Reports, Inc., at 5, 34 (1997). "The extent of the power system's short-run physical interdependence is remarkable, if not entirely unique. No other large, multi-stage industry is required to keep every single producer in a region – whether or not owned by the same company – in immediate synchronization with all other producers." *Id.* at 34. "At an early date, those providing electric power recognized that peak use for one system often occurred at a different time from peak use in other systems. They also recognized that equipment failures occurred at different times in various systems. Analyses showed significant economic benefits from interconnecting systems to provide mutual assistance; the investment required for generating capacity could be reduced and reliability could be improved. This lead [sic] to the development of local, then regional, and subsequently three transmission grids that covered the U.S. and parts of Canada." Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 5-6 (2d ed. 2010).

[94] Burn, An Energy Journal, *The Electricity Grid: A History*, *available at* http://burnanenergyjournal.com/the-electric-grid-a-history/ (last visited Mar. 9, 2015). Because of the ease and low cost of converting voltages in an alternating current (AC) system from one level to another, the bulk power system is predominantly an AC system rather than a direct current (DC) system. In an AC system, electricity cannot be controlled like a gas or liquid by utilizing a valve in a pipe. Instead, absent the presence of expensive control devices, electricity flows freely along all available paths, according to the laws of physics. U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and*

into a lower voltage that is transported across localized transmission lines to homes and businesses.[95] Localized transmission lines make up the distribution system. These three components of the electricity system - generation, transmission, and distribution - are closely related and must work in coordination to deliver electricity from the point of generation to the point of consumption. This interconnectedness is a fundamental aspect of the nation’s electricity system, requiring a complicated integration of all components of the system to balance supply and demand and a federal, state, and local regulatory network to oversee the physically interconnected network. Facilities planned and constructed in one segment can impact facilities and operations in other segments and vice versa.

The North American electric grid has developed into a large, interconnected system.[96] Electricity from a diverse set of generation resources such as natural gas, nuclear, coal, and

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Canada: Causes and Recommendations, at 6 (Apr. 2004), *available at* http://www.ferc.gov/industries/electric/indus-act/reliability/blackout/ch1-3.pdf.

[95] Peter Fox-Penner, *Electric Utility Restructuring: A Guide to the Competitive Era*, Public Utility Reports, Inc., at 5 (1997).

[96] U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, at 5 (Apr. 2004), *available at* http://www.ferc.gov/industries/electric/indus-act/reliability/blackout/ch1-3.pdf.

renewables is distributed over high-voltage transmission lines divided across the continental U.S. into three synchronous interconnections – the Eastern Interconnection, Western Interconnection, and the Texas Interconnection.[97] These three synchronous systems each act like a single machine.[98] Diverse resources generate electricity that is transmitted and distributed through a complex system of interconnected components to industrial, business, and residential consumers.

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[97] Regulatory Assistance Project (RAP), *Electricity Regulation in the US: A Guide*, 2011, at 1, *available at* http://www.raponline.org/document/download/id/645.

[98] Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 159 (2d ed. 2010). In an amicus brief to the Supreme Court, a group of electrical engineers, economists, and physicists specializing in electricity explained, "*Energy* is transmitted, not electrons. Energy transmission is accomplished through the propagation of an electromagnetic wave. The electrons merely oscillate in place, but the *energy* – the *electromagnetic wave* – moves at the speed of light. The energized electrons making the lightbulb in a house glow are not the same electrons that were induced to oscillate in the generator back at the power plant. . . . Energy flowing onto a power network or grid *energizes the entire grid*, and consumers then draw undifferentiated energy from that grid. A networked grid flexes, and electric current flows, in conformity with physical laws, and those laws do not notice, let alone conform to, political boundaries. . . . The path taken by electric energy is the path of least resistance . . . or, more accurately, the *paths* of least resistance. . . . If a generator on the grid increases its output, the current flowing from the generator on all paths on the grid increases. These increases affect the energy flowing *into* each point in the network, which in turn leads to compensating and corresponding changes in the energy flows *out* of each point." Brief Amicus Curiae of Electrical Engineers, Energy Economists and Physicists in Support of Respondents at 2, 8-9, 11, New York v. FERC, 535 U.S. 1 (2001) (No. 00-568).

Unlike other industries where sources make operational decisions independently, the utility power sector is unique in that electricity system resources operate in a complex, interconnected grid system that is physically interconnected and operated on an integrated basis across large regions. Additionally, a federal, state, and local regulatory network oversees policies and practices that are applied to how the system is designed and operates. In this interconnected system, system operators must ensure that the amount of electricity available is precisely matched with the amount needed in real time. System operators have a number of resources potentially available to meet electricity demand, including electricity generated by electric generation units such as coal, nuclear, renewables, and natural gas, as well as demand-side resources[99], such as EE[100] and demand response.[101] Generation, outages, and

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[99] "Measures using demand-side resources comprise actions taken on the customer's side of the meter to change the amount and/or timing of electricity use in ways that will provide benefits to the electricity supply system." David Crossley, Regulatory Assistance Project (RAP), *Effective Mechanisms to Increase the Use of Demand-Side Resources*, at 9 (2013), *available at* www.raponline.org.

[100] Energy efficiency is using less energy to provide the same or greater level of service. Demand-side energy efficiency refers to an extensive array of technologies, practices and measures that are applied throughout all sectors of the economy to reduce energy demand while providing the same, and sometimes better, level and quality of service.

[101] Demand response involves "[c]hanges in electric usage by demand-side resources from their normal consumption patterns in

transmission changes in one part of the synchronous grid can affect the entire interconnected grid.[102] The interconnection is such that "[i]f a generator is lost in New York City, its affect is felt in Georgia, Florida, Minneapolis, St. Louis, and New Orleans."[103] The U.S. Supreme Court has similarly recognized the interconnected nature of the electricity grid.[104]

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response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized." Federal Energy Regulatory Commission, *Reports on Demand Response & Advanced Metering*, (Dec. 23, 2014), *available at* http://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp.

[102] Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 159 (2d ed. 2010).

[103] Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 160 (2d ed. 2010).

[104] *Federal Power Comm'n v. Florida Power & Light Co.*, 404 U.S. 453, at 460 (1972) (quoting a Federal Power Commission hearing examiner, "`If a housewife in Atlanta on the Georgia system turns on a light, every generator on Florida's system almost instantly is caused to produce some quantity of additional electric energy which serves to maintain the balance in the interconnected system between generation and load.'") (citation omitted). *See also New York v. FERC*, 535 U.S. 1, at 7 (2002) (stating that "any electricity that enters the grid immediately becomes a part of a vast pool of energy that is constantly moving in interstate commerce.") (citation omitted). In *Federal Power Comm'n v. Southern California Edison Co.*, 376 U.S. 205 (1964), the Supreme Court found that a sale for resale of electricity from Southern California Edison to the City of Colton, which took place solely in California, was under Federal Power Commission jurisdiction because some of the electricity that Southern California Edison marketed came from out of state. The Supreme Court stated that, "`federal jurisdiction was to follow the flow of electric energy, an engineering and scientific, rather than a legalistic or governmental, test.'" *Id.* at 210 (quoting *Connecticut Light & Power Co. v. Federal Power Commission*, 324 U.S. 515, 529 (1945) (emphasis omitted)).

Today, federal, state, and local entities regulate electricity providers.[105] Overlaid on the physical electricity network is a regulatory network that has developed over the last century or more. This regulatory network "plays a vital role in the functioning of all other networks, sometimes providing specific rules for functioning while at other times providing restraints within which their operation must be conducted."[106] This unique regulatory network results in an electricity grid that is both physically interconnected and connected through a network of regulation on the local, state, and federal levels. This regulation seeks to reconcile the fact that electricity is a public good with the fact that facilities providing that electricity are privately owned.[107] While this regulation began on the state and local levels, federal regulation of the electricity system increased over time. With the passage of the EPAct 1992 and the EPAct 2005, the federal government's role in electricity regulation greatly increased.[108] "The role of the regulator now includes support for the development of open and

[105] Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 214 (2d ed. 2010).
[106] Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 213 (2d ed. 2010).
[107] Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 213 (2d ed. 2010).
[108] Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 214 (2d ed. 2010).

fair wholesale electric markets, ensuring equal access to the transmission system and more hands-on oversight and control of the planning and operating rules for the industry.”[109]

2. Electric system dispatch

System operators typically dispatch the electric system through a process known as Security Constrained Economic Dispatch.[110] Security Constrained Economic Dispatch has two components – economic generation of generation facilities and ensuring that the electric system remains reliable.[111] Electricity demand varies across geography and time in response to numerous conditions, such that electric generators are constantly responding to changes in the most reliable and cost-effective manner possible. The cost of operating electric generation varies based on a number of factors, such as fuel and generator efficiency.

[109] Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 214 (2d ed. 2010).
[110] *Economic Dispatch: Concepts, Practices and Issues*, FERC Staff Presentation to the Joint Board for the Study of Economic Dispatch, Palm Springs, California (Nov. 13, 2005).
[111] Federal Energy Regulatory Commission, *Security Constrained Economic Dispatch: Definitions, Practices, Issues and Recommendations: A Report to Congress* (July 31, 2006). The Energy Policy Act of 2005 defined economic dispatch as “the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities.” Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594 (2005), section 1234(b).

The decision to dispatch any particular electric generator depends upon the relative operating cost, or marginal cost, of generating electricity to meet the last increment of electric demand. Fuel is one common variable cost – especially for fossil-fueled generators. Coal plants will often have considerable variable costs associated with running pollution controls.[112] Renewables, hydroelectric, and nuclear have little to no variable costs. If electricity demand decreases or additional generation becomes available on the system, this impacts how the system operator will dispatch the system. EGUs using technologies with relatively low variable costs, such as nuclear units and RE, are for economic reasons generally operated at their maximum output whenever they are available. When lower cost units are available to run, higher variable cost units, such as fossil-fuel generators, are generally the first to be displaced.

In states with cost-of-service regulation of vertically-integrated utilities, the utilities themselves form the balancing authorities who determine dispatch based upon the lowest marginal cost. These utilities sometimes arrange to buy and sell electricity with other balancing authorities. RTOs and

[112] Variable costs also include costs associated with operation and maintenance and costs of operating a pollution control and/or emission allowance charges.

ISOs coordinate, control, and monitor electricity transmission systems to ensure cost-effective and reliable delivery of power, and they are independent from market participants.

3. Reliability considerations

The reliability of the electric system has long been a focus of the electric industry and regulators. Industry developed a voluntary organization in the early 1960s that assisted with bulk power system coordination in the U.S. and Canada.[113] In 1965, the northeastern U.S. and southeastern Ontario, Canada experienced the largest power blackout to date, impacting 30 million people.[114] In response to the 1965 blackout and a Federal Power Commission recommendation,[115] industry developed the National Electric Reliability Council (NERC) and nine reliability councils. The organization later became known as the North American Electric Reliability Council to recognize

[113] North American Electric Reliability Corporation, *History of NERC*, at 1 (2013), *available at* http://www.nerc.com/AboutNERC/Documents/History%20AUG13.pdf.
[114] Federal Energy Regulatory Commission, *Energy Primer: A Handbook of Energy Market Basics*, at 39 (2012), *available at* http://www.ferc.gov/market-oversight/guide/energy-primer.pdf.
[115] The Federal Power Commission, a precursor to FERC, recommended "the formation of a council on power coordination made up of representatives from each of the nation's regional coordinating organizations, to exchange and disseminate information and to review, discuss and assist in resolving interregional coordination matters." North American Electric Reliability Corporation, *History of NERC*, at 1 (2013), *available at* http://www.nerc.com/AboutNERC/Documents/History%20AUG13.pdf.

Canada's participation.[116] The North American Electric Reliability Council became the North American Electric Reliability Corporation in 2007.[117]

In August 2003, North America experienced its worst blackout to date creating an outage in the Midwest, Northeast, and Ontario, Canada.[118] This blackout was massive in scale impacting an area with an estimated 50 million people and 61,800 megawatts of electric load.[119] The U.S. and Canada formed a joint task force to investigate the causes of the blackout and made recommendations to avoid similar outages in the future. One of the task force's major recommendations was that the U.S. Congress should pass legislation making electric reliability standards mandatory and enforceable.[120]

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[116] North American Electric Reliability Corporation, *History of NERC*, at 2 (2013), *available at* http://www.nerc.com/AboutNERC/Documents/History%20AUG13.pdf.
[117] North American Electric Reliability Corporation, *History of NERC*, at 4 (2013), *available at* http://www.nerc.com/AboutNERC/Documents/History%20AUG13.pdf.
[118] North American Electric Reliability Corporation, *History of NERC*, at 3 (2013), *available at* http://www.nerc.com/AboutNERC/Documents/History%20AUG13.pdf.
[119] U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, at 1 (Apr. 2004), *available at* http://www.ferc.gov/industries/electric/indus-act/reliability/blackout/ch1-3.pdf. The outage impacted areas within Ohio, Michigan, Pennsylvania, New York, Vermont, Massachusetts, Connecticut, New Jersey, and the Canadian province of Ontario. *Id.*
[120] U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada:*

Congress responded to this recommendation in EPAct 2005, adding a new section 215 to the Federal Power Act making reliability standards mandatory and enforceable and authorizing the creation of a new Electric Reliability Organization (ERO). Under this new system, FERC certifies an entity as the ERO. The ERO develops reliability standards, which are subject to FERC review and approval. Once FERC approves reliability standards the ERO may enforce those standards or FERC can do so independently.[121] In 2006, the Federal Energy Regulatory Commission (FERC) certified NERC as the ERO.[122] "NERC develops and enforces Reliability Standards; monitors the Bulk-Power System; assesses adequacy annually via a 10-year forecast and winter and summer forecasts; audits owners, operators and users for preparedness; and educates and trains industry personnel."[123]

Causes and Recommendations, at 2 (Apr. 2004), *available at* http://www.ferc.gov/industries/electric/indus-act/reliability/blackout/ch1-3.pdf.

[121] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 118 FERC ¶ 61,218, at P 3 (2007) (citing 16 U.S.C. 824o(e)(3)).

[122] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, 114 FERC ¶ 61,104 (2006).

[123] North American Electric Reliability Corporation, *Frequently Asked Questions*, at 2 (Aug. 2013), *available at* http://www.nerc.com/AboutNERC/Documents/NERC%20FAQs%20AUG13.pdf.

The U.S., Canada, and part of Mexico are divided up into eight reliability regional entities.[124] These regional entities include Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), Reliability First Corporation (RFC), SERC Reliability Corporation (SERC), Southwest Power Pool, RE (SPP), Texas Reliability Entity (TRE), and Western Electricity Coordinating Council (WECC).[125] Regional entity members come from all segments of the electric industry.[126] NERC delegates authority, with FERC approval, to these regional entities to enforce reliability standards, both national and regional reliability standards, and engage in other standards-related duties delegated to them by NERC.[127] NERC ensures that there is a

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[124] Federal Energy Regulatory Commission, *Energy Primer: A Handbook of Energy Market Basics*, at 49-50 (2012), *available at* http://www.ferc.gov/market-oversight/guide/energy-primer.pdf.
[125] Federal Energy Regulatory Commission, *Energy Primer: A Handbook of Energy Market Basics*, at 50 (2012), *available at* http://www.ferc.gov/market-oversight/guide/energy-primer.pdf.
[126] North American Electric Reliability Corporation, *Key Players*, *available at* http://www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx (last visited Mar. 12, 2015). "The members of the regional entities come from all segments of the electric industry: investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal and provincial utilities; independent power producers; power marketers; and end-use customers." *Id.*
[127] North American Electric Reliability Corporation, *Frequently Asked Questions*, at 5 (2013), *available at* http://www.nerc.com/AboutNERC/Documents/NERC%20FAQs%20AUG13.pdf. For example, a regional entity may propose reliability

consistency of application of delegated functions with appropriate regional flexibility.[128] NERC divides the country into assessment areas and annually analyzes the reliability, adequacy, and associated risks that may affect the upcoming summer, winter, and long-term, 10-year period. Multiple other entities such as FERC, the Department of Energy, state public utility commissions, ISOs/RTOs[129], and other planning authorities also consider the reliability of the electric system. There are

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standards, including regional variances or regional reliability standards required to maintain and enhance electric service reliability, adequacy, and security in the region. *See, e.g.*, *Amended and Restated Delegation Agreement Between North American Reliability Corporation and Midwest Reliability Organization*, *Bylaws of the Midwest Reliability Organization, Inc.*, Section 2.2 (2012), *available at* http://www.nerc.com/FilingsOrders/us/Regional%20Delegation%20Agreements%20DL/MRO_RDA_Effective_20130612.pdf.

[128] North American Electric Reliability Corporation, *Frequently Asked Questions*, at 5 (2013), *available at* http://www.nerc.com/AboutNERC/Documents/NERC%20FAQs%20AUG13.pdf.

[129] ISOs/RTOs plan for system needs by "effectively managing the load forecasting, transmission planning, and system and resource planning functions." For example, the New York Independent System Operator (NYISO) conducts reliability planning studies, which "are used to assess current reliability needs based on user trends and historical energy use." NYISO, *Planning Studies*, *available at* http://www.nyiso.com/public/markets_operations/services/planning/planning_studies/index.jsp. *See also* PJM, *Reliability Assessments*, *available at* https://www.pjm.com/planning/rtep-development/reliability-assessments.aspx (stating that the PJM "Regional Transmission Expansion Planning (RTEP) process includes the development of periodic reliability assessments to address specific system reliability issues in addition to the ongoing expansion planning process for the interconnection process of generation and merchant transmission.").

numerous remedies that can be utilized to solve a potential reliability problem, including long-term planning, transmission system upgrades, installation of new generating capacity, demand response, and other demand side actions.

4. Modern electric system trends

Today, the electricity sector is undergoing a period of intense change. Fossil fuels – such as coal, natural gas, and oil – have historically provided a large percentage of electricity in the U.S., along with nuclear power, with smaller amounts provided by other types of generation, including renewables such as wind, solar, and hydroelectric power. Coal provided the largest percentage of the fossil fuel generation.[130] In recent years, the nation has seen a sizeable increase in renewable generation such as wind and solar, as well as a shift from coal to natural gas.[131] In 2013, fossil fuels supplied 67 percent of U.S. electricity,[132] but the amount of renewable

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[130] U.S. Energy Information Administration, "Table 7.2b Electricity Net Generation: Electric Power Sector" data from Monthly Energy Review May 2015, *available at* http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf (last visited May 26, 2015).

[131] U.S. Energy Information Administration, "Table 7.2b Electricity Net Generation: Electric Power Sector" data from Monthly Energy Review May 2015, release data April 25, 2014, *available at* http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf (last visited May 26, 2015).

[132] U.S. Energy Information Administration, "Table 7.2b Electricity Net Generation: Electric Power Sector" data from

generation capacity continued to grow.[133] From 2007 to 2014, use of lower- and zero-carbon energy sources such as wind and solar grew, while other major energy sources such as coal and petroleum generally experienced declines.[134] Renewable electricity generation, including from large hydro-electric projects, grew from 8 percent to 13 percent over that time period.[135] Between 2000 and 2013, approximately 90 percent of new power generation capacity built in the U.S. came in the form of natural gas or RE facilities.[136] In 2015, the U.S. Energy

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Monthly Energy Review May 2015, release data April 25, 2014, *available at* http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf (last visited May 26, 2015).

[133] Based on Table 6.3 (New Utility Scale Generating Units by Operating Company, Plant, Month, and Year) of the U.S. Energy Information Administration (EIA) Electric Power Monthly, data for December 2013, for the following REsources: solar, wind, hydro, geothermal, landfill gas, and biomass. Available at: http:// www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_03.

[134] U.S. Energy Information Administration, "Table 7.2b Electricity Net Generation: Electric Power Sector" data from Monthly Energy Review May 2015, *available at* http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf (last visited May 26, 2015).

[135] Bloomberg New Energy Finance and the Business Council for Sustainable Energy*, 2015 Factbook: Sustainable Energy in America*, at 16 (2015), *available at* http://www.bcse.org/images/2015%20Sustainable%20Energy%20in%20America%20Factbook.pdf. Bloomberg gave projections for 2014 values, accounting for seasonality, based on latest monthly values from EIA (data available through October 2014).

[136] Energy Information Administration, *Electricity: Form EIA-860 detailed data* (Feb. 17, 2015), *available at* http://www.eia.gov/electricity/data/eia860/.

Information Administration (EIA) projected the need for 28.4 GW of additional base load or intermediate load generation capacity through 2020.[137] The vast majority of this new electric capacity (20.4 GW) is already under development (under construction or in advanced planning), with approximately 0.7 GW of new coal-fired capacity, 5.5 GW of new nuclear capacity, and 14.2 GW of new NGCC capacity already in development.

While the change in the resource mix has accelerated in recent years, wind, solar, other renewables, and EEresources have been reliably participating in the electric sector for a number of years. This rapid development of non-fossil fuel resources is occurring as much of the existing power generation fleet in the U.S. is aging and in need of modernization and replacement. In 2025, the average age of the coal-fired generating fleet is projected to be 49 years old, and 20 percent of those units would be more than 60 years old if they remain in operation at that time. In its *2013 Report Card for America's Infrastructure*, the American Society for Civil Engineers noted that "America relies on an aging electrical grid and pipeline

[137] EIA, *Annual Energy Outlook for 2015 with Projections to 2040*, *Final Release*, *available at* http://www.eia.gov/forecasts/AEO/pdf/0383(2015).pdf. The AEO numbers include projects that are under development and model-projected nuclear, coal, and NGCC projects.

distribution systems, some of which originated in the 1880s."[138] While there has been an increased investment in electric transmission infrastructure since 2005, the report also found that "ongoing permitting issues, weather events, and limited maintenance have contributed to an increasing number of failures and power interruptions."[139] However, innovative technologies have increasingly entered the electric energy space, helping to provide new answers to how to meet the electricity needs of the nation. These new technologies can enable the nation to answer not just questions as to how to reliably meet electricity demand, but also how to meet electricity demand reliably and cost-effectively with the lowest possible emissions and the greatest efficiency.

Natural gas has a long history of meeting electricity demand in the U.S., with a rapidly growing role as domestic supplies of natural gas have dramatically increased. Natural gas net generation increased by approximately 32 percent between 2005 and 2014.[140] In 2014, natural gas accounted for

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[138] American Society for Civil Engineers, *2013 Report Card for America's Infrastructure* (2013), *available at* http://www.infrastructurereportcard.org/energy/.
[139] American Society for Civil Engineers, *2013 Report Card for America's Infrastructure* (2013), *available at* http://www.infrastructurereportcard.org/energy/.
[140] U.S. Energy Information Administration (EIA), *Electric Power Monthly: Table 1.1 Net Generation by Energy Source: Total (All Sectors), 2005-February 2015* (2015), *available at*

approximately 27 percent of net generation.[141] EIA projects that this demand growth will continue with its *Annual Energy Outlook 2015* (AEO 2015) Reference case forecasting that natural gas will produce 31 percent of U.S. electric generation in 2040.[142]

Renewable sources of electric generation also have a history of meeting electricity demand in the U.S. and are expected to have an increasing role going forward. A series of energy crises provided the impetus for RE development in the early 1970s. The OPEC oil embargo in 1973 and oil crisis of 1979 caused oil price spikes, more frequent energy shortages, and significantly affected the national and global economy. In 1978, partly in response to fuel security concerns, Congress passed the Public Utilities Regulatory Policies Act (PURPA) which required local electric utilities to buy power from qualifying

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http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_1_1 (last visited May 26, 2015).

[141] *Id.*

[142] U.S. Energy Information Administration (EIA), *Annual Energy Outlook 2015 with Projections to 2040*, at 24-25 (2015), *available at* http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf. According to the EIA, the reference case assumes, "Real gross domestic product (GDP) grows at an average annual rate of 2.4% from 2013 to 2040, under the assumption that current laws and regulations remain generally unchanged throughout the projection period. North Sea Brent crude oil prices rise to $141/barrel (bbl) (2013 dollars) in 2040." *Id.* at 1. The EIA provides complete projection tables for the reference case in Appendix A of its report.

facilities (QFs).[143] QFs were either cogeneration facilities[144] or small generation resources that use renewables such as wind, solar, biomass, geothermal, or hydroelectric power as their primary fuels.[145] Through PURPA, Congress supported the development of more RE generation in the U.S. States have also taken a significant lead in requiring the development of renewable resources. In particular, a number of states have adopted renewable portfolio standards (RPS). As of 2013, 29 states and the District of Columbia have enforceable RPS or similar laws.[146]

Use of RE continues to grow rapidly in the U.S. In 2013, electricity generated from renewable technologies, including conventional hydropower, represented 13 percent of total U.S. electricity, up from 9 percent in 2005.[147] In 2013, U.S. non-

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[143] Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 220-221 (2d ed. 2010).

[144] Cogeneration facilities utilize a single source of fuel to produce both electricity and another form of energy such as heat or steam. Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 220-221 (2d ed. 2010).

[145] Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 220-221 (2d ed. 2010).

[146] U.S. Energy Information Administration (EIA), *Annual Energy Outlook 2014 with Projections to 2040*, at LR-5 (2014), *available at* http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf (last visited May 26, 2015).

[147] Energy Information Administration, Annual Energy Outlook 2015 with Projections to 2040, at ES-6 (2014) and Energy Information Administration, Monthly Energy Review, May 2015, Table 7.2b, *available at* http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf.

hydro RE capacity for the total electric power industry exceeded 80,000 MW, reflecting a fivefold increase in just 15 years.[148] In particular, there has been substantial growth in the wind and photovoltaic (PV) markets in the past decade. Since 2009, U.S. wind generation has tripled and solar generation has grown twenty-fold.[149]

The global market for RE is projected to grow to $460 billion per year by 2030.[150] RE growth is further encouraged by the significant amount of existing natural resources that can support RE production in the U.S.[151] In the Energy Information Administration's Annual Energy Outlook 2015, RE generation grows substantially from 2013 to 2040 in the reference case and all alternative cases.[152] In the reference case, RE generation

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148 Non-hydro RE capacity for the total electric power industry was more than 16,000 megawatts (MW) in 1998. Energy Information Administration, 1990-2013 Existing Nameplate and Net Summer Capacity by Energy Source Producer Type and State (EIA-860), *available at* http://www.eia.gov/electricity/data/state/.

149 Energy Information Administration, Monthly Energy Review, May 2015, Table 7.2b, *available at* http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf.

150 "Global Renewable Energy Market Outlook." Bloomberg New Energy Finance (Nov. 16, 2011), *available at* http://bnef.com/WhitePapers/download/53.

151 Lopez et al., NREL, ''U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis,'' (July 2012).

152 Energy Information Administration, Annual Energy Outlook 2015 with Projections to 2040, at 25 (2014), *available at* http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf.

increases by more than 70 percent from 2013 to 2040 and accounts for over one-third of new generation capacity.[153]

Price pressures caused by oil embargoes in the 1970s also brought the issues of conservation and EE to the forefront of U.S. energy policy.[154] This trend continued in the early 1990s. EE has been utilized to meet energy demand to varying levels since that time. As of April 2014, 25 states[155] have "enacted long-term (3+ years), binding energy savings targets, or energy

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[153] Energy Information Administration, Annual Energy Outlook 2015 with Projections to 2040, at ES-6 (2015), *available at* http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf (last visited May 27, 2015).

[154] Edison Electric Institute, *Making a Business of Energy Efficiency: Sustainable Business Models for Utilities*, at 1 (2007), *available at* http://www.eei.org/whatwedo/PublicPolicyAdvocacy/StateRegulation/Documents/Making_Business_Energy_Efficiency.pdf. Congress passed legislation in the 1970s that jumpstarted energy efficiency in the U.S. For example, President Ford signed the Energy Policy and Conservation Act (EPCA) of 1975 – the first law on the issue. EPCA authorized the Federal Energy Administration (FEA) to "develop energy conservation contingency plans, established vehicle fuel economy standards, and authorized the creation of efficiency standards for major household appliances." Alliance to Save Energy, *History of Energy Efficiency*, at 6 (2013) (citing Anders, "*The Federal Energy Administration,"* 5; Energy Policy and Conservation Act, S. 622, 94th Cong. (1975-1976)), *available at* https://www.ase.org/sites/ase.org/files/resources/Media%20browser/ee_commission_history_report_2-1-13.pdf.

[155] American Council for an Energy-Efficient Economy, *State Energy Efficiency Resource Standards (EERS)* (2014), *available at* http://aceee.org/files/pdf/policy-brief/eers-04-2014.pdf. ACEEE did not include Indiana (EERS eliminated), Delaware (EERS pending), Florida (programs funded at levels far below what is necessary to meet targets), Utah, or Virginia (voluntary standards) in its calculation.

efficiency resource standards (EERS)."[156] Funding for EE programs has grown rapidly in recent years, with budgets for electric efficiency programs totaling $5.9 billion in 2012.[157]

Advancements and innovation in power sector technologies provide the opportunity to address CO_2 emission levels at affected power plants while at the same time improving the overall power system in the U.S. by lowering the carbon intensity of power generation, and ensuring a reliable supply of power at a reasonable cost.

E. Clean Air Act Regulations for Power Plants

In this section, we provide a general description of major CAA regulations for power plants. We refer to these in later sections of this preamble.

1. Title IV Acid Rain Program

The EPA's Acid Rain Program, established in 1990 under Title IV of the CAA, addresses the presence of acidic compounds and their precursors (i.e., SO_2 and NO_x), in the atmosphere by targeting "the principal sources" of these pollutants through an

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[156] American Council for an Energy-Efficient Economy, *State Energy Efficiency Resource Standards (EERS)* (2014), *available at* http://aceee.org/files/pdf/policy-brief/eers-04-2014.pdf.

[157] American Council for an Energy-Efficient Economy, *The 2013 State Energy Efficiency Scorecard*, at 17 (Nov. 2013), *available at* http://aceee.org/sites/default/files/publications/researchreports/e13k.pdf.

SO_2 cap-and-trade program for fossil-fuel fired power plants and through a technology based NO_x emission limit for certain utility boilers. Altogether, Title IV was designed to achieve reductions of ten million tons of annual SO_2 emissions, and, in combination with other provisions of the CAA, two million tons of annual NO_x emissions.[158]

The SO_2 cap-and-trade program was implemented in two phases. The first phase, beginning in 1995, targeted one-hundred and ten named power plants, including specific generator units at each plant, requiring the plants to reduce their cumulative emissions to a specific level.[159] Under certain conditions, the owner or operator of a named power plant could reassign an affected unit's reduction requirement to another unit and/or request an extension of two years for meeting the requirement.[160] Congress also established an energy conservation and RE reserve from which up to 300,000 allowances could be allocated for qualified energy conservation measures or qualified RE.[161]

The second phase, beginning in 2000, expanded coverage to more than 2,000 generating units and set a national cap at 8.90

[158] 42 U.S.C. § 7651(b).
[159] 42 U.S.C. § 7651c (Table A).
[160] 42 U.S.C. § 7651c(b) and (d).
[161] 42 U.S.C. § 7651c(f) and (g).

million tons.[162] Generally, allowances were allocated at a rate of 1.2 lbs./mmBtu multiplied by the unit's baseline and divided by 2000.[163] However, bonus allowances could be awarded to certain units.

Title IV also required the EPA to hold or sponsor annual auctions and sales of allowances for a small portion of the total allowances allocated each year. This ensured that some allowances would be directly available for new sources, including independent power production facilities.[164]

The provisions of the EPA's Acid Rain Program are implemented through permits issued under the EPA's Title V Operating Permit Program.[165] In accordance with Title IV, moreover, each Title V permit application must include a compliance plan for the affected source that details how that source expects to meet the requirements of Title IV.[166]

2. Transport rulemakings

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[162] U.S. Dept. of Energy, Energy Information Administration, "The Effects of Title IV of the Clean Air Act Amendments of 1990 on Electric Utilities: An Update," p. vii. (March 1997).

[163] *See* 42 U.S.C. § 7651d.

[164] 42 U.S.C. § 7651o.

[165] 42 U.S.C. § 7651g.

[166] Such plans may simply state that the owner or operator expects to hold sufficient allowances or, in the case of alternative compliance methods, must provide a "comprehensive description of the schedule and means by which the unit will rely on one or more alternative methods of compliance in the manner and time authorized under [Title IV]." 42 U.S.C. § 7651g(b).

CAA section 110(a)(2)(D)(i)(I), the "Good Neighbor Provision," requires SIPs to prohibit emissions that "contribute significantly to nonattainment . . . or interfere with maintenance" of the NAAQS in any other state.[167] If the EPA finds that a state has failed to submit an approvable SIP, the EPA must issue a federal implementation plan (FIP) to prohibit those emissions "at any time" within the next two years.[168]

In three major rulemakings — the NOx SIP Call,[169] the Clean Air Interstate Rule (CAIR),[170] and the Cross State Air Pollution Rule (CSAPR)[171] — the EPA has attempted to delineate the scope of the Good Neighbor Provision. These rulemakings have several features in common. Although the Good Neighbor Provision does not speak specifically about EGUs, in all three rulemakings, the EPA set state emission "budgets" for upwind states based in part on emissions reductions achievable by EGUs through application of cost-effective controls. Each rule also adopted a phased approach to reducing emissions with both interim and final goals.

a. <u>NO_x SIP Call</u>. In 1998, the EPA promulgated the NO_x SIP Call, which required 23 upwind states to reduce emissions of NO_x that

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[167] 42 U.S.C. § 7410(a)(2)(D)(i)(I).
[168] *EPA v. EME Homer City Generation, L.P.*, 134 S. Ct. 1584, 1600-01 (2014) (citing 42 U.S.C. § 7410(c)).
[169] 63 FR 57356 (Oct. 27, 1998).
[170] 70 FR 25162 (May 12, 2005).
[171] 76 FR 48208 (Aug. 8, 2011).

would impact downwind areas with ozone problems. The EPA determined emission reduction requirements based on reductions achievable through "highly cost-effective" controls—*i.e.*, controls that would cost on average no more than $2,000 per ton of emissions reduced.[172] The EPA determined that a uniform emission rate on large EGUs coupled with a cap-and-trade program was one such set of highly cost-effective controls.[173] Accordingly, the EPA established an interstate cap-and-trade program—the NO_x Budget Trading Program—as a mechanism for states to reduce emissions from EGUs and other sources in a highly cost-effective manner. The D.C. Circuit upheld the NO_x SIP Call in most significant respects, including its use of costs to apportion emission reduction responsibilities.[174]

b. <u>Clean Air Interstate Rule (CAIR)</u>. In 2005, the EPA promulgated CAIR, which required 28 upwind states to reduce emissions of NO_x and SO_2 that would impact downwind areas with projected nonattainment and maintenance problems for ozone and $PM_{2.5}$. The EPA determined emission reduction requirements based on "controls that are known to be highly cost effective for

[172] 63 FR at 57377–78.
[173] 63 FR at 57377–78. In addition to EGUs, the NO_x SIP Call also set budgets based on highly cost-effective emission reductions from certain other large sources. *Id.*
[174] *Michigan v. EPA*, 213 F.3d 663 (D.C. Cir. 2000).

EGUs."[175] The EPA established cap-and-trade programs for sources of NO_x and SO_2 in states that chose to participate in the trading programs via their SIPs and for states ultimately subject to a FIP.[176] As relevant here, the D.C. Circuit remanded CAIR in *North Carolina v. EPA* due to in part the structure of its interstate trading provisions and the way in which EPA applied the cost-effective standard, but kept the rule in place while the EPA developed an acceptable substitute.[177]

c. Cross-state Air Pollution Rule (CSAPR). In 2011, the EPA promulgated CSAPR, which required 27 upwind states to reduce emissions of NO_x and SO_2 that would impact downwind areas with projected nonattainment and maintenance problems for ozone and $PM_{2.5}$. The EPA determined emission reduction requirements based in part on the reductions achievable at certain cost thresholds by EGUs in each state, with certain provisions developed to account for the need to ensure reliability of the electric generating system.[178] In the same action establishing these emission reduction requirements, the EPA promulgated FIPs that subjected states to trading programs developed to achieve the

[175] 70 FR at 25163.
[176] 70 FR at 25273–75; 71 FR 25328 (April 28, 2006).
[177] 531 F.3d 896, 917–22 (D.C. Cir. 2008), *modified on rehearing* 550 F.3d 1176, 1178 (D.C. Cir. 2008).
[178] 76 FR at 48270. The EPA adopted this approach in part to comport with the D.C. Circuit's opinion in *North Carolina v. EPA* remanding CAIR. *Id.* at 48270–71.

necessary reductions within each state.[179] The U.S. Supreme Court upheld the EPA's use of cost to set emission reduction requirements, as well as its authority to issue the FIPs.[180]

3. Clean Air Mercury Rule

On March 15, 2005, the EPA issued a rule to control mercury (Hg) emissions from new and existing fossil fuel-fired power plants under CAA section 111(b) and (d). The rule, known as the Clean Air Mercury Rule (CAMR), established, in relevant part, a nationwide cap-and-trade program under CAA section 111(d), which was designed to complement the cap-and-trade program for SO_2 and NO_x emissions under the Clean Air Interstate Rule (CAIR), discussed above.[181] Though CAMR was later vacated by the D.C. Circuit on account of the EPA's flawed CAA section 112 delisting rule, the court declined to reach the merits of the EPA's interpretation of CAA section 111(d).[182] Accordingly, CAMR continues to be an informative model for a cap-and-trade program under CAA section 111(d).

The cap-and-trade program in CAMR was designed to take effect in two phases: in 2010, the cap was set at 38 tons of mercury per year, and in 2018, the cap would be lowered to 15

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[179] 76 FR at 48209–16.

[180] *EPA v. EME Homer City Generation, L.P.*, 134 S. Ct. 1584 (2014).

[181] *See* 70 FR 28606 (May 18, 2005).

[182] *New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008).

tons per year. The Phase I cap was set at a level reflecting the co-benefits of CAIR as determined through economic and environmental modeling.[183] For the more stringent Phase II cap, the EPA projected that sources would "install SCR [selective catalytic reduction] to meet their SO_2 and NO_x requirements and take additional steps to address the remaining Hg reduction requirements under CAA section 111, including adding Hg-specific control technologies (model applies ACI [activated carbon injection]), additional scrubbers and SCR, dispatch changes, and coal switching."[184] Based on this analysis, EPA determined that the BSER "refers to the combination of the cap-and-trade mechanism and the technology needed to achieve the chosen cap level."[185]

To accompany the nationwide emissions cap, the EPA also assigned a statewide emissions budget for mercury. Pursuant to CAA section 111(d), states would be required to submit plans to the EPA "detailing the controls that will be implemented to meet its specified budget for reductions from coal-fired Utility

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[183] 70 FR 28606, at 28617. The EPA's projections under CAIR showed a significant number of affected sources would install scrubbers for SO_2 and selective catalytic reduction for NO_x on coal-fired power plants, which had the co-benefit of capturing mercury emissions. *Id.* at 28619.
[184] 70 FR 28606, at 28619.
[185] 70 FR 28606, at 28620.

Units."[186] Of course, states were "not required to adopt and implement" the emission trading program, "but they [were] required to be in compliance with their statewide Hg emission budget."[187]

4. Mercury Air Toxics Rule

On February 16, 2012, the EPA issued the MATS rule (77 FR 9304) to reduce emissions of toxic air pollutants from new and existing coal- and oil-fired EGUs. The MATS rule will reduce emissions of heavy metals, including mercury, arsenic, chromium, and nickel; and acid gases, including hydrochloric acid and hydrofluoric acid. These toxic air pollutants, also known as hazardous air pollutants or air toxics, are known to cause, or suspected of causing, nervous system damage, cancer, and other serious health effects. The MATS rule will also reduce SO_2 and fine particle pollution, which will reduce particle concentrations in the air and prevent thousands of premature deaths and tens of thousands of heart attacks, bronchitis cases and asthma episodes.

New or reconstructed EGUs (i.e., sources that commence construction or reconstruction after May 3, 2011) subject to the

[186] 70 FR 28606, at 28621.
[187] 70 FR 28606, at 28621. That said, states could "require reductions beyond those required by the [s]tate budget." *Id.* at 28621.

MATS rule are required to comply by April 16, 2012 or upon startup, whichever is later.

Existing sources subject to the MATS rule were required to begin meeting the rule’s requirements on April 16, 2015. Controls that will achieve the MATS performance standards are being installed on many units. Certain units, especially those that operate infrequently, may be considered not worth investing in given today’s electricity market, and are closing. The final MATS rule provided a foundation on which states and other permitting authorities could rely in granting an additional, fourth year for compliance provided for by the CAA. States report that these fourth year extensions are being granted. In addition, the EPA issued an enforcement policy that provides a clear pathway for reliability-critical units to receive an administrative order that includes a compliance schedule of up to an additional year, if it is needed to ensure electricity reliability.

Following promulgation of the MATS rule, industry, states and environmental organizations challenged many aspects of the EPA's threshold determination that regulation of EGUs is "appropriate and necessary" and the final standards regulating hazardous air pollutants from EGUs. The U.S. Court of Appeals for the D.C. Circuit upheld all aspects of the MATS rule. *White Stallion Energy Center v. EPA*, 748 F.3d 1222 (D.C. Cir.

2014). In *Michigan v. EPA*, case no. 14-46, the U.S. Supreme Court reversed the portion of the D.C. Circuit decisionfinding the EPA was not required to consider cost when determining whether regulation of EGUs was "appropriate" pursuant to section 112(n)(1). The Supreme Court considered only the narrow question of whether the EPA erred in not considering cost when making this threshold determination. The Court's decision did not disturb any of the other holdings of the D.C. Circuit. The Court remanded the case to the D.C. Circuit for further proceedings, and the MATS rule remains in place at this time.

5. Regional Haze Rule

Under CAA section 169A, Congress "declare[d] as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility" in national parks and wilderness areas that results from anthropogenic emissions.[188] To achieve this goal, Congress directed the EPA to promulgate regulations directing states to submit SIPs that "contain such emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal . . . ."[189] One such measure that Congress deemed necessary to make reasonable progress was a requirement that certain older stationary sources that cause or contribute to

[188] 42 U.S.C. § 7491(a)(1).
[189] 42 U.S.C. § 7491(b)(2).

visibility impairment "procure, install, and operate, as expeditiously as practicable . . . the best available retrofit technology," more commonly referred to as BART.[190] When determining BART for large fossil-fuel fired utility power plants, Congress required states to adhere to guidelines to be promulgated by the EPA.[191] As with other SIP-based programs, the EPA is required to issue a FIP within two years if a state fails to submit a regional haze SIP or if the EPA disapproves such SIP in whole or in part.[192]

In 1999, the EPA promulgated the Regional Haze Rule to satisfy Congress' mandate that EPA promulgate regulations directing states to address visibility impairment.[193] Among other things, the Regional Haze Rule allows states to satisfy the Act's BART requirement either by adopting source-specific emission limitations or by adopting alternatives, such as emissions-trading programs, that achieve greater reasonable progress than would source-specific BART.[194] The Ninth Circuit and D.C. Circuit have both upheld the EPA's interpretation that CAA section 169A(b)(2) allows for BART alternatives in lieu of

[190] 42 U.S.C. § 7491(b)(2)(A).
[191] 42 U.S.C. § 7491(b)(2).
[192] 42 U.S.C. §§ 7410(c); 7491(b)(2)(A).
[193] 64 FR 35714 (July 1, 1999) (codified at 40 CFR 51.308-309).
[194] 40 CFR 51.308(e)(1) & (2).

source-specific BART.[195] In 2005, the EPA promulgated BART Guidelines to assist states in determining which sources are subject to BART and what emission limitations to impose at those sources.[196]

The Regional Haze Rule set a goal of achieving natural visibility conditions by 2064 and requires states to revise their regional haze SIPs every ten years.[197] The first planning period, which ends in 2018, focused heavily on the BART requirement. States (or the EPA in the case of FIPs) made numerous source-specific BART determinations, and developed several BART alternatives, for utility power plants. For the next planning period, states will need to determine whether additional controls are necessary at these plants (and others that were not subject to BART) in order to make reasonable progress towards the national visibility goal.[198]

F. Congressional Awareness of Climate Change in the Context of the Clean Air Act Amendments[199]

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[195] *See* Utility Air Regulatory Grp. v. EPA, 471 F.3d 1333 (D.C. Cir. 2006); Ctr. for Econ. Dev. v. EPA, 398 F.3d 653 (D.C. Cir. 2005); Cent. Ariz. Water Dist. v. EPA, 990 F.2d 1531 (9th Cir. 1993).

[196] 70 FR 39104 (July 6, 2005) (codified at 40 CFR pt. 51, app. Y).

[197] *See* 40 CFR 51.308(d)(1)(i)(B), (f).

[198] *See* 42 U.S.C. § 7491(b)(2); 40 CFR 51.308(d)(3).

[199] The following discussion is not meant to be exhaustive. There are many other instances outside the context of the CAA, before

During its deliberations on the 1970 Clean Air Act Amendments, Congress learned that ongoing pollution, including from manmade carbon dioxide, could "threaten irreversible atmospheric and climatic changes."[200] At that time, Congress heard the views of scientists that carbon dioxide emissions tended to increase global temperatures, but that there was uncertainty as to the extent to which those increases would be offset by the decreases in temperatures brought about by emissions of particulates. President Nixon's Council on Environmental Quality (CEQ) reported that "the addition of particulates and carbon dioxide in the atmosphere could have dramatic and long-term effects on world climate."[201] The CEQ's First Annual Report, which was transmitted to Congress, devoted a chapter to "Man's Inadvertent Modification of Weather and Climate."[202] Moreover, Charles Johnson, Jr., Administrator of the

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and after 1970, when Congress discussed or was presented with evidence on climate change.

[200] Sen. Scott, S. Debate on S. 4358 (Sept. 21, 1970), 1970 CAA Legis. Hist. at 349.

[201] Council on Environmental Quality, "The First Annual Report of the Council on Environmental Quality," p. 110 (Aug. 1970) (recognizing also that "[man] can increase the carbon dioxide content of the atmosphere by burning fossil fuels" and postulating that an increase in the earth's average temperature by about 2° to 3° F "could in a period of decades, lead to the start of substantial melting of ice caps and flooding of coastal regions.").

[202] Council on Environmental Quality, "The First Annual Report of the Council on Environmental Quality," p. 93-104 (Aug. 1970)

Consumer Protection and Environmental Health Service, testified before the House Subcommittee on Public Health that "the carbon dioxide balance might result in the heating up of the atmosphere whereas the reduction of the radiant energy through particulate matter released to the atmosphere might cause reduction in radiation that reaches the earth."[203] Administrator Johnson explained that the Nixon Administration was "concerned ... that neither of these things happen" and that they were "watching carefully the kind of prognosis, the kind of calculations that the scientists make to look at the continuous balance between heat and cooling of the total earth's atmosphere."[204] He concluded that "[w]hat we are trying to do, however, in terms of our air pollution effort should have a very salutary effect on either of these."[205]

[203] Testimony of Charles Johnson, Jr., Administrator of the Consumer Protection and Environmental Health Service (Administration Testimony), Hearing of the House Subcommittee on Public Health and Welfare (Mar. 16, 1970), 1970 CAA Legis. Hist. at 1381.
[204] Testimony of Charles Johnson, Jr., Administrator of the Consumer Protection and Environmental Health Service (Administration Testimony), Hearing of the House Subcommittee on Public Health and Welfare (Mar. 16, 1970), 1970 CAA Legis. Hist. at 1381.
[205] Testimony of Charles Johnson, Jr., Administrator of the Consumer Protection and Environmental Health Service (Administration Testimony), Hearing of the House Subcommittee on Public Health and Welfare (Mar. 16, 1970), 1970 CAA Legis. Hist. at 1381.

Scientific reports on climatic change continued to gain traction in Congress through the mid-1970s, including while Congress was considering the 1977 CAA Amendments. However, uncertainty continued as to whether the increased warming brought about by carbon dioxide emissions would be offset by cooling brought about by particulate emissions.[206] Congress ordered, as part of the 1977 CAA Amendments, the National Oceanic and Atmospheric Administration to research and monitor the stratosphere "for the purpose of early detection of changes in the stratosphere and climatic effects of such changes."[207]

Between the 1977 and 1990 Clean Air Act Amendments, scientific uncertainty yielded to the predominant view that global warming "was likely to dominate on time scales that would

[206] For instance, while scientists, such as Stephen Schneider of the National Center for Atmospheric Research, testified that "manmade pollutants will affect the climate," they believed that we would "see a general cooling of the Earth's atmosphere." Rep. Scheuer, H. Debates on H.R. 10498 (Sept. 15, 1976), 1977 CAA Legis. Hist. at 6477. Additionally, the Department of Transportation's climatic impact assessment program and the Climatic Impact Committee of the National Research Council, National Academies of Science and Engineering both reported that "warming or cooling" could occur. *Id.* at 6476. *See also* Sen. Bumpers, S. Debates on S. 3219 (August 3, 1976), 1977 CAA Legis. Hist. at 5368 (inserting "Summary of Statements Received [in the Subcommittee on the Environment and the Atmosphere] from Professional Societies for the Hearings on Effects of Chronic Pollution" into the record, which noted that "there is near unamity [sic] that carbon dioxide concentrations in the atmosphere are increasing rapidly.").

[207] "Clean Air Act Amendments of 1977," § 125, 91 Stat. at 728.

be significant to human societies."[208] In fact, as part of the 1990 Clean Air Act Amendments, Congress specifically required the EPA to collect data on carbon dioxide emissions -- the most significant of the GHGs -- from all sources subject to the newly enacted operating permit program under Title V.[209] Although Congress did not require the EPA to take immediate action to address climate change, Congress did identify certain tools that were particularly helpful in addressing climate change in the utility power sector. The Senate report discussing the acid rain provisions of Title IV noted that some of the measures that would reduce coal-fired power plant emissions of the precursors to acid rain would also reduce those facilities' emissions of CO_2. The report stated:

> Energy efficiency is a crucial tool for controlling the emissions of carbon dioxide, the gas chiefly responsible for the intensification of the atmospheric 'greenhouse effect.' In the last several years, the Committee has received extensive scientific testimony that increases in the human-caused emissions of carbon dioxide and other greenhouse gases will lead to catastrophic shocks in the global climate system. Accordingly, new title IV shapes an acid rain reduction policy that encourages energy efficiency and

[208] Peterson, Thomas C., William M. Connolley, and John Fleck, "The Myth of the 1970s Global Cooling Scientific Consensus," Bulletin of the American Meteorological Society, p. 1326 (September 2008), *available at* http://journals.ametsoc.org/doi/pdf/10.1175/2008BAMS2370.1.
[209] "Clean Air Act Amendments of 1990," § 820, 104 Stat. at 2699.

other policies aimed at controlling greenhouse gases.[210]

Similarly, Title IV provisions to encourage RE were justified because "renewables not only significantly curtail sulfur dioxide emissions, but they emit little or no nitrogen oxides and carbon dioxide".[211]

G. International Agreements and Actions

In this final rule, the U.S. is taking action to limit GHGs from one of its largest emission sources. Climate change is a global problem, and the U.S. is not alone in taking action to address it. The United Nations Framework Convention on Climate Change (UNFCCC)[212] is the international treaty under which countries (called "Parties") cooperatively consider what can be done to limit anthropogenic climate change[213] and adapt to

[210] Sen. Chaffe, S. Debate on S. 1630 (Jan. 24, 1990), 1990 CAA Legis. Hist. at 8662.
[211] Additional Views of Rep. Markey and Rep. Moorhead, H.R. Rep. No. 101-490, at 674 (May 17, 1990).
[212] http://unfccc.int/2860.php
[213] Article 2, Objective, The ultimate objective of this Convention and any related legal instruments that the Conference of the Parties may adopt is to achieve, in accordance with the relevant provisions of the Convention, stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. Such a level should be achieved within a time frame sufficient to allow ecosystems to adapt naturally to climate change, to ensure that food production is not threatened and to enable economic development to proceed in a sustainable manner. http://unfccc.int/files/essential_background/convention/background/application/pdf/convention_text_with_annexes_english_for_posting.pdf

climate change impacts. Currently, there are 195 Parties to the UNFCCC, including the U.S. The Conference of the Parties (COP) meets annually and is currently considering commitments countries can make to limit emissions after 2020. The 2015 COP will be in Paris and is expected to represent an historic step for climate change mitigation. The Parties to the UNFCCC will meet to establish a climate agreement that applies to all countries and focuses on reducing GHG emissions. Such an outcome would send a beneficial signal to the markets and civil society about global action to address climate change.

Many countries have announced their intended post-2020 commitments already, and other countries are expected to do so before December. In April 2015, the U.S.announced its commitment to reduce GHG emissions 26-28 percent below 2005 levels by 2025.[214]

As Parties to both the UNFCCC and the Kyoto Protocol[215], the European Union (EU) and member countries have taken aggressive action to reduce GHG emissions.[216] EU initiatives to reduce GHG emissions include the EU Emissions Trading System, legislation

[214] United States Cover Note to Intended Nationally Determined Contribution (INDC). Available online at: http://www4.unfccc.int/submissions/INDC/Published%20Documents/United%20States%20of%20America/1/U.S.%20Cover%20Note%20INDC%20and%20Accompanying%20Information.pdf.

[215] http://unfccc.int/kyoto_protocol/items/2830.php.

[216] http://ec.europa.eu/clima/policies/brief/eu/index_en.htm.

to increase the adoption of RE sources, strengthened EE targets, vehicle emission standards, and support for the development of CCS technology for use by the power sector and other industrial sources. In 2009, the EU announced its “20-20-20 targets,” including a 20 percent reduction in GHG emissions from 1990 levels by 2020, an increase of 20 percent in the share of energy consumption produced by renewable resources, and a 20 percent improvement in EE. In March 2015, the EU announced its commitment to reduce domestic GHG emissions by at least 40% from 1990 levels by 2030.

Recently, China has also agreed to take action to address climate change. In November 2014, in a joint announcement by President Obama and China’s President Xi, China pledged to curtail GHG emissions, with emissions peaking in 2030 and then declining thereafter, and to increase the share of energy from non-carbon sources (solar, wind, hydropower, nuclear) to 20 percent by 2030.

Mexico is committed to reduce unconditionally 25 percent of its emissions of GHGs and short-lived climate pollutants (below business as usual) for the year 2030. This commitment implies a 22 percent reduction of GHG emissions and a 51 percent reduction of black carbon emissions.

Brazil has reduced its net CO_2 emissions more than any other country through a historic effort to slow forest loss. The deforestation rate in Brazil in 2014 was roughly 75 percent below the average for 1996 to 2005.[217]

Together, countries that have already announced their intended post-2020 commitments, including the U.S., China, European Union, Mexico, Russian Federation and Brazil, make up a large majority of global emissions.

President Obama's Climate Action Plan contains a number of policies and programs that are intended to cut carbon pollution that causes climate change and affects public health. The Clean Power Plan is a key component of the plan, addressing the nation's largest source of emissions in a comprehensive manner. Collectively, these policies will help spark business innovation, result in cleaner forms of energy, create jobs, and cut dependence on foreign oil. They also demonstrate to the rest of the world that the U.S.is contributing its share of the global effort that is needed to address climate change.218 This demonstration encourages other major economies to take on similar contributions, which is critical given the global impact

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[217] http://www.nature.com/news/stopping-deforestation-battle-for-the-amazon-1.17223

[218] President Obama stated, in announcing the Climate Action Plan:
"The actions I've announced today should send a strong signal to the world that America intends to take bold action to reduce carbon pollution. We will continue to lead by the power of our example, because that's what the United States of America has always done." President Obama, Climate Action Plan speech, Georgetown University, 2013.

of GHG emissions. The State Department Special Envoy for Climate Change Todd Stern, the lead U.S. climate change negotiator, noted the connection between domestic and international action to address climate change in his speech at Yale University on October 14, 2014:

> "This mobilization of American effort matters. Enormously. It matters because the United States is the biggest economy and largest historic emitter of greenhouse gases. Because, here, as in so many areas, we feel a responsibility to lead. And because here, as in so many areas, we find that American commitment is indispensable to effective international action.
>
> And make no mistake – other countries see what we are doing and are taking note. As I travel the world and meet with my counterparts, the palpable engagement of President Obama and his team has put us in a stronger, more credible position than ever before."

This final rule demonstrates to other countries that the U.S. is taking action to limit GHG emissions from its largest emission sources, in line with our international commitments. The impact of GHGs is global, and U.S. action to reduce GHG emissions complements and encourages ongoing programs and efforts in other countries.

H. Legislative and Regulatory Background for CAA Section 111

In the final days of December 1970, Congress enacted sweeping changes to the Air Quality Act of 1967 to confront an "environmental crisis."[219] The Air Quality Act—which expanded

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[219] Sen. Muskie, S. Debate on S. 4358 (Sept. 21, 1970), 1970 CAA Legis. Hist. at 224.

federal air pollution control efforts after the enactment of the Clean Air Act of 1963—prioritized the adoption of ambient air standards but failed to target stationary sources of air pollution. As a result, "[c]ities up and down the east coast were living under clouds of smoke and daily air pollution alerts."[220] In fact, "[o]ver 200 million tons of contaminants ... spilled into the air" each year.[221] The 1970 CAA Amendments were designed to face this crisis "with urgency and in candor."[222]

For the most part, Congress gave EPA and the states flexible tools to implement the CAA. This is best exhibited by the newly enacted programs regulating stationary sources. For these sources, Congress crafted a three-legged regime upon which the regulation of stationary sources was intended to sit.

The first prong—CAA sections 107-110—addressed what are commonly referred to as criteria pollutants, "the presence of which in the ambient air results from numerous or diverse mobile or stationary sources" and are determined to have "an adverse

[220] Sen. Muskie, S. Consideration of H.R. Conf. Rep. No. 91-1783 (Dec. 18, 1970), 1970 CAA Legis. Hist.pa at 123.
[221] Sen. Muskie, S. Debate on S. 4358 (Sept. 21, 1970), 1970 CAA Legis. Hist. at 224. These pollutants fell into five main classes of pollutants: carbon monoxide, particulates, sulfur oxides, hydrocarbons, and nitrogen oxides. *See* Sen. Boggs, *id.* at 244.
[222] Sen. Muskie, S. Consideration of H.R. Conf. Rep. No. 91-1783 (Dec. 18, 1970), 1970 CAA Legis. Hist. at 123.

effect on public health or welfare".[223] Under these provisions, states would have the primary responsibility for assuring air quality within their entire geographic area but would submit plans to the Administrator for "implementation, maintenance, and enforcement" of national ambient air quality standards. These plans would include "emission limitations, schedules, and timetables for compliance ... and such other measures as may be necessary to insure attainment and maintenance" of the national ambient air quality standards.[224]

The second prong—CAA section 111—addressed pollutants on a source category-wide basis. Under CAA section 111(b), the EPA lists source categories which "contribute significantly to air pollution which causes or contributes to the endangerment of public health or welfare," And then establishes "standards of performance" for the new sources in the listed category.[225] For existing sources in a listed source category, CAA section 111(d) set out procedures for the establishment of federally

[223] "Clean Air Act Amendments of 1970," Pub. L. 91-604, § 4, 84 Stat. 1676, 1678 (Dec. 31, 1970). The "adverse effect" criterion was later amended to refer to pollutants "which may reasonably be anticipated to endanger public health or welfare". *See* 42 U.S.C. § 7408(a)(1)(A). Similar language is also used under the current CAA section 111. *See* 42 U.S.C. § 7411(b)(1)(A).
[224] "Clean Air Act Amendments of 1970," § 4, 84 Stat. at 1680.
[225] "Clean Air Act Amendments of 1970," § 4, 84 Stat. at 1684.

enforceable "emission standards" of any pollutant not otherwise controlled under the CAA's SIP provisions or CAA section 112.

Lastly, the third prong—CAA section 112—addressed hazardous air pollutants through the establishment of national "emission standards" at a level which "provides an ample margin of safety to protect the public health".[226] All new or modified sources of any hazardous air pollutant would be required to meet these emission standards. Existing sources were required to meet the same standards or would be shut down unless they obtained a temporary EPA waiver or Presidential exemption.[227]

At its inception, CAA section 111 was intended to bear a significant weight under this three-legged regime. Indeed, by 1977, the EPA had promulgated six times as many performance standards under CAA section 111 than emission standards under CAA section 112.[228] That said, states, including Texas and New Jersey, levied "substantial criticisms" against the EPA for not moving rapidly enough.[229] Accordingly, the 1977 CAA Amendments were designed to "provide a greater role for the [s]tates in standards setting under the [CAA]," "protect [s]tates from 'environmental blackmail' as they attempt to regulate mobile and

[226] "Clean Air Act Amendments of 1970," § 4, 84 Stat. at 1685.
[227] "Clean Air Act Amendments of 1970," § 4, 84 Stat. at 1685.
[228] H.R. Rep. No. 95-294, at 194 (May 12, 1977).
[229] H.R. Rep. No. 95-294, at 194 (May 12, 1977).

competitive industries," and lastly "provide a check on the Administrator's inaction or failure to control emissions adequately."[230]

At bottom, CAA section 111 rests on the definition of a standard of performance under CAA section 111(a)(1), which reads nearly the same now as it did when it was first adopted in the 1970 CAA Amendments. In 1970, Congress defined standard of performance—a term which had not previously appeared in the CAA—as

> a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction) the Administrator determines has been adequately demonstrated.[231]

Despite significant changes to this definition in 1977, Congress reversed course in 1990 and largely reinstated the original definition.[232] As presently defined, the term applies to the regulation of new and existing sources under CAA sections 111(b) and (d).[233]

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[230] H.R. Rep. No. 95-294, at 195 (May 12, 1977).
[231] "Clean Air Act Amendments of 1970," § 4, 84 Stat. at 1683.
[232] "Clean Air Act Amendments of 1990," Pub. L. 101-549, § 403, 104 Stat. 2399, 2631 (Nov. 15, 1990) (retaining only the obligation to account for "any nonair quality health and environmental impact and energy requirements" that was added in 1977).
[233] As CAA section 111(d) was originally adopted, state plans would have established "emission standards" instead of "standards of performance." This distinction was later abandoned

The level of control reflected in the definition is generally referred to as the "best system of emission reduction," or the BSER. The BSER, however, is not further defined, and only appeared after conference between the House and Senate in late 1970, and was neither discussed in the conference report nor openly debated in either chamber. Nevertheless, the originating bills from both houses shed light on its construction.

The BSER grew out of proposed language in two bills, which, for the first time, targeted air pollution from stationary sources. The House bill sought to establish national emission standards to "prevent and control ... emissions [of non-hazardous pollutants] to the fullest extent compatible with the available technology and economic feasibility".[234] The House also proposed to prohibit the construction or operation of new sources of "extremely hazardous" pollutants.[235] The Senate bill, on the other hand, authorized "Federal standards of performance," which would "reflect the greatest degree of emission control which the Secretary [later, the Administrator] determines to be achievable through application of the latest

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in 1977 and the same term is used in both CAA sections 111(b) and (d).

[234] H.R. 17255, 91st Cong. § 5 (1970).

[235] H.R. 17255, 91st Cong. § 5 (1970).

available control technology, processes, operating methods, or other alternatives."[236] The Senate also would have authorized "national emission standards" for hazardous air pollution and other "selected air pollution agents."[237]

After conference, CAA section 111 emerged as one of the CAA's three programs for regulating stationary sources. In defining the newly formed "standards of performance," Congress appeared to merge the various "means of preventing and controlling air pollution" under the Senate bill with the consideration of costs that was central to the House bill into the BSER. At the time, however, this definition only applied to new sources under CAA section 111(b).

To regulate existing sources, Congress collapsed section 114 of the Senate bill into CAA section 111(d).[238] Section 114 of the Senate bill established emission standards for "selected air pollution agents," and was intended to bridge the gap between criteria pollutants and hazardous air pollutants. As proposed,

[236] S. 4358, 91st Cong. § 6 (1970) (emphasis added). The breadth of the Senate bill is further emphasized in the conference report, which explains that a standard of performance "refers to the degree of emission control which can be achieved through process changes, operation changes, direct emission control, or other methods" and also includes "other means of preventing or controlling air pollution." S. Rep. No. 91-1196, at 15-16 (Sept. 17, 1970).
[237] S. 4358, 91st Cong. § 6 (1970).
[238] The House bill did not provide for the direct regulation of existing sources.

the Senate identified fourteen substances for regulation under section 114 and only four substances for regulation under Senate bill 4358, section 115, the predecessor of CAA section 112.[239]

As adopted, CAA section 111(d) requires states to submit plans to the Administrator establishing "emission standards" for certain existing sources of air pollutants that were not otherwise regulated as criteria pollutants or hazardous air pollutants. This ensured that there would be "no gaps in control activities pertaining to stationary source emissions that pose any significant danger to public health or welfare."[240]

The term "emission standards," however, was not expressly defined in the 1970 CAA Amendments (save for purposes of citizen suit enforcement) even though the term was also used under the CAA's SIP provisions and CAA section 112.[241] That said, under the newly enacted "ambient air quality and emission standards" sections, Congress directed the EPA to provide states with information "on air pollution control techniques," including data on "available technology and alternative methods of prevention and control of air pollution" and on "alternative

[239] *See* S. Rep. No. 91-1196, at 18 and 20 (Sept. 17, 1970).
[240] S. Rep. No. 91-1196, at 20 (Sept. 17, 1970) (discussing the relationship between sections 114 (addressing emission standards for "selected air pollution agents") and 115 (addressing hazardous air pollutants) of the Senate bill).
[241] *See* "Clean Air Act Amendments of 1970," § 12, 84 Stat. at 1706.

fuels, processes, and operating methods which will result in elimination or significant reduction of emissions."[242] Similarly, the Administrator would "issue information on pollution control techniques for air pollutants" in conjunction with establishing emission standards under CAA section 112. However, analogous text is absent from CAA section 111(d).

After the enactment of the 1970 CAA Amendments, the EPA proposed standards of performance for an "initial list of five stationary source categories which contribute significantly to air pollution" in August 1971.[243] The first category listed was for fossil-fuel fired steam generators, for which EPA proposed and promulgated standards for particulate matter, SO_2, and NOx.[244]

Several years later, the EPA proposed its implementing regulations for CAA section 111(d).[245] These regulations were finalized in November 1975, and provided for the publication of

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[242] "Clean Air Act Amendments of 1970," § 4, 84 Stat. at 1679.
[243] "Standards of Performance for New Stationary Sources: Proposed Standards for Five Categories," 36 FR 15704 (Aug. 17, 1971). *See* "Clean Air Act Amendments of 1970," § 4, 84 Stat. at 1684 (requiring the Administrator to publish a list of categories of stationary sources within 90 days of the enactment of the 1970 CAA Amendments).
[244] 36 FR at 15704-706; and "Standards of Performance for New Stationary Sources," 36 FR 24876, 24879 (Dec. 23, 1971).
[245] *See* "State Plans for the Control of Existing Facilities," 39 FR 36102 (Oct. 7, 1974).

emission guidelines.[246] The first emission guidelines were proposed in May 1976 and finalized in March 1977.[247]

Despite these first steps taken under CAA sections 111(b) and (d), Congress revisited the CAA in 1977 to address growing concerns with the nation's response to the 1973 oil embargo (noted above), to respond to new environmental problems such as stratospheric ozone depletion, and to resolve other issues associated with implementing the 1970 CAA Amendments.[248] Most notably, an increase in coal use as a result of the oil crisis meant that "vigorous and effective control" of air emissions was

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[246] *See* "State Plans for the Control of Certain Pollutants from Existing Facilities," 40 FR 53340 (Nov. 17, 1975).

[247] *See* "Phosphate Fertilizer Plants; Draft Guideline Document; Availability," 41 FR 19585 (May 12, 1976); and "Phosphate Fertilizer Plants; Final Guideline Document Availability," 42 FR 12022 (Mar. 1, 1977)

[248] For example, Congress recognized that many air pollutants had not been regulated despite "mounting evidence" that these pollutants "are associated with serious health hazards". H.R. Rep. No. 94-1175, 22 (May, 15, 1976). Because EPA "failed to promulgate regulations to institute adequate control measures," Congress ordered EPA to regulate four specific pollutants that had "been found to be cancer-causing or cancer-promoting". *Id.* at 23. This directive, reflected in CAA section 122, specifically added radioactive pollutants, cadmium, arsenic, and polycyclic organic matter "under the various provisions of the Clean Air Act and allows their regulation as criteria pollutants under ambient air quality standards, as hazardous air pollutants, or under new source performance standards, as appropriate." H.R. Conf. Rep. No. 95-564, 142 (Aug. 3, 1977), 1977 CAA Legis. Hist. at 522. At the same time, Congress made sure that these commands would have no effect on the Administrator's discretion to address "any substance (whether or not enumerated [under CAA section 122(a))" under CAA sections 108, 112, or 111. 42 U.S.C. § 7422(b).

"even more urgent."[249] Thus, to curb the projected surge in air emissions, Congress enacted several new provisions to the CAA. These new provisions include the prevention of significant deterioration (PSD) program, visibility protections, and requirements for nonattainment areas.[250]

Congress also made significant changes to CAA section 111. For example, Congress amended the definition of a standard of performance (including by requiring the consideration of "nonair quality health and environmental impact and energy requirements"), authorized alternative (*e.g.*, work practice or design) standards in limited circumstances, provided states with authority to petition the Administrator for new or revised (and more stringent) standards, and imposed a strict regulatory schedule for establishing standards of performance for categories of major stationary sources that had not yet been listed.[251]

The 1977 definition for a standard of performance required "all new sources to meet emission standards based on the reductions achievable through the use of the 'best technological

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[249] *See* Statement of EPA Administrator Costle, S. Hearings on S. 272, S. 273, S. 977, and S. 1469 (Apr. 5, 7, May 25, June 24 and 30, 1977), 1977 CAA Legis. Hist. at 3532.
[250] *See* "Clean Air Act Amendments of 1977," Pub. L. 95-95, §§ 127-129, 91 Stat. 685 (Aug. 7, 1977).
[251] "Clean Air Act Amendments of 1977," § 109, 91 Stat. at 697.

system of continuous emission reduction.'"[252] For fossil-fuel fired stationary sources, Congress further required a percentage reduction in emissions from the use of fuels.[253] Together, this was designed to "force new sources to burn high-sulfur fuel thus freeing low-sulfur fuel for use in existing sources where it is harder to control emissions and where low-sulfur fuel is needed for compliance."[254]

Congress also clarified that with respect to CAA section 111(d), standards of performance (now applicable in lieu of emission standards) "would be based on the best available means (not necessarily technological)".[255] This was intended to distinguish existing source standards from new source standards, for which "the requirement for [the BSER] has been more narrowly redefined as best technological system of continuous emission

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[252] H.R. Rep. No. 95-294, at 192 (May 12, 1977). Congress separately defined "technological system of continuous emission reduction" as "(A) a technological process for production or operation by any source which is inherently low-polluting or nonpolluting, or (B) technological system for continuous reduction of the pollution generated by a source before such pollution is emitted into the ambient air, including precombustion cleaning or treatment of fuels." "Clean Air Act Amendments of 1977," § 109, 91 Stat. at 700; *see also* 42 U.S.C. § 7411(a)(7).
[253] "Clean Air Act Amendments of 1977," § 109, 91 Stat. at 700.
[254] "New Stationary Sources Performance Standards; Electric Utility Steam Generating Units," 44 FR 33580, 33581-82 (June 11, 1979).
[255] H.R. Rep. No. 95-294, at 195 (May 12, 1977).

reduction."[256] Additionally, Congress clarified that states could consider "the remaining useful life" of a source when applying a standard of performance to a particular existing source.[257]

In the twenty years since the 1970 CAA Amendments and in spite of the refinements of the 1977 CAA Amendments, "many of the Nation's most important air pollution problems [had] failed to improve or [had] grown more serious."[258] Indeed, in 1988, President George Bush said that "'progress has not come quickly enough and much remains to be done.'"[259] This time, with the 1990 CAA Amendments, Congress substantially overhauled the CAA. In particular, Congress again added to the NAAQS program, completely revised CAA section 112, added a new title to target existing fossil fuel-fired stationary sources and address growing concerns with acid rain, imported an operating permit modeled off the Clean Water Act, and established a phase out of certain ozone depleting substances.

All told, however, there was minimal debate on changes to CAA section 111. In fact, the only discussion centered on the repeal of the percentage reduction requirement, which became

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[256] Sen. Muskie, S. Consideration of the H.R. Conf. Rep. No. 95-564 (Aug. 4, 1977), 1977 CAA Legis. Hist. at 353.
[257] This concept was already reflected in the EPA's CAA section 111(d) implementing regulations under 40 CFR 60.24(f). *See* 40 FR 53340, 53347 (Nov. 17, 1975).
[258] H.R. Rep. No. 101-490, at 144 (May 17, 1990).
[259] H.R. Rep. No. 101-490, at 144 (May 17, 1990).

seen as unduly restrictive. Accordingly, Congress reverted the definition of "standard of performance" to the definition agreed to in the 1970 CAA Amendments, but retained the requirement to consider nonair quality environmental impacts and energy requirements added in 1977.[260] However, the repeal would only apply so long as the SO_2 cap under CAA section 403(e) of the newly established acid rain program remained in effect.[261] Lastly, Congress instructed the EPA to revise its new source performance standards for SO_2 emissions from fossil fuel-fired power plants but required that the revised emission rate be no less stringent than before.[262]

I. Statutory and Regulatory Requirements

Clean Air Act section 111, which Congress enacted as part of the 1970 Clean Air Act Amendments, establishes mechanisms for controlling emissions of air pollutants from stationary sources. This provision requires the EPA to promulgate a list of categories of stationary sources that the Administrator, in his or her judgment, finds "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger

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[260] Congress also updated the regulatory schedule that was added in the 1977 CAA Amendments to reflect the newly enacted 1990 CAA Amendments. *See* "Clean Air Act Amendments of 1990," § 108, 104 Stat. 2467.
[261] "Clean Air Act Amendments of 1990," § 403, 104 Stat. at 2631.
[262] "Clean Air Act Amendments of 1990," § 301, 104 Stat. at 2631.

public health or welfare."[263] The EPA has listed more than 60 stationary source categories under this provision.[264] Once the EPA lists a source category, the EPA must, under CAA section 111(b)(1)(B), establish "standards of performance" for emissions of air pollutants from new sources in the source categories.[265] These standards are known as new source performance standards (NSPS), and they are national requirements that apply directly to the sources subject to them.

When the EPA establishes NSPS for new sources in a particular source category, the EPA is also required, under CAA section 111(d)(1), to prescribe regulations for states to submit plans regulating existing sources in that source category for any air pollutant that, in general, is not regulated under the CAA section 109 requirements for the NAAQS or regulated under the CAA section 112 requirements for HAP. CAA section 111(d)'s mechanism for regulating existing sources differs from the one that CAA section 111(b) provides for new sources because CAA section 111(d) contemplates states submitting plans that establish "standards of performance" for the affected sources and that contain other measures to implement and enforce those standards.

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[263] CAA section 111(b)(1)(A).
[264] *See* 40 CFR 60 subparts Cb - OOOO.
[265] CAA section 111(b)(1)(B), 111(a)(1).

"Standards of performance" are defined under CAA section 111(a)(1) as standards for emissions that reflect the emission limitation achievable from the "best system of emission reduction," considering costs and other factors, that "the Administrator determines has been adequately demonstrated." CAA section 111(d)(1) grants states the authority, in applying a standard of performance to a particular source, to take into account the source's remaining useful life or other factors. Under CAA section 111(d), a state must submit its plan to the EPA for approval, and the EPA must approve the state plan if it is "satisfactory."[266] If a state does not submit a plan, or if the EPA does not approve a state's plan, then the EPA must establish a plan for that state.[267] Once a state receives the EPA's approval of its plan, the provisions in the plan become federally enforceable against the entity responsible for noncompliance, in the same manner as the provisions of an approved SIP under the Act.

Section 302(d) of the CAA defines the term "state" to include the Commonwealth of Puerto Rico, the Virgin Islands, Guam, American Samoa and the Commonwealth of the Northern Mariana Islands. While 40 CFR part 60 contains a separate definition of "state" at § 60.2, this definition expands on,

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[266] CAA section 111(d)(2)(A).
[267] CAA section 111(d)(2)(A).

rather than narrows, the definition in section 302(d) of the CAA. The introductory language to 40 CFR 60.2 provides: "The terms in this part are defined in the Act or in this section as follows." Section 60.2 defines "State" as "all non-Federal authorities, including local agencies, interstate associations, and State-wide programs that have been delegated authority to implement: (1) the provisions of this part and/or (2) the permit program established under part 70 of this chapter. The term State shall have its conventional meaning where clear from the context." The EPA believes that the last sentence refers to the conventional meaning of "state" under the CAA. Thus, the EPA believes the term "state" as used in the emission guidelines is most reasonably interpreted as including the meaning ascribed to that term in section 302(d) of the CAA, which expressly includes U.S. territories.

Section 301(d)(A) of the CAA recognizes that the American Indian tribes are sovereign Nations and authorizes the EPA to "treat tribes as States under this Act". The Tribal Authority Rule (63 Federal Register 7254, February 12, 1998) identifies that EPA will treat tribes in a manner similar to states for all of the CAA provisions with the exception of, among other things, specific plan submittal and implementation deadlines under the CAA. As a result, though they operate as part of the interconnected system of electricity production and distribution, affected EGUs located in Indian country would not be encompassed within a state's CAA section 111(d) plan. Instead, an Indian tribe with one or more affected EGUs located in its area of Indian country[268] will have the opportunity, but not the obligation, to apply for eligibility to develop and implement a CAA section 111(d) plan. The Indian tribe would need to be approved by the EPA as eligible to develop and implement a CAA section 111(d) plan following the procedure set forth in 40 CFR part 49. Once a tribe is approved as eligible for that purpose, it would be treated in the same manner as a state, and references in the emission guidelines to states would refer equally to the tribe. The EPA notes that, while tribes have the opportunity to apply for eligibility to administer CAA programs, they are not required to do so. Further, the EPA has established procedures in 40 CFR part 49 (see particularly 40 CFR 49.7(c)) that permit eligible tribes to request approval of reasonably severable partial program elements. Those procedures are applicable here.

In these final emission guidelines, the term "state"

[268] The EPA is aware of at least four affected sources located in Indian Country: two on Navajo lands – the Navajo Generating Station and the Four Corners Generating Station; one on Ute lands – the Bonanza Generating Station; and one on Fort Mojave lands, the South Point Energy Center. The affected EGUs at the first three plants are coal-fired EGUs. The fourth affected EGU is an NGCC facility.

encompasses the 50 states and the District of Columbia, U.S. territories, and any Indian tribe that has been approved by the EPA pursuant to 40 CFR 49.9 as to develop and implement a CAA section 111(d) plan.

The EPA issued regulations implementing CAA section 111(d) in 1975,[269] and has revised them in the years since.[270] (We refer to the regulations generally as the implementing regulations.) These regulations provide that, in promulgating requirements for sources under CAA section 111(d), the EPA first develops regulations known as "emission guidelines," which establish binding requirements that states must address when they develop their plans.[271] The implementing regulations also establish timetables for state and EPA action: states must submit state plans within 9 months of the EPA's issuance of the guidelines,[272] and the EPA must take final action on the state plans within 4 months of the due date for those plans,[273] although the EPA has authority to extend those deadlines.[274] In this rulemaking, the

[269] "State Plans for the Control of Certain Pollutants from Existing Facilities," 40 FR 53340 (Nov. 17, 1975).
[270] The most recent amendment was in 77 FR 9304 (Feb. 16, 2012).
[271] 40 CFR 60.22. In the 1975 rulemaking, the EPA explained that it used the term "emission guidelines" – instead of emissions limitations – to make clear that guidelines would not be binding requirements applicable to the sources, but instead are "criteria for judging the adequacy of State plans." 40 FR at 53343.
[272] 40 CFR 60.23(a)(1).
[273] 40 CFR 60.27(b).
[274] *See* 40 CFR 60.27(a).

EPA is following the requirements of the implementing regulations, and is not re-opening them, except that the EPA is extending the timetables, as described below.

Over the last forty years, under CAA section 111(d), the agency has regulated four pollutants from five source categories (i.e., sulfuric acid plants (acid mist), phosphate fertilizer plants (fluorides), primary aluminum plants (fluorides), Kraft pulp plants (total reduced sulfur), and municipal solid waste landfills (landfill gases)).[275] In addition, the agency has regulated additional pollutants under CAA section 111(d) in conjunction with CAA section 129.[276] The agency has not previously regulated CO_2 or any other GHGs under CAA section 111(d).

The EPA's previous CAA section 111(d) actions were necessarily geared toward the pollutants and industries regulated. Similarly, in this rulemaking, in defining CAA

[275] *See* "Phosphate Fertilizer Plants; Final Guideline Document Availability," 42 FR 12022 (Mar. 1, 1977); "Standards of Performance for New Stationary Sources; Emission Guideline for Sulfuric Acid Mist," 42 FR 55796 (Oct. 18, 1977); "Kraft Pulp Mills, Notice of Availability of Final Guideline Document," 44 FR 29828 (May 22, 1979); "Primary Aluminum Plants; Availability of Final Guideline Document," 45 FR 26294 (Apr. 17, 1980); "Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills, Final Rule," 61 FR 9905 (Mar. 12, 1996).
[276] *See, e.g.,* "Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Sewage Sludge Incineration Units, Final Rule," 76 FR 15372 (Mar. 21, 2011).

section 111(d) emission guidelines for the states and determining the BSER, the EPA believes that taking into account the particular characteristics of carbon pollution, the interconnected nature of the power sector and the manner in which EGUs are currently operated is warranted. Specifically, the operators themselves treat increments of generation as interchangeable between and among sources in a way that creates options for relying on varying utilization levels, lowering carbon generation, and reducing demand as components of the overall method for reducing CO_2 emissions. Doing so results in a broader, forward-thinking approach to the design of programs to yield critical CO_2 reductions that improve the overall power system by lowering the carbon intensity of power generation, while offering continued reliability and cost-effectiveness. These opportunities exist in the utility power sector in ways that were not relevant or available for other industries for which the EPA has established CAA section 111(d) emission guidelines.[277]

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[277] *See* "Phosphate Fertilizer Plants; Final Guideline Document Availability," 42 FR 12022 (Mar. 1, 1977); "Standards of Performance for New Stationary Sources; Emission Guideline for Sulfuric Acid Mist," 42 FR 55796 (Oct. 18, 1977); "Kraft Pulp Mills, Notice of Availability of Final Guideline Document," 44 FR 29828 (May 22, 1979); "Primary Aluminum Plants; Availability of Final Guideline Document," 45 FR 26294 (Apr. 17, 1980); "Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills, Final Rule," 61 FR 9905 (Mar. 12, 1996).

In this action, the EPA is promulgating emission guidelines for states to follow in developing their CAA section 111(d) plans to reduce emissions of CO_2 from the utility power sector.

J. Clean Power Plan Proposal and Supplemental Proposal

On June 18, 2014, the EPA proposed emission guidelines for states to follow in developing plans to address GHG emissions from existing fossil fuel-fired electric generating units (EGUs). Specifically, the EPA proposed rate-based goals for CO2 emissions for each state with existing fossil fuel-fired EGUs, as well as guidelines for plans to achieve those goals. On November 4, 2014, the EPA published a supplemental proposal that proposed emission rate-based goals for CO_2 emissions for U.S. territories and areas of Indian country with existing fossil fuel-fired EGUs. In the supplemental proposal, the EPA also solicited comment on authorizing jurisdictions (including any states, territories and areas of Indian country) without existing fossil fuel-fired EGUs subject to the proposed emission guidelines to partner with jurisdictions (including any states) that do have existing fossil fuel-fired EGUs subject to the proposed emission guidelines in developing multi-jurisdictional plans. The EPA also solicited comment on the treatment of RE, demand-side EE and other new low- or zero-emitting electricity generation across international boundaries in a state plan.

The EPA also issued two notices after the June 18, 2014 proposal. On October 30, 2014, the EPA published a notice of data availability (NODA) in which the agency provided additional information on several topics raised by stakeholders and solicited comment on the information presented. The notice covered three topic areas: 1) the emission reduction compliance trajectories created by the interim goal for 2020 to 2029, 2) certain aspects of the building block methodology, and 3) the way state-specific CO_2 goals are calculated.

In a separate action, the EPA published a notice regarding potential methods for determining the mass that is equivalent to an emission rate-based CO_2 goal (79 FR 67406; November 13, 2014). With the notice, the EPA also made available, in the docket for this rulemaking, a technical support document (TSD) that provided two examples of how a state, U.S. territory or tribe could translate a rate-based CO_2 goal to total metric tons of CO_2 (a mass-based equivalent).

K. Stakeholder Outreach and Consultations

Following the direction in the Presidential Memorandum to the Administrator (June 25, 2013),[278] the EPA engaged in extensive and vigorous outreach to stakeholders and the general

[278] Presidential Memorandum – Power Sector Carbon Pollution Standards, June 25, 2013. http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.

public at every stage of development of this rule. Our outreach has included direct engagement with the energy and environment officials in states, tribes, and a full range of stakeholders including leaders in the utility power sector, labor leaders, non-governmental organizations, other federal agencies, other experts, community groups and members of the public. The EPA participated in more than 300 meetings before the rule was proposed and more than 300 after the proposal.

Throughout the rulemaking process, the agency has encouraged, organized, and participated in hundreds of meetings about CAA section 111(d) and reducing carbon pollution from existing power plants. The agency's outreach prior to proposal, as well as during the public comment period, was designed to solicit policy ideas,[279] concerns, and technical information. The agency received 4.3 million comments about all aspects of the proposed rule and thousands of people participated in the agency's public hearings, webinars, listening sessions,[280] teleconferences and meetings held all across the country.

[279] The EPA received more than 2,000 emails offering input into the development of these guidelines through email and a web-based form. These emails and other materials provided to the EPA are posted on line as part of a non-regulatory docket, EPA Docket ID No. EPA-HQ-OAR-2014-0020, at www.regulations.gov.
280 Summaries of the 11 public listening sessions in 2013 are available at www.regulations.gov at EPA Docket ID No. EPA-HQ-OAR-2014-0020.

Our engagement has brought together a variety of states and stakeholders to discuss a wide range of issues related to the utility power sector and the development of emission guidelines under CAA section 111(d). The meetings were attended by the EPA Regional Administrators, other senior managers and staff who have been instrumental in the development of the rule and will play key roles in developing and implementing it.

This outreach process has produced a wealth of information which has informed this rule significantly. The pre-proposal outreach efforts far exceeded what is required of the agency in the normal course of a rulemaking process, and the EPA expects that the dialogue with states and stakeholders will continue after the rule is finalized. The EPA recognizes the importance of working with all stakeholders, and in particular with the states, to ensure a clear and common understanding of the role the states will play in addressing carbon pollution from power plants. We firmly believe that our outreach has resulted in a more workable rule that will achieve the statutory goals and has enhanced the likelihood of timely and successful achievement of the carbon reduction goals, given the critical importance and urgency of the concrete action.

The EPA has given stakeholder comments careful consideration and, as a result, this final rule includes features that are responsive to many stakeholder concerns.

1. Public hearings

More than 2,700 people attended the public hearings sessions held in Atlanta, Denver, Pittsburgh, and Washington, DC. More than 1,300 people spoke at the public hearings. Additionally, about 100 people attended the public hearing held in Phoenix, Arizona, on the November 4, 2014 supplemental proposal. Speakers at the public hearings included Members of Congress, other public officials, industry representatives, faith-based organizations, unions, environmental groups, community groups, students, public health groups, energy groups, academia and concerned citizens.

Participants shared a range of perspectives. Many were concerned with the impacts of climate change on their health and on future generations, others were worried about the impact of regulations on the economy. Their support for the agency’s efforts varied.

2. State officials

Since fall 2013, the agency has provided multiple opportunities for the states to inform this rulemaking. Administrator McCarthy has engaged with governors from states with a variety of interests in the rulemaking. Other senior agency officials have engaged with every branch and major agency of state government - including state legislators, attorneys general, state energy, environment, and utility officials, and governors' staff.

On several occasions, state environmental commissioners met with senior agency officials to provide comments on the Clean Power Plan. The EPA organized, encouraged and attended meetings with states to discuss multi-state planning efforts. States have come together with several collaborative groups to discuss ways to work together to make the Clean Power Plan more affordable. The EPA has participated in and supported the states in these discussions. Because of the interconnectedness of the power sector, and the fact that electricity generated at power plants crosses state lines; states, utilities and ratepayers may benefit from states working together to implement the requirements of this rulemaking. The meetings provided state leaders, including governors, environmental commissioners, energy officers, public utility commissioners, and air directors, opportunities to engage with the EPA officials. In addition, the states submitted public comments from several agencies within each state. The wealth of comments and input from states was important in developing the final rulemaking.

Agency officials listened to ideas, concerns and details from states, including from states with a wide range of experience in reducing carbon pollution from power plants. The EPA reached out to all 50 states to engage with both environmental and energy departments at all levels of government. As an example, a three-part webinar series in June/July 2014 for the states and tribes offered an interactive format for technical staff at the EPA and in the states/tribes to exchange ideas and ask clarifying question. The webinars were then posted online so other stakeholders could view them. A few weeks after the postings, the EPA organized follow-up conference calls with stakeholder groups. Also, the EPA hosted scores of technical meetings between states and the EPA in the weeks and months after the rule was proposed.

Additionally, the EPA organized "hub" calls; these teleconferences brought all of the states in a given EPA region together to discuss technical and interstate aspects of the proposal. These exchanges helped provide the stakeholders with the information they needed to comment on the proposal effectively. The EPA also held a series of webinars with state environmental associations and their members on a series of technical issues.

The agency has collected policy papers and comment letters from states with overarching energy goals and technical details on the states' utility power sector. EPA leadership and staff also participated in webinars and meetings with state and tribal officials hosted by collaborative groups and trade associations. After the comment period closed, and based on our meetings over the last year, as well as written comments on the proposal and NODA, the EPA analyzed information about data errors that needed to be addressed for the final rule. In February and March 2015, we reached out to particular states to clarify ambiguous or unclear information that was submitted to the EPA related to NEEDS and eGRID data. The EPA contacted particular states to clarify the technical comments or concerns to ensure that any changes we make are accurate and appropriate.

To help prepare for implementation of this rule, the agency initiated several outreach activities to assist with state planning efforts. The agency participated in meetings organized by the National Association of State Energy Officials (NASEO), the National Association of Regulatory Utility Commissioners (NARUC), and the National Association of Clean Air Agencies (NACAA) (the "3N" groups). Meeting participants discussed issues related to EE and RE.

To help state officials prepare for the planning process that will take place in the states, the EPA presented a webinar on February 24, 2015. This webinar provided an update on training plans and further connection with states in the implementation process. Forty-nine states, the District of Columbia, and 14 tribes were represented at this webinar. The EPA is developing a state plan electronic collection system to receive, track, and store state submittals of plans and reports.

The EPA plans to use an integrated project team to solicit stakeholder input on the system during development. The team membership, including state representatives, will bring together the business and technology skills required to construct a successful product and promote transparency in the EPA's implementation of the rule.

To help identify training needs for the final Clean Power Plan, the agency reached out to a number of state and local organizations such as the Central State Air Resources Agencies and other such regional air agencies. The EPA's outreach on training has included sharing the plans with the states and incorporating changes to the training topics based on the states' needs. The EPA training plan includes a wide variety of topics such as basic training on the electric power sector as well as specific pollution control strategies to reduce carbon emissions from power plants. In particular, the states requested training on how to use programs such as combined heat and power, EE and RE to reduce carbon emissions. The EPA will continue to work with states to tailor training activities to their needs.

The agency has engaged, and will continue to engage with states, territories, Washington, D.C., and tribes after the rulemaking process and throughout implementation.

3. Tribal officials

The EPA conducted significant outreach to and consultation with tribes. Tribes are not required to, but may, develop or adopt Clean Air Act programs. The EPA is aware of four facilities with affected EGUs located in Indian country: the South Point Energy Center, in Fort Mojave Indian country, geographically located within Arizona; the Navajo Generating Station, in Navajo Indian country, geographically located within Arizona; the Four Corners Power Plant, in Navajo Indian country, geographically located within New Mexico; and the Bonanza Power Plant, in Ute Indian country, geographically located within Utah. The EPA offered consultation to the leaders of the tribes on whose lands these facilities are located as well as all of the federally recognized tribes to ensure that they had the opportunity to have meaningful and timely input into this rule. Section III ("Stakeholder Outreach and Conclusions") of the June 18, 2014 proposal documents the EPA's extensive outreach efforts to tribal officials prior to that proposal, including an informational webinar, outreach meeting, teleconferences with tribal officials and the National Tribal Air Association (NTAA), and letters offering consultation. Additional outreach to tribal officials conducted by the EPA prior to the November 4, 2014 supplemental proposal is discussed in Section II.D ("Additional Outreach and Consultation") of the supplemental proposal. The additional outreach for the supplemental proposal included consultations with all three tribes that have affected EGUs on their lands, as well as several other tribes that requested consultation, and also additional teleconferences with the NTAA.

After issuing the supplemental proposal, the EPA offered an additional consultation to the leaders of all federally recognized tribes. The EPA held an informational meeting open to all tribes and also held consultations with the Navajo Nation, Fort McDowell Yavapai Nation, Fort Mojave Tribe, Ak-Chin Indian Community, and Hope Tribe on November 18, 2014. The EPA held a consultation with the Ute Tribe of the Uintah and Ouray Reservation on December 16, 2014, and a consultation with the Gila River Indian Community on January 15, 2015. The EPA held a public hearing on the supplemental proposal on November 19, 2014, in Phoenix, Arizona. On April 28, 2015, the EPA held an additional consultation with the Navajo Nation.

Tribes were interested in the impact of this rule on other ongoing regulatory actions at the affected EGUs, such as permitting or requirements for the best available retrofit technology (BART). Tribes also noted that it was important to allow RE projects on tribal lands to contribute toward meeting state goals. Some tribes indicated an interest in being involved in the development of implementation plans for areas of Indian country. Additional detail regarding the EPA’s outreach to tribes and comments and recommendations from tribes can be found in Section X.F of this preamble.

4. U.S. territories

The EPA has met with individual U.S. territories and affected EGUs in U.S. territories during the rulemaking process. On July 22, 2014, the EPA met with representatives from the Puerto Rico Environmental Quality Board, the Puerto Rico Electric Power Authority, the Governor's Office, and the Office of Energy, Puerto Rico. On September 8, 2014, the EPA held a meeting with representatives from the Guam Environmental Protection Agency (GEPA) and the Guam Power Authority and, on February 18, 2015, the EPA met again with representatives from GEPA.

5. Industry representatives

Agency officials have engaged with industry leaders and representatives from trade associations in many one-on-one and national meetings. Many meetings occurred at the EPA headquarters and in the EPA's Regional Offices and some were sponsored by stakeholder groups. Because the focus of the rule is on the utility power sector, many of the meetings with industry have been with utilities and industry representatives directly related to the utility power sector. The agency has also met with energy industries such as coal and natural gas interests, as well as companies that offer new technology to prevent or reduce carbon pollution, including companies that have expertise in RE and EE. Other meetings have been held with representatives of energy intensive industries, such as the iron and steel and aluminum industries, to help understand the issues related to large industrial users of electricity.

6. Electric utility representatives

Agency officials participated in many meetings with utilities and their associations to discuss all aspects of the proposed guidelines. We have met with all types of companies that produce electricity, including private utilities or investor owned utilities. Public utilities and cooperative utilities were also part of in-depth conversations about CAA section 111(d) with EPA officials.

The conversations included meetings with the EPA headquarters and regional offices. State officials were included in many of the meetings. Meetings with utility associations and groups of utilities were held with key EPA officials. The meetings covered technical, policy and legal topics of interest and utilities expressed a wide variety of support and concerns about CAA section 111(d).

7. Electricity grid operators

The EPA had a number of conversations with the ISOs and RTOs to discuss the rule and issues related to grid operations and reliability. EPA staff met with the ISO/RTO Council on several occasions to collect their ideas. The EPA regional offices also met with the ISOs and RTOs in their regions. System operators have offered suggestions in using regional approaches to implement CAA section 111(d) while maintaining reliable, affordable electricity.

8. Representatives from community and non-governmental organizations

Agency officials engaged with community groups representing vulnerable communities, and faith-based groups, among others, during the outreach effort. In response to a request from communities, the EPA held a day-long training on the Clean Power Plan on October 30, 2014, in Washington D.C. At this meeting, the EPA met with a number of environmental groups to provide information on how the agency plans on reducing carbon pollution from existing power plants using CAA section 111(d).

Many environmental organizations discussed the need for reducing carbon pollution. Meetings were technical, policy and legal in nature and many groups discussed specific state policies that are already in place to reduce carbon pollution in the states.

A number of organizations representing religious groups have reached out to the EPA on several occasions to discuss their concerns and ideas regarding this rule. Many members of faith communities attended the four public hearings.

Public health groups discussed the need for protection of children's health from harmful air pollution. Doctors and health care providers discussed the link between reducing carbon pollution and air pollution and public health. Consumer groups representing advocates for low income electricity customers discussed the need for affordable electricity. They talked about reducing electricity prices for consumers through EE and low-cost carbon reductions.

In winter/spring 2015, EPA continued to offer webinars and teleconferences for community groups on the rulemaking.

9. Environmental Justice Organizations

Agency officials engaged with environmental justice groups representing communities of color, low-income communities and others during the outreach effort. Agency officials also engaged with the EPA's National Environmental Justice Advisory Council (NEJAC) members in September 2013. The NEJAC is composed of stakeholders, including environmental justice leaders and other leaders from state and local government and the private sector. Additionally, the agency conducted a community call on February 26, 2015, and on February 27, 2015, the EPA conducted a follow up webinar for participants in an October 30, 2014 training session. The EPA also held a webinar for communities on the Clean Air Act (CAA) and section 111(d) of the CAA on April 2, 2015. The agency, in partnership with FERC and DOE, held two additional webinars for communities on the electricity grid and on energy markets on June 11, 2015, and July 9, 2015.

During the EPA's extensive outreach conducted before and after proposal, the EPA has heard a variety of issues raised by environmental justice communities. Communities expressed the desire for the agency to conduct an environmental justice (EJ) analysis and to require that states in the development of their state plans conduct one as well. Additionally, they asked that the agency require that states engage with communities in the development of their state plans and that the agency conduct meaningful involvement with communities, throughout the whole rulemaking process, including the implementation phase. Furthermore, communities stressed the importance of low-income and communities of color receiving the benefits of this rulemaking and being protected from being adversely impacted by this rulemaking.

The purpose of this rule is to substantially reduce emissions of CO_2, a key contributor to climate change, which adversely and disproportionately affects vulnerable and disadvantaged communities in the U.S. and around the world. In addition, the rule will result in substantial reductions of conventional air pollutants, providing immediate public health benefits to the communities where the facilities are located and for many miles around. The EPA is committed to ensuring that all

Americans benefit from the public health and other benefits that this rule will bring. Further discussion of the impacts of this rule on vulnerable communities and actions that the EPA is taking to address concerns cited by communities is available in Sections IX and XII.J of this preamble.

10. Labor

Senior agency officials met with a number of labor union representatives about reducing carbon pollution using CAA section 111(d). Those unions included: the United Mine Workers of America; the Sheet Metal, Air, Rail and Transportation Union (SMART); the International Brotherhood of Boilermakers, Iron Ship Builders, Blacksmiths, Forgers and Helpers (IBB); United Association of Journeymen and Apprentices of the Plumbing and Pipe Fitting Industry of the United States and Canada; the International Brotherhood of Electrical Workers (IBEW): and the Utility Workers Union of America. In addition, agency leaders met with the Presidents of several unions and the President of the American Federation of Labor-Congress of Industrial Organizations (AFL-CIO) at the AFL-CIO headquarters.

EPA officials attended meetings sponsored by labor unions to give presentations and engage in discussions about reducing carbon pollution using CAA section 111(d). These included meetings sponsored by the IBB and the IBEW.

11. Other federal agencies and independent agencies

Throughout the development of the rulemaking, the EPA consulted with other federal agencies with relevant expertise. For example, the EPA met with managers from the U.S. Department of Agriculture’s (USDA’s) Rural Utility Service to discuss the rule and potential effects on affected EGUs in rural areas and how USDA programs could interact with affected EGUs during rule implementation.

The U.S. Department of Energy (DOE) was a frequent source of expertise on the proposed and final rule. EPA management and staff had numerous meetings with management and staff at DOE on a range of topics, including the effectiveness and costs of energy generation technologies, and EE.

DOE provided technical assistance relating to RE and demand-side EE, including RE and demand-side EE cost and performance data and, for RE, information on the feasibility of deploying and reliably integrating increased RE generation. Further, EPA and DOE staff discussed emission measurement and verification (EM&V) strategies.

The EPA also consulted with DOE on electric reliability issues. EPA staff and managers met and spoke with DOE staff and managers throughout the development of the proposed and final rules on topic related to electric system reliability.

EPA officials worked closely with DOE and Federal Energy Regulatory Commission (FERC) officials to ensure, to the greatest extent possible, that actions taken by states and affected EGUs to comply with the final rule mitigate potential electric system reliability issues. Senior EPA officials met with each of the FERC Commissioners and EPA staff had frequent contact with FERC staff throughout the development the rule. FERC held four technical conferences to discuss implications of compliance approaches to the rule for electric reliability. EPA staff attended the four conferences and EPA leadership spoke at all of them. The EPA, DOE, and FERC will continue to work together to ensure electric grid reliability in the development and implementation of state plans.

L. Comments on the Proposal

The Administrator signed the proposed emission guidelines on June 2, 2014, and, on the same day, the EPA made this version available to the public at http://www.epa.gov/cleanpowerplan/. The 120-day public comment period on the proposal began on June 18, 2014, the day of publication of the proposal in the *Federal Register*. On September 18, 2014, in response to requests from stakeholders, the EPA extended the comment period by 45 days, to December 1, 2014, giving stakeholders over 165 days to review and comment upon the proposal. Stakeholders also had the opportunity to comment on the NODA, as well as the notice and TSD regarding potential methods for determining the mass that is equivalent to an emission rate-based CO_2 goal, through December

1, 2014. The EPA offered a separate 45-day comment period for the November 4, 2014 supplemental proposal, and that comment period closed on December 19, 2014.

The EPA received more than 4.2 million comments on the proposed carbon pollution emission guidelines from a range of stakeholders that included, including state environmental and energy officials, local government officials, tribal officials, public utility commissioners, system operators, utilities, public interest advocates, and members of the public. The agency received comments on many aspects of the proposal and many suggestions for changes that would address issues of concern.

III. Rule Requirements and Legal Basis

A. Summary of Rule Requirements

The EPA is establishing emission guidelines for states to use in developing plans to address GHG emissions from existing fossil fuel-fired electric generating units. The emission guidelines are based on the EPA's determination of the "best system of emission reduction ... adequately demonstrated" (BSER) and include source category-specific CO_2 emission performance rates, state-specific goals, requirements for state plan components, and requirements for the process and timing for state plan submittal and compliance.

Under CAA section 111(d), the states must establish standards of performance that reflect the degree of emission limitation achievable through the application of the "best system of emission reduction" that, taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements, the Administrator determines has been adequately demonstrated.

The EPA has determined that the BSER is the combination of emission rate improvements and limitations on overall emissions at affected EGUs that can be accomplished through the following three sets of measures or building blocks:

1. Improving heat rate at affected coal-fired steam EGUs.
2. Substituting increased generation from lower-emitting existing natural gas combined cycle units for reduced generation from higher-emitting affected steam generating units.
3. Substituting increased generation from new zero-emitting RE generating capacity for reduced generation from affected fossil fuel-fired generating units.

Consistent with CAA section 111(d) and other rules promulgated under this section, the EPA is taking a traditional, performance-based approach to establishing emission guidelines for affected sources and applying the BSER to two source subcategories of existing fossil fuel-fired EGUs -- fossil fuel-fired electric utility steam generating units and stationary combustion turbines. The EPA is finalizing source subcategory-specific emission performance rates that reflect the EPA's application of the BSER. For fossil fuel-fired steam generating units, we are finalizing a performance rate of 1,305 lb CO_2/MWh. For stationary combustion turbines, we are finalizing a performance rate of 771 lb CO_2/MWh. The EPA has also translated the source subcategory-specific CO_2 emission performance rates into equivalent statewide rate-based and mass-based CO_2 goals and is providing those as an option for states to use.

Under CAA section 111(d), each state must develop, adopt, and then submit its plan to the EPA. For its CAA section 111(d) plan, a state will determine whether to apply these emission performance rates to each affected EGU, individually or together, or to take an alternative approach and meet either an equivalent statewide rate-based goal or an equivalent statewide mass-based goal, as provided by the EPA in this rulemaking.

States with one or more affected EGUs will be required to develop and implement plans that set emission standards for affected EGUs. The CAA section 111(d) emission guidelines that the EPA is promulgating in this action apply to only the 48 contiguous states and any Indian tribe that has been approved by the EPA pursuant to 40 CFR 49.9 as eligible to develop and implement a CAA section 111(d) plan..[281]Because Vermont and the District of Columbia do not have affected EGUs, they will not be required to submit a state plan. Because the EPA does not possess all of the information and analytical tools needed to quantify the BSER for the two non-contiguous states with otherwise affected EGUs (Alaska and Hawaii) and the two U.S. territories with otherwise affected EGUs (Guam and Puerto Rico), these emission guidelines do not apply to those areas, and those areas will not be required to submit state plans on the schedule required by this final action.

In developing its CAA section 111(d) plan, a state will have the option of choosing from two different approaches: 1) an "emission standards" approach, or 2) a "state measures" approach. With an emission standards approach, a state will apply all requirements for achieving the subcategory-specific CO_2 emission performance rates or the state-specific CO_2 emission goal to affected EGUs in the form of federally enforceable

[281] In the case of a tribe that has one or more affected EGUs in its area of Indian country, the tribe has the opportunity, but not the obligation, to establish a CO_2 emission standard for each affected EGU located in its area of Indian country and a CAA section 111(d) plan for its area of Indian country. If the tribe chooses to establish its own plan, it must seek and obtain authority from the EPA to do so pursuant to 40 CFR 49.9. If it chooses not to seek this authority, the EPA has the responsibility to determine whether it is necessary or appropriate, in order to protect air quality, to establish a CAA section 111(d) plan for an area of Indian country where affected EGUs are located.

emission standards. With a state measures approach, a state plan would be comprised, at least in part, of measures implemented by the state that are not included as federally enforceable components of the plan, along with a backstop of federally enforceable emission standards for affected EGUs that would apply in the event the plan does not achieve its anticipated level of CO_2 emission performance.

The EPA is requiring states to make their final plan submittals by September 6, 2016, or to make an initial submittal by this date in order to obtain an extension for making their final plan submittals no later than September 6, 2018, which is 3 years from the signature date of the rule. In order to receive an extension, states, in the initial submittal, must address three required components sufficiently to demonstrate that a state is able to undertake steps and processes necessary to timely submit a final plan by the extended date of September 6, 2018. The first required component is identification of final plan approach or approaches under consideration, including a description of progress made to date. The second required component is an appropriate explanation for why the state requires additional time to submit a final plan beyond September 6, 2016. The third required component for states to address in the initial submittal is a demonstration of how they have been engaging with the public, including vulnerable communities, and a description of how they intend to meaningfully engage with community stakeholders during the additional time (if an extension is granted) for development of the final plan.

Affected EGUs must achieve the final emission performance rates or equivalent state goals by 2030 and maintain that level thereafter. The EPA is establishing an eight-year interim period over which states must achieve the full required reductions to meet the CO_2 performance rates, and this begins in 2022. This eight-year interim period from 2022 through 2029, is separated into three steps, 2022-2024, 2025-2027, and 2028-2029, each associated with its own interim CO_2 emission performance rates that states must meet, as explained in Section VI of this preamble.

For the final emission guidelines, the EPA is revising the list of components required in a final state plan submittal to reflect: 1) components required for all state plan submittals; 2) components required for the emission standards approach; and 3) components required for the state measures approach. The revised list of components also reflects the approvability criteria, which are no longer separate from the state plan submittal components.

All state plans must include the following components:

- Description of the plan approach and geographic scope
- Identification of the state's CO_2 interim period goal (for 2022-2029), interim steps (interim step goal 1 for 2022-

2024; interim step goal 2 for 2025-2027; interim step goal 3 for 2028-2029) and final CO_2 emission goal of 2030 and beyond
- Demonstration that the plan submittal is projected to achieve the state's CO_2 emission goal[282]
- State recordkeeping and reporting requirements
- Certification of hearing on state plan
- Supporting documentation

Also, in all state plans, as part of the supporting documentation, a state must include a description of how they considered reliability in developing its state plan.

State plan submittals using the emission standards approach must also include:

- Identification of each affected EGU; identification of federally enforceable emission standards for the affected EGUs; and monitoring, recordkeeping and reporting requirements.
- Demonstrations that each emission standard will result in reductions that are quantifiable, non-duplicative, permanent, verifiable, and enforceable.

State plan submittals using the state measures approach must also include:

- Identification of each affected EGU; identification of federally enforceable emission standards for affected EGUs (if applicable); identification of backstop of federally enforceable emission standards; and monitoring, recordkeeping and reporting requirements.
- Identification of each state measure and demonstration that each state measure will result in reductions that are quantifiable, non-duplicative, permanent, verifiable, and enforceable.

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[282] A state that chooses to set emission standards that are identical to the emission performance rates for both the interim period and in 2030 and beyond need not identify interim state goals nor include a separate demonstration that its plan will achieve the state goals.

In addition to these requirements, each state plan must follow the EPA implementing regulations at 40 CFR 60.23.

If a state with affected EGUs does not submit a plan or if the EPA does not approve a state's plan, then under CAA section 111(d)(2)(A), the EPA must establish a plan for that state. A state that has no affected EGUs must document this in a formal negative declaration submitted to the EPA by September 6, 2016. In the case of a tribe that has one or more affected EGUs in its area of Indian country,[283] the tribe has the opportunity, but not the obligation, to establish a CAA section 111(d) plan for its area of Indian country. If a tribe with one or more affected EGUs located in its area of Indian country does not submit a plan or does not receive EPA approval of a submitted plan, the EPA has the responsibility to establish a CAA section 111(d) plan for that area if it determines that such a plan is necessary or appropriate.

During implementation of its approved state plan, each state must demonstrate to the EPA that its affected EGUs are

[283] The EPA is aware of at least four affected EGUs located in Indian country: two on Navajo lands, the Navajo Generating Station and the Four Corners Power Plant; one on Ute lands, the Bonanza Power Plant; and one on Fort Mojave lands, the South Point Energy Center. The affected EGUs at the first three plants are coal-fired EGUs. The fourth affected EGU is an NGCC facility.

meeting the interim and final performance requirements included in this final rule through monitoring and reporting requirements. State plan requirements and flexibilities are described more fully in Section VIII of this preamble.

B. Brief Summary of Legal Basis

This rule is consistent with the requirements of CAA section 111(d) and the implementing regulations.[284] As an initial matter, the EPA reasonably interprets the provisions identifying which air pollutants are covered under CAA section 111(d) to authorize the EPA to regulate CO_2 from fossil fuel-fired EGUs. In addition, the EPA recognizes that CAA section 111(d) applies to sources that, if they were new sources, would be covered under a CAA section 111(b) rule. Concurrently with this rule, the EPA is finalizing a CAA section 111(b) rulemaking establishing

[284] Under CAA section 111(d), there is no requirement that the EPA make a finding that the emissions from existing sources that are the subject of regulation cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. As predicates to promulgating regulations under CAA section 111(d) for existing sources, the EPA must make endangerment and cause-or-contribute-significantly findings for emissions from the source category, and the EPA must promulgate regulations for new sources in the source category. In the CAA section 111(b) rule for CO_2 emissions for new affected EGUs that the EPA is promulgating concurrently with this rule, the EPA discusses the endangerment and cause-or-contribute-significantly findings and explains why the EPA has already made them for the affected EGU source categories so that the EPA is not required to make them for CO_2 emissions from affected EGUs, and, in the alternative, why, if the EPA were required to make those findings, it was making them in that rulemaking.

standards of performance for CO_2 emissions from new fossil fuel-fired EGUs, from modified fossil fuel-fired EGUs, and from reconstructed fossil fuel-fired EGUs, and any of those sets of section 111(b) standards of performance provides the requisite predicate for this rulemaking.

A key step in promulgating requirements under CAA section 111(d)(1) is determining the "best system of emission reduction which ... the Administrator determines has been adequately demonstrated" (BSER) under CAA section 111(a)(1). It is clear by the terms of section 111(a)(1) and the implementing regulations for section 111(d) that the EPA is authorized to determine the BSER;[285] accordingly, in this rulemaking, the EPA is determining the BSER.

The EPA is finalizing the BSER for fossil fuel-fired EGUs based on building blocks 1, 2, and 3. Building block 1 includes operational improvements and equipment upgrades that the coal-fired steam-generating EGUs in the state may undertake to improve their heat rate. It qualifies as part of the BSER because it improves the carbon intensity of the affected EGUs in generating electricity through actions the affected sources may undertake that are adequately demonstrated and whose cost is "reasonable." Building blocks 2 and 3 include increases in low-

[285] The EPA is not re-opening that interpretation in this rulemaking.

or zero-emitting generation which substitute for generation from the affected EGUs and thereby reduce CO_2 emissions from those sources. All of these measures are components of a "system of emission reduction" for the affected EGUs because they entail actions that the affected EGUs may themselves undertake that have the effect of reducing their emissions. Further, these measures meet the criteria in CAA section 111(a)(1) and the case law for the "best" system of emission reduction that is "adequately demonstrated" because they achieve the appropriate level of reductions, their cost is "reasonable," they do not have adverse non-air quality health and environmental impacts or impose adverse energy requirements, and they are each well-established among affected EGUs. It should be emphasized that these measures are consistent with current trends in the electricity sector.

Building blocks 2 and 3 may be implemented through a set of measures, including reduced generation from the fossil fuel-fired EGUs. These measures do not, however, reduce the amount of electricity that can be sold or that is available to end users. In addition, states should be expected to allow their affected EGUs to trade rate-based emission credits or mass-based emission allowances (trading) because trading is well-established for this industry and has the effect of focusing costs on the affected EGUs for which reducing emissions is most cost-effective. Because trading facilitates implementation of the building blocks and may help to optimize cost-effectiveness, trading is a method of implementing the BSER as well.

As a result, an affected EGU has a set of choices for achieving its emission standards. For example, an affected coal-fired steam generating unit can achieve a rate-based standard through a set of actions that implement the building block 1 measures and that implement the building block 2 and 3 measures through a set of actions that range from purchasing full or partial interest in existing NGCC or new RE assets to purchasing ERCs that represent the environmental attributes of increased NGCC generation or new renewable generation. In addition, the affected EGU may reduce its generation and thereby reduce the extent that it needs to implement the building blocks. The affected EGU may also purchase rate-based emission credits from other affected EGUs. If the state chooses to impose a mass-based emission standard, the coal-fired steam generating unit may implement building block 1 measures, purchase mass-based emission allowances from other affected EGUs, or reduce its generation. In light of the available sources of lower- and zero-emitting replacement generation, this approach would achieve an appropriate level of emission reductions and maintain the reliability of the electricity system.

With the promulgation of the emission guidelines, each state must develop and submit a plan to achieve the CO_2 emission performance rates established by the EPA or the equivalent statewide rate-based or mass-based goal provided by the EPA in this rule. The EPA interprets CAA section 111(d) to allow states to establish standards of performance and provide for their implementation and enforcement through either the "emission standards" or the "state measures" plan type. In the case of the "emission standards" plan type, the emission standards establish standards of performance, and the other components of the plan provide for their implementation and enforcement. In the case of the "state measures" plan type, –the state submits a plan that relies upon measures that are only enforceable as a matter of state law that will, in conjunction with any emission standards on affected EGUs, result in the achievement of the applicable performance rates or state goals by the affected EGUs. Under the state measures plan type, states must also submit a federally enforceable backstop and a mechanism that would trigger implementation of the backstop; therefore, in a state measures plan, the standards of performance take the form of the backstop, the trigger mechanism provides for the implementation of such backstop, and the other required components of the plan provide for implementation and enforcement of the standards of performance.

These two types of state plans and their respective approaches, which could be implemented on a single-state or multi-state basis, allow states to meet the statutory requirements of section 111(d) while accommodating the wide range of regulatory requirements and other programs that states have deployed or will deploy in the electricity sector that reduce CO_2 emissions from affected EGUs. It should be noted that both state plan types allow the state flexibility in assigning the emission performance obligations to its affected EGUs in the form of standards of performance as long as the required emission performance level is met. Both plan types harness the efficiencies of emission reduction opportunities in the interconnected electricity system and are fully consistent with the principles of cooperative federalism that underlie the Clean Air Act generally and CAA section 111(d) particularly. That is, both plan types achieve the emission performance requirements through the vehicle of a state plan, and provide each state significant flexibility to take local circumstances and state policy goals into account in determining how to reduce emissions from its affected sources, as long as the plan meets minimum federal requirements.

Both state plan types, and the standards of performance for the affected EGUs that the states will establish through the state plan process, are consistent with the applicable CAA section 111 provisions. A state has discretion in determining the appropriate measures to rely upon for its plan. The state may adopt measures that assure the achievement of the requisite CO_2 emission performance rate or state goal by the affected EGUs, and is not limited to the measures that the EPA identifies as part of the BSER.

In this rulemaking, the EPA establishes reasonable deadlines for state plan submission. Under CAA section 111(d)(1), state plans must "provide for implementation and enforcement" of the standards of performance, and under CAA section 111(d)(2), the state plans must be "satisfactory" for the EPA to approve them. In this rulemaking, the EPA is finalizing the criteria that the state plans must meet under these requirements.

The EPA discusses its legal interpretation in more detail in other parts of this preamble and provides additional information about certain issues in the Legal Memorandum included in the docket for this rulemaking.

IV. Authority for this Rulemaking, Definition of Affected Sources, and Treatment of Source Categories

A. EPA's Authority under CAA Section 111(d)

EPA's authority for this rule is CAA section 111(d). CAA section 111(d) provides that the EPA will promulgate regulations under which each state will establish standards of performance for existing sources for any air pollutant that meets two criteria. First, CAA section 111(d) applies to air pollutants that are not regulated as a criteria pollutant under section 108 or as a hazardous air pollutant (HAP) under CAA section 112. 42 U.S.C. 7411(d)(1)(A)(i).[286] Second, section 111(d) applies only to air pollutants for which the existing source would be regulated under section 111 if it were a new source. 42 U.S.C. 7411(d)(1)(A)(ii). Here, carbon dioxide (CO_2) meets both criteria: (1) it is not a criteria pollutant regulated under section 108 nor a HAP regulated under CAA section 112, and (2) CO_2 emissions from new power plants (including newly constructed, modified and reconstructed power plants) are regulated under the CAA section 111(b) rule that is being finalized along with this rule.

B. CAA Section 112 Exclusion to CAA Section 111(d) Authority

CAA section 111(d) contains an exclusion that limits the regulation under CAA section 111(d) of air pollutants that are regulated under CAA section 112. 42 U.S.C. 7411(d)(1)(A)(i). This “Section 112 Exclusion” in CAA section 111(d) was the subject of a significant number of comments based on two differing amendments to this exclusion enacted in the 1990 CAA

[286] Section 111(d) might be read to apply to HAP under certain circumstances. However, because carbon dioxide is not a HAP, this issue does not need to be resolved in the context of this rule.

Amendments. As discussed in more detail below, the House and the Senate each initially passed different amendments to the Section 112 Exclusion and both amendments were ultimately passed by both houses and signed into law. In 2005, in connection with the Clean Air Mercury Rule (CAMR), the EPA discussed the agency's interpretation of the Section 112 Exclusion in light of these two differing amendments and concluded that the two amendments were in conflict and that the provision should be read as follows to give both amendments meaning: where a source category has been regulated under CAA section 112, a CAA section 111(d) standard of performance cannot be established to address any HAP listed under CAA section 112(b) that may be emitted from that particular source category. See 70 FR 15994, 16029-32 (March 29, 2005).

In June 2014, the EPA presented this previous interpretation as part of the proposal and requested comment on it. The EPA received numerous comments on its previous interpretation, including comments on the proper interpretation and effect of each of the two differing amendments, and whether the Section 112 Exclusion should be read to mean that the EPA's regulation of HAP from power plants under CAA section 112 bars the EPA from establishing CAA section 111(d) regulations covering CO_2 emissions from power plants. In particular, many comments focused on two specific issues. First, some commenters

-- including some industry and state commenters that had previously endorsed the EPA's interpretation of the Section 112 Exclusion in other contexts[287] -- argued that the EPA's 2005 interpretation was in error because it allowed the regulation of certain pollutants from source categories under CAA section 111(d) when those source categories were also regulated for different pollutants under CAA section 112. Second, some commenters argued that the EPA's previous interpretation of the House amendment (as originally represented in 2005 at 70 FR at 16029-30) was in error because it improperly read that amendment as focusing on whether a source category was regulated under CAA section 112 rather than on whether the air pollutant was regulated under CAA section 112, and that improper reading lead to an interpretation that was inconsistent with the structure and purpose of the CAA.

In light of the comments, the EPA has reconsidered its previous interpretation of the Section 112 Exclusion and, in

[287] For example, in the CAMR litigation (State of New Jersey v. EPA, No. 05-1097 (D.C. Cir.), the joint brief filed by a group of intervenors and an amicus (including six states and the West Virginia Department of Environmental Protection, and Utility Air Regulatory Group and nine other industry entities) stated that the EPA had interpreted section 111(d) in light of the two different amendments and that the EPA's interpretation was "a reasoned way to reconcile the conflicting language and the Court should defer to the EPA's interpretation." Joint Brief of State Respondent-Intervenors, Industry Respondent-Intervernors, and State Amicus, filed May 18, 2007, at 25.

particular, considered whether the exclusion precludes the regulation under CAA section 111(d) of CO_2 from power plants given that power plants are regulated for certain HAP under CAA section 112. On this issue, the EPA has concluded that the two differing amendments are not properly read as conflicting. Instead, the House amendment and the Senate Amendment should each be read to mean the same in the context presented by this rule: that the Section 112 Exclusion does not bar the regulation under CAA section 111(d) of non-HAP from a source category, regardless of whether that source category is subject to standards for HAP under CAA section 112. In reaching this conclusion, the EPA has revised its previous interpretation of the House amendment, as discussed below.

1. Structure of the CAA and Pre-1990 Section 112 Exclusion

The Clean Air Act sets out a comprehensive scheme for air pollution control, addressing three general categories of pollutants emitted from stationary sources: (1) criteria pollutants (which are addressed in sections 108-110); (2) hazardous pollutants (which are addressed under section 112); and (3) "pollutants that are (or may be) harmful to public health or welfare but are not or cannot be controlled under sections 108-110 or 112." 40 FR 53340 (Nov. 17, 1975).

Six "criteria" pollutants are regulated under sections 108-110. These are pollutants that the Administrator has concluded "cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare;" "the presence of which in the ambient air results from numerous and diverse mobile or stationary sources;" and for which the Administrator has issued, or plans to issue, "air quality criteria. 42 U.S.C. §7408(a)(1). Once the EPA issues air quality criteria for such pollutants, the Administrator must propose primary National Ambient Air Quality Standards (NAAQS) for them, set at levels "requisite to protect the public health" with an "adequate margin of safety." 42 U.S.C. § 7409(a)-(b). States must then adopt plans for implementing NAAQS. 42 U.S.C. § 7410.

Hazardous air pollutants (HAP) are regulated under CAA section 112 and include the pollutants listed by Congress in section 112(b)(1) and other pollutants that the EPA lists under sections 112(b)(2) and (b)(3). CAA section 112 further provides that the EPA will publish and revise a list of "major" and "area" source categories of HAP, and then establish emissions standards for (HAP) emitted by sources within each listed category. 42 U.S.C. § 7412(c)(1) & (2).

CAA section 111, 42 U.S.C. § 7411, is the third part of the CAA's structure for regulating stationary sources. Section 111 has two main components. First, section 111(b) requires the EPA to promulgate federal "standards of performance" addressing *new* stationary sources that cause or contribute significantly to "air pollution which may reasonably be anticipated to endanger public health or welfare." 42 U.S.C. § 7411(b)(1)(A). Once the EPA has set *new* source standards addressing emissions of a particular pollutant under CAA section 111(b), CAA section 111(d) provides that the EPA will promulgate regulations requiring states to establish standards of performance for *existing* stationary sources of the same pollutant. 42 U.S.C. § 7411(d)(1).

Together, the criteria pollutant/NAAQS provisions in sections 108-110, the hazardous air pollutant provisions in section 112, and performance standard provisions in section 111 constitute a comprehensive scheme to regulate air pollutants with "no gaps in control activities pertaining to stationary source emissions that pose any significant danger to public health or welfare." S. Rep. No. 91-1196, at 20 (1970). [288]

The specific role of CAA section 111(d) in this structure can be seen in CAA subsection 111(d)(1)(A)(i), which provides that regulation under CAA section 111(d) is intended to cover pollutants that are not regulated under either the criteria pollutant/NAAQS provisions or the HAP regulated under section 112. Prior to 1990, this limitation was laid out in plain

[288] In subsequent CAA amendments, Congress has maintained this three-part scheme, but supplemented it with the Preservation of Significant Deterioration (PSD) program, the Acid Rain Program and the Regional Haze program.

language, which stated that CAA section 111(d) regulation applied to "any air pollutant… for which air quality criteria have not been issued or which is not included on a list published under section [108(a)] or [112(b)(1)(A)]." This plain language demonstrated that section 111(d) is designed to regulate pollutants from existing sources that fall in the gap not covered by the criteria pollutant provisions or the hazardous air pollutant provisions.

This gap-filling purpose can be seen in the early legislative history of the CAA. As originally enacted in the 1970 CAA, the precursor to CAA section 111 (which was originally section 114) was described as covering pollutants that would not be controlled by the criteria pollutant provisions or the hazardous air pollutant provisions. See S. Committee Rep. to accompany S. 4358 (Sept. 17, 1970), 1970 CAA Legis. Hist. at 420 ("It should be noted that the emission standards for pollutants which cannot be considered hazardous (as defined in section 115 [which later became section 112]) could be established under section 114 [later, section 111]. Thus, there should be no gaps in control activities pertaining to stationary source emissions that pose any significant danger to public health or welfare."); Statement by S. Muskie, S. Debate on S. 4358 (Sept. 21, 1970), 1970 CAA Legis. Hist. at 227 ("[T]he bill [in section 114] provides the Secretary with the authority to set emission standards for selected pollutants which cannot be controlled through the ambient air quality standards and which are not hazardous substances.”).

2. The 1990 Amendments to the Section 112 Exclusion

The Act was amended extensively in 1990. Among other things, Congress sought to accelerate the EPA’s regulation of hazardous pollutants under section 112. To that end, Congress established a lengthy list of HAP; set criteria for listing “source categories” of such pollutants; and required the EPA to establish standards for each listed source category’s hazardous pollutant emissions. 42 U.S.C. § 7412(b), (c) and (d). In the course of overhauling the regulation of (HAP) under section 112, Congress needed to edit section 111(d)’s reference to section 112(b)(1)(A), which was to be eliminated as part of the revisions to section 112.

To address the obsolete cross-reference to section 7412(b)(1)(A), Congress passed two differing amendments – one from the Senate and one from the House – that were never reconciled in conference. The Senate amendment replaced the cross reference to old section 112(b)(1)(A) with a cross-reference to new section 112. Pub. L. No. 101-549, § 302(a), 104 Stat. 2399, 2574 (1990). The House amendment replaced the cross-reference with the phrase “emitted from a source category which is regulated under section [112].” Pub. L. No. 101-549, §

108(g), 104 Stat. 2399, 2467 (1990).[289] Both amendments were enacted into law, and thus both are part of the current CAA. To determine how this provision is properly applied in light of the two differing amendments, we first look at the Senate amendment, then at the House amendment, then discuss how the two amendments are properly read together.

3. The Senate Amendment is Clear and Unambiguous

[289] Originally, when the House bill to amend the CAA was introduced in January 1989, it focused on amendments to control HAP. Of particular note, the amendments to section 112 included a provision that excluded regulation under section 112 of "[a]ny air pollutant which is included on the list under section 108(a), or which is regulated for a source category under section 111(d)." H.R. 4, § 2 (Jan. 3, 1989), 1990 CAA Legist. Hist. at 4046. In other words, the Section 112 Exclusion in section 111(d) that was ultimately contained in the House amendment was originally crafted as what might be called a "Section 111(d) Exclusion" in section 112. This is significant because the "source category" phrasing in the original January 1989 text with respect to section 111(d) makes sense, whereas the "source category" phrasing in the 1990 House amendment does not. When referring to the scope of what is regulated under section 111(d), it makes sense to frame that scope with respect to source categories, because section 111 regulation begins with the identification of source categories under section 111(b)(1)(A). By contrast, regulation under section 112 begins with the identification of HAP under section 112(b); the listing of source categories under section 112(c) is secondary to the listing of HAP. From this history, and in light of this difference between the scope of what is regulated in sections 111 and 112, it is reasonable to conclude that the "source category" phrasing is a legacy from the original 1989 bill—that is, when converting the 1989 text into the Section 112 Exclusion that we see in the 1990 House amendment, the legislative drafters continued to use phrasing based on "source category" notwithstanding that this phrasing created a mismatch with the way that the scope of section 112 regulation is determined.

Unlike the ambiguous amendment to CAA section 111(d) in the House amendment (discussed below), the Senate amendment is straightforward and unambiguous. It maintained the pre-1990 meaning of the Section 112 Exclusion by simply substituting "section 112(b)" for the prior cross-reference to "section 112(b)(1)(A)." Pub. L. No. 101-549, § 302(a), 104 Stat. 2399, 2574 (1990). So amended, section 111(d) mandates that the EPA require states to submit plans establishing standards for "any air pollutant . . . which is not included on a list published under section [108(a)] or section [112(b)]." Thus, the Section 112 Exclusion resulting from the Senate amendment would preclude section 111(d) regulation of HAP emission but would not preclude section 111(d) regulation of CO_2 emissions from power plants notwithstanding that power plants are also regulated for HAP under CAA section 112.

Some commenters have argued that the Senate amendment should be given no effect, because only the House amendment is shown in the U.S. Code, and because the Senate amendments appeared under the heading "conforming amendments," and for various other reasons. The EPA disagrees. The Senate amendment, like the House amendment, was enacted into law as part of the 1990 CAA amendments, and must be given effect.

First, that the U.S. Code only reflects the House amendment does not change the fact that both amendments were signed into law as part of the 1990 Amendments, as shown in the Statutes at Large. Pub. L. No. 101-549, §§ 108(g) and 302(a), 104 Stat. 2399, 2467, 2574 (1990). Where there is a conflict between the U.S. Code and the Statutes at Large, the latter controls. See 1 U.S.C. §§ 112 & 204(a); Stephan v. United States, 319 U.S. 423, 426 (1943) ("the Code cannot prevail over the Statutes at Large when the two are inconsistent"); Five Flags Pipe Line Co. v. Dep't of Transp., 854 F.2d 1438, 1440 (D.C. Cir. 1988) ("[W]here the language of the Statutes at Large conflicts with the language in the United States Code that has not been enacted into positive law, the language of the Statutes at Large controls.").

Second, the "conforming" label is irrelevant. A "conforming" amendment may be either substantive or non-substantive. Burgess v. United States, 553 U.S. 124, 135 (2008). And while the House Amendment contains more words, it also qualifies as a "conforming amendment" under the definition in the Senate Legislative Drafting Manual, Section 126(b)(2) (defining "conforming amendments" as those "necessitated by the substantive amendments of provisions of the bill"). Here, both the House and Senate amendments were "necessitated by" Congress' revisions to section 112 in the 1990 CAA Amendment, which included the deletion of old section 112(b)(1)(A). Thus, the House's amendment is no less "conforming" than the Senate's, and the heading under which it was enacted ("Miscellaneous Guidance") does not suggest any more importance than "Conforming Amendments." In any event, courts gives full effect to conforming amendments, see Washington Hosp. Ctr. v. Bowen, 795 F.2d 139, 149 (D.C. Cir. 1986), and so neither the Senate Amendment nor the House amendment can be ignored.

Third, the legislative history of the Senate amendment supports the conclusion that the substitution of the updated cross-reference was not a mindless, ministerial decision, but reflected a decision to choose an update of the cross reference instead of the text that was inserted into the Section 112 Exclusion by the House amendment. In mid-1989, the House and Senate introduced identical bills (H.R. 3030 and S. 1490, respectively) to provide for "miscellaneous" changes to the CAA. In both the Senate and House bills as they were introduced in mid-1989, the Section 112 Exclusion was to be amended by taking out "or 112(b)(1)(A)" and inserting "or emitted from a source category which is regulated under section 112." H.R. 3030, as introduced, 101st Cong. § 108 (Jul. 27, 1989); S. 1490, as introduced, 101st Cong. § 108 (Aug. 3, 1989). See 1990 CAA Legis. Hist. at 3857 (noting that H.R. 3030 and S.1490, as introduced, were the same). Although S. 1490 was identical to H.R. 3030 when they were introduced, the Senate reported a vastly different bill (S.1630) at the end of 1989. See S. 1630, as reported (Dec. 20, 1989), 1990 CAA Legis. Hist. at 7906. As reported and eventually passed, S. 1630 did not contain the text in the House amendment ("or emitted from a source category which is regulated under section 112") and instead contained the substitution of cross references (changing "section 112(b)(1)(A)" to "section 112(b)"). *See* S. 1630, as reported, 101st Cong. § 305, 1990 CAA Legis. Hist. at 8153; S. 1630, as passed, § 305 (Apr. 3, 1990), 1990 CAA Legis. Hist. at 4534. Though the EPA is not aware of any statements in the legislative history that expressly explain the Senate's intent in making these changes to the Senate bill, the sequence itself supports the conclusion that the Senate's substitution reflects a decision to retain the pre-1990 approach of using a cross-reference to 112(b) to define the scope of the Section 112 Exclusion. Whether the difference in approach between the final Senate amendment in S.1630 and the House amendment in H.R. 3030 creates a substantive difference or are simply two different means of achieving the same end depends on what interpretation one gives to the text in the House amendment, which we turn to next.

4. The House amendment

a. The House amendment is ambiguous. Before looking at the specific text of the House amendment, it is helpful to review some principles of statutory interpretation. First, statutory interpretation begins with the text, but does not end there. As the D.C. Circuit Court has explained, "[t]he literal language of a provision taken out of context cannot provide conclusive proof of congressional intent." Bell Atlantic Telephone Cos. v. F.C.C., 131 F.3d 1044, 1047 (D.C. Cir. 1977). See King v. Burwell, 2015 U.S. LEXIS 4248, *19("[O]ftentimes the 'meaning—or ambiguity—of certain words or phrases may only become evident when placed in context.' Brown & Williamson, 529 U. S., at 132, 120 S. Ct. 1291, 146 L. Ed. 2d 121. So when deciding whether the language is plain, we must read the words 'in their context and with a view to their place in the overall statutory scheme.' Id., at 133, 120 S. Ct. 1291, 146 L. Ed. 2d 121 (internal quotation marks omitted). Our duty, after all, is 'to construe statutes, not isolated provisions.' Graham County Soil and Water Conservation Dist. v. United States ex rel. Wilson, 559 U. S. 280, 290, 130 S. Ct. 1396, 176 L. Ed. 2d 225 (2010) (internal quotation marks omitted)."). In addition, statutes should not be given a "hyperliteral" reading that is contrary to established canons of statutory construction and common sense. See RadLAX Gateway Hotel v. Amalgamated Bank, 132 S.Ct. 2065, 20, 2070-71 (2012), 2070-71 (2012).

Further, a proper reading of statutory text "must employ all the tools of statutory interpretation, including text, structure, purpose, and legislative history." Loving v. I.R.S., 742 F.3d

1013, 1016 (D.C. Cir. 2014) (internal quotation omitted). See, also, Robinson v. Shell Oil Co., 519 U.S. 337, 341 (1997) (statutory interpretation involves consideration of "the language itself, the specific context in which that language is used, and the broader context of the statute as a whole."). Moreover, one principle of statutory construction that has particular application here is that provisions in a statute should be read to be consistent, rather than conflicting, if possible. This principle was discussed in the recent case of Scialabba v. Cuellar De Osorio, 134 S. Ct. 2191, 2214 (concurring opinion by Chief Justice Roberts and Justice Scalia), 2219-2220 (dissent by Justices Sotomayor, Breyer and Thomas)(2014). As Justice Sotomayor wrote (at 134 S. Ct. at 2220):

> "We do not lightly presume that Congress has legislated in self-contradicting terms. See A. Scalia & B. Garner, Reading Law: The Interpretation of Legal Texts 180 (2012) ("The provisions of a text should be interpreted in a way that renders them compatible, not contradictory. . . . [T]here can be no justification for needlessly rendering provisions in conflict if they can be interpreted harmoniously"). . . . Thus, time and again we have stressed our duty to "fit, if possible, all parts [of a statute] into [a] harmonious whole." FTC v. Mandel Brothers, Inc., 359 U.S. 385, 389, 79 S. Ct. 818, 3 L. Ed. 2d 893 (1959); see also Morton v. Mancari, 417 U.S. 535, 551, 94 S. Ct. 2474, 41 L. Ed. 2d 290 (1974) (when two provisions "are capable of co-existence, it is the duty of the courts . . . to regard each as effective"). In reviewing an agency's construction of a statute, courts "must," we have emphasized, "interpret the statute 'as a . . . coherent regulatory scheme'" rather than an internally inconsistent muddle, at war with itself and defective from the day it was written. Brown &

Williamson, 529 U.S., at 133, 120 S. Ct. 1291, 146 L. Ed. 2d 121.

As amended by the House, CAA section 111(d)(1)(A)(i) limits CAA section 111(d) to any air pollutant "for which air quality criteria have not been issued or which is not included on a list published under section 7408(a) of this title or emitted from a source category which is regulated under section 7412 of this title . . ." This statutory text is ambiguous and subject to numerous possible readings.

First, the text of the House-amended version of CAA section 111(d) could be read literally as authorizing the regulation of any pollutant that is not a criteria pollutant. This reading arises if one focuses on the use of "or" to join the three clauses:

> The Administrator shall prescribe regulations . . . under which each State shall submit to the Administrator a plan which establishes standards of performance for any existing source for any air pollutant [1] for which air quality criteria have not been issued or [2] which is not included on a list published under section 7408(a) of this title or [3] emitted from a source category which is regulated under section 7412 of this title . . . .

42 U.S.C. § 7411(d)(1) (emphasis and internal numbering added). Because the text contains the conjunction "or" rather than "and" between the three clauses, a literal reading could read the three clauses as alternatives, rather than requirements to be imposed simultaneously. In other words, a literal reading of the language of section 111(d) provides that the Administrator may

require states to establish standards for an air pollutant so long as *either* air quality criteria have not been established for that pollutant, *or* one of the remaining criteria is met. If this reading were applied to determine whether the EPA may promulgate section 111(d) regulations for CO_2 from power plants, the result would be that CO_2 from power plants coule be regulated under section 111(b) because air quality criteria have not been issued for CO_2 and therefore whether CO_2 or power plants are regulated under section 112 would be irrelevant. This reading, however, is not a reasonable reading of the statute because, among other reasons, it gives little or no meaning to the limitation covering (HAP) that are regulated under CAA section 112 and thus is contrary to both the CAA's comprehensive scheme created by the three sets of provisions (under which CAA section 111 is not intended to duplicate the regulation of pollutants regulated under section112) and the principle of statutory construction that text should not be construed such that a provision does not have effect.

A second reading of CAA section 111(d) as revised by the House amendment focuses on the lack of a negative before the third clause. That is, unlike the first and second clauses that each contain negative phrases (either "has not been issued" or "which is not included"), the third clause does not. One could presume that the negative from the second clause was intended to carry over, implicitly inserting another "which is not" before "emitted from a source category which is regulated under section [112]." But that is a presumption, and not the plain language of the statute. The text as amended by the House says that the EPA "shall" prescribe regulations for "any air pollutant . . . emitted from a source category which is regulated under section [112]." 42 U.S.C. § 7411(d)(1). Thus, CAA section 111(d)(1)(A)(i) could be read as providing for the regulation of emissions of pollutants if they are emitted from a source category that is regulated under CAA section 112. Like the first reading discussed above, this reading would authorize the regulation of CO_2 emissions from existing power plants under CAA section 111(d). But, this second reading is not reasonable because it would provide for the regulation of a source's HAP emissions under CAA section 111(d) when those same emissions were also subject to standards under CAA section 112. Thus, this reading would be contrary to Congress's intent that CAA section 111(d) regulation fill the gap between the other programs by covering pollutants that the other programs do not, but not duplicate the regulation of pollutants that the other programs cover.

If one does presume that the "which is not" phrase is intended to carry over to the third clause, then CAA section 111(d) regulation under the House amendment would be limited to "any air pollutant…which is not… emitted from a source category which is regulated under section [112]." Even with this presumption, however, the House amendment contains further ambiguities with respect to the phrases "a source category" and "regulated under section 112," and how those phrases are used within the structure of the provision limiting what air pollutants may be regulated under CAA section 111(d).

The phrase "regulated under section 112" is ambiguous. As the Supreme Court has explained in the context of other statutes using a variation of the word "regulate," an agency must consider what is being regulated. See Rush Prudential HMO, Inc. v. Moran, 536 U.S. 355, 366 (2002) (It is necessary to "pars[e] . . . the 'what'" of the term "regulates."); UNUM Life Ins. Co. of Am. v. Ward, 526 U.S. 358, 363 (1999) (the term "'regulates insurance' . . . requires interpretation, for [its] meaning is not plain."). Here, one possible reading is that the phase modifies the words "a source category" without regard to what pollutants are regulated under section 112, which then presents the issue of what meaning to give to the phrase "a source category."

Under this reading, and assuming the phrase "a source category" is read to mean the particular source category, the House amendment would preclude the regulation under CAA section 111(d) of a specific source category for any pollutant if that source category has been regulated for any HAP under CAA section 112.[290] The effect of this reading would be to preclude the regulation of CO_2 from power plants under CAA section 111(d) because power plants have been regulated for (HAP) under CAA section 112. This is the interpretation that the EPA applied to the House amendment in connection with the CAMR rule in 2005, when looking at the question of whether HAP can be regulated under CAA section 111(d) for a source category that is not regulated for HAP under section 112, and some commentors have advocated for this interpretation here. But, after considering all of the comments and reconsidering this interpretation, the EPA has concluded that this interpretation of the House amendment is not a reasonable reading because it would disrupt the comprehensive scheme for regulating existing sources created by the three sets of provisions covering criteria pollutants, (HAP) and the other pollutants that fall outside of those two programs and frustrate the role that section 111 is intended to

[290] "A source category" could also be interpreted to mean "any source category." Under this interpretation, CAA 111(d) regulation would be limited to air pollutants that are not emitted by any source category for which the EPA has issued standards for HAP under CAA section 112. This interpretation is not reasonable because it would effectively read CAA 111(d) out of the statute. Given the extensive list of source categories regulated under CAA 112 and the breadth of pollutants emitted by those categories collectively, literally all air pollutants would be barred from CAA 111(d) regulation under this interpretation.

play.[291] Specifically, under this interpretation, the EPA could not regulate a source category's emissions of HAP under CAA section 112, and then promulgate regulations for other pollutants from that source category under CAA section 111(d).[292] There is no reason to conclude that the House amendment was intended to abandon the existing structure and relationship between the three programs in this way. Indeed, Congress expressly provided that regulation under CAA section 112 was not to "diminish or replace the requirements of" the EPA's regulation of non-hazardous pollutants under section 7411. See 42 U.S.C. § 7412(d)(7). Further, consistent with CAA section 112's direction that EPA list "all categories and subcategories of major sources and area [aka, non-major] sources" of HAP and then establish CAA section 112 standards for those categories

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[291] In assessing any interpretation of section 111(d), EPA must consider how the three main programs set forth in the CAA work together. See UARG, 134 S. Ct. at 2442 (a "reasonable statutory interpretation must account for . . . the broader context of the statute as a whole") (quotation omitted).

[292] Supporters of this interpretation have noted that the EPA could regulate power plants under both CAA section 111(d) and CAA section 112 if it regulated under section 111(d) first, before the Section 112 Exclusion is triggered. But that argument actually further demonstrates another reason why this interpretation is unreasonable. There is no basis for concluding that Congress intended to mandate that section 111(d) regulation occur first, nor is there any logical reason why the need to regulate under section 111(d) should be dependent on the timing of such regulation in relation to CAA 112 regulation of that source category.

and subcategories, 42 U.S.C. §§ 7412(c)(1) and (c)(2), the EPA has listed and regulated over 140 categories of sources under CAA section 112. Thus, this reading would eviscerate the EPA's authority under section 111(d) and prevent it from serving as the gap-filling provision within the comprehensive scheme of the CAA as Congress intended.[293] In short, it is not reasonable to interpret the Section 112 Exclusion in section 111(d) to mean that the existence of CAA section 112 standards covering hazardous pollutants from a source category would entirely

[293] Some commenters have stated that EPA could choose to regulate both HAP and non-HAP under section 111(d), and thus could regulate HAP without creating a gap. But this presumes that Congress intended EPA to have the choice of declining to regulate a section 112-listed source category for HAP under section 112, which is inconsistent with the mandatory language in section 112. See, e.g., section 112(d)(1)("The Administrator shall promulgate regulations establishing emissions standards for each category or subcategory of major sources and area sources of hazardous air pollutants listed for regulation pursuant to subsection (c) of this section in accordance with the schedules provided in subsections (c) and (e) of this section."). Moreover, given the prescriptive language that Congress added into section 112 concerning how to set standards for HAP, see section 112(d)(2) and (d)(3), it is unreasonable to conclude that Congress intended that the EPA could simply choose to ignore the provisions in section 112 and instead regulate HAP for a section 112 listed source category under section 111(d).

Further, some supporters of this interpretation have suggested that EPA could regulate CO_2 under section 112. But this suggestion fails to consider that sources emitting HAP are major sources if they emit 10 tons of any HAP. See CAA section 112(a)(1). Thus, if CO_2 were regulated as a HAP, and because emissions of CO_2 tend to be many times greater than emissions of other pollutants, a huge number of smaller sources would become regulated for the first time under the CAA.

eliminate regulation of non-hazardous emissions from that source category under section 111(d).[294]

b. The EPA's Interpretation of the House Amendment. Having concluded that the interpretations discussed above are not reasonable, the EPA now turns to what it has concluded is the best, and sole reasonable, interpretation of the House amendment as it applies to the issue here.

The EPA's interpretation of the House amendment as applied to the issue presented in this rule is that the Section 112 Exclusion excludes the regulation of HAP under CAA section 112 if the source category at issue is regulated under CAA section 112, but does not exclude the regulation of other pollutants, regardless of whether that source category is subject to CAA section 112 standards. This interpretation reads the phrase "regulated under section 112" as modifying the words "source category" (as does the interpretation discussed above) but also

[294] Even if one were to determine that this interpretation were the proper reading of the House amendment that would not be the end of the analysis. Instead, that reading would create a conflict between the Senate amendment and the House amendment that would need to be resolved. In that event, the proper resolution of a conflict between the two amendments would be the analysis and conclusion discussed in the Proposed Rule's legal memorandum (discussing EPA's analysis in the CAMR rule at 70 FR 15994, 16029-32): The two amendments must be read together so as to give some effect to each amendment and they are properly read together to provide that, where a source category is regulated under section 112, the EPA may not establish regulations covering the HAP emissions from that source category under section 111(d).

recognizes that the phrase “regulated under section 112” refers only to the regulation of HAP emissions. In other words, the EPA’s interpretation recognizes that source categories “regulated under section 112” are not regulated by CAA section 112 with respect to all pollutants, but only with respect to HAP. Thus, it is reasonable to interpret the House amendment of the Section 112 Exclusion as only excluding the regulation of HAP emissions under CAA section 111(d) and only when that source category is regulated under CAA section 112. We note that this interpretation of the House amendment alone is the same as the 2005 CAMR interpretation of the two amendments combined: where a source category has been regulated under CAA section 112, a CAA section 111(d) standard of performance cannot be established to address any HAP listed under CAA section 112(b) that may be emitted from that particular source category. See 70 FR 15994, 16029-30 (March 29, 2005).

There are a number of reasons why the EPA’s interpretation is reasonable and avoids the issues discussed above.

First, the EPA’s interpretation reads the House amendment to the Section 112 Exclusion as determining the scope of what air pollutants are to be regulated under CAA section 111(d), as opposed to creating a wholesale exclusion for source categories. The other text in subsections 111(d)(1)(A)(i) and (ii) modify the phrase “any air pollutant.” Thus, reading the Section 112

Exclusion to also address the question of what air pollutants may be regulated under CAA section 111(d) is consistent with the overall structure and focus of CAA section 111(d)(1)(A).

Second, the EPA's interpretation furthers – rather than undermines – the purpose of CAA section 111(d) within the long-standing structure of the CAA. That is, this interpretation supports the comprehensive structure for regulating various pollutants from existing sources under the criteria pollutant/NAAQS program under sections 108-110, the HAP program under section 112, and other pollutants under section 111(d), and avoids creating a gap in that structure. See King v. Burwell, 2015 U.S. LEXIS 4248, *28 (2015)("A provision that may seem ambiguous in isolation is often clarified by the remainder of the statutory scheme . . . because only one of the permissible meanings produces a substantive effect that is compatible with the rest of the law.") (quoting United Sav. Assn. of Tex. v. Timbers of Inwood Forest Associates, Ltd., 484 U. S. 365, 371, 108 S. Ct. 626, 98 L. Ed. 2d 740 (1988)")

Third, by avoiding the creation of gaps in the statutory structure, the EPA's interpretation is consistent with the legislative history demonstrating that Congress's intent in the 1990 CAA Amendments was to expand the EPA's regulatory authority across the board, compelling the agency to regulate more pollutants, under more programs, more quickly.[295] Conversely, the EPA is aware of no statement in the legislative history indicating that Congress simultaneously sought to restrict the EPA's authority under CAA section 111(d) or to create gaps in the comprehensive structure of the statute. If Congress had intended this amendment to make such a change, one would expect to see some indication of that in the legislative history.

Fourth, when applied in the context of this rule, the EPA's interpretation of the House amendment is consistent with the Senate amendment. Thus, this interpretation avoids creating a conflict within the statute. See discussion above of Scialabba, 134 S. Ct. 2191 at 2220 (citing and quoting, among other authorities, A. Scalia & B. Garner, Reading Law: The

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[295] See S. Rep. No. 101-228 at 133 ("There is now a broad consensus that the program to regulate hazardous air pollutants . . . should be restructured to provide the EPA with authority to regulate industrial and area sources of air pollution . . . in the near term"), reprinted in 5 A Legislative History of the Clean Air Act Amendments of 1990 ("Legis. Hist.") 8338, 8473 (Comm. Print 1993); S. Rep. No. 101-228 at 14 ("The bill gives significant authority to the Administrator in order to overcome the deficiencies in [the NAAQS program]") & 123 ("Experience with the mobile source provisions in Title II of the Act has shown that the enforcement authorities . . . need to be strengthened and broadened . . ."), reprinted in 5 Legis. Hist. at 8354, 8463; H.R. Rep. No. 101-952 at 336-36, 340, 345 & 347 (discussing enhancements to Act's motor vehicle provisions, the EPA's new authority to promulgate chemical accident prevention regulations, the enactment of the Title V permit program, and enhancements to the EPA's enforcement authority), reprinted in 5 Legis. Hist. at 1786, 1790, 1795, & 1997.

Interpretation of Legal Texts 180 (2012) ("The provisions of a text should be interpreted in a way that renders them compatible, not contradictory. . . . [T]here can be no justification for needlessly rendering provisions in conflict if they can be interpreted harmoniously")).

In sum, when this interpretation of the House amendment is applied in the context of this rule, the result is that the EPA may promulgate CAA section 111(d) regulations covering carbon dioxide emissions from existing power plants notwithstanding that power plants are regulated for their HAP emissions under CAA section 112.

5. The Two Amendments Are Easily Reconciled And Can Be Given Full Effect

Given that both the House and Senate amendments should be read individually as having the same meaning in the context presented in this rule, giving each amendment full effect is straight-forward: the Section 112 Exclusion in section 111(d) does not foreclose the regulation of non-HAP from a source category regardless of whether that source category is also regulated under CAA section 112. As applied here, the EPA has the authority to promulgate CAA section 111(d) regulations for CO_2 from power plants notwithstanding that power plants are regulated for HAP under CAA section 112.

C. Authority to Regulate EGUs

In a separate, concurrent action, the EPA is also finalizing a CAA section 111(b) rulemaking that regulates CO_2 emissions from new, modified, and reconstructed EGUs. The promulgation of these standards provides the requisite predicate for applicability of CAA section 111(d).

CAA section 111(d)(1) requires the EPA to promulgate regulations under which states must submit state plans regulating "any existing source" of certain pollutants "to which a standard of performance would apply if such existing source were a new source." A "new source" is "any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under [CAA section 111] which will be applicable to such source." It should be noted that these provisions make clear that a "new source" includes one that undertakes either new construction or a modification. It should also be noted that the EPA's implementing regulations define "construction" to include "reconstruction," which the implementing regulations go on to define as the replacement of components of an existing facility to an extent that (i) the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and (ii) it is technologically and economically feasible to meet the applicable standards.

Under CAA section 111(d)(1), in order for existing sources to become subject to that provision, the EPA must promulgate standards of performance under CAA section 111(b) to which, if the existing sources were new sources, they would be subject. Those standards of performance may include standards for sources that undertake new construction, modifications, or reconstructions.

The EPA is finalizing a rulemaking under CAA section 111(b) for CO_2 emissions from affected EGUs concurrently with this CAA section 111(d) rulemaking, which will provide the requisite predicate for applicability of CAA section 111(d).[296]

D. Definition of Affected Sources

For the emission guidelines, an affected EGU is any fossil fuel-fired electric utility steam generating unit (i.e., utility boiler or integrated gasification combined cycle (IGCC) unit) or stationary combustion turbine that was in operation or had

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[296] In the past, the EPA has issued standards of performance under section 111(b) and emission guidelines under section 111(d) simultaneously. *See* "Standards of Performance for new Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills – Final Rule," 61 FR 9905 (March 12, 1996).

commenced construction as of January 8, 2014,[297] and that meets the following criteria, which differ depending on the type of unit. To be an affected EGU, such a unit, if it is a fossil fuel-fired electric utility steam generating unit (i.e., a utility boiler or IGCC unit), must serve a generator capable of selling greater than 25 MW to a utility power distribution system and have a base load rating greater than 260 GJ/h (250 MMBtu/h) heat input of fossil fuel (either alone or in combination with any other fuel). If such a unit is a stationary combustion turbine, the unit must meet the definition of a combined cycle or combined heat and power combustion turbine, serve a generator capable of selling greater than 25 MW to a utility power distribution system, and have a base load rating of greater than 260 GJ/h (250 MMBtu/h).

When considering and understanding applicability, the following definitions may be helpful. Simple cycle combustion turbine means any stationary combustion turbine which does not recover heat from the combustion turbine engine exhaust gases for purposes other than enhancing the performance of the stationary combustion turbine itself. Combined cycle combustion

[297] Under Section 111(a) of the CAA, determination of affected sources is based on the date that the EPA proposes action on such sources. January 8, 2014 is the date the proposed GHG standards of performance for new fossil fuel-fired EGUs were published in the *Federal Register* (79 FR 1430).

turbine means any stationary combustion turbine which recovers heat from the combustion turbine engine exhaust gases to generate steam that is used to create additional electric power output in a steam turbine. Combined heat and power (CHP) combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine engine exhaust gases to heat water or another medium, generate steam for useful purposes other than exclusively for additional electric generation, or directly uses the heat in the exhaust gases for a useful purpose.

We note that certain affected EGUs are exempt from inclusion in a state plan. Affected EGUs that may be excluded from a state’s plan are (1) those units that are subject to subpart TTTT as a result of commencing modification or reconstruction; (2) steam generating units or IGCC units that are currently and always have been subject to a federally enforceable permit limiting net-electric sales to one-third or less of its potential electric output or 219,000 MWh or less on an annual basis; (3) non-fossil units (i.e., units that are capable of combusting 50 percent or more non-fossil fuel) that have historically limited the use of fossil fuels to 10 percent or less of the annual capacity factor or are subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor; (4) stationary combustion turbines that are not capable of combusting natural gas (i.e., not connected to a natural gas pipeline); (5) combined heat and power units that are subject to a federally enforceable permit limiting, or have historically limited, annual net electric sales to a utility power distribution system to the product of the design efficiency and the potential electric output or 219,000 MWh (whichever is greater) or less; (6) units that serve a generator along with other steam generating unit(s), IGCC(s), or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less; (7) municipal waste combustor unit subject to subpart Eb of Part 60; or (8) commercial or industrial solid waste incineration units that are subject to subpart CCCC of Part 60.

The rationale for applicability of this final rule is multi-fold. We had proposed that affected EGUs were those existing fossil fuel-fired EGUs that met the applicability criteria for coverage under the final GHG standards for new fossil fuel-fired EGUs being promulgated under section 111(b). However, we are finalizing that States need not include certain units that would otherwise meet the CAA section 111(b) applicability in this CAA section 111(d) emission guidelines. These include simple cycle turbines, certain non-fossil units, and certain combined heat and power units. The final 111(b) standards include applicability criteria for simple cycle combustion turbines, for reasons relating to implementation and minimizing emissions from all future combustion turbines. However, for the following reasons none of the building blocks would result in emission reductions from simple cycle turbines so we are not requiring that States including them in their CAA section 111(d) plans.

First, even more than combined cycle units, simple cycle units have limited opportunities, compared to steam generating units, to reduce their heat rate. Most combustion turbines likely already follow the manufacturer's recommended regular preventive/restorative maintenance for both reliable and efficiency reasons. These regularly scheduled maintenance practices are highly effective methods to maintain heat rates, and additional fleet-wide reductions from simple cycle combustion turbines are likely less than 2 percent. In addition, while approximately one-fifth of overall fossil fuel-fired capacity (GW) consists of simple cycle turbines, these units historically have operated at capacity factors of less than 5 percent and only provide about 1 percent of the fossil fuel-fired generation (GWh). Combustion turbine capacity can therefore only contribute CO_2 emissions amounting to approximately 2 percent of total coal-steam CO_2 emissions. Any single-digit percentage reduction in combustion turbine heat rates would therefore provide less than 1 percent reduction in total fossil-fired CO_2 emissions.

Further, we are not aware of an approach to estimate any limited opportunities that existing simple cycle turbines may have to reduce their heat rate. Similar to coal-steam EGUs, we do not have the unit-specific detailed design information on existing individual simple cycle combustion turbines that is necessary for a detailed assessment of the heat rate improvement potential via best practices and upgrades for each unit. While the EPA could conduct a "variability analysis" of simple cycle historical hourly heat rate data (as was done for coal-steam EGUs), the various simple cycle models in use and the historically lower capacity factors of the simple cycle fleet (less run time per start, and more part load operation) would require a simple cycle analysis that includes more complexity and likely more uncertainty than in the coal-steam analysis. Therefore, we do not consider it feasible to estimate potential reductions due to heat rate improvements from simple cycle turbines, and even if it were, we have concluded those reductions would be negligible compared to the reductions from steam generating units. Hence, we do not consider building block 1 as practically applicable to simple cycle units.

Second, the vast majority of simple cycle turbines serve a specific need – providing power during periods of peak electric demand (i.e., peaking units). The existing block of simple cycle turbines are the only units that are able to start fast enough and ramp to full load quickly enough to serve as peaking units. If these units were to be used under building block 2 to displace higher emitting coal-fired units, they would no longer be available to serve as peaking units. Therefore, building block 2 could not be applied to simple cycle combustion turbines without jeopardizing grid reliability.

Third, many commenters on the CAA section 111(b) proposal stated that simple cycle turbines will be used to provide backup power to intermittent renewable sources of power such as wind and solar. Consequently, adding additional generation from intermittent renewable sources has the potential to actually increase emissions from simple cycle turbines. Therefore, applying building block 3 based on the capacity of simple cycle turbines would not result in emission reductions from simple cycle combustion turbines. Finally, the EPA expects existing simple cycle turbines to continue to operate as they historically have operated, as peaking units. Including simple cycle turbines in CAA section 111(d) applicability would impact the numerical value of state goals, but it would not impact the stringency of the plans. Such inclusion would increase burden but result in no environmental benefit.

Additionally, under CAA section 111(b) final applicability criteria, new dedicated non-fossil and industrial CHP units are not affected sources if they include permit restrictions on the amount of fossil fuel they burn and the amount of electricity they sell. Such units historically have had no regulatory mandate to include permit requirements limiting the use of fossil fuel or electric sales. We are exempting them from inclusion in CAA section 111(d) state plans in the interest of consistency with CAA section 111(b) and based on their historical fuel use and electric sales.

We discuss changes in applicability of units in relation to state plans in Section VIII of this preamble.

E. Combined Categories and Codification in the Code of Federal Regulations

In this rulemaking, the EPA is combining the listing of sources from the two existing source categories for the affected EGUs, as listed in 40 CFR subpart Da and 40 CFR subpart KKKK, into a single location, 40 CFR subpart UUUU, for purposes of addressing the CO_2 emissions from existing affected EGUs. The EPA is also codifying all of the requirements for the affected EGUs in a new subpart UUUU of 40 CFR part 60 and including all GHG emission guidelines for the affected sources – fossil fuel-fired electric utility steam generating units, as well as stationary combustion turbines -- in that newly created subpart.[298]

We believe that combining the emission guidelines for affected sources into a new subpart UUUU is appropriate because the emission guidelines the EPA is establishing do not vary by type of source. Combining the listing of sources into one location, subpart UUUU, will facilitate implementation of CO_2 mitigation measures, such as shifting generation from higher to lower-carbon intensity generation among existing sources (e.g., shifting from utility boilers to NGCC units), and emission trading among sources in the source category.

As discussed in the January 8, 2014 proposal for the CAA section 111(b) standards for GHG emissions from EGUs (79 FR 1430), in 1971 the EPA listed fossil fuel-fired steam generating boilers as a new category subject to section 111 rulemaking, and in 1979 the EPA listed fossil fuel-fired combustion turbines as a new category subject to the CAA section 111 rulemaking. In the ensuing years, the EPA has promulgated standards of performance for the two categories and codified those standards, at various times, in 40 CFR part 60 subparts D, Da, GG, and KKKK.

In the January 8, 2014 proposal, the EPA proposed separate standards of performance for new sources in the two categories

[298] The EPA is not codifying any of the requirements of this rulemaking in subparts Da or KKKK.

and proposed codifying the standards in the same Da and KKKK subparts that currently contain the standards of performance for conventional pollutants from those sources. In addition, the EPA co-proposed combining the two categories into a single category solely for purposes of the CO_2 emissions from new construction of affected EGUs, and codifying the proposed requirements in a new 40 CFR part 60 subpart TTTT. For the final standards of performance for new construction of affected EGUs, the EPA is codifying the final requirements in a new 40 CFR part 60 subpart TTTT.

In this rulemaking, the EPA is combining the two listed source categories into a single source category for purposes of the emission guidelines for the CO_2 emissions from existing affected EGUs. Because the two source categories are pre-existing and the EPA would not be subjecting any additional sources to regulation, the combined source category is not considered a new source category that the EPA must list under CAA section 111(b)(1)(A). As a result, this final rule does not list a new source category under section 111(a)(1)(A), nor does this final rule revise either of the two source categories – fossil fuel-fired electric utility steam generating units and stationary combustion turbines – that the EPA has already listed under that provision. Thus, the EPA is not required to make a finding that the combined source category causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare.

V. The Best System of Emission Reduction and Associated Building Blocks

In the June 2014 proposal, the EPA proposed to determine that the best system of emission reduction adequately demonstrated (BSER) for reducing CO_2 emissions from existing EGUs was a combination of measures -- (1) increasing the operational efficiency of existing coal-fired steam EGUs, (2) substituting increased generation at existing NGCC units for generation at existing steam EGUs, (3) substituting generation from low- and zero-carbon generating capacity for generation at existing fossil fuel-fired EGUs, and (4) increasing demand-side EEto reduce the amount of fossil fuel-fired generation -- which we categorized as four "building blocks." As an alternative to the proposed building blocks 2, 3, and 4, the EPA also identified reduced generation in the amount of those building blocks as part of the BSER. These measures are not the only approaches EGUs can take to reduce CO_2, but are those that the EPA felt best met the statutory criteria. We solicited comment on all aspects of our BSER determination, including a broad array of other approaches. We have considered thoroughly the extensive comments submitted on a variety of topics related to the BSER and the individual building blocks, along with our own continued analysis, and we are finalizing the BSER based on the first three building blocks, with certain refinements.

Consistent with the approach taken in the proposed rule, in determining the BSER we have taken account of the unique characteristics of CO_2 pollution, particularly its global nature, huge quantities, and the limited means for controlling it; and the unique characteristics of the source category, particularly the exceptional degree of interconnectedness among individual affected EGUs and the longstanding practice of coordinating planning and operations across multiple sources, reflecting the fact that each EGU's function is interdependent with the function of other EGUs. Each building block is a proven approach for reducing emissions from the affected source category that is appropriate in this pollutant- and industry-specific context. The BSER also encompasses a variety of measures or actions that individual affected EGUs could take to implement the building blocks, including (i) direct investment in efficiency improvements and in lower- and zero-carbon generation, (ii) cross-investment in these activities through mechanisms such as emissions trading approaches, where the state-established standards of performance to which sources are subject incorporate such approaches, and (iii) reduction of higher-carbon generation.

With attention to emission reduction costs, electricity rates, and the importance of ensuring continued reliability of electricity supplies, the individual building blocks and the overall BSER have been defined not at the maximum possible degree of stringency but at a reasonable degree of stringency designed to appropriately balance consideration of the various BSER factors. Additional, non-building block-specific aspects of the BSER quantification methodology discussed below are similarly mindful of these considerations. This approach to determination of the BSER provides compliance headroom that ensures that the emission limitations reflecting the BSER are achievable by the source category, but nevertheless, as required by the CAA, will result in meaningful reductions in CO_2 emissions from this sector. The wide range of actions encompassed in the building blocks, and a further wide range of possible emissions-reducing actions not included in the BSER but nevertheless available to help with compliance, ensure that those emission limitations are achievable by individual affected EGUs as well.

The final BSER incorporates certain changes from the proposed rule, reflecting the EPA's consideration of comments responding to the approaches outlined in the proposal and our own further analysis. The principal changes are the exclusion from the BSER of emission reductions achievable through demand-side EE and through nuclear generation; a revised approach to determination of emission reductions achievable through increased RE generation; a consistent approach to determination of emission reductions achievable through all the building blocks that better reflects the regional nature of the electricity system and entails separate analyses for the Eastern, Western, and Texas Interconnections; and a revised interim goal period of 2022 to 2029 (instead of the proposed interim period of 2020 to 2029). These changes to the BSER and the building blocks are discussed in more detail later in this section of the preamble.

Also, to address concerns identified in the proposal and the October 30, 2014 Notice of Data Availability and in response to associated comments, in the final rule we have represented the emission limitations achievable through the BSER in the form of uniform CO_2 emission performance rates for each of two affected source subcategories: steam generating units and stationary combustion turbines. However, like the proposed rule, the final rule also provides weighted-average state-specific goals that a state may choose as an alternative method for complying with its obligation to set standards of performance for its affected EGUs -- an alternative, that is, to adopting the nationwide subcategory-based CO_2 emission performance rates as the standard of performance for its affected EGUs. The reformulation of the emission limitations as uniform CO_2 emission performance rates is discussed in this section and in section VI of the preamble, and the relation of the performance rates to the state-specific goals and states' section 111(d) plan options is discussed in sections VII and VIII of the preamble.

Section V.A. describes our determination of the final BSER, including a discussion of the associated emissions performance level, and provides the rationale for our determination. In section V.B. we address certain legal issues in greater detail, including key issues raised in comments. Sections V.C. through V.E. contain more detailed discussions of the three individual building blocks included in the final BSER. Further information can be found in the GHG Mitigation Measures TSD for the CPP Final Rule, the CO_2 Emission Performance Rate and Goal Computation TSD for the CPP Final Rule, the Response to Comments document, and, about certain topics, the Legal Memorandum for the Clean Power Plan Final Rule, all of which are available in the docket.

A. The Best System of Emission Reduction

This section sets forth our determination of the BSER for reducing CO_2 emissions from existing EGUs, including a discussion of the associated emissions performance level, and the rationale for that determination. In section V.A.1., we describe the legal framework for determination of the BSER in general. Section V.A.2. summarizes the determination of the BSER for this rule.

In section V.A.3., we discuss changes from the proposal. Section V.A.4. provides more detail on our determination of the BSER, including our determinations regarding the individual elements of the BSER, as applied to the two subcategories of fossil steam units and combustion turbines. In section V.A.5., we explain the specific actions that individual affected EGUs in the two subcategories may take to implement the building blocks and thereby achieve the EPA-identified source subcategory-specific emission performance rates that, in turn, form the basis for the standards of performance that states must set. Because these actions implement the building blocks, they may be understood as part of the BSER. In this discussion, we recognize that states can choose to set sources’ standards of performance in different forms and that the form of the standard affects how various types of actions can be used to comply with the standard. In section V.A.6., we discuss the substantial compliance flexibility provided by additional measures, not included in the BSER, that individual affected EGUs can use to achieve their standards of performance. Finally, section V.A.7. addresses the severability of the building blocks.

1. Legal requirements for BSER in the emission guidelines

a. Introduction. In the June 2014 proposal for this rule, we described the principal legal requirements for standards of performance under CAA section 111(d)(1) and (a)(1). We based our description in part on our discussion of the legal requirements for standards of performance under CAA section 111(b) and (a)(1), which we included in the January 2014 proposal for standards of performance for CO_2 emissions from new fossil fuel-fired EGUs. In the latter proposal, we noted that the D.C. Circuit has handed down numerous decisions that interpret CAA section 111(a)(1), including its component elements, and we reviewed that case law in detail.[299]

We received comments on our proposed interpretation, and in light of those comments, in this final rule, we are clarifying our interpretation in certain respects. We discuss our interpretation below.[300]

b. CAA requirements and court interpretation.[301] Section

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[299] 79 FR 1430, 1462 (January 8, 2014).

[300] We also discuss our interpretation of the requirements for standards of performance and the BSER under section 111(b), for new sources, in the section 111(b) rulemaking that the EPA is finalizing simultaneously with this rule and in the Legal Memorandum for this rule. Our interpretations of these requirements in the two rules are generally consistent except to the extent that they reflect distinctions between new and existing sources. For example, as discussed in the section 111(b) rule, the legislative history indicates that Congress intended that the BSER for new industrial facilities, which were expected to have lengthy useful lives, would include the most advanced pollution controls available, but Congress had a broader conception of the BSER for existing facilities.

[301] Our interpretation of the CAA provisions at issue is guided by *Chevron U.S.A. Inc. v. NRDC*, 467 U.S. 837, 842-43 (1984). In *Chevron*, the U.S. Supreme Court set out a two-step process for agency interpretation of statutory requirements: the agency must, at step 1, determine whether Congress's intent as to the

111(d)(1) directs the EPA to promulgate regulations establishing a section 110-like procedure under which states submit state plans that establish "standards of performance" for emissions of certain air pollutants from sources which, if they were new sources, would be regulated under section 111(b), and that implement and enforce those standards of performance.

The term "standard of performance" is defined to mean—

> a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

Section 111(a)(1).

These provisions authorize the EPA to determine the BSER for the affected sources and, based on the BSER, to establish emission guidelines that identify the minimum amount of emission limitation that a state, in its state plan, must impose on its sources through standards of performance. Consistent with these CAA requirements, the EPA's regulations require that the EPA's guidelines reflect--

> the degree of emission reduction achievable through the application of the best system of emission reduction which

specific matter at issue is clear, and, if so, the agency must give effect to that intent. If congressional intent is not clear, then, at step 2, the agency has discretion to fashion an interpretation that is a reasonable construction of the statute.

(taking into account the cost of such reduction) the Administrator has determined has been adequately demonstrated.[302]

The EPA’s approach in this rulemaking is to determine the BSER on a source subcategory-wide basis, to determine the emission limitation that results from applying the BSER to the sources in the subcategory, and then to establish emission guidelines for the states that incorporate those emission limitations. The EPA expresses these emission limitations in the form of emission performance rates, and they must be achievable by the source subcategory through the application of the BSER.

Following the EPA’s promulgation of emission guidelines, each state must determine the standards of performance for its sources, which the EPA’s regulations call “designated facilities.”[303] A state has broad discretion in doing so. CAA section 111(d)(1) requires the EPA’s regulations to “permit the State in applying a standard of performance to any particular source ... to take into consideration, among other factors, the remaining useful life of the ... source....”[304] In addition,

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[302] 40 CFR 60.21(e). This definition was promulgated as part of the EPA’s CAA 111(d) implementing regulations and was not updated to reflect the textual changes adopted by Congress in 1977. That said, Congress recognized that those changes “merely make[] explicit what was implicit in the previous language.” H.R. Rep. No. 95-294, at 190 (May 12, 1977).

[303] 40 CFR 60.24(b)(3).

[304] The EPA’s regulations, promulgated prior to enactment of the “remaining useful life” provision of section 111(d)(1), provide:

under CAA section 116, the state is authorized to set a standard of performance for any particular source that is more stringent than the emission limit contained in the EPA's emission guidelines.[305] Thus, for any particular source, a state may apply a standard of performance that is either more stringent or less stringent than the performance level in the emission guidelines, as long as, in total, the state's sources achieve at least the same degree of emission limitation as included in the EPA's emission guidelines. The states must include the standards of performance in their state plans and submit the plans to the EPA for review.[306] Under CAA section 111(d)(2)(A), the EPA approves state plans as long as they are "satisfactory."

As noted in the January 2014 proposal and discussed in more detail above under section II.G, Congress first included the

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"Unless otherwise specified in the applicable subpart on a case-by-case basis for particular designated facilities, or classes of facilities, States may provide for the application of less stringent emission standards or longer compliance schedules than those otherwise required" by the corresponding emission guideline. 40 CFR 60.24(f). Some of the factors that a state may consider for this case-by-case analysis include the "cost of control resulting from plant age, location, or basic process design" and the "physical impossibility of installing necessary control equipment," among other factors "that make application of a less stringent standard or final compliance time significantly more reasonable." *Id.*

[305] In addition, CAA section 116 authorizes the state to set standards of performance for all of its sources that, together, are more stringent than the EPA's emission guidelines.

[306] 40 CFR 60.23.

definition of "standard of performance" when enacting CAA section 111 in the 1970 Clean Air Act Amendments (CAAA), amended it in the 1977 CAAA, and then amended it again in the 1990 CAAA to largely restore the definition as it read in the 1970 CAAA. It is in the legislative history for the 1970 and 1977 CAAA that Congress primarily addressed the definition as it read at those times and that legislative history provides guidance in interpreting this provision.[307] In addition, although the D.C.

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[307] In the 1970 CAAA, Congress defined "standard of performance," under §111(a)(1), as:

> a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction) the Administrator determines has been adequately demonstrated.

In the 1977 CAAA, Congress revised the definition to distinguish among different types of sources, and to require that for fossil fuel-fired sources, the standard (i) be based on, in lieu of the "best system of emission reduction ... adequately demonstrated," the "best technological system of continuous emission reduction ... adequately demonstrated;" and (ii) require a percentage reduction in emissions. In addition, in the 1977 CAAA, Congress expanded the parenthetical requirement that the Administrator consider the cost of achieving the reduction to also require the Administrator to consider "any nonair quality health and environment impact and energy requirements."

In the 1990 CAAA, Congress again revised the definition, this time repealing the requirements that the standard of performance be based on the best technological system and achieve a percentage reduction in emissions, and replacing those provisions with the terms used in the 1970 CAAA version of §111(a)(1) that the standard of performance be based on the "best system of emission reduction ... adequately demonstrated." This 1990 CAAA version is the current definition, which is applicable at present. Even so, because parts of the definition

Circuit has never reviewed a section 111(d) rulemaking, the Court has reviewed section 111(b) rulemakings on numerous occasions during the past 40 years, handing down decisions dated from 1973 to 2011,[308] through which the Court has developed a body of case law that interprets the term "standard of performance."

c. Key elements of interpretation. The emission guidelines promulgated by the Administrator must include emission limitations that are "achievable" by the source category by application of a "system of emission reduction" that is "adequately demonstrated" and that the EPA determines to be the "best," "taking into account" the factors of "cost … nonair quality health and environmental impact and energy requirements." The D.C. Circuit has stated that in determining the "best" system, the EPA must also take into account "the amount of air pollution"[309] reduced and the role of

as it read under the 1977 CAAA were retained in the 1990 CAAA, the explanation in the 1977 CAAA legislative history, and the interpretation in the case law, of those parts of the definition in the case law remain relevant to the definition as it reads today.

[308] *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375 (D.C. Cir. 1973); *Essex Chemical Corp. v. Ruckelshaus*, 486 F.2d 427, (D.C. Cir. 1973); *Portland Cement Ass'n v. EPA*, 665 F.3d 177 (D.C. Cir. 2011). *See also Delaware v. EPA*, No. 13-1093 (D.C. Cir. May 1, 2015).

[309] *See Sierra Club v. Costle,* 657 F.2d 298, 326 (D.C. Cir. 1981).

"technological innovation."[310] The Court has emphasized that the EPA has discretion in weighing those various factors.[311, 312]

Our overall approach to determining the BSER and emission guidelines, which incorporates the various elements, is as follows: In developing an emission guideline, we generally engage in an analytical approach that is similar to what we conduct under CAA section 111(b) for new sources. First, we identify "system[s] of emission reduction" that have been "adequately demonstrated" for a particular source category. Second, we determine the "best" of these systems after evaluating the amount of reductions, costs, any nonair health and environmental impacts, energy requirements, and, in the alternative, the advancement of technology (that is, we apply a

[310] *See Sierra Club v. Costle,* 657 F.2d at 347.

[311] *See Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999).

[312] Although CAA section 111(a)(1) may be read to state that the factors enumerated in the parenthetical are part of the "adequately demonstrated" determination, the D.C. Circuit's case law appears to treat them as part of the "best" determination. *See Sierra Club v. Costle,* 657 F.2d at 330 (recognizing that CAA section 111 gives the EPA authority "when determining the best technological system to weigh cost, energy, and environmental impacts"). Nevertheless, it does not appear that those two approaches would lead to different outcomes. *See, e.g.*, *Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999) (rejecting challenge to the EPA's cost assessment of the "best demonstrated system"). In this rule, the EPA treats the factors as part of the "best" determination, but, as noted, even if the factors were part of the "adequately demonstrated" determination, our analysis and outcome would be the same.

formulation of the BSER with the above noted factors, and then, in the alternative, we apply a formulation of the BSER with those same factors plus the advancement of technology). And third, we select an achievable emission limit -- here, the emission performance rates -- based on the BSER.[313] In contrast to subsection (b), however, subsection (d)(1) assigns to the states, not the EPA, the obligation of setting standards of performance for the affected sources. As discussed below in the following subsection, in examining the range of reasonable options for states to consider in setting standards of performance under these guidelines, we identified a number of considerations, including the interconnected operations of the affected sources and the characteristics of the CO_2 pollutant.

The remainder of this subsection discusses the various elements in our general analytical approach.

(1) System of emission reduction.

As we discuss below, the CAA does not define the phrase "system of emission reduction." The ordinary, everyday meaning of "system" is a set of things or parts forming a complex whole; a set of principles or procedures according to which something

[313] *See, e.g.*, Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air pollutants Reviews, 77 FR 49490, 49494 (Aug. 16, 2012) (describing the three-step analysis in setting a standard of performance).

is done; an organized scheme or method; and a group of interacting, interrelated, or interdependent elements.[314] With this definition, the phrase "system of emission reduction" takes a broad meaning: a set of measures that work together to reduce emissions. The EPA interprets this phrase to carry an important limitation: because the emission guidelines for the existing sources must reflect "the degree of emission limitation achievable *through the application of* the best system of emission reduction … adequately demonstrated," the system must be limited to measures that can be implemented -- "appl[ied]" -- by the sources themselves, that is, as a practical matter, by actions taken by the owners or operators of the sources. As we discuss below, this definition is sufficiently broad to include the building blocks.

(2) "Adequately demonstrated."

Under section 111(a)(1), in order for a "system of emission reduction" to serve as the basis for an "achievable" emission limitation, the Administrator must determine that the system is

[314] *Oxford Dictionary of English* (3rd ed.) (2010), *available at* http://www.oxforddictionaries.com/us/definition/american_english/system; *see also* American Heritage Dictionary (5th ed.) (2013), *available at* http://www.yourdictionary.com/system#americanheritage; and The American College Dictionary (C.L. Barnhart, ed. 1970) ("an assemblage or combination of things or parts forming a complex or unitary whole").

"adequately demonstrated." This means, according to the D.C. Circuit, that the system is "one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way."[315] It does not mean that the system "must be in actual routine use somewhere."[316] Rather, the Court has said, "[t]he Administrator may make a projection based on existing technology, though that projection is subject to the restraints of reasonableness and cannot be based on 'crystal ball' inquiry."[317] Similarly, the EPA may "hold the industry to a standard of improved design and operational advances, so long as there is substantial evidence that such improvements are feasible."[318] Ultimately, the analysis "is partially dependent on 'lead time,'" that is, "the time in which the technology will have to be available."[319] Unlike for CAA section 111(b) standards that are applicable immediately after the effective date of

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[315] *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973), *cert. denied*, 416 U.S. 969 (1974).
[316] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973) (citations omitted) (discussing the Senate and House bills and reports from which the language in CAA section 111 grew).
[317] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973) (citations omitted).
[318] *Sierra Club v. Costle*, 657 F.2d 298, 364 (1981).
[319] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973) (citations omitted).

their promulgation, under CAA section 111(e), compliance with CAA section 111(d) standards may be set sometime in the future. This is due, in part, to the period of time for states to submit state plans and for the EPA to act on them.

(3) "Best."

In determining which adequately demonstrated system of emission reduction is the "best," the EPA considers the following factors:

(a) Costs.

Under CAA section 111(a)(1), the EPA is required to take into account "the cost of achieving" the required emission reductions. As described in the January 2014 proposal,[320] in several cases the D.C. Circuit has elaborated on this cost factor and formulated the cost standard in various ways, stating that the EPA may not adopt a standard the cost of which would be "exorbitant,"[321] "greater than the industry could bear and survive,"[322] "excessive,"[323] or "unreasonable."[324] These formulations appear to be synonymous, and for convenience, in this rulemaking, we will use reasonableness as the standard, so

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[320] 79 FR 1430, 1464 (January 8, 2014).
[321] *Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999).
[322] *Portland Cement Ass'n v. EPA*, 513 F.2d 506, 508 (D.C. Cir. 1975).
[323] *Sierra Club v. Costle*, 657 F.2d 298, 343 (D.C. Cir. 1981).
[324] *Sierra Club v. Costle*, 657 F.2d 298, 343 (D.C. Cir. 1981).

that a control technology may be considered the "best system of emission reduction ... adequately demonstrated" if its costs are reasonable, but cannot be considered the best system if its costs are unreasonable.[325, 326]

The D.C. Circuit has repeatedly upheld the EPA's consideration of cost in reviewing standards of performance. In

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[325] These cost formulations are consistent with the legislative history of section 111. The 1977 House Committee Report noted:

> In the [1970] Congress [sic: Congress's] view, it was only right that the costs of applying best practicable control technology be considered by the owner of a large new source of pollution as a normal and proper expense of doing business.

1977 House Committee Report at 184. Similarly, the 1970 Senate Committee Report stated:

> The implicit consideration of economic factors in determining whether technology is "available" should not affect the usefulness of this section. The overriding purpose of this section would be to prevent new air pollution problems, and toward that end, maximum feasible control of new sources at the time of their construction is seen by the committee as the most effective and, in the long run, the least expensive approach.

S. Comm. Rep. No. 91-1196 at 16.

[326] We received comments that we do not have authority to revise the cost standard as established in the case law, e.g., "exorbitant," "excessive," etc., to a "reasonableness" standard that the commenters considered less protective of the environment. We agree that we do not have authority to revise the cost standard as established in the case law, and we are not attempting to do so here. Rather, our description of the cost standard as "reasonableness" is intended to be a convenient term for referring to the cost standard as established in the case law.

several cases, the Court upheld standards that entailed significant costs, consistent with Congress's view that "the costs of applying best practicable control technology be considered by the owner of a large new source of pollution as a normal and proper expense of doing business."[327] *See Essex Chemical Corp. v. Ruckelshaus*, 486 F.2d 427, 440 (D.C. Cir. 1973);[328] *Portland Cement Association v. Ruckelshaus*, 486 F.2d 375, 387-88 (D.C. Cir. 1973); *Sierra Club v. Costle*, 657 F.2d 298, 313 (D.C. Cir. 1981) (upholding standard imposing controls on SO_2 emissions from coal-fired power plants when the "cost of the new controls ... is substantial").[329]

As discussed below, the EPA may consider costs on both a source-specific basis and a sector-wide, regional, or nationwide basis.

(b) Non-air health and environmental impacts.

Under CAA section 111(a)(1), the EPA is required to take

[327] 1977 House Committee Report at 184.

[328] The costs for these standards were described in the rulemakings. *See* 36 FR 24876 (December 23, 1971), 37 FR 5767, 5769 (March 21, 1972).

[329] Indeed, in upholding the EPA's consideration of costs under other provisions requiring consideration of cost, courts have also noted the substantial discretion delegated to the EPA to weigh cost considerations with other factors. *Chemical Mfr's Ass'n v. EPA*, 870 F. 2d 177, 251 (5th Cir. 1989); *Association of Iron and Steel Inst. v. EPA*, 526 F. 2d 1027, 1054 (3d Cir. 1975); *Ass'n of Pacific Fisheries v. EPA,* 615 F. 2d 794, 808 (9th Cir. 1980).

into account "any nonair quality health and environmental impact" in determining the BSER. As the D.C. Circuit has explained, this requirement makes explicit that a system cannot be "best" if it does more harm than good due to cross-media environmental impacts.[330]

(c) Energy considerations.

Under CAA section 111(a)(1), the EPA is required to take into account "energy requirements." As discussed below, the EPA may consider energy requirements on both a source-specific basis and a sector-wide, region-wide, or nationwide basis. Considered on a source-specific basis, "energy requirements" entails, for example, the impact, if any, of the system of emission reduction on the source's own energy needs.

(d) Amount of emissions reductions.

In the proposed rulemakings for this rule and the associated section 111(b) rule, we noted that although the definition of "standard of performance" does not by its terms identify the amount of emissions from the category of sources or the amount of emission reductions achieved as factors the EPA must consider in determining the "best system of emission reduction," the D.C. Circuit has stated that the EPA must do so.

[330] *Portland Cement v. EPA*, 486 F. 2d at 384; *Sierra Club v. Costle*, 657 F. 2d at 331; *see also Essex Chemical Corp. v. Ruckelshaus*, 486 F. 2d at 439 (remanding standard to consider solid waste disposal implications of the BSER determination).

See Sierra Club v. Costle, 657 F.2d 298, 326 (D.C. Cir. 1981) ("we can think of no sensible interpretation of the statutory words "best ... system" which would not incorporate the amount of air pollution as a relevant factor to be weighed when determining the optimal standard for controlling … emissions").[331] The fact that the purpose of a "system of emission reduction" is to reduce emissions, and that the term itself explicitly incorporates the concept of reducing emissions, supports the Court's view that in determining whether a "system of emission reduction" is the "best," the EPA must consider the amount of emission reductions that the system would yield. Even if the EPA were not required to consider the amount of emission reductions, the EPA has the discretion to do so, on grounds that either the term "system of emission reduction" or the term "best" may reasonably be read to allow that discretion.

(e) <u>Sector- or nationwide component of factors in determining the BSER</u>.

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[331] *Sierra Club v. Costle*, 657 F.2d 298 (D.C. Cir. 1981) was governed by the 1977 CAAA version of the definition of "standard of performance," which revised the phrase "best system of emission reduction" to read, "best technological system of continuous emission reduction." As noted above, the 1990 CAAA deleted "technological" and "continuous" and thereby returned the phrase to how it read under the 1970 CAAA. The court's interpretation of the 1977 CAAA phrase in *Sierra Club v. Costle* to require consideration of the amount of air emissions remains valid for the 1990 CAAA phrase "best system of emission reduction."

As discussed in the January 2014 proposal for the section 111(b) rulemaking and the proposal for this rulemaking, another component of the D.C. Circuit's interpretations of CAA section 111 is that the EPA may consider the various factors it is required to consider on a national or regional level and over time, and not only on a plant-specific level at the time of the rulemaking.[332] The D.C. Circuit based this interpretation – which it made in the 1981 *Sierra Club v. Costle* case, which concerned the NSPS for new power plants -- on a review of the legislative history, stating,

> [T]he Reports from both Houses on the Senate and House bills illustrate very clearly that Congress itself was using a long-term lens with a broad focus on future costs, environmental and energy effects of different technological systems when it discussed section 111.[333]

The Court has upheld EPA rules that the EPA "justified ... in terms of the policies of the Act," including balancing long-term national and regional impacts:

> The standard reflects a balance in environmental, economic, and energy consideration by being sufficiently stringent to bring about substantial reductions in SO_2 emissions (3 million tons in 1995) yet does so at reasonable costs without significant energy penalties.... By achieving a balanced coal demand within the utility sector and by promoting the development of less expensive SO_2 control technology, the final standard will expand environmentally

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[332] 79 FR 1430, 1465 (January 8, 2014) (citing *Sierra Club v. Costle*, 657 F.2d at 351).
[333] *Sierra Club v. Costle*, 657 F.2d at 331 (citations omitted) (citing legislative history).

> acceptable energy supplies to existing power plants and industrial sources.
>
> By substantially reducing SO_2 emissions, the standard will enhance the potential for long term economic growth at both the national and regional levels.[334]

In this rule, the EPA is considering costs and energy implications on the basis of (i) their source-specific impacts and (ii) a sector-wide, regional, or national basis, both separately and in combination with each other.

(4) Achievability of the emission limitation in the emission guidelines.

Before discussing the requirement under section 111(d) that the emission limitation in the emission guidelines must be "achievable," it is useful to discuss the comparable requirement under section 111(b) for new sources. For new sources, CAA section 111(b)(1)(B) and (a)(1) provides that the EPA must establish "standards of performance," which are standards for emissions that reflect the degree of emission limitation that is "achievable" through the application of the BSER. According to the D.C. Circuit, a standard of performance is "achievable" if a technology can reasonably be projected to be available to an

[334] *Sierra Club v. Costle*, 657 F.2d at 327-28 (quoting 44 FR at 33583/3-33584/1). In the January 2014 proposal, we explained that although the D.C. Circuit decided *Sierra Club v. Costle* before the *Chevron* case was decided in 1984, the D.C. Circuit's decision could be justified under either *Chevron* step 1 or 2. 79 FR 1430, 1466 (January 8, 2014).

individual source at the time it is constructed that will allow it to meet the standard.[335] Moreover, according to the Court, "[a]n achievable standard is one which is within the realm of the adequately demonstrated system's efficiency and which, while not at a level that is purely theoretical or experimental, need not necessarily be routinely achieved within the industry prior to its adoption."[336] To be achievable, a standard "must be capable of being met under most adverse conditions which can reasonably be expected to recur and which are not or cannot be taken into account in determining the 'costs' of compliance."[337] To show a standard is achievable, the EPA must "(1) identify variable conditions that might contribute to the amount of expected emissions, and (2) establish that the test data relied on by the agency are representative of potential industry-wide performance, given the range of variables that affect the achievability of the standard."[338]

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[335] *Sierra Club v. Costle*, 657 F.2d 298, 364, n. 276 (D.C. Cir. 1981).
[336] *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433-34 (D.C. Cir. 1973), *cert. denied*, 416 U.S. 969 (1974).
[337] *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 433, n.46 (D.C. Cir. 1980).
[338] *Sierra Club v. Costle*, 657 F.2d 298, 377 (D.C. Cir. 1981) (citing *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416 (D.C. Cir. 1980). In considering the representativeness of the source tested, the EPA may consider such variables as the "'feedstock, operation, size and age' of the source." *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 433 (D.C. Cir. 1980). Moreover, it may be sufficient to "generalize from a sample of one when one is the only available

The D.C. Circuit established these standards for achievability in cases concerning CAA section 111(b) new source standards of performance. There is no case law under CAA section 111(d). Assuming that those standards for achievability apply under section 111(d), in this rulemaking, we are taking a similar approach for the emission limitation that the EPA identifies in the emission guidelines. For existing sources, section 111(d)(1) requires the EPA to establish requirements for state plans that, in turn, must include "standards of performance." Through long-standing regulations[339] and consistent practice, the EPA has interpreted this provision to require the EPA to promulgate emission guidelines that determine the BSER for a source category and that identify the amount of emission limitation achievable by application of the BSER.

The EPA has promulgated these emission guidelines on the basis that the existing sources can achieve the limitation, even though the state retains discretion to apply standards of performance to individual sources that are more or less stringent.

(a) <u>Technical feasibility</u>.

As indicated in the proposed rulemakings for this rule and

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sample, or when that one is shown to be representative of the regulated industry along relevant parameters." *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 434, n.52 (D.C. Cir. 1980).

[339] 40 CFR 60.21(e).

the associated section 111(b) rule, the requirement that the emission limitation in the emission guidelines be "achievable" based on the "best system of emission reduction ... adequately demonstrated" indicates that the technology or other measures that the EPA identifies as the BSER must be technically feasible. *See* 79 FR 1430, 1463 (January 8, 2014). At least in some cases, in determining whether the emission limitation is achievable, it is useful to analyze the technical feasibility of the system of emission reduction, and we do so in this rulemaking.

(5) Expanded use and development of technology.

The D.C. Circuit has long held that Congress intended for CAA section 111 to create incentives for new technology and therefore that the EPA is required to consider technological innovation as one of the factors in determining the "best system of emission reduction." *See Sierra Club v. Costle*, 657 F.2d at 346-47. The Court has grounded its reading in the statutory text.[340] In addition, the Court's interpretation finds firm

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[340] *Sierra Club v. Costle*, 657 F. 2d at 346 ("Our interpretation of section 111(a) is that the mandated balancing of cost, energy, and nonair quality health and environmental factors embraces consideration of technological innovation as part of that balance. The statutory factors which EPA must weigh are broadly defined and include within their ambit subfactors such as technological innovation.").

support in the legislative history.[341] The legislative history identifies three different ways that Congress designed CAA section 111 to authorize standards of performance that promote technological improvement: (i) the development of technology that may be treated as the "best system of emission reduction … adequately demonstrated;" under section 111(a)(1);[342] (ii) the expanded use of the best demonstrated technology;[343] and (iii) the development of emerging technology.[344] Even if the EPA were not required to consider technological innovation as part of its determination of the BSER, it would be reasonable for the EPA to consider it, either because technological innovation may be considered an element of the term "best," or because the term "best system of emission reduction" is ambiguous as to whether

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[341] *See* S. Rep. No. 91-1196 at 16 (1970) ("Standards of performance should provide an incentive for industries to work toward constant improvement in techniques for preventing and controlling emissions from stationary sources"); S. Rep. No. 95-127 at 17 (1977) (cited in *Sierra Club v. Costle*, 657 F.2d at 346 n. 174) ("The section 111 Standards of Performance ... sought to assure the use of available technology and to stimulate the development of new technology").

[342] *See Portland Cement Ass'n v.Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973) (the best system of emission reduction must "look[] toward what may fairly be projected for the regulated future, rather than the state of the art at present").

[343] *See* 1970 Senate Committee Report No. 91-1196 at 15 ("The maximum use of available means of preventing and controlling air pollution is essential to the elimination of new pollution problems").

[344] *See Sierra Club v. Costle*, 657 F.2d at 351 (upholding a standard of performance designed to promote the use of an emerging technology).

technological innovation may be considered, and it is reasonable for the EPA to interpret it to authorize consideration of technological innovation in light of Congress's emphasis on technological innovation.

In any event, as discussed below, the EPA may justify the control measures identified in this rule as the BSER even without considering the factor of incentivizing technological innovation or development.

(6) EPA discretion.

The D.C. Circuit has made clear that the EPA has broad discretion in determining the appropriate standard of performance under the definition in CAA section 111(a)(1), quoted above. Specifically, in *Sierra Club v. Costle*, 657 F.2d 298 (D.C. Cir. 1981), the Court explained that "section 111(a) explicitly instructs the EPA to balance multiple concerns when promulgating a NSPS,"[345] and emphasized that "[t]he text gives the EPA broad discretion to weigh different factors in setting the standard."[346] In *Lignite Energy Council v. EPA*, 198 F.3d 930 (D.C. Cir. 1999), the Court reiterated:

Because section 111 does not set forth the weight that

[345] *Sierra Club v. Costle*, 657 F.2d at 319.
[346] *Sierra Club v. Costle*, 657 F.2d at 321; *see also New York v. Reilly*, 969 F. 2d at 1150 (because Congress did not assign the specific weight the Administrator should assign to the statutory elements, "the Administrator is free to exercise [her] discretion" in promulgating an NSPS).

> should be assigned to each of these factors, we have granted the agency a great degree of discretion in balancing them…. EPA's choice [of the 'best system'] will be sustained unless the environmental or economic costs of using the technology are exorbitant…. EPA [has] considerable discretion under section 111.[347]

d. <u>Approach to the source category and subcategorizing</u>. Section 111 requires the EPA first to list source categories that may reasonably be expected to endanger public health or welfare and then to regulate new sources within each such source category. Section 111(b)(2) grants the EPA discretion whether to "distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing [new source] standards," which we refer to as "subcategorizing." Section 111(d)(1), in conjunction with section 111(a)(1), simply requires the EPA to determine the BSER, does not prescribe the method for doing so, and is silent as to whether the EPA may subcategorize. The EPA interprets this provision to authorize the EPA to exercise discretion as to whether and, if so, how to

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[347] *Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999) (paragraphing revised for convenience). *See New York v. Reilly*, 969 F.2d 1147, 1150 (D.C. Cir. 1992) ("Because Congress did not assign the specific weight the Administrator should accord each of these factors, the Administrator is free to exercise his discretion in this area."); *see also NRDC v. EPA*, 25 F.3d 1063, 1071 (D.C. Cir. 1994) (EPA did not err in its final balancing because "neither RCRA nor EPA's regulations purports to assign any particular weight to the factors listed in subsection (a)(3). That being the case, the Administrator was free to emphasize or deemphasize particular factors, constrained only by the requirements of reasoned agency decisionmaking.").

subcategorize. In addition, the regulations under CAA section 111(d) provide --

> The Administrator will specify different emission guidelines or compliance times or both for different sizes, types, and classes of designated facilities when costs of the control, physical limitations, geographical location, or similar factors make subcategorization appropriate.[348]

As with any of its own regulations, the EPA has authority to interpret or revise these regulations.

Of course, regardless of whether the EPA subcategorizes within a source category for purposes of determining the BSER and the emissions performance level for the emission guideline, as part of its section 111(d) plan, a state retains great flexibility in assigning standards of performance to its affected EGUs. Thus, the state may, if it wishes, impose different emission reduction obligations on different sources, as long as the overall level of emission limitation is at least as stringent as the emission guidelines.

2. The BSER for this Rule -- Overview

a. Summary. This section describes the EPA's overall approach to establishing the BSER. This rule, promulgated under CAA section 111(d), establishes emission guidelines for states to use in establishing standards of performance for affected EGUs, and the BSER is the central determination that the EPA must make in

[348] 40 CFR 60.22(b)(5).

formulating the guidelines. In order to establish the BSER we have considered the subcategory of the steam affected EGUs as a whole, and the subcategory of the combustion turbine affected EGUs as a whole, and have identified the BSER for each subcategory as the measures that the sources, viewed together and operating under the standards of performance established for them by the states, can implement to reduce their emissions to an appropriate amount, and that meet the other requirements for the BSER including, for example, cost reasonableness.[349] After identifying the BSER in this manner, the EPA determines the performance levels -- in this case, the CO_2 emission performance rates -- for the steam generators and for the combustion turbines.

In establishing the BSER the EPA also considered the set of actions that an EGU, operating under a standard of performance established by its state, may take to achieve the applicable performance rate, if the state adopts that rate as the standard of performance and applies it to the EGUs in its jurisdiction, or to achieve the equivalent mass-based limit, and that meet the

[349] In this rulemaking, our determination that the costs are reasonable means that the costs meet the cost standard in the case law no matter how that standard is articulated, that is, whether the cost standard is articulated through the terms that the case law uses, e.g., "exorbitant," "excessive," etc., or through the term we use for convenience, "reasonableness".

other requirements for the BSER. These actions implement the BSER and may therefore be understood as part of the BSER.

An example illustrating the relationship between the measures determined to constitute the BSER for the source category and the actions that may be undertaken by individual sources that are therefore also part of the BSER is the substitution of zero-emitting generation for CO_2-emitting generation. This measure involves two distinct actions: increasing the amount of zero-emitting generation and reducing the amount of CO_2-emitting generation. From the perspective of the source category, the two actions are halves of a single balanced endeavor, but from the perspective of any individual affected EGU, the two actions are separable, and a particular affected EGU may decide to implement either or both of the actions. Further, an individual source may choose to invest directly in actions at its own facility or an affiliated facility or to cross-invest in actions at other facilities on the interconnected electricity system.

To reiterate the overall context for the BSER: in this rule, the EPA determined the BSER, and applied it to the category of affected EGUs to determine the performance levels -- that is, the CO_2 emission performance rates -- for steam generators and for combustion turbines. States must impose standards of performance on their sources that implement the CO_2

emission performance rates, or, as an alternative method of compliance, in total, achieve the equivalent emissions performance level that the CO_2 emission performance rates would achieve if applied directly to each source as the standard or emissions limitation it must meet.[350] Each state has flexibility in how it assigns the emission limitations to its affected EGUs -- and in fact, the state can be more stringent than the guidelines require -- but one of the state's choices is to convert the CO_2 emission performance rates into standards of performance -- which may incorporate emissions trading -- for each of its affected EGUs. If a state does so, then the affected EGUs may achieve their emission limits by taking the actions that qualify as the BSER. Since the BSER and, in this case its constituent elements, reflect the criteria of reasonable cost and other BSER criteria, the BSER assures that there is at least one pathway -- the CO_2 emission performance rates -- for the state and its affected EGUs to take that achieves the requisite level of emission reductions, while, again, assuring that the affected EGUs can achieve those emission limits at reasonable cost and consistent with the other factors for the BSER.

[350] The approaches that states may take in their plans are discussed in section VIII.

This section describes the EPA's process and basis for determining the BSER for the purpose of determining the CO_2 emission performance rates.[351] The EPA is identifying the BSER as a well-established set of measures that have been used by EGUs for many years to achieve various business and policy purposes, and have been used in recent years for the specific purpose of reducing EGUs' CO_2 emissions, and that are appropriate for carbon pollution (given its global nature and large quantities, and the limited means to control it) and afforded by the highly integrated nature of the utility power sector. We evaluated these measures with a view to the states' obligation to establish standards of performance and included in our BSER determination consideration of the range of options available for states to employ in establishing those standards of performance. These measures include: (i) improving heat rate at existing coal-fired steam EGUs on average by a specified percentage (building block 1); (ii) substituting increased generation from existing NGCC units for reduced generation at existing steam EGUs in specified amounts (building block 2); and (iii) substituting increased generation from new zero-emitting RE generating capacity for reduced generation at existing fossil

[351] Other sections in this preamble describe how EPA calculated the CO_2 emission performance rates based on the BSER.

fuel-fired EGUs in specified amounts (building block 3). It should be noted that building block 2 incorporates reduced generation from steam EGUs and building block 3 incorporates reduced generation from all fossil fuel-fired EGUs.[352] Further, as discussed below, given the global nature of carbon pollution and the highly integrated utility power sector, each of the building blocks incorporates various mechanisms for facilitating cross-investment by individual affected EGUs in emission rate improvements or emission reduction activities at other locations on the interconnected electricity system. The range of mechanisms includes bilateral investment of various kinds; the issuance and acquisition of ERCsrepresenting the emissions-reducing effects of specific activities, where available under state plans; and more general emissions trading using rate-based credits or mass-based allowances (as discussed in section V.A.2.f. below), where the affected EGUs are operating under standards of performance that incorporate emissions trading.[353]

The set of measures identified as the BSER for the source category encompasses a menu of actions that are part of the BSER and that individual affected EGUs may implement in different

[352] The building block measures are not designed to reduce electricity generation overall; they are focused on maintaining the same level of electricity generation, but through less polluting processes.
[353] Conditions for the use of these mechanisms under various state plans are discussed in section VIII.

amounts and combinations in order to achieve their emission limits at reasonable cost. This menu includes actions that: (i) affected steam EGUs can implement to improve their heat rates; (ii) affected steam EGUs can implement to increase generation from lower-emitting existing NGCC units in specified amounts; (iii) all affected EGUs can implement to increase generation from new low- or zero-carbon generation sources in specified amounts; (iv) all affected EGUs can implement to reduce their generation in specified amounts; and (v) all affected EGUs operating under a standard of performance that incorporates emissions trading can implement by means of purchasing rate-based emission credits or mass-based emission allowances from other affected EGUs, since the effect of the purchase would be the same as achieving the other listed actions through direct means.[354]

Importantly, affected EGUs also have available numerous other measures that are not included in the BSER but that could materially help the EGUs achieve their emission limits and thereby provide compliance flexibility. Examples include, among numerous other approaches, investment in demand-side EE, co-firing with natural gas (for coal-fired steam EGUs), and investment in new generating units using low- or zero-carbon

[354] Again, conditions for the use of these mechanisms under various state plans are discussed in section VIII.

generating technologies other than those that are part of building block 3.

b. <u>The EPA's review of measures for determining the BSER</u>. The EPA described in the proposal for this rule the analytical process by which the EPA determined the BSER for this source category. The EPA is finalizing large parts of that analysis, but the EPA is also refining that analysis as informed by the information and data discussed by commenters and our further evaluation. What follows is the EPA's final determination.

As described in the proposal, to determine the BSER, the EPA began by considering the characteristics of CO_2 pollution and the utility power sector. Not surprisingly, whenever the EPA begins the regulatory process under section 111, it initially undertakes these same inquiries and then proceeds to fashion the rule to fit the industry. For example, in 1979, the EPA finalized new standards of performance to limit emissions of SO_2 from new, modified, and reconstructed EGUs.[355] In assessing the

[355] The need for new standards was due in part to findings that in 1976, steam electric generating units were responsible for "65 percent of the SO_2 ... emissions on a national basis." 44 FR 33580, 33587 (June 11, 1979). The EPA explained that [u]nder the current performance standards for power plants, national SO_2 emissions are projected to increase approximately 17 percent between 1975 and 1995. Impacts will be more dramatic on a regional basis." *Id.* Thus, "[o]n January 27, 1977, EPA announced that it had initiated a study to review the technological, economic, and other factors needed to determine to what extent

final SO_2 standard, the EPA carried out extensive analyses of a range of alternative SO_2 standards "to identify environmental, economic, and energy impacts associated with each of the alternatives considered at the national and regional levels."[356] In identifying the best system underlying the final standard, the EPA evaluated "coal cleaning and the relative economics of FGD [flue gas desulfurization] and coal cleaning" together as the "best demonstrated system for SO_2 emission reduction."[357] The EPA also took into account the unique features of power transmission along the interconnected grid and the unique commercial relationships that rely on those features.[358]

Similarly, in 1996, the EPA finalized section 111(b) standards and 111(d) emission guidelines to ensure that certain municipal solid waste (MSW) landfills controlled landfill gases

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the SO_2 standard for fossil-fuel-fired steam generators should be revised." *Id.* at 33587-33588.

[356] 44 FR 33580, 33582 (June 11, 1979).

[357] 44 FR 33580, 33593. The EPA considered an investigation by the U.S. Department of the Interior regarding the amount of sulfur that could be removed from various coals by physical coal cleaning. *Id.* at 33593.

[358] *See* 44 FR 33580, 33597-33600 (taking into account "the amount of power that could be purchased from neighboring interconnected utility companies" and noting that "[a]lmost all electric utility generating units in the United States are electrically interconnected through power transmission lines and switching stations" and that "load can usually be shifted to other electric generating units").

to the level achievable through application of the BSER.[359] EPA's identification of this BSER was critically influenced by the "unique emission pattern of landfills."[360] Unlike "typical stationary source[s]," which only generate emissions while in operation, MSW landfills can "continue to generate and emit a significant quantity of emissions" long after the facility has closed or otherwise stopped accepting waste.[361] In recognition of this salient and unique characteristic of landfills, the EPA set the BSER based on an emission-reducing system of gas collection and control that remained in place as long as emissions remained above a certain threshold -- even after the regulated landfill had permanently closed.[362] The EPA acknowledged that for some landfills, it could take 50 to 100 years for emissions to drop below the cutoff.[363]

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[359] 61 FR 9905, 9905 (March 12, 1996). In the rule, the EPA referred to the BSER for both new and existing MSW landfills as "the best demonstrated system of continuous emission reduction," as well as the "BDT"—short for "best demonstrated technology." *See, e.g., id.* at 9905–07, 9913–14.
[360] 61 FR 9905, 9908; *see* 56 FR 24468, 24478 (May 30, 1991) (explaining at proposal that because landfill-gas emission rates "gradually increase" from zero after the landfill opens, and "gradually decrease" from peak emissions after closure, the EPA's identification of the BSER for landfills inherently requires a determination of "when controls systems must be installed and when they may be removed").
[361] *See* U.S. EPA, *Municipal Solid Waste Landfills, Volume 1: Summary of the Requirements for the New Source Performance Standards and Emission Guidelines for Municipal Solid Waste Landfills*, Docket No. EPA-453R/96-004 at 1-3 (February 1999).
[362] 61 FR 9905, 9907–08.
[363] 61 FR 9905, 9908.

For this rule, we discuss at length in the proposed rule and in section II above the unique characteristics of CO_2 pollution. The salient facts include the global nature of CO_2, which makes the specific location of emission reductions unimportant; the enormous quantities of CO_2 emitted by the utility power sector, coupled with the fact that CO_2 is relatively unreactive, which make CO_2 much more difficult to mitigate by measures or technologies that are typically utilized within an existing power plant; the need to make large reductions of CO_2 in order to protect human health and the environment; and the fact that the utility power sector is the single largest source category by a considerable margin.

We also discuss at length in the proposal and in section II above the unique characteristics of the utility power sector. Topics of that discussion include the physical properties of electricity and the integrated nature of the electricity system. Here, we reiterate and emphasize that the utility power sector is unique in the extent to which it must balance supply and demand on a real-time basis, with limited electricity storage capacity to act as a buffer. In turn, the need for real-time synchronization across each interconnection has led to a uniquely high degree of coordination and interdependence in both planning and real-time system operation among the owners and operators of the facilities comprised within each of the three large electrical interconnections covering the contiguous 48 states. Given these unique characteristics, it is not surprising that the North American power system has been characterized as a "complex machine."[364] The core function of providing reliable electricity service is carried out not by individual electricity generating units but by the complex machine as a whole. Important subsidiary functions such as management of costs and management of environmental impacts are also carried out to a great extent on a multi-unit basis rather than an individual-unit basis. Generation from one generating unit can be and routinely is substituted for generation from another generating unit in order to keep the complex machine operating while observing the machine's technical, environmental, and other constraints and managing its costs.

The EPA also reviewed broad trends within the utility power sector.[365] It is evident that, in the recent past, coal-fired electricity generation has been reduced, and projected future trends are for continued reduction. By the same token, lower-emitting NGCC generation and renewable generation have increased, and projected future trends are for continued

[364] S. Massoud Amin, "Securing the Electricity Grid," The Bridge, Spring 2010, at 13, 14; Phillip F. Schewe, The Grid: A Journey Through the Heart of Our Electrified World 1 (2007).
[365] These trends are discussed in more detail in sections V.D. and V.E. below.

increases.[366] A survey of integrated resource plans (IRPs), included in the docket, shows that fossil fuel-fired EGUs are taking actions to reduce emissions of both non-GHG air pollutants and GHGs.[367] Some fossil fuel-fired EGUs are investing in lower- or zero-emitting generation. In fact, our review indicates that the great majority of fossil fuel-fired generators surveyed are including new RE resources in their planning. In addition, some fossil fuel-fired EGUs are using those measures to replace their higher-emitting generation. Some fossil fuel-fired generators appear to be reducing their higher-emitting generation without fully replacing it themselves. These measures in aggregate result in the replacement of higher-emitting generation with lower- or zero-emitting generation, reflecting the integrated nature of the electricity system.

The EPA examined state and company programs intended at least in part to reduce CO_2 from fossil fuel-fired power plants. These programs include GHG performance standards established by states including California, New York, Oregon, and Washington; utility planning approaches carried out by companies in Colorado and Minnesota; and renewable portfolio standards (RPS)

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[366] Demand-side energy efficiency measures have also increased, and the projected future trends are for continued increase.
[367] See memo entitled "Review of Electric Utility Integrated Resource Plans" (May 7, 2015) available in the docket.

established in more than 25 states.[368] They also include market-based initiatives, such as RGGI and the GHG emissions trading program established by the California Global Warming Solutions Act, and conservation and demand reduction programs.

We also examined federal legislative and regulatory programs, as well as state programs currently in operation, that address pollutants other than CO_2 emitted by the power sector. These programs include, among others, the CAA Title IV program to reduce SO_2 and NO_X, the MATS program to reduce mercury and air toxic emissions, and the CSAPR program to reduce SO_2 and NO_X.[369] This analysis demonstrated that, among other measures, the application of control technology, fuel-switching, and improvements in the operational efficiency of EGUs all resulted in reductions in a range of pollutants. These programs also demonstrate that replacement of higher-emitting generation with lower-emitting generation -- including generation shifts between coal-fired EGUs and natural gas-fired EGUs and generation shifts between fossil fuel-fired EGUs and RE generation –- also reduces emissions. Some of these programs also include emissions trading among the power plants.

In this rule, when evaluating the types and amounts of measures that the source category can take to reduce CO_2

[368] *See* 79 FR 34848-34850.
[369] Many of these programs are discussed in section II.

emissions, we have appropriately taken into account the global nature of the pollutant and the high degree to which each individual affected EGU is integrated into a "complex machine" that makes it possible for generation from one generating unit to be replaced with generation from another generating unit for the purpose of reducing generation from CO_2-emitting generating units. We have also taken into account the trends away from higher-carbon generation toward lower- and zero-carbon generation. These factors strongly support consideration of emission reduction approaches that focus on the machine as a whole -- that is, the overall source category -- by shifting generation from dirtier to cleaner sources in addition to emission reduction approaches that focus on improving the emission rates of individual sources.

The factors just discussed that support consideration of emission reduction measures at the source-category level likewise strongly support consideration of mechanisms such as emissions trading approaches, especially since, as discussed in section VIII, the states will have every opportunity to design their section 111(d) plans to allow the affected EGUs in their respective jurisdictions to employ emissions trading approaches to achieve the standards of performance established in those plans. In short, as discussed in more detail in section V.A.2.f. below, it is entirely feasible for states to establish standards of performance that incorporate emissions trading, and it is reasonable to expect that states will do so. These approaches lower overall costs, add flexibility, and make it easier for individual sources to address pollution control objectives. To the extent that the purchase of an emissions credit or allowance represents the purchase of surplus emission reductions by an emitting source, emissions trading represents, in effect, the investment in pollution control by the purchasing source, notwithstanding that the control activity may be occurring at another source. As noted above, the utility power sector has a long history of using the "complex machine" to address objectives and constraints of various kinds. When afforded the opportunity to address environmental objectives on a multi-unit basis, the industry has done so. Congress and the EPA have selected emissions trading approaches when addressing regional pollution from the utility power sector contributing to problems such as acid precipitation and interstate transport of ozone and particulate matter. Similarly, states have selected market-based approaches for their own programs to address regional and global pollutants. The industry has readily adapted to that form of regulation, taking advantage of the flexibility and incorporating those programs into the planning and operation of the "machine." Further reinforcing our conclusion that reliance on trading is appropriate is the extensive interest in using such mechanisms that states and utilities demonstrated through their formal comments and in discussions during the outreach process. The role of emissions trading is discussed further in section V.A.2.f. below.

This entire review has made clear that there are numerous measures that, alone or in various combinations, merit analysis for inclusion in the BSER. The review has also made clear that the unique characteristics of CO_2 pollution and the unique, interconnected and interdependent manner in which affected EGUs and other generating sources operate within the electricity sector make certain types of measures and mechanisms available and appropriate for consideration as the BSER for this rule that would not be appropriate for other pollutants and other industrial sectors. For purposes of this discussion, the measures can be categorized in terms of the essential characteristics of the four building blocks described in the proposal: measures that (i) reduce the CO_2 emission rate at the unit; (ii) substitute generation from existing lower-emitting fossil fuel-fired units for generation from higher-emitting fossil fuel-fired units; (iii) substitute generation from new low- or zero-emitting generating capacity, especially RE, for generation from fossil fuel-fired units; and (iv) increase demand-side EE to avoid generation from fossil fuel-fired units. In the proposal, we described our evaluations of various measures in each of these categories. In this rule, with the benefit of comments, we have refined our evaluation of which specific measures should comprise the first three building blocks, and, for reasons discussed below, we have determined that the fourth building block, demand-side EE, should not be included in the BSER in these guidelines.

The measures are discussed more fully below, but it should be noted here that because of the integrated nature of the utility power sector -- in which individual EGUs' operations intrinsically depend on the operations of other generators -- coupled with the sector's high degree of planning and reliability safeguards, the measures in the second and third categories (which involve generation shifts to lower- and zero-emitting sources) may occur through several different actions from the perspective of an individual source, all of which are equivalent from the perspective of the source category as a whole. First, a higher-emitting fossil unit may invest in cleaner generation without reducing its own generation, which, in the presence of requirements for the source category as a whole to reduce CO_2 emissions, would result in less demand for, and therefore reductions in generation by, other higher-emitting units. Second, a higher-emitting fossil unit may reduce its generation, which, in the presence of requirements for the source category as a whole to reduce CO_2 emissions, would result in increased demand for, and therefore increased amounts of, cleaner generation. Third, a higher-emitting fossil unit may do both of these things, directly replacing part of its generation with investments in lower- or zero-emitting generation. In addition, for measures in all of the categories, multiple mechanisms exist by which an individual affected EGU may make these investments, ranging from bilateral investments, to purchase of credits representing the emissions-reducing benefits of specific activities, to purchase of general rate-based emissions credits or mass-based emission allowances. As discussed below, mechanisms involving tradable credits or allowances are well within the realm of consideration for the standards of performance states can choose to apply to their EGUs and hence, are entirely appropriate for EPA to consider in evaluating these measures in the course of making its BSER determination.

c. State establishment of standards of performance and source compliance. Before identifying in detail the measures that the BSER comprises, it is useful to describe the process by which the states establish the standards of performance with which the affected EGUs must comply, and the implications for the sources that will be operating subject to those standards of performance. As part of the EPA's emission guidelines in this rule, and based on the BSER, the EPA is identifying CO_2 emission performance rates that reflect the BSER and, pursuant to subsection 111(d)(1), requiring states to establish standards of performance for affected EGUs in order to implement those rates. States, of course, could simply impose those rates on each affected EGU in their respective jurisdictions, but we are also offering states alternative approaches to carrying out their obligations. For purposes of defining these alternatives and facilitating states' efforts to formulate compliance plans encompassing maximum flexibilities, we are aggregating the performance rates into goals for each state. The state, in turn, has the option of setting specific standards of performance for its EGUs such that the emission limitations from the EGUs operating under those standards of performance together meet the performance rates or the state goal. To do this, the state must adopt a plan that establishes the EGUs' standards of performance and that implements and enforces those standards.

Each state has significant flexibility in several respects. For example, as mentioned, a state may impose standards of performance on its steam EGU sources and on its combustion turbine sources that simply reflect the respective CO_2 emission performance rates for those subcategories set in the emission guidelines. Alternatively, a state may impose standards with differing degrees of stringency on various sources, and, in fact, may be more stringent overall than its state goal requires. In addition -- and most importantly for purposes of describing the BSER -- a state may set standards of performance as mass limits (e.g., tons of CO_2 per year) rather than as emission rates (e.g., lbs of CO_2 per MWh). Moreover, a state may make the limits tradable (subject to conditions described in section VIII below), whether the limits are rate-based or mass-based. The form of the emission limits, whether emission rate limits or mass limits, has implications for what specific actions that are part of the BSER the individual affected EGUs may take to achieve those limits as well as what specific non-BSER measures are available to the individual affected EGUs for compliance flexibility. For example, if an individual source chooses to adopt building block 3 by both investing in lower- or zero-emitting generation and reducing its own generation, both those actions will be accounted for in its emission rate and both will therefore help the source meet its rate-based limit. If the same individual source takes the same actions but is subject to a mass-based limit, the action of reducing its generation will directly count in helping the source meet its own mass-based limit but the action of investing in cleaner generation will not. However, the investment in lower-or zero-emitting generation by that source and other sources collectively will help the overall source category achieve the emission limits consistent with the BSER and in doing so will make it easier for that source and other sources collectively to meet their mass-based limits.

In instances where a state establishes standards of performance that incorporate emissions trading, the tradable credits or allowances can serve as a medium through which affected EGUs can invest in any emission reduction measure.

d. Identification of the BSER measures. We now discuss the evaluation of potential measures for inclusion in the BSER for the source category as a whole.

(1) Measures that reduce individual affected EGUs' CO_2 emission rates.

As described in the proposal, the measures that the affected EGUs could implement to improve their CO_2 emission rates include a set of measures that the EPA determined would result in improvements in heat rate at coal-fired steam EGUs in the amount of 6 percent on average, and the EPA proposed that this set of measures qualifies as a component of the BSER. In this final rule, the EPA concludes that those measures do qualify as a component of the BSER. However, as described in section V.C. below, based on responsive comments and further evaluation, the EPA has refined its approach to quantifying the emission reductions achievable through heat rate improvements and no longer includes a separate increment of emission reductions attributable to equipment upgrades. Also, rather than evaluating the emission reductions available from these measures on a nationwide basis as in the proposal, the EPA has quantified the emission reductions achievable through building block 1 on a regional basis, consistent with the EPA's proposals to better reflect the regional nature of the interconnected electrical system and the treatment of the other building blocks in this final rule. As a result of these refinements, the EPA is identifying the heat rate improvements achievable by coal-fired steam EGUs as 4.3 percent for the Eastern Interconnection, 2.1 percent for the Western Interconnection, and 2.3 percent for the Texas Interconnection. The refinements are based, in significant part, on the numerous comments we received on our proposed approaches, especially those from states and utilities.

These heat rate improvement measures include best practices such as improved staff training, boiler chemical cleaning, cleaning air preheater coils, and use of various kinds of software, as well as equipment upgrades such as turbine overhauls. These are measures that the owner/operator of an affected coal-fired steam EGU may take that would have the effect of reducing the amount of CO_2 the source emits per MWh. As a result, these measures would help the source achieve an emission limit expressed as either an emission rate limit or as a mass limit. We note again that in the context both of the integrated electricity system and of available and anticipated state approaches to setting standards of performance, emissions trading approaches could be used as mechanisms through which one affected EGU could invest in heat rate improvements at another EGU. We note this aspect below in describing the actions an individual affected EGU can take to implement the BSER and discuss it in more detail in section V.A.2.f.

These heat rate improvements are a low-cost option that fit the criteria for the BSER, except that they lead to only small emission reductions for the source category.[370] Given the magnitude of the environmental problem and projections by climate scientists that much larger emission reductions are needed from fossil fuel-fired EGUs to address climate change, the EPA looked at additional measures to reduce emission rates. This reflects our conclusion that, given the availability of other measures capable of much greater emission reductions, the emission reductions limited to this set of heat rate improvement measures would not meet one of the considerations critical to the BSER determination -- the quantity of emissions reductions

[370] As further discussed below, if heat rate improvements at coal-fired steam EGUs were implemented in isolation, without other measures to reduce CO_2 emissions, the heat rate improvements could lead to increases in competitiveness and utilization of the coal-fired EGUs – a so-called "rebound effect" - causing increases in CO_2 emissions that could partially or even entirely offset the CO_2 emission reductions achieved through the reductions in the amount of CO_2 emissions per MWh of generation.

resulting from the application of these measures is too small for these measures to be the BSER by themselves for this source category.

Specifically, as described in the proposal, the EPA also considered co-firing (including 100 percent conversion) with natural gas, a measure that presented itself in part because of the recent increase in availability and reduction in price of natural gas, and the industry's consequent increase in reliance on natural gas.[371] The EPA also considered implementation of carbon capture and storage (CCS).[372] The EPA found that some of these co-firing and CCS measures are technically feasible and within price ranges that the EPA has found to be cost effective in the context of other GHG rules, that a segment of the source category may implement these measures, and that the resulting emission reductions could be potentially significant.

However, these co-firing and CCS measures are more expensive than other available measures for existing sources. This is because the integrated nature of the electricity system affords significantly lower cost options, ones that fossil fuel-fired power plants throughout the U.S. and in foreign nations are already using to reduce their CO_2 emissions.

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[371] The EPA further addressed co-firing in the October 30, 2014 Notice of Data Availability. 79 FR 64549-51.
[372] CCS is also sometimes referred to as carbon capture and sequestration.

The less expensive options include shifting generation to existing NGCC units -- an option that has become particularly attractive in light of the increased availability and lower prices of natural gas -- as well as shifting generation to new RE generating units. A comparison of the costs of converting an existing coal-fired boiler to burn 100 percent natural gas compared to the cost of shifting generation to an existing NGCC unit illustrates this point. Because an NGCC unit burns natural gas significantly more efficiently than an affected steam EGU does, the cost of shifting generation from the steam EGU to an existing NGCC unit is significantly cheaper in most cases than more aggressive emission rate reduction measures at the steam EGU. As a result, as a practical matter, were the EPA to include co-firing and CCS in the BSER and promulgate performance standards accordingly, few EGUs would likely comply with their emission standards through co-firing and CCS; rather, the EGUs would rely on the lower cost options of substituting lower- or zero-emitting generation or, as a related matter, reducing generation.[373]

The EPA also considered heat rate improvement opportunities at oil- and gas-fired steam EGUs and NGCC units and found that the available emission reductions would likely be more expensive

[373] Many EGUs would also rely on demand-side energy efficiency measures.

or too small to merit consideration as a material component of the BSER.

Thus, in reviewing the entire range of control options, it became clear that controlling CO_2 from affected EGUs at levels that are commensurate with the sector's contribution to GHG emissions and thus necessary to mitigate the dangers presented by climate change, could depend in part, but not primarily, on measures that improve efficiency at the power plants. Rather, most of the CO_2 controls need to come in the form of those other measures that are available to the utility power sector thanks specifically to the integrated nature of the electricity system, and that involve, in one form or another, replacement of higher emitting generation with lower- or zero-emitting generation.

Although the presence of lower-cost options that achieve the emission reduction goals mean that the EPA is not identifying either natural gas co-firing or CCS at coal-fired steam EGUs, or heat rate improvements at other types of EGUs, as part of the BSER, those controls remain measures that some affected EGUs may be expected to implement and that as a result, will provide reductions that those affected EGUs may rely on to achieve their emission limits or may sell, through emissions trading, to other affected EGUs to achieve emission limits (to the extent permitted under the relevant section 111(d) plans). Another example of a non-BSER measure that an affected EGU in certain circumstances could choose to implement is the conversion of waste heat from electricity generation into useful thermal energy. The EPA further discusses the potential use of these non-BSER measures for compliance flexibility below.

The EPA's quantification of the CO_2 emission reductions achievable through heat rate improvements as a component of the BSER (building block 1) is discussed in section V.C. of this preamble and in the GHG Mitigation Measures TSD for the CPP Final Rule.

(2) Measures available because of the integrated electricity system.

To determine the BSER that meets the expectations and requirements of the CAA, including the achievement of meaningful reductions of CO_2, the EPA turned next to the set of measures that presented themselves as a result of the fact that the operations of individual affected EGUs are interdependent on and integrated with one another and with the overall electricity system. Those are the measures in the categories represented in the proposal by building blocks 2, 3, and 4. This section discusses the components of the BSER that relate to building blocks 2 and 3, which the EPA is finalizing as components of the BSER. This section also discusses the measures comprising the proposed building block 4, which the EPA is not including in the BSER in this final rule.

It bears reiterating that the extent to which the operations of individual affected EGUs are integrated with one another and with the overall electricity system is a highly salient and unique attribute of this source category. Because of this integration, the individual sources in the source category operate through a network that physically connects them to each other and to their customers, an interconnectedness that is essential to their operation under the status quo and by all indications is projected to be augmented further on a continual basis in the future to address fundamental objectives of reliability assurance and cost reduction. This physical interconnectedness exists to serve a set of interlocking regimes that, to a substantial extent, determine, if not dictate, any given EGU's operations on a nearly moment-to-moment basis. In analyzing BSER from the perspective of the overall source category, because the affected EGUs are connected to each other operationally, a combination of dispatching and investment in lower- and zero-emitting generation allows the replacement of higher-emitting generation with lower-emitting and zero-emitting generation (measures in building blocks 2 and 3), and thereby reduces emissions while continuing to serve load.

As noted above, substitution of higher-emitting generation for lower- or zero-emitting generation may include reduced generation, depending on the specific action taken by the individual EGU. Likewise, when incorporated into standards of performance, emissions trading mechanisms may be readily used for implementing these building blocks. We discuss these aspects below in describing the actions that individual sources may take to implement the building blocks.

(a) Substituting generation from lower-emitting affected EGUs for reduced generation from higher-emitting affected EGUs.

In the proposal, the EPA observed that substantial CO_2 emission reductions could be achieved at reasonable cost by increasing generation from existing NGCC units and commensurately reducing generation from steam EGUs. Because NGCC units produce much less CO_2 per MWh of generation than steam EGUs -- typically less than half as much CO_2 as coal-fired steam EGUs, which account for most generation from steam EGUs -- this generation shift reduces CO_2 emissions. We also noted that because NGCC units can generate as much as 46 percent more electricity from a given quantity of natural gas than a steam unit can, generation shifting from coal-fired steam EGUs to existing NGCC units is a more cost-effective strategy for reducing CO_2 emissions from the source category than converting coal-fired steam EGUs to combust natural gas or co-firing coal and natural gas in steam EGUs. We proposed to find that shifting generation consistent with a 70 percent target utilization rate (based on nameplate capacity) for NGCC units was feasible and should be a component of the BSER.

As described in section V.D. below, analysis reflecting consideration of the many comments we received on the EPA's proposal with respect to this issue supports the inclusion of generation shifting from higher-emitting to lower-emitting EGUs as a component of the BSER. Shifting of generation among EGUs is an everyday occurrence within the integrated operations of the utility power sector that is used to ensure that electricity is provided to meet customer demands in the most economic manner consistent with system constraints. Generation shifting to lower-emitting units has been recognized as an approach for reducing emissions in other EPA rules such as CSAPR.

The EPA's analysis continues to show that the magnitude of emission reductions included in the proposed rule from generation shifting is achievable. In response to our request for comment on the proposed target utilization rates, some commenters stated that summer capacity ratings are a more appropriate basis upon which to compute a target utilization than nameplate capacity ratings used at proposal. We agree, and accordingly, using the same data on historical generation as at proposal, we have reanalyzed feasible NGCC utilization levels expressed in terms of summer capacity ratings and have found that a 75 target utilization rate based on summer capacity ratings is feasible.

The EPA is finalizing a determination that generation shift from higher-emitting affected EGUs to lower-emitting affected EGUs is a component of the BSER (building block 2). Our quantification of the associated emission reductions is discussed in section V.D. of this preamble and in the GHG Mitigation Measures TSD for the CPP Final Rule.

(b) Substituting increased generation from new low- or zero-carbon generating capacity for reduced generation from affected EGUs.

Reducing generation from fossil fuel-fired EGUs and replacing it with generation from lower- or zero-emitting EGUs is another method for reducing CO_2 emissions from the utility power sector. In the proposal, the EPA identified RE generating capacity and nuclear generating capacity as potential sources of lower- or zero-CO_2 generation that could replace higher-CO_2 generation from affected EGUs.

(i) Increased generation from new RE generating capacity.

The EPA's survey of trends and actions already being taken in the utility power sector indicated that RE generating capacity and generation have grown rapidly in recent years, in part because of the environmental benefits of shifting away from fossil fuel-fired generation and in part because of improved economics of RE generation relative to fossil fuel-fired generation. It is clear that increasing the amount of new RE generating capacity and allowing the increased RE generation to replace generation from fossil fuel-fired EGUs can reduce CO_2 emissions from the affected source category. Accordingly, we proposed to include replacement of defined quantities of fossil generation by RE generation in the BSER.

The EPA is finalizing the determination that substitution of RE generation from new RE generating capacity is a component of the BSER but, with the benefit of comments responding to the EPA’s proposals on regionalization and techno-economic analytic approaches, the EPA has adjusted the approach for determining the quantities of RE generation. As part of the adjustment in approach, we have also refocused the quantification solely on generation from new RE generating capacity rather than total (new and existing) RE generating capacity as in the proposal. Our quantification of the RE generation component of the BSER is discussed in section V.E. of the preamble and in the GHG Mitigation Measures TSD for the CPP Final Rule.

(ii) Increased and preserved generation from nuclear generating capacity.

In the June 2014 proposal, the EPA also identified the replacement of generation from fossil fuel-fired EGUs with generation from nuclear units as a potential approach for reducing CO_2 emissions from the affected source category. We proposed to include two elements of nuclear generation in the BSER: an element representing projected generation from nuclear units under construction; and an element representing preserved generation from existing nuclear generating capacity at risk of retirement, and we took comment on all aspects of these proposals.

Like generation from new RE generating capacity, generation from new nuclear generating capacity can clearly replace fossil fuel-fired generation and thereby reduce CO_2 emissions. However, there are also important differences between these types of low- or zero-CO_2 generation. Investments in new nuclear capacity are very large capital-intensive investments that require substantial lead times. By comparison, investments in new RE generating capacity are individually smaller and require shorter lead times. Also, important recent trends evidenced in RE development, such as rapidly growing investment and rapidly decreasing costs, are not as clearly evidenced in nuclear generation. We view these factors as distinguishing the under-construction nuclear units from RE generating capacity, indicating that the new nuclear capacity is likely of higher cost and therefore less appropriate for inclusion in the BSER. Accordingly, as described in section V.A.3., the EPA is not finalizing increased generation from under-construction nuclear capacity as a component of the BSER.

The EPA is likewise not finalizing the proposal to include a component representing preserved existing nuclear generation in the BSER. On further consideration, we believe it is inappropriate to base the BSER on elements that will not reduce CO_2 emissions from affected EGUs below current levels. Existing nuclear generation helps make existing CO_2 emissions lower than they would otherwise be, but will not further lower CO_2 emissions below current levels. Accordingly, as described in section V.A.3., the EPA is not finalizing preservation of generation from existing nuclear capacity as a component of the BSER.

(iii) Generation from new NGCC units.

New NGCC units -- that is, units that had not commenced construction as of January 8, 2014, the date of publication of the proposed CO_2 standards of performance for new EGUs under section 111(b) -- are not subject to the standards of performance that will be established for existing sources under section 111(d) plans based on the BSER determined in this final rule. In the June 2014 proposed emission guidelines for existing EGUs, the EPA solicited comment on whether to include this measure in the BSER. Commenters raised numerous concerns, and after consideration of the comments, we are not including replacement of generation from affected EGUs through the construction of new NGCC capacity in the BSER. In this section, we discuss the reasons for our approach.

The EPA did not include reduced generation from affected EGUs achieved through construction and operation of new NGCC capacity in the proposed BSER because we expected that the CO_2 emission reductions achieved through such actions would, on average, be more costly than CO_2 emission reductions achieved through the proposed BSER measures. However, our determination not to include new construction and operation of new NGCC capacity in the BSER in this final rule rests primarily on the achievable magnitude of emission reductions rather than costs.

Unlike emission reductions achieved through the use of any of the building blocks, emission reductions achieved through the use of new NGCC capacity require the construction of additional CO_2-emitting generating capacity, a consequence that is inconsistent with the long-term need to continue reducing CO_2 emissions beyond the reductions that will be achieved through this rule. New generating assets are planned and built for long lifetimes -- frequently 40 years or more --that are likely longer than the expected remaining lifetimes of the steam EGUs whose CO_2 emissions would initially be displaced be the generation from the new NGCC units. The new capacity is likely to continue to emit CO_2 throughout these longer lifetimes, absent decisions to retire the units before the end of their planned lifetimes or to install CCS technology in the future at substantial additional cost. Because of the likelihood of CO_2 emissions for decades, the overall net emission reductions achievable through the construction and operation of new NGCC are less than for the measures including in the BSER, such as increased generation at existing NGCC capacity, which would be expected to reach the end of its useful life sooner than new NGCC capacity, or construction and operation of zero-emitting RE generating capacity. We view the production of long-term CO_2 emissions that otherwise would not be created as inconsistent with the BSER requirement that we consider the magnitude of emissions reductions that can be achieved. For this reason, we are not including replacement of generation from affected EGUs through the construction and operation of new NGCC capacity in the final BSER.

Commenters also raised a concern with the interrelation of section 111(b) and section 111(d). New NGCC capacity is distinguished from the other non-BSER measures discussed above by the fact that its CO_2 emissions would be subject to the CO_2 standards for new EGUs being established under section 111(b). Section 111 creates an express distinction between the sources subject to section 111(b) and the sources subject to section 111(d), and commenters expressed concern that to allow section 111(b) sources to play a direct role in setting the BSER under section 111(d) would be inconsistent with congressional intent to treat the two sets of sources separately. Section VIII of this preamble includes a discussion of ways to address new NGCC capacity in the context of different types of section 111(d) plans.

(c) Increasing demand-side EE to avoid generation and emissions from fossil fuel-fired EGUs.

The final category of approaches for reducing generation and CO_2 emissions from affected EGUs that the EPA considered in the proposal involves increasing demand-side EE. When demand-side EE is increased, energy consumers need less electricity in order to provide the same level of electricity-dependent services – e.g., heating, cooling, lighting, and use of motors and electronic devices. Through the integrated electricity system, including the connection of customers to affected EGUs through the electricity grid, reduced demand for electricity, in turn, leads to reduced generation and reduced CO_2 emissions. Our examination of actions and trends underway in the utility power sector confirmed that investments in demand-side EE programs are increasing. We proposed to include avoidance of defined quantities of fossil fuel-fired generation through increased demand-side EE as a component of the BSER (proposed building block 4). However, we also took comment on which building blocks should comprise the BSER and on our determination as to whether each building block met the various statutory factors.

Commenters expressed a wide range of views on the proposed reliance on demand-side EE in the BSER. Some commenters strongly supported the proposal, with suggestions for improvements, while some commenters strongly opposed the proposal and took the position that it exceeded the EPA’s legal authority. We do not address the merits of these comments here because, for the reasons discussed in section V.B.3.c.(8) below, we are not finalizing the proposal to include avoided generation achieved through demand-side EE as a component of the BSER. However, we note that most commenters also supported the use of demand-side EE for compliance whether or not it is used in determining the BSER, and we are allowing demand-side EE to be used for that purpose. (We also emphasize that the emission limitations reflective of the BSER are achievable even if aggregate generation is not reduced through demand-side EE.)

(3) Further analysis to quantify the BSER.

While the discussion above summarizes how and why the components of the BSER were determined in terms of qualitative characteristics, it still leaves a wide range of potential stringencies for the BSER. As explained in sections V.C., V.D., and V.E. below, discussing building blocks 1, 2, and 3 respectively, the EPA has determined a reasonable level of stringency for each of the building blocks rather than the maximum possible level of stringency. We have taken this approach in part to ensure that there is "headroom" within the BSER measures that provides greater assurance of the achievability of the BSER for the source category and for individual sources. We believe this approach is permissible under the CAA. Another aspect of our methodology for computing the CO_2 emission performance rates, further described in section V.A.3.f. and section VI, is that the CO_2 emission performance rate applicable to a given source subcategory in all three interconnections reflects the emission rate achievable by that source subcategory through application of the building blocks in the interconnection where that achievable emission rate is the highest (i.e., least stringent).[374] This aspect of our methodology not only ensures that the nationwide CO_2 emission performance rates are achievable by affected EGUs in all three interconnections but also provides additional headroom within

[374] Specifically, the annual CO_2 emission performance rates applicable to steam EGUs in all three interconnections are the annual emission rates achievable by that subcategory in the Eastern Interconnection through application of the building blocks. Similarly, the annual CO_2 emission performance rates applicable to stationary combustion turbines in all three Interconnections are the annual emission rates achievable by that subcategory in the Texas Interconnection for years from 2022 to 2026, and in the Eastern Interconnection for years from 2027 to 2030, through application of the building blocks. Additional information is provided in the CO_2 Emission Performance Rate and State Goal Computation TSD in the docket.

the BSER for affected EGUs in the two interconnections that did not set the CO_2 emission performance rates ultimately used. Additional headroom within the BSER is available through the use of emissions trading approaches, because the final rule does not limit the use of these mechanisms to sources within the same interconnections. In fact, in response to proposals that emerged from the comment record and direct engagement with states and stakeholders reflecting their strong interest in pursuing multi-state approaches, the guidelines include mechanisms for implementing standards of performance that incorporate interstate trading, as discussed in section VIII. (In addition, as further discussed below, the rule also permits section 111(d) plans to allow the use of non-BSER measures for compliance in certain circumstances, increasing both compliance flexibility and the assurance that the emission limitations reflecting application of the BSER are achievable.)

Further, the sets of measures in each of these individual building blocks, in the stringency assigned in this rule, meet the criteria for the BSER. That is, they each achieve the appropriate level of reductions, are of reasonable cost, do not impose energy penalties on the affected EGUs and do not result in non-air quality pollutants, and have acceptable cost and energy implications on a source-by-source basis and for the energy sector as a whole. In addition, as explained below, each is adequately demonstrated. Importantly, past industry practice and current trends strongly support each of the building blocks, as do federal and state pollution control programs that require or result in similar measures.

For example, all of the measures in building blocks 2 and 3 have been implemented for decades, initially for reasons unrelated to pollution control, then in recent years in order to control non-GHG air pollutants, and more recently, for purposes of CO_2-emission control by states and companies. Moreover, Congress itself recognized in enacting the acid rain provisions of CAA Title IV that RE measures reduce CO_2 from affected EGUs. In addition, the EPA has relied on the measures in building blocks 2 and 3 in other rules.

It should also be noted that building blocks 2 and 3 also meet the criteria for the BSER in combination with one another and with building block 1, as described below.

e. Actions that individual affected EGUs could take to apply or implement the building blocks. We now turn to a summary of measures or actions that individual EGUs could take to apply or implement the building blocks and that are therefore, in that sense, part of the BSER.

(1) Improvement in CO_2 emission rate at the unit.

An affected EGU may take steps to improve its CO_2 emission rate as discussed above for the source category as a whole. As discussed in section V.C., the record makes clear that coal-fired steam EGUs can make, and have made, heat rate improvements to a greater or lesser degree, resulting in reductions in CO_2 emissions. The resulting improvement in an EGU's CO_2 emission rate would help the EGU achieve an emission limit imposed in the form of an emission rate. If the EGU's emission limit is imposed in the form of a mass standard, the heat rate improvement would also lower the EGU's mass emissions provided that the EGU held the amount of its generation constant or increased its generation by a smaller percentage than the efficiency improvement. Under a mass-based standard that incorporates emission trading, an EGU that improves its heat rate would need fewer emission allowances for each MWh of generation whatever level of generation it chose to produce.

(2) Actions to implement measures in building blocks 2 and 3.

Viewing the BSER from the perspective of an individual EGU, there are several ways that affected EGUs can access the measures in building blocks 2 and 3, thanks to the integrated nature of the electricity system, coupled with the system's high degree of planning and reliability mechanisms. The affected EGUs can: (a) invest in lower- or zero-emitting generation, which will lead to reductions in higher-emitting generation at other units in the integrated system; (b) reduce their generation, which in the presence of emission reduction requirements applicable to the source category as a whole will have the effect of increasing demand for, and thereby incentivize investment in, the measures in the building blocks elsewhere in the integrated system; or (c) both invest in the measures in the building blocks and reduce their own generation, effectively replacing their generation with cleaner generation. The availability of these options is further enhanced where the individual EGU is operating under a standard of performance that incorporates emissions trading.

(a) Investment in measures in building blocks 2 and 3.

An affected EGU may take the following actions to invest in the measures in building blocks 2 and 3: For building block 2, the owner/operator of a steam EGU may increase generation at an existing NGCC unit it already owns, or one that it purchases or invests in. In addition, the owner/operator may, through a bilateral transaction with an existing NGCC unit, pay the unit to increase generation, and acquire the CO_2-reducing effects of that increased generation in the form of a credit, as discussed below.

Similarly, for building block 3, an owner/operator of an affected EGU may build, or purchase an ownership interest in, new RE generating capacity and acquire the CO_2-reducing effects of that increased generation. Alternatively, an owner/operator may, through bilateral transactions, purchase the CO_2-reducing effects of that increased generation from renewable generation providers, again, in the form of a credit.

In case of an investment in either building block 2 or building block 3 by a unit subject to a rate-based form of CO_2 performance standard, it would be reasonable for state plans to authorize affected EGUs to use an approved and validated instrument such as an "emission rate credit" (ERC) representing the emissions-reducing benefit of the investment.[375]

When combined with reduced generation, either at the affected EGU or elsewhere in the interconnected system, the types of actions listed above would be fully equivalent to building blocks 2 and 3 when viewed from the perspective of the overall source category. Thus, a source could achieve a standard of performance identical to the applicable CO_2 emission performance rate in the EPA emission guidelines, through implementation of the actions described above for building blocks 2 and 3, along with the actions described further above for building block 1.

The EPA anticipates that in instances where section 111(d) plans provide for the use of instruments such as ERCs as a mechanism to facilitate use of these measures, organized markets

[375] Criteria for issuance of valid ERCs and for tracking credits after issuance are discussed in section VIII below.

will develop so that owner/operators of affected EGUs that have invested in measures eligible for the issuance of ERCs will be able to sell those credits and other affected EGUs will be able to purchase them. Such markets have developed for other instruments used for emissions trading purposes. For example, liquid markets for SO_2 allowances developed rapidly following the implementation of Title IV of the 1990 Clean Air Act Amendments establishing the Acid Rain Program. Members of Congress and industry had expressed concern during the legislative debate that the lack of a liquid SO_2 allowance market would create challenges for affected sources that needed to acquire allowances to meet their compliance obligations. Congress added statutory provisions to ensure that, should a market not develop, sources could purchase needed allowances directly from the EPA. In fact, these provisions went unused because a liquid market for allowances did develop very quickly. Sources engaged in allowance transactions directly with other sources as they sought to lower compliance costs. Market intermediaries offered services to sources to match allowance buyers and sellers and helped sources understand their compliance options. Trade associations worked with members to develop standardized contracts and other tools to facilitate allowance transactions, thereby reducing transaction costs. Similar developments have occurred in state-level renewable portfolio standard programs.[376]

If states choose to allow through their section 111(d) plans mechanisms or standards of performance involving instruments such as ERCs, the EPA believes that there would be an ample supply of such credits, for several reasons. First, as discussed in sections V.D. and V.E., the EPA has established the stringencies for building blocks 2 and 3 at levels that are reasonable and not at the maximum achievable levels, providing headroom for investment in the measures in these building blocks beyond the amounts reflected in the CO_2 emission performance rates reflecting application of the BSER. In addition, if emission limits are set at the CO_2 emission performance rates, affected EGUs in two of the three interconnections on average do not need to implement the building blocks to their full available extent in order to achieve their emission limits (because the performance rates for each source category are the emission rates achievable by that source subcategory through

[376] The emergence of markets under the Acid Rain Program and other environmental programs where trading has been permitted, as well as state and industry support for the development of markets under states' section 111(d) plans, is discussed in a recent report by the Advanced Energy Economy Institute. AEE Institute, *Markets Drive Innovation – Why History Shows that the Clean Power Plan Will Stimulate a Robust Industry Response* (July 2015), available at https://www.aee.net/aeei/initiatives/epa-111d.html#epa-reports-and-white-papers.

application of the building blocks in the interconnection where that achievable emission rate is the highest), providing further opportunities in those interconnections to generate surplus emission reductions that could be used as the basis for issuance of ERCs. Further, to the extent that section 111(d) plans take advantage of the latitude the final guidelines provide for states to set standards of performance incorporating emissions trading on an interstate basis among affected EGUs in different interconnections, all sources can take advantage of the headroom available in other interconnections. As a result, significant amounts of existing NGCC capacity and potential for RE remain available to serve as the basis for issuance of ERCs for all affected EGUs in both source subcategories to rely on to achieve their emission limits. Because we recognize the ready availability to states of standards of performance that incorporate emissions trading –- and because such standards can easily encompass interstate trading -- this rule includes by express design a variety of options that states and utilities can select to pursue interstate compliance regimes that mirror the interconnected operation of the electricity system. As a result, the EPA believes that it is reasonable to anticipate that a virtually nationwide emissions trading market for compliance will emerge, and that ERCs will be effectively available to any affected EGU wherever located, as long as its state plan authorizes emissions trading among affected EGUs.[377]

[377] There is a theoretical possibility – which we view as extremely unlikely – that the affected EGUs in a given state or group of states that has chosen to pursue a technology-specific rate-based approach could have insufficient access to ERCs because of the choices of certain other states to pursue mass-based or blended-rate approaches. We view this as very unlikely in part because of the conservative assumptions used in calculating the emission reductions available through the building blocks and the broad availability of non-BSER emission reduction opportunities, such as energy efficiency, that will generate ERCs. If such a situation arises, and the state or states implementing the technology-specific rates does not have, within the state or states, sufficient ERC-generation potential to match their compliance requirements, the EPA will work with the state or states to ensure that there is a mechanism that the state or states can include in their state plans to allow the affected EGUs in the state or states to generate additional ERCs where the state or states can demonstrate that the ERCs do not represent double-counting under other state programs. One potential mechanism would be to assume for purposes of demonstrating compliance with their standards of performance that the generation replacing any reductions in generation at those affected EGUs that was not paired with verified ERCs came from existing NGCC units in other states from which ERCs were not accessible. In other words, any reductions in fossil steam generation from 2012 levels in a state or states that was implementing technology-specific rates that could not be matched by increases in NGCC generation or by ERCs from zero-emitting sources, and for which it could be demonstrated that no further ERCs can be procured, could generate building block 2 ERCs as if that level of displaced generation were NGCC generation. A demonstration that no further ERCs are procurable would have to include demonstrations that the capacity factor of all NGCC generation in the state or states was expected to be greater than 75 percent and that further deployment of RE would go beyond the amounts found available in the BSER. States could distribute these additional ERCs to ensure compliance by affected EGUs. Before such ERCs could be created by a state or states, a framework would have to be submitted to the EPA for approval including documentation of the levels of fossil steam and NGCC generation in the state or states, a demonstration that

It should also be noted that although in a state that sets emission limits in a rate-based form the measures in building blocks 2 and 3 can be taken into account directly in computations to determine whether an individual affected EGU has achieved its emission limit, in a state that sets emission limits in a mass-based form these measures are not taken into account directly in computations to determine whether an individual affected EGU has achieved its emission limit. However, by reducing generation and therefore CO_2 emissions from the group of affected EGUs within a region, in a state with mass-based limits implementation of these measures facilitates the ability of the individual EGUs within the region to achieve their limits by choosing to reduce their own generation and emissions.

(b) Reduced generation.

In addition, the owner/operator of an affected EGU may help itself meet its emission limit by reducing its generation. If the owner/operator reduces generation and therefore the amount of its CO_2 emissions, then, if the affected EGU is subject to an emission rate limit, the owner/operator will need to implement fewer of the building block measures, e.g., buy fewer ERCs, to achieve its emission rate; and if the affected EGU is subject to

no further ERCs are accessible, and the total amount of building block 2 ERCs to be created.

a mass emission limit, the owner/operator will need fewer mass allowances. As discussed below, at the levels that the EPA has selected for the BSER, reduced generation at higher-emitting EGUs does not decrease the amount of electricity available to the system and end users because lower-emitting (or zero-emitting) generation will be available from other sources.

An owner/operator may take actions to ensure that it reduces its generation. For example, it may accept a permit restriction on the amount of hours that it generates. In addition or alternatively, it may represent the cost of additional emission credits or allowances that would be required due to incremental generation as an additional variable cost that increases the total variable cost considered when dispatch decisions are made for the unit.

Because of the integrated nature of the electricity system, combined with the system's high degree of planning and reliability safeguards, as well as the long planning horizon afforded by this rule, individual affected EGUs can implement the building blocks by reducing generation to achieve their emission performance standards.[378] Individual affected steam EGUs can reduce their generation in the amounts of building blocks 2

[378] For purposes of this discussion, we assume that coal-fired steam generators also implement building block 1 measures so that they will implement the full set of measures needed to achieve their emission limit.

and 3, while individual affected NGCC units can reduce their generation in the amount of building block 3. With emission limits for the source category as a whole in place, the resulting reduction in supply of higher-emitting generation will incentivize additional utilization of existing NGCC capacity, the resulting reduction in overall fossil fuel-fired generation will incentivize investment in additional RE generating capacity, and the integrated system's response to these incentives will ensure that there will be sufficient electricity generated to continue to meet the demand for electricity services.

(c) Emissions trading.

As described above, viewed from the perspective of the source category as a whole, it is reasonable for our analysis of the BSER to include an element of source-category-wide multi-unit compliance which could be implemented via a state-set standard of performance incorporating emissions trading, under which EGUs could engage in trading of rate-based emission credits or mass-based emission allowances. By the same token, viewed from the perspective of an individual EGU, consideration of the ready availability to states of the opportunity to establish standards of performance that incorporate emissions trading is integral to our analysis. Accordingly, our assessment of the actions available to individual EGUs for achieving standards of performance reflecting the BSER includes the purchase of rate-based emission credits or mass-based emission allowances, because one of the things an affected EGU can do to achieve its emission limit is to buy a credit or an allowance from another affected EGU that has over-complied. The use of purchased credits or allowances would have to be authorized, of course, in the purchasing EGUs' states' section 111(d) plans and would have to meet conditions set out for such approaches in section VIII below. The role of emissions trading in the BSER analysis is discussed further in section V.A.2.f. below.

f. <u>The role of emissions trading</u>. In making its BSER determination here, the EPA examined a number of technologies and emission reduction measures that result in lower levels of CO2 emissions and evaluated each one on the basis of the several criteria on which the EPA relies in determining the BSER. In contrast to section 111(b), however, section 111(d)(1) obliges the states, not the EPA, to set standards of performance for the affected EGUs in order to implement the BSER. Accordingly, with respect to each measure or control strategy under consideration, the EPA also evaluated whether or not the states could establish standards of performance for affected EGUs that would allow those sources to adopt the measure in question. In this case, the EPA identified a host of factors that persuaded us that states could –- and, in fact, may be expected to -- establish standards of performance that incorporate emissions trading.379 These wide-ranging factors include (i) the global nature of the air pollutant in question – i.e., CO2; (ii) the transactional nature of the industry; (iii) the interconnected functioning of the industry and the coordination of generation resources at the level of the regional grid; (iv) the extensive experience that states – and EGUs – already have with emissions trading; and (v) material in the record demonstrating strong interest on the part of many states and affected EGUs in using emissions trading to help meet their obligations.[380]

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[379] As an alternative to authorizing trading that would still provide a degree of multi-unit flexibility, a state could choose in its state plan to give an owner of multiple affected EGUs flexibility regarding how the owner distributes any credits or allowances it acquires among its affected EGUs.

[380] Numerous states submitted comments urging the EPA to allow states to develop trading programs, as suggested in the proposal, including interstate trading programs. They include, for example, Alabama (EPA should develop and issue guidelines that allow options for multi-state plans and interstate credit trading programs, comment 23584), California (EPA should provide flexibility for allowance trading programs to be integrated into state plans, comment 23433), Hawaii (supports use of emission credit trading with other entities to achieve compliance, comment 23121), Massachusetts (EPA should explore possibility of hosting a third-party emissions trading bank that can allow states interested in allowance trading to plug and play in to a wider, more cost-effective market, comment 31910), Michigan (supports emissions trading programs, comment 23987), Minnesota (develop model trading rule that states could incorporate by reference as part of plan and automatically be included in multi-state mass trading program, comment 23987), North Carolina (EPA should examine a system of banking and trading for energy efficiency, comment 23542), Oregon (EPA should expand the

explicit options for multi-state plans beyond cap-and-trade, comment 20678), Washington (supporting trading, comment 22764), Wisconsin (requesting EPA to develop a national trading program, Post-111(d) Proposal Questions to EPA WI Questions for 7/16 Hub call).

In addition, several groups of states supported trading programs: Georgetown Climate Center (a group of state environmental agency leaders, energy agency leaders, and public utility commissioners from California, Colorado, Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Minnesota, New Hampshire, New York, Oregon, Rhode Island, Vermont, and Washington) ("We believe states should have maximum flexibility to determine what kinds of collaborations might work for them. These could include submission of joint plans, standardized approaches to trading renewable or energy efficiency credits.... We also encourage EPA to help facilitate such interstate agreements or multi-state collaborations by working with states to either identify or provide a platform or framework that states may elect to use for the tracking and trading of avoided generation or emissions credits due to interstate efficiency or renewable energy." comment 23597, at 39-40); RGGI (including Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, Vermont) ("[E]very serious proposal to reduce carbon emissions from EGUs, from proposed US legislation to programs in place in California and Europe, has identified allowance trading as the best approach." Comment 22395 at 7-8); Western States Center for New Energy Economy (including Arizona, California, Colorado, Idaho, Montana, Nevada, Oregon, South Dakota, Utah, Washington) ("Some degree of RE and EE credit trading among states may support compliance, even in the absence of a comprehensive regional plan. Therefore, EPA should support approaches which allow states flexibility to allocate credit for these zero-carbon resources, along with approaches which allow states to reach agreements on the allocation of carbon liabilities. This includes ensuring that existing tracking mechanisms for renewable energy in the West, such as the Western Renewable Energy Generation Information System (WREGIS), are compatible with the final proposal." Comment 21787 at 5); Midcontinent States Environmental and Energy Regulators (including Arkansas, Illinois, Michigan, Minnesota Missouri, Wisconsin) (EPA should also provide states with optional ... systems (or system) for tracking emissions, allowances, reduction credits, and/or generation attributes that states may choose to use in their 111(d) plans," comment 22535 at 3).

The states' and EGUs' interest in emissions trading is rooted in the well-recognized benefits that trading provides. The experience of multiple trading programs over many years has shown that some units can achieve emission reductions at lower cost than others, and a system that allows for those lower-cost reductions to be maximized is more cost-effective overall to the industry and to society. Trading provides an affected EGU other options besides direct implementation of emission reduction measures in its own facility or an affiliated facility when lower-cost emission reduction opportunities exist elsewhere. Specifically, the affected EGU can cross-invest, that is, invest in actions at facilities owned by others, in exchange for rate-based emission credits or mass-based emission allowances.

In addition, trading programs were supported by, among others, a group of Attorneys General from 11 states and the District of Columbia. Comment 25433 (Attorneys General from New York, California, Connecticut, Maine, Maryland, Massachusetts, New Mexico, Oregon, Rhode Island, Vermont, Washington, District of Columbia, and New York City Corporation Counsel).

Numerous industry commenters also supported trading, including Alliant Energy Corporate Services, Inc. (comment 22934), Calpine (comment 23167), DTE Energy (comment 24061), Exelon (comment 23428 and 23155), Michigan Municipal Electric Association (MMEA) (comment 23297), National Climate Coalition (comment 22910), Pacific Gas and Electric Company (comment 23198), Western Power Trading Forum (WPTF) (comment 22860). Environmental advocates also supported trading, including Clean Air Task Force (comment 22612), Environmental Defense Fund (comment 23140), Institute for Policy Integrity, New York University School of Law (comment 23418).

Through cross-investment, trading allows each affected EGU to access the control measures that other affected EGUs decide to implement, which in this case include all the building blocks as well as other measures.

Accordingly, our analysis of the measures under consideration in our BSER determination reflected the well-founded conclusion that it is reasonable for states to incorporate emissions trading in the standards of performance they establish for affected EGUs and that many, if not all, would do so.[381]

Whether viewed from the perspective of an individual EGU or the source category as a whole, emissions trading is thus an integral part of our BSER analysis. Again, we concluded that this is reasonable given the global nature of the pollutant, the transactional and interconnected nature of this industry, and the long history and numerous examples demonstrating that, in this sector, trading is integral to how regulators have established, and sources have complied with, environmental and similar obligations (such as RE standards) when it was appropriate to do so given the program objective. The

[381] As discussed in the Legal Memorandum, the EPA has promulgated other rulemakings, including the transport rulemakings -- the NOx SIP Call and CAIR, which required states to submit SIPs, and CSAPR, which allows SIPs -- on the premise of interstate emission trading.

reasonableness is further demonstrated by the numerous comments (some of which are noted above) from industry, states, and other stakeholders in this rulemaking that supported allowing states to adopt trading programs to comply with section 111(d) and encouraged EPA to facilitate trading across state lines through the use of trading-ready state plans. The EPA's reliance on trading in its BSER determination does not mean, however, that states are required to establish trading programs (just as states are not required to implement the building blocks that comprise BSER). Nor does it mean that trading is the only transactional approach that we could have considered in setting the BSER or that states could use to effectuate the building blocks were they to decide that they did not want to take on the responsibility of running a trading program. Rather, it is simply a recognition of the nature of this industry and the long history of trading as an important regulatory tool in establishing regulatory regimes for this industry and its reasonable availability to states in establishing standards of performance.

As an initial matter, trading is permissible for these emission guidelines because CO_2 is a global pollutant; the location of its emission does not affect the location of the environmental harm it causes. For CO_2, it is the total amount of emissions from the source category that matters, not the specific emissions from any one EGU. The fact that trading allows sources to shift emissions from one location to another does not impede achievement of the environmental goal of reducing CO_2 pollution. In its character as a pollutant whose impacts extend beyond local areas, CO_2 pollution resembles to some extent the regional SO_2 pollution that Congress chose to address with the emissions trading program enacted in Title IV of the 1990 CAA Amendments. The argument in support of trading approaches is even stronger for CO_2 pollution, whose adverse effects are global rather than merely regional like the SO_2 emissions contributing to acid precipitation.

Further, as discussed elsewhere in the preamble, the utility power sector – and the affected EGUs and other generation assets that it encompasses – has a long history of working on a coordinated basis to meet operating and environmental objectives, necessitated and facilitated by the unique interconnectedness and interdependence of the sector. That history includes joint dispatch for economic and reliability purposes, both within large utility systems and in multi-utility power pools that have evolved into RTOs; joint power plant ownership arrangements; and long-term and short-term bilateral power purchase arrangements. More recently, the sector’s history also includes emissions trading programs designed by Congress, the EPA, and the states to address regional environmental problems and, most recently, climate change. Examples of such programs are noted below.

Essentially, trading does nothing more than commoditize compliance, with the following two important results emerging from that: it reduces the overall costs of controls and spreads those costs among the entire category of regulated entities while providing a greater range of options for sources that may not want to make on-site investments for controlling their emissions and may prefer to make the same investment, via the purchase of the tradable compliance instrument, at another generating source. Building blocks 2 and 3 entail affected EGUs investing in increased generation from existing NGCC units and RE. The affected EGUs could do so in any number of ways, including acquiring ownership interests in existing NGCC or RE facilities or entering into bilateral transactions with the owners of existing NGCC facilities or RE sources. As discussed elsewhere, it is reasonable to expect that these actions can develop into discrete, tradable commodities (e.g., an ERC) and that liquid markets will develop, which would reduce transaction costs and allow an affected EGU to comply with its emission limits by purchasing discrete units in amounts tailored closely to its compliance needs. The existence of such tradable commodities also incentivizes over-compliance by affected EGUs, which can then sell their over-compliance in the form of ERCs or allowances to other affected EGUs. Moreover, as noted elsewhere, the opportunity to trade is consistent with the EPA's regional approach for the building blocks.

By the same token, the opportunity to trade incentivizes affected EGUs to over-comply with building block 1. Thus, the opportunity to trade supports the EPA's assumptions about what an average affected EGU can achieve with regards to heat rate improvement even if each and every affected EGU cannot achieve that level of improvement. In addition, trading incentivizes affected EGUs to consider low-cost, non-BSER methods to reduce emissions as well, and, as discussed below, there are numerous non-BSER methods, ranging from implementation of demand-side EE programs to natural gas co-firing.

Trading has become an important mechanism for achieving environmental goals in the electricity sector in part because trading allows environmental regulators to set an environmental goal while preserving the ability of the operators of the affected EGUs to decide the best way to meet it taking account of the full range of considerations that govern their overall operations. For example, commenters were concerned that because of building block 2, the emission guidelines would require state environmental regulators to make dispatch decisions for the electricity markets, a role that state environmental regulators do not currently play. Although building block 2 entails substituting existing NGCC generation for steam generation, implementing the emission limits that are based in part on building block 2 through a trading program provides the individual affected EGUs with a great deal of control over their own generation while the industry as a whole achieves the environmental goals. For example, individual steam generators have the option of maintaining their generation as long as they acquire additional ERCs. Moreover, trading provides a way for states to set standards of performance that realize the required emissions reduction without requiring any form of “environmental dispatch” because, as many existing trading programs have shown, monetization of the environmental constraint is consistent with a least-cost dispatch system. Trading also supports the EPA’s approach to the “remaining useful life” provision in section 111(d)(1) because with trading, an affected EGU with a limited remaining useful life can avoid the need to implement long-term emission reduction measures and can instead purchase ERCs or other tradable instruments, such as mass-based allowances, thereby allowing the state to meet the requirements of this rule.

The EPA’s job in issuing these emission guidelines is to determine the BSER that has been adequately demonstrated and to set emission limitations that are achievable through the application of the BSER and implementable through standards of performance established by the states. The three building blocks are the EPA's determination of what technology is adequately demonstrated. We also consider trading an integral part of the BSER analysis because, in addition to being available to states for incorporation in the standards of performance they set for affected EGUs, trading has been adequately demonstrated for this industry in circumstances where systemic rather than unit-level reductions are central. Congress, the EPA, and state regulators have established successful environmental programs for this industry that allow trading of environmental (or similar) attributes, and trading has been widely used by the industry to comply with these programs. Examples include the CAA Title IV Acid Rain Program, the NO_X SIP Call (currently referred to as the NO_X Budget Trading Program), the Clean Air Interstate Rule (CAIR), the Cross-State Air Pollution Rule (CSAPR),[382] the Regional Haze trading programs, the Clean Air Mercury Rule,[383]

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[382] For example, in CSAPR, which covered the states in the eastern half of the U.S., the EPA assumed the existence of trading across those states in the rule's cost estimates contained in the RIA. "Regulatory Impact Analysis for the Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone in 27 States; Correction of SIP Approvals for 22 States" 32 (June 2011), http://www.epa.gov/airtransport/CSAPR/pdfs/FinalRIA.pdf. In addition, the rule is being implemented either through federal implementation plans (FIPs) that authorize interstate emission trading or SIPs that authorize interstate emissions trading.

[383] Although the CAMR trading program never took effect because the rule was vacated on other grounds, it consisted of a

RGGI, the trading program established by California AB32, and the South Coast Air Quality Management District RECLAIM program. We describe these programs in section II.E. of this preamble. In addition, we note in the Legal Memorandum accompanying this preamble that Congress, in enacting the Title IV acid rain trading program, and the EPA, in promulgating the regulatory trading programs listed, recognized both the suitability of trading for the EGU industry and the benefits of trading in reducing costs, spreading costs to affected EGUs throughout the sector, and facilitating the ability of affected EGUs to comply with their emission limits. In addition, as we discuss in section V.E. of this preamble, many states have adopted RE standards that promote RE through the trading of renewable energy certificates (RECs).

Based on this history, it is reasonable for the EPA to determine that states can establish standards of performance that incorporate trading and, as a result, for the purpose of making a BSER determination here to evaluate prospective emission control measures in light of the availability of trading. Trading is a regulatory mechanism that works well for

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nationwide trading program that the EPA adopted under CAA section 111(d). Some states declined to allow their sources to participate in the trading program on the grounds that nationwide trading was not appropriate for the air pollutant at issue, mercury, a HAP that caused adverse local impacts.

this industry. The environmental attributes in the preceding programs (representing emissions of air pollutants) are identical to or similar in nature to the environmental attribute here (CO_2 emissions). The markets for RECs show that robust markets for RE, in particular, already exist.

Given the benefits of trading and the background of multi-unit coordination grounded in the nature of the utility power sector, it is natural for sources and states to look for opportunities to apply similar coordination to a regional problem such as reduction of CO_2 emissions from the sector. As noted earlier, the EPA heard this interest expressed during the outreach process for this rulemaking and saw it reflected in comments on the proposal. Emissions trading was prominent in these expressions of interest; while the proposal allowed trading and encouraged the development of multi-state plans which would allow the benefits of trading to extend over larger regions, we heard that interest was even greater in "trading-ready" plans that would use trading mechanisms and market-based coordination, rather than state-to-state coordination, as the primary means of facilitating multi-unit approaches to compliance. The general industry and state preference for multi-unit compliance approaches makes great sense in the context of the industry and this pollutant, as does the specific preference for trading-ready section 111(d) plans, and we have made efforts in the final rule to accommodate trading-ready plans as described in section VIII.

g. Measures that reduce CO_2 emissions or CO_2 emission rates but are not included in the BSER. There are numerous other measures that are available to at least some affected EGUs to help assure that they can achieve their emission limits, even though the EPA is not identifying these measures as part of the BSER. These measures include demand-side EE implementable by affected EGUs; new or uprated nuclear generation; renewable measures other than those that are part of building block 3, including distributed generation solar power and off-shore wind; combined heat and power and waste heat power; and transmission and distribution improvements. In addition, a state may implement measures that yield emission reductions for use in reducing the obligations on affected EGUs, such as demand-side EE measures not implementable by affected EGUs, including appliance standards, building codes, and drinking water or wastewater system efficiency measures. The availability of these measures further assures that the appropriate level of emission reductions can be achieved and that affected EGUs will be able to achieve their emission limits.

h. Ability of EGUs to implement the BSER. The EPA’s analysis, based in part on observed decades-long behavior of EGUs, shows that all types and sizes of affected EGUs in all locations are able to undertake the actions described as the BSER, including investor-owned utilities, merchant generators, rural cooperatives, municipally-owned utilities, and federal utilities. Some may need to focus more on certain measures; for example, an owner of a small generation portfolio consisting of a single coal-fired steam EGU may need to rely more on cross-investment approaches, possibly including the purchase of emission credits or allowances, because of a lack of sufficient scale to diversify its own portfolio to include NGCC capacity and RE generating capacity in addition to coal-fired capacity. As a legal matter, it is not necessary that each affected EGU be able to implement the BSER, but in any event, in this rule, all affected EGUs can do so. Since states can reasonably be expected to establish standards of performance incorporating emissions trading, affected EGUs may rely on emissions trading approaches authorized under their states' section 111(d) plans to, in effect, invest in building block measures that are physically implemented at other locations. As discussed above, the EPA's quantification of the CO_2 emission performance rates in a manner that provides headroom within the BSER also contributes to the ability of all affected EGUs to implement the BSER and achieve emissions limitations consistent with those performance rates.

i. Subcategorization. As noted above, in this rule, we are treating all fossil fuel-fired EGUs as a single category, and, in the emission guidelines that we are promulgating with this rule, we are treating steam EGUs and combustion turbines as separate subcategories. We are determining the BSER for steam EGUs and the BSER for combustion turbines, and applying the BSER to each subcategory to determine a performance rate for that subcategory. We are not further subcategorizing among different types of steam EGUs or combustion turbines. As we discuss below, this approach is fully consistent with the provisions of section 111(d), which simply require the EPA to determine the BSER, do not prescribe the method for doing so, and are silent as to subcategorization. This approach is also fully consistent with other provisions in section 111, which require the EPA first to list source categories that may reasonably be expected to endanger public health or welfare and then to regulate new sources within each such source category, and which grant the EPA discretion whether to subcategorize the sources for purposes of determining the BSER.

As discussed below, each affected EGU can achieve the performance rate by implementing the BSER, specifically, by taking a range of actions –- some of which depend on features of the section 111(d) plan chosen by the state, such as the choice of rate-based or mass-based standards of performance and the choice of whether and how to permit emissions trading -- including investment in the building blocks, replaced or reduced generation, and purchase of emission credits or allowances. Further, in the case of a rate-based state plan, several other compliance options not included in the BSER for this rule are also available to all affected EGUs, including investment in demand-side EE measures. Such compliance options may also indirectly help affected EGUs achieve compliance under a mass-based plan.

Our approach of subcategorizing between steam EGUs and combustion turbines is reasonable because building blocks 1 and 2 apply only to steam EGUs. Moreover, our approach of not further subcategorizing as between different types of steam EGUs or combustion turbines reflects the reasonable policy that affected EGUs with higher emission rates should reduce their emissions by a greater percentage than affected EGUs with lower emission rates and can do so at a reasonable cost using the approaches we have identified as the BSER as well as other available measures.

Of course, a state retains great flexibility in assigning standards of performance to its affected EGUs and can impose different emission reduction obligations on its sources, as long as the overall level of emission limitation is at least as stringent as the emission guidelines, as discussed below.

3. Changes from proposal

For the BSER determined in this final rule, based on consideration of comments responding to a broad array of topics considered in the proposal, the EPA has adopted certain modifications to the proposed BSER. In this subsection we describe the most important modifications, including some that relate to individual building blocks and some that are more general. Additional modifications that relate to individual building blocks are discussed in the respective sections for those building blocks below (sections V.C. through V.E.).

We note that taken together, the modifications yield emission reductions requirements that commence more gradually than the proposed goals but are projected to produce greater overall annual emission reductions by 2030.[384] We also note that the modifications lead to requirements that are more uniform across states than the proposed state goals (consistent with the direction of certain alternatives on which we sought comment in the proposal), with the final requirements generally becoming more stringent (compared to the proposal) in states with the

[384] For the proposed rule, the EPA projected total CO_2 emission reductions from 2005 levels of 29% in 2025 and 30% in 2030. For the final rule, the EPA projects total CO_2 emissions reductions from 2005 levels of 28% in 2025 and 32% in 2030. See Regulatory Impact Analysis for the CPP Proposed Rule, Table 3-6, and Regulatory Impact Analysis for the CPP Final Rule, Table 3-6, available in the docket.

highest 2012 CO_2 emission rates and less stringent in states with lower 2012 CO_2 emission rates.

a. Interpretations of CAA section 111. In the June 2014 proposal, the EPA proposed interpretations of section 111(a)(1) and (d), and applied these interpretations to existing fossil fuel-fired EGUs.[385] Informed by comments, the EPA has clarified some of these interpretations, and has developed a more refined understanding of how some of these interpretations should be applied. The clarified and more refined interpretations replace the proposed interpretations.

Two of these points merit mention here. First, the EPA is clarifying in this rule that the interpretation of "system of emission reduction" does not include emission reduction measures that the states have authority to mandate without the affected EGUs being able to implement the measures themselves (e.g., appliance standards or building codes). In the final rule, we have clarified that the components of the BSER must be implementable by the affected EGUs, not just by the states, and we show that all the components of the BSER have been demonstrated to be achievable on that basis without reliance on actions that can be accomplished only through government

[385] The June 2014 proposal in part referenced proposed interpretations of section 111(a)(1) that the EPA explained in the January 2014 proposal to address CO_2 emissions from new fossil fuel-fired EGUs under section 111(b).

mandates. Further discussion of these points can be found throughout this section on the BSER and the following sections on the individual building blocks.

Second, the EPA has adopted a combined interpretation of sections 111(a)(1) and 111(d) that, compared to the proposal, better reflects the historical interpretations of section 111(a)(1), which have generally supported emissions standards that are nationally uniform for sources incorporating a given technology, and gives less weight to the state-focused character of section 111(d), which calls for emissions standards to be implemented through the development of individual state plans. The proposed state goals were heavily (although not entirely) dependent on the emission reduction opportunities available to the EGUs in each individual state, and because the relative magnitudes of these opportunities varied by state, states with similar EGU fleet compositions could have faced state goals of different stringencies, potentially making it difficult for multiple states to set the same standards of performance for affected EGUs using the same technologies (assuming the states were interested in setting standards of performance for their various affected EGUs in such a manner). Some commenters viewed this potential result as inconsistent with section 111(a)(1), inequitable, or both. In response, we took further comment on these potential disparities in the October 30, 2014 Notice of

Data Availability. In this final rule, we are obviating those concerns by assessing the emission reduction opportunities at an appropriate regional scale, consistent with alternatives on which we sought comment, and using this regional information to reformulate the proposed emissions standards as nationally uniform emissions standards for the emission guidelines.[386] National uniformity is consistent with prior section 111 rulemaking and advances a number of other goals central to this rulemaking. The methodological refinements related to regional assessment of emission reduction opportunities and the use of uniform emissions standards by technology subcategory are further discussed below.

b. Approach to quantification of emission reductions from increased RE generation. In the June 2014 proposal, the EPA described two possible approaches for quantifying the amount of emission reductions achievable from affected EGUs through the use of RE generation. The proposed approach used information on state RPS aggregated at a regional level along with historical RE generation data to project the amount of RE generation used in quantifying the emission reductions achievable through the

[386] Of course, a source in one state may face different requirements than similar sources in other states, depending on whether the state adopts the state measures approach or, if it adopts the emission standards approach, whether it imposes a mass limit or an emission rate and, if the latter, at what level.

BSER. The alternative approach used information on the technical and market potential for development of renewable resources in each state to project the RE-related emission reductions. In the October 30, 2014 Notice of Data Availability, we sought comment on an additional approach of aggregating the state-level information to a regional level, as suggested by some commenters. In this final rule we are adopting a combination of these approaches that uses historical RE generating capacity deployment data aggregated to a regional level, supported and confirmed by projections of market potential developed through a techno-economic approach.

In the June 2014 proposal, RE generation was also quantified as generation from total -- that is, existing and new -- RE generating capacity, a formulation that was consistent with the formulation of most RPS, which are typically framed in terms of total rather than incremental generation. In response to the EPA’s request for comment on this approach, commenters observed that the approach was inconsistent with the approach taken for other building blocks, and that generation from RE generating capacity that already existed as of 2012 should not be treated as reducing emissions of affected EGUs from 2012 levels. As just noted, we are not using the RPS-based methodology in the final rule, and we agree with comments that quantification of RE generation on an incremental basis is both more consistent with the treatment of other building blocks and more consistent with the general principle that the BSER should comprise incremental measures that will reduce emissions below existing levels, not measures that are already in place, even if those in-place measures help current emission levels be lower than would be the case without the measures. The final rule therefore defines the RE component of the BSER in terms of incremental rather than total RE generation.[387] Further details regarding the final rule's quantification of RE generation are provided in section V.E. below.

c. Exclusion from the BSER of emission reductions from use of under-construction or preserved nuclear capacity. In the June 2014 proposal, the EPA included in building block 3 provisions reflecting the ability for nuclear generation to replace fossil generation and thereby reduce CO_2 emissions at affected EGUs. We proposed to include in building block 3 the potential generation from five under-construction nuclear generating units whose construction had commenced prior to the issuance of the proposal. In addition, to address the potential that some currently operating nuclear facilities may shut down prior to

[387] Generation from existing RE capacity will continue to make compliance with mass-based standards easier to achieve by making the overall amount of fossil fuel-fired generation that is required to meet the demand for energy services lower than it would otherwise be, thereby keeping CO_2 emissions lower than they would otherwise be.

2030, the proposal incorporated into the BSER for each state with nuclear capacity a projected 5.8 percent reduction in nuclear generation, based on an estimate of potential nationwide loss of nuclear generation from existing units. We sought comment on all aspects of these proposed approaches. While we recognize the important role nuclear power plants have to play in providing carbon-free generation in an all-of-the-above energy system, for this final rule, the BSER does not include either of the components related to nuclear generation.

The EPA received numerous comments on the proposed BSER components related to nuclear power. With respect to generation from under-construction nuclear units, some commenters expressed strong opposition to the inclusion of this generation in the BSER and the setting of state goals, stating that inclusion would result in very stringent state goals for the states where the units are being built and that the inclusion of the generation in the goals is premature because the units' actual completion dates could be delayed. Commenters also stated that inclusion of the under-construction nuclear generation in the BSER would be inequitable because states where the same heavy investment in zero-CO_2 generation was not being made would have relatively less stringent goals.

With respect to generation from existing nuclear units, some commenters stated that our method of accounting for potential unit shutdowns was flawed, observing that even if the prediction of a 5.8 percent nationwide loss of nuclear generation were accurate, the actual shutdowns would occur in a handful of states, resulting in much larger losses of generation in those particular states.

Upon consideration of comments and the accompanying data, the EPA has determined that the BSER should not include either of the components related to nuclear generation from the proposal. With respect to nuclear units under construction, although we believe that other refinements to this final rule would address commenters' concerns that goals for the particular states where the units are located would be overly stringent either in absolute terms or relative to other states, we also acknowledge that, in comparison to RE generating technology, investments in new nuclear units tend to be individually much larger and to require longer lead times. Also, important recent trends evidenced in RE development, such as rapidly growing investment and rapidly decreasing costs, are not as clearly evidenced in nuclear generation. We view these factors as distinguishing the under-construction nuclear units from RE generating capacity, indicating that the new nuclear capacity is likely of higher cost and therefore less appropriate for inclusion in the BSER. Excluding the under-construction nuclear units from the BSER, but allowing emission reductions attributable to generation from the units to be used for compliance as discussed below and in section VIII, will recognize the CO_2 emission reduction benefits achievable through the significant ongoing commitment required to complete these major investments.

With respect to existing nuclear units, although again we believe that other refinements in the final rule would address the concern about disparate impacts on particular states, we acknowledge that we lack information on shutdown risk that would enable us to improve the estimated 5.8 percent factor for nuclear capacity at risk of retirement. Further, based in part on comments received on another aspect of the proposal -- specifically, the proposed inclusion of existing RE generation in the goal-setting computations -- we believe that it is inappropriate to base the BSER in part on the premise that the preservation of existing low- or zero-carbon generation, as opposed to the production of incremental, low- or zero-carbon generation, could reduce CO_2 emissions from current levels. Accordingly, we have determined not to reflect either of the nuclear elements in the final BSER.

Generation from under-construction or other new nuclear units and capacity uprates at existing nuclear units would still be able to help sources meet emission rate-based standards of performance through the creation and use of credits, as noted in section V.A.6.b. and section VIII.K.1.a.(8), and would help sources meet mass-based standards of performance through reduced utilization of fossil generating capacity leading to reduced CO_2 emissions at affected EGUs. However, consistent with the reasons just discussed for not reflecting preservation of existing nuclear capacity in the BSER -- namely, that such preservation does not actually reduce existing levels of emissions from affected EGUs -- the rule does not allow preservation of generation from existing or relicensed nuclear capacity to serve as the basis for creation of credits that individual affected EGUs could use for compliance, as further discussed in section VIII.K.1.a.(8).[388]

d. <u>Exclusion from the BSER of emission reductions from demand-side EE</u>. The June 2014 proposal included demand-side EE measures in building block 4 as part of the BSER. The EPA took comment on the attributes of each of the proposed building blocks, and building block 4 was a topic of considerable controversy among commenters. While many commenters recognized demand-side EE as an integral part of the electricity system, emphasized its cost-effectiveness as a means of reducing CO_2 emissions from the

[388] As with generation from existing RE capacity, generation from existing nuclear capacity will continue to make compliance with mass-based standards easier to achieve by making the overall amount of fossil fuel-fired generation that is required to meet the demand for energy services lower than it would otherwise be, thereby keeping CO_2 emissions lower than they would otherwise be.

utility power sector, and strongly supported its inclusion in the BSER, other commenters expressed significant concerns.

As explained in section V.B.3.c.(8) below, our traditional interpretation and implementation of CAA section 111 has allowed regulated entities to produce as much of a particular good as they desire provided that they do so through an appropriately clean (or low-emitting) process. While building blocks 1, 2, and 3 fall squarely within this paradigm, the proposed building block 4 does not. In view of this, since the BSER must serve as the foundation of the emission guidelines, the EPA has not included demand-side EE as part of the final BSER determination.

It should be noted that commenters also took the position that the EPA should allow demand-side EE as a means of compliance with the requirements of this rule, and, as discussed in section V.A.6.b. and section VIII below, we agree.

e. <u>Consistent regionalized approach to quantification of emission reductions from all building blocks</u>. In the June 2014 proposal, the EPA treated each of the building blocks differently with respect to the regional scale on which the building block was applied for purposes of assessing the emission reductions achievable through use of that building block. Building block 1 was quantified at a national scale, identifying a single heat rate improvement opportunity applicable on average to all coal-fired steam EGUs. Building block 2 was quantified at the scale of each individual state, considering the amount of generation that could be shifted from steam EGUs to NGCC units within the state, although we solicited comment on considering generation shifts at a broader regional scale. The RE component of building block 3 was quantified at a regional scale using RPS information as a proxy for RE development potential, and the regional results were then applied to each state in the region using the state's baseline data; an alternative methodology on which we requested comment quantified the RE component using a techno-economic approach on a state-specific basis. In the October 2014 Notice of Data Availability, we requested comment on using a techno-economic approach to quantify RE generation potential at a regional scale and took broad comment on strategies for better aligning the BSER with the regionally interconnected electrical grid.[389] We also solicited comment on the appropriate regional boundaries or regional structure to facilitate this approach.

For the final rule, with the benefit of comments received in response to these proposals and alternatives, we have adopted a consistent regionalized approach to quantification of emission reductions achievable through all the building blocks. Under this approach, each of the building blocks is quantified and applied at the regional level, resulting in the computation for

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[389] 79 FR 64543, 64551-62

each region of a performance rate for steam EGUs and a performance rate for NGCC units. For each of the technology subcategories, we identify the most conservative -- that is, the least stringent -- of the three regional performance rates. We then apply these least stringent subcategory-specific performance rates to the baseline data for the EGU fleet in each state to establish state goals of consistent stringency across the country. (Note that the actual state goals vary among states to reflect the differences in generation mix among states in the baseline year.) Further description of the steps in this overall process is contained in the preamble sections addressing the individual building blocks (sections V.C., V.D., and V.E.), CO_2 emission performance rate computation (section VI), and state goal computation (section VII), as well as the GHG Mitigation Measures TSD for the CPP Final Rule and the CO_2 Emission Performance Rate and Goal Computation TSD for the CPP Final Rule available in the docket.

Compared to the more state-focused quantification approach selected in the proposal, and as recognized in the Notice of Data Availability, a regionalized approach better reflects the interconnected system within which interdependent affected EGUs actually carry out planning and operations in order to meet electricity demand. We have already discussed the relevance of the interconnected system and the interdependent operations of

EGUs as factors supporting consideration of building blocks 2 and 3 as elements of the BSER for this pollutant and this industry, and these same factors support quantifying the emission reductions achievable through building blocks 2 and 3 on a regionalized basis. Because it better reflects how the industry works, a regionalized approach also better represents the full scope of emission reduction opportunities available to individual affected EGUs through the normal transactional processes of the industry, which do not stop at state borders but rather extend throughout these interconnected regions. With respect to building block 1, which comprises types of emission reduction measures that in other rulemakings under CAA section 111 would typically be evaluated on a nationwide basis, for this rule, as discussed in section V.C. below, we are quantifying the emission reductions achievable through building block 1 on a regional basis in order to treat the building blocks consistently and to ensure that for each region the quantification of the BSER represents only as much potential emission reduction from building block 1 as our analysis of historical data indicates can be achieved on average by the affected EGUs in that region.

Characterizing and quantifying the measures included in the BSER on a regional basis rather than a state-limited basis is also appropriate because states can establish standards of performance that incorporate emissions trading, including trading between and among EGUs operating in different states, and thus provide EGUs the opportunity to trade. Emissions trading provides at least one mechanism by which owners of affected EGUs can access any of the building blocks at other locations. With emissions trading, an affected EGU whose access to heat rate improvement opportunities, incremental generation from existing NGCC units, or generation from new RE generating capacity is relatively favorable can overcomply with its own standard of performance and sell rate-based emission credits or mass-based emission allowances to other affected EGUs. Purchase of the credits or allowances by the other EGUs represents cross-investment in the emission reduction opportunities, and such cross-investment can be carried out on as wide a geographic scale as trading rules allow.

The regions we have determined to be appropriate for the regionalized approach in the final rule are the Eastern, Western, and Texas Interconnections.[390] In determining that the appropriate regional level for quantification of the BSER was the level of the interconnection, the EPA considered several

[390] The Texas Interconnection encompasses the portion of the Texas electricity system commonly known as ERCOT (for the Electric Reliability Council of Texas). The state of Texas has areas within the Eastern and Western Interconnections as well as the Texas Interconnection.

factors. First, consistent with our goal of aligning regulation with the reality of the interconnected electricity system, we considered the regional scale on which electricity is actually produced, physically coordinated, and consumed in real time -- specifically the Eastern, Western, and Texas Interconnections. The Bulk Power System (BPS) in the contiguous U.S. (including adjacent portions of Canada and Mexico) consists of these three interconnections, which are alternating current (AC) power grids where power flows freely from generating sources to consuming loads. These interconnections are separately planned and operated; they are connected to each other only through low-capacity direct current (DC) tie lines. Each interconnection is managed to maintain a single frequency and to maintain stable voltage levels throughout the interconnection. Physically, each interconnection functions as a large pool, where all electricity delivered to the electric grid flows by displacement over all transmission lines in the interconnection and must be continually balanced with load to ensure reliable electricity service to customers throughout each interconnection. "Since power flows on all transmission paths, it is not uncommon to find circumstances in which part of a power delivery within one balancing area flows on transmission lines in adjoining areas, or part of a power delivery between two balancing areas flows over the transmission facilities of a third area."[391] The interconnections are the "complex machines" within which EGUs plan, coordinate, and operate, manifesting a degree of both long-term and real-time interdependence that is unique to this industry. We concluded that, absent a compelling reason to adopt a smaller regional scale for evaluation of CO_2 emission reduction opportunities for the electric power sector -- which we have not found, as discussed below -- the interconnections should be the regions used for evaluation of the BSER for CO_2 emission reductions from the electric power sector because of the fundamental characteristics of electricity, the industry's basic interconnected physical infrastructure, and the interdependence of the affected EGUs within each interconnection.

Second, we considered whether the interconnection subregions for which various planning and operational functions are carried out by separate institutional actors would represent more appropriate regions than the entire Interconnnections, and concluded that they would not. Interconnection planning and management follows the NERC functional model, which defines subregional areas and regional entities within each interconnection for the purposes of balancing generation with load and ensuring that reliability is maintained. While a

[391] Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 188 (2d ed. 2010).

variety of organizations plan and operate these subregions, those activities always occur in the context of the interconnections, and the subregions cannot be operated autonomously. The need to maintain common frequency and stable voltage levels throughout the interconnections requires constantly changing flows of electricity between the planning and operating subregions within each interconnection.

Because each interconnection is a freely flowing AC grid, any power generated or consumed flows through the entire interconnection in real time; as a result of this highly interconnected nature of the power system, the management of generation and load on the grid must be carefully maintained. This management is carried out principally by subregional entities responsible for the operation of the grid, but this operation must be coordinated in real time to ensure the reliability of the system. Regional operators must coordinate the dispatch of power, not only in their own areas, but also with the other subregions within the interconnection. Although this coordination has always been important, grid planning and management has evolved to be increasingly interconnection-wide, through the development of larger regional entities, such as RTO/ISOs, or large-utility dispatch across multiple balancing areas. As a result, the fact that much of the necessary coordination for the interconnections is performed regionally on a partially decentralized basis (at least in the case of the Eastern and Western Interconnections) or occurs through the operation of automated equipment and the physics of the grid does not render the subregions more relevant than the interconnections as the ultimate regions within which electricity supply and demand must balance.

Moreover, some planning and standard setting activities are undertaken explicitly at the interconnection level. For example, interconnections also have interconnection reliability operating limits (IROLs).[392] A joint FERC-NERC report on the September 8, 2011 Arizona-Southern California outages outlined the importance of IROLs.[393] The report noted that to ensure the reliable operation of the bulk power system, entities must identify a plan for IROLs to avoid cascading outages. "In order to ensure the reliable operation of the BPS, entities are required to

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[392] For example, the Eastern Interconnection has Reliability Standard IRO-006-EAST-1, Transmission Loading Relief Procedure for the Eastern Interconnection, *available at* http://www.nerc.com/files/IRO-006-EAST-1.pdf (providing an "Interconnection-wide transmission loading relief procedure (TLR) for the Eastern Interconnection that can be used to prevent and/or mitigate potential or actual System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances to maintain reliability of the Bulk Electric System (BES).").

[393] FERC-NERC, *Arizona-Southern California Outages on September 8, 2011: Causes and Recommendations* (Apr. 2012), *available at* http://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf.

identify and plan for IROLs, which are SOLs that, if violated, can cause instability, uncontrolled separation, and cascading outages. Once an IROL is identified, system operators are then required to create plans to mitigate the impact of exceeding such a limit to maintain system reliability."[394]

Congress recognized the significance of the three interconnections in the American Recovery and Reinvestment Act of 2009 (Recovery Act) when it provided $80 million in funding for interconnection-based transmission planning.[395] In order to fulfill this Congressional mandate, DOE and FERC signed a memorandum of understanding to enumerate their roles "for activities related to the Resource Assessment and Interconnection Planning project funded by the American Recovery and Reinvestment Act of 2009 (Recovery Act). Among the objectives of the project is to facilitate the development or strengthening of capabilities in each of the three interconnections serving the contiguous lower forty-eight States, to prepare analyses of transmission requirements under a broad range of alternative futures and develop long-term

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[394] FERC-NERC, *Arizona-Southern California Outages on September 8, 2011: Causes and Recommendations*, at 97 (Apr. 2012), *available at* http://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf.

[395] American Reinvestment and Recovery Act of 2009, Title IV, Public Law 111-5 (2009).

interconnection-wide transmission plans."[396] DOE issued awards to five organizations that performed work in the Western, Eastern, and Texas Interconnections to develop long-term interconnection-wide transmission expansion plans.[397]

In Order No. 1000, FERC also took a broader regional view of transmission planning.[398] FERC required each public utility transmission provider to participate in a regional transmission planning process that produces a regional transmission plan. FERC also required neighboring transmission planning regions to coordinate with each other. This interregional coordination includes identifying methods for evaluating interregional transmission facilities as well as establishing a common method or methods of cost allocation for interregional transmission facilities.

In addition to Congressional, DOE, and FERC recognition of the importance of the three interconnections, NERC also

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[396] Memorandum of Understanding Between the U.S. Department of Energy and the Federal Energy Regulatory Commission, *available at* http://www.ferc.gov/legal/mou/mou-doe-ferc.pdf.

[397] DOE, *Recovery Act Interconnection Transmission Planning*, *available at* http://energy.gov/oe/services/electricity-policy-coordination-and-implementation/transmission-planning/recovery-act.

[398] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

considers them to be significant. NERC Organizational Standards "are based upon certain Reliability Principles that define the foundation of reliability for North American bulk electric systems."[399] These principles take a broad view of electric system reliability, considering the reliability of interconnected bulk electric systems. For example, Reliability Principle 1 states, "Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC standards."[400] NERC took a similarly broad view of system reliability when it delegated its authority to monitor and enforce mandatory reliability standards to a single Regional Entity in both the Western and Texas Interconnections (WECC in the West and the Texas Reliability Entity in the ERCOT region of Texas).[401] Moreover, both WECC and ERCOT have interconnection-wide reliability standards.[402] The Eastern Interconnection has

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[399] NERC, *Reliability and Market Interface Principles*, at 1, *available at* http://www.nerc.com/pa/Stand/Standards/ReliabilityandMarketInterfacePrinciples.pdf.
[400] NERC, *Reliability and Market Interface Principles*, at 1, *available at* http://www.nerc.com/pa/Stand/Standards/ReliabilityandMarketInterfacePrinciples.pdf.
[401] NERC, *Key Players*, *available at* http://www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx.
[402] WECC, *Standards*, *available at* https://www.wecc.biz/Standards/Pages/Default.aspx (last visited July 3, 2015); Texas Reliability Entity, *Reliability Standards*,

multiple reliability regions with some differences in standards, but power flows and reliability are managed through a single Reliability Coordinator Information System that tracks power flows for all transmission transactions.[403]

The importance that Congress, DOE, FERC, and NERC each place upon the interconnections for electric reliability and operational issues is another factor supporting our decision to set the interconnections as the regional boundaries for the establishment of BSER. The utilization of the three interconnections for both planning and reliability purposes is a clear indication of the importance that electricity system regulators, operators, and industry place upon the interconnections. Those responsible for the electricity system recognize the need to ensure that there is a free flow of electricity throughout each interconnection such that transmission planning and reliability analysis are occurring at the interconnection level. Further, this vigilance with respect

available at http://www.texasre.org/standards_rules/Pages/Default.aspx (last visited July 3, 2015).

[403] The NERC glossary defines the Reliability Coordinator Information System as the "system that Reliability Coordinators use to post messages and share operating information in real time." NERC, *Glossary of Terms Used in Reliability Standards* (Apr. 20, 2009), *available at* http://www.eia.gov/electricity/data/eia411/nerc_glossary_2009.pdf.

to considering reliability from an interconnection-wide basis recognizes that each of the interconnections behaves as a single machine where "outages, generation, transmission changes, and problems in any one area in the synchronous network can affect the entire network."[404] By setting the three interconnections as the regions for purposes of BSER, we are acting consistent with the way in which planning, reliability, and industry experts view the electricity system.

An additional factor weighing against the use of planning or operational subregions of the interconnections as the regions for our BSER analysis for this rule is that the borders of those subregions occasionally change as planning and management functions evolve or as owners of various portions of the grid change affiliations. This is not a merely theoretical consideration; numerous ISO/RTO and other regional boundaries have substantially changed in recent years. For example, in 2012, Duke Energy Ohio and Duke Energy Kentucky integrated into PJM.[405] The following year, in December 2013, Entergy and its six utility operating companies joined MISO, creating the MISO South

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[404] Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 159 (2d ed. 2010).
[405] PJM, *Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc., Successfully Integrated Into PJM* (Jan. 3, 2012), *available at http://www.pjm.com/~/media/about-pjm/newsroom/2012-releases/20120103-duke-ohio-and-kentucky-integrate-into-pjm.ashx.*

Region.[406] The integration of MISO South correspondingly led to changes in NERC's regional assessment areas.[407] FERC also recently approved the integration of the Western Areas Power Administration – Upper Great Plains, Basin Electric Power Cooperative, and Heartland Consumers Power District into SPP.[408] Additionally, PacifiCorp and the CAISO recently began operating the western Energy Imbalance Market (EIM).[409] Other entities such as NV Energy, Arizona Public Service Co., and Puget Sound Energy are planning to participate in the EIM in the future.[410] The EIM "creates significant reliability and renewable integration

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[406] Miso, *South Region Integration*, *available at* https://www.misoenergy.org/WhatWeDo/StrategicInitiatives/SouthernRegionIntegration/Pages/SouthernRegionIntegration.aspx (noting that the creation of the MISO South Region "brought over 18,000 miles of transmission, ~50,000 megawatts of generation capacity, and ~30,000 MW of load into the MISO footprint.").

[407] NERC previously included Entergy and its six operating areas as part of the SERC Assessment Areas. NERC, *2014 Reliability Assessment* (May 2014). "MISO now coordinates all RTO activities in the newly combined footprint, consisting of all or parts of 15 states with the integration of Entergy and other MISO South entities. This transition has led to substantial changes to MISO's market dispatch, creating the potential for unanticipated flows across the following systems: Tennessee Valley Authority (TVA), Associated Electric Cooperative Inc. (AECI), and Southern Balancing Authority." *Id. at 7.*

[408] SPP, *FERC approves Integrates System joining SPP* (Nov. 12, 2014), *available at* *http://www.spp.org/publications/FERC%20approves%20IS%20membership.pdf.*

[409] NREL, *Energy Imbalance Market*, *available at* http://www.nrel.gov/electricity/transmission/energy_imbalance.html.

[410] CAISO, *EIM Company Profiles* (May 2015), *available at* http://www.caiso.com/Documents/EIMCompanyProfiles.pdf.

benefits for consumers by sharing and economically dispatching a broad array of resources."[411] This history of changing regional boundaries leads us to the conclusion that selecting smaller regional boundaries for purposes of setting the BSER would merely represent a snapshot of current, changeable regional boundaries. As we have seen with recent, large-scale changes regarding ISO/RTO boundaries and NERC reliability assessment areas, such regions would likely not stand the test of the time, nor would smaller regional boundaries accurately reflect electricity flows on the grid. The EPA believes that the interconnections are the most stable and reasonable regional boundaries for setting BSER.

Third, we considered whether transmission constraints, and the fact that the specific locations of generation resources and loads within each interconnection clearly matter to grid planning and operations, necessitate evaluation of the emission reductions available from the building blocks at scales smaller than the interconnections. We concluded that no reduction in scale was needed due to such constraints. The same industry trends that are reflected in the BSER -- the changing efficiencies and mix of existing fossil EGUs and the development

[411] CAISO, *Energy Imbalance Market*, *available at* http://www.caiso.com/informed/pages/stakeholderprocesses/energyimbalancemarket.aspx.

of RE throughout each interconnection -- as well as the management of the interconnected grid as loads are reduced through EE, which is not reflected in the final BSER, are already driving power system development and are being managed through interconnection-wide planning, coordination and operations, and will continue to be managed in that manner in the future with or without this rule. While electricity supply and demand must be balanced in real time in a manner that observes all security constraints at that point in time, and key aspects of that management are carried out at a subregional scale, the emissions standards established in this rule can be met over longer timeframes through processes managed at larger geographic scales, just as they are today. We believe this rule will reinforce these developments and help provide a secure basis for moving forward. If a local transmission constraint requires that for reliability reasons a higher-emitting resource must operate during a certain period of time in preference to a lower-emitting resource that would otherwise be the more economic choice when all costs are considered, nothing in this rule prevents the higher-emitting source from being operated. If the same transmission constraint causes the same conditions to occur frequently, the extra cost associated with finding alternative ways to reduce emissions will provide an economic incentive for concerned parties to explore ways to relieve the transmission constraint. If relieving the constraint would be more costly than employing alternative measures to reduce emissions, the rule allows parties to pursue those alternative emission reduction measures. Accommodation of intermittent constraints and evaluation of alternatives for relieving or working around them have been routine operating and planning practices within the utility power sector for many years; the rule will not change these basic economic practices that occur today. The 2022-29 schedule for the rule’s interim goals and the 2030 schedule for the rule’s final goals allow time for planning and investment comparable to the sector’s typical planning horizons.

Finally, the EPA also considered whether the smaller geographic scales on which affected EGUs may typically engage in energy and capacity transactions necessitate evaluating the emission reductions available from the building blocks at scales smaller than the interconnections, and again concluded that a smaller scale was not necessary or justified. We first note that electricity trading occurs today throughout the interconnection through RTO/ISO markets and active spot markets, often over large areas such as RTO/ISOs, or managed over large dispatch areas outside RTOs. These trades result in interconnection-wide changes in flow that are managed in real time. Moreover, the exchange of power is not limited to these areas. For example, RTOs regularly manage flows between RTOs, and EGUs near the boundaries of RTOs impact multiple subregions across the interconnections, so that any subregional boundaries that might be evaluated for potential relevance as trading region boundaries will change as conditions and EGU choices change, while interconnection boundaries will remain stable.

In addition, the final rule permits trading of rate-based emission credits or mass-based emission allowances. Emission allowances and other commodities associated with electricity generation activities, such as RECs, which, again, represent investments in pollution control measures, are already traded separately from the underlying electric energy and capacity. There is no reason that whatever geographic limits may exist for electricity and capacity transactions by an affected EGU should also limit the EGU's transactions for validly issued rate-based emission credits or mass-based emission allowances. In fact, as discussed below, the final rule not only allows national trading without regard to the interconnection boundaries, but also includes a number of options that readily facilitate states' and utilities' very extensive reliance on emissions trading. It is appropriate for the rule to take this approach, in part, because the non-local nature of the impacts of CO_2 pollution do not necessitate geographic constraints, and in the absence of a policy reason to constrain the geographic scope of trading, the largest possible scope is the most efficient scope.

f. Uniform CO_2 emission performance rates by technology subcategory. In conjunction with the refinements to the interpretations of section 111 reflected in the final rule, the EPA has refined the methodology for applying the BSER to the affected EGUs so as to incorporate performance rates that are uniform across technology subcategories.

Specifically, the final rule establishes a performance rate of 1305 lbs. per net MWh for all affected steam EGUs nationwide and a performance rate of 771 lbs. per net MWh for all affected stationary combustion turbines nationwide. The computations of these performance rates and the determinations of state goals reflecting the performance rates are described in sections VI and VII of the preamble, respectively. As described above, in its proposed rule and Notice of Data Availability, the EPA solicited comment on a number of proposals to reflect the regional nature of the electricity system in the methodology for quantifying the emission limitations reflective of the BSER. At the same time, the EPA also consistently emphasized the need for strategies to ensure the achievability and flexibility of the established emission limitations and to increase opportunities for interstate and industry-wide coordination. This modification is consistent with a number of comments we received in response to those proposals. The commenters took the position that the proposed state goals varied too much among states and unavoidably implied, or would inevitably result in, states establishing inconsistent standards of performance for sources of the same technology type in their respective states, which in the commenters' view was not appropriate under section 111.

Having determined to adopt regional alternatives for computing the emission reductions achievable under each building block, the EPA has further determined to exercise discretion not to subcategorize based on the regions, and instead to apply a nationally uniform CO_2 emission performance rate for each source subcategory. Evaluating the emission reduction opportunities achievable through application of the BSER on a broad regionalized basis, which is appropriate for the reasons discussed above, makes it possible to express the degree of emission limitation reflecting the BSER as CO_2 emission performance rates that are uniform for all affected EGUs in a technology subcategory within each region. However, the goals and strategies embodied in the EPA's proposed rule are best effected by setting uniform emission performance rates nationally and not just regionally, as recognized by commenters favoring the use of nationally uniform performance rates by technology subcategory. Nationally uniform emission performance rates create greater parity among the emission reduction goals established for states across the contiguous U.S. and increase the ability of states and affected EGUs to coordinate emission reduction strategies, including through the use of emission trading mechanisms if states choose to allow such mechanisms, which we consider likely.

Having determined that the performance rates computed on a regional basis merit consideration as nationally applicable performance rates, we are also determining that the objectives of achievability and flexibility would best be met by using the least stringent of the regional performance rates for the three interconnections for each technology subcategory as the basis for nationally uniform performance rates for that technology subcategory than by using the most stringent of the regional performance rates.[412] Under this approach, the CO_2 emission performance rate reflecting the BSER for all steam EGUs is uniform across the contiguous U.S., regardless of the state or interconnection where the steam EGUs are located. While it is true that steam EGUs in the Western and Texas Interconnections

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[412] The Eastern, Western, and Texas Interconnections each encompass large and diverse populations of EGUs with numerous and diverse opportunities to reduce CO_2 emissions through application of the measures in each of the three building blocks. Based on these considerations of scale and diversity, we conclude that each of the interconnections is sufficiently representative of the source subcategories and emission reduction opportunities encompassed in the BSER to potentially serve as the basis for CO_2 emission performance rates applicable to the respective source subcategories on a nationwide basis.

have opportunities to implement the measures in the building blocks to a greater extent than the steam EGUs in the Eastern Interconnection -- for example, under building block 2, they have relatively greater amounts of incremental NGCC generation available to replace their generation in all years for which performance rates were computed -- we do not conclude that this means that the EGUs in all three interconnections should be assigned the most stringent CO_2 emission performance rate computed for any of the three regions. Applying nationally the performance rate computed for the interconnection with the lease stringent rate ensures that the emission limitations are achievable by the affected EGUs in all three interconnections. The use of a common CO_2 emission performance rate across all of the steam EGUs in all three regions also allocates the burdens of the BSER equally across the steam EGU source subcategory. The same is true for the combustion turbine source subcategory, even though, in any year for which emission performance rates are computed, the combustion turbines in two of the interconnections have relatively greater opportunities to replace their generation with generation from new RE generating capacity than combustion turbines in the third interconnection.[413]

[413] As discussed in section VI and the CO_2 Emission Performance Rate and State Goal Computation TSD, the emission performance rates for each technology subcategory are computed by region for

In addition, using the least stringent rate provides greater “headroom” -- that is, emission reduction opportunities beyond those reflected in the performance rates -- to affected EGUs in the interconnections that do not set the nationwide level. This greater “headroom” provides greater nationwide compliance flexibility and assurance that the standards set by the states based on the emission guidelines will be achievable at reasonable cost and without adverse impacts on reliability. This is because affected EGUs in the interconnections that do not set the nationwide level have more opportunities to directly invest in each of the building blocks in their respective regions, and affected EGUs in the interconnection that does set the nationwide level may in effect invest in the opportunities in the other interconnections through trading. At the same time, our approach still represents the degree of emission limitation achievable through use of an appropriately large and diverse set of emission reduction opportunities and can therefore reasonably

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each year from 2022 through 2030, and the region with the least stringent emission rate for a particular subcategory, whose rate therefore is used for all three regions, can differ across years. In the case of the steam EGU subcategory, the nationwide rate for all years is the rate computed for the Eastern Interconnection. In the case of the NGCC subcategory, the nationwide rate is the rate computed for the Texas Interconnection for the years from 2022 through 2026 and the rate computed for the Eastern Interconnection for the years from 2027 through 2030.

be considered the "best" system of emission reduction for each technology subcategory.

Our approach in this rulemaking thus not only addresses the comments we received regarding potentially disparate impacts of the approach presented in the proposal, it is also generally consistent with the approach we have taken in other NSPS rulemakings, where standards of performance or emission guidelines have typically been established at uniform stringencies for all units in a given source subcategory, and where once the best system of emission reduction has been identified, stringencies are generally set based on what is reasonably achievable using that system.

Providing each state with a state-specific weighted average rate-based goal allows the state to determine how the emission reduction requirements should be allocated among the state's affected EGUs. We continue to believe that, as in the proposal, this is an important source of flexibility for states in developing their section 111(d) plans. Accordingly, in this final rule we are providing uniform CO_2 emission performance rates for each source subcategory and also translating those rates to state-specific weighted average rate-based goals. For additional flexibility, we are also translating the state-specific rate-based goals into state-specific mass-based goals. Our determinations of the emission performance rates are described in section VI below, and our determinations of the rate-based and mass-based state goals are described in section VII below.

We note here that the weighted-average state goals reflect the application of the uniform CO_2 emission performance rates for affected steam EGUs and affected NGCC units to the respective units in each subcategory in each state. Each state goal therefore reflects uniform stringency of emission reduction requirements with respect to affected units in each source subcategory, but also reflects the EGU fleet composition and historical generation specific to that particular state. Compared to the computation approach reflected in the proposed state goals, the revised approach to quantify the BSER on a regional basis and to translate the results into nationally uniform emission performance rates by source subcategory results in more stringent goals (compared to the proposal) for states whose generation has historically been most heavily concentrated at coal-fired steam EGUs. This shift is an expected consequence of the use of uniform performance rates by source subcategory. At proposal, these states' goals reflected artificial assumptions in the selected goal quantification methodology that to a considerable extent limited their emission reduction opportunities based on their states' borders, and the proposed goals therefore were less stringent in states which had substantial coal generation and little local NGCC capacity. The final rule more realistically recognizes that emission reduction opportunities, like other aspects of the interconnected electricity system, are regional and are not constrained by state borders. The final rule also reflects the EPA's emphasis in the proposal on ensuring the achievability and flexibility of the emission guidelines and increasing opportunities for interstate and industry-wide coordination. We consequently apply the same emission performance rates to coal-fired units in states with heavy reliance on coal-fueled generation as we do to coal-fired units in other states, which produces more stringent state goals than at proposal for the states with the highest concentrations of coal-fired generation. At the same time, the final goals for some states are less stringent than their proposed goals. For example, a goal based on the least stringent regional rates is less stringent for some states than a goal based on state-specific emission reduction opportunities would be. Accordingly, the differences among the final state goals are generally smaller than the differences among the proposed state goals. All of the final rate-based state goals are necessarily in the range bounded by the CO_2 emission performance rate for NGCC units and the CO_2 emission performance rate for steam EGUs because all of the state goals are computed as a weighted average of those two performance rates, and this range is narrower than the range of state goals in the proposal.

The computations of the uniform CO_2 emission performance rates are shown in the CO_2 Emission Performance Rate and Goal Computation TSD for the CPP Final Rule. These uniform emission performance rates are applicable to the states and areas of Indian country[414] located in the contiguous U.S. that have affected EGUs.[415] We have not in this rule applied the uniform emission performance rates to Alaska, Hawaii, Puerto Rico, or Guam -- states and territories that have otherwise affected EGUs but are isolated from the three major interconnections -- and will determine how to address the requirements of section 111(d) with respect to these jurisdictions at a later time. Further discussion regarding the isolated jurisdictions can be found in section VII.F. of the preamble.

g. Establishment of a 2022-2029 interim compliance period. The June 2014 proposal separately quantified emission limitations applicable to an interim 2020-29 period and to the period beginning in 2030. The EPA took broad comment on this proposed

[414] As explained in section III.A. above, an Indian tribe whose area of Indian country has affected EGUs will have the opportunity but not the obligation to seek authority to develop and implement a section 111(d) plan. If no tribal plan is approved, the EPA has the responsibility to establish a plan if it determines that such a plan is necessary or appropriate.

[415] As noted earlier, there are currently no affected EGUs in Vermont or the District of Columbia.

timing. Although the proposal provided flexibility in the timing with which emission reductions could be made over the course of the 2020-2029 period in order to achieve compliance with the emission limitations applicable to that interim period, many commenters perceived the start of the period as too soon and stated that it provided insufficient time for planning and investments necessary for sources to begin implementation activities while maintaining reliable electricity supplies.

The EPA has considered these comments and in the final rule has established an interim compliance period of 2022-2029, providing two additional years for planning and investment before the start of compliance. We are persuaded by comments and by our own further analysis that this timeframe is appropriate and will, in combination with the glide path of emission reductions reflected in the final building blocks and the states' flexibility to define their own paths of emission reductions over the interim period (as discussed in section VIII), provide adequate time for necessary planning and investment activities. This will enable the final rule's requirements to be implemented in an orderly manner while reliability of electricity supplies is maintained. Further discussion is provided in the sections of the preamble addressing the individual building blocks (sections V.C., V.D., and V.E.) and on electricity system reliability (section VIII.G.2.).

The initial compliance date of 2022, coupled with the fact that the 2030 standard is phased in over the subsequent eight years, affords affected EGUs the benefit of having an extended planning period before they need to incur any significant obligations. Where needed, states may take the period through September 2018 to develop their final plans, and affected EGUs will be able to work with the states during that period to develop compliance approaches. States will also have the flexibility to select their own emissions trajectories in such a way that certain emission reduction measures could be implemented later in the interim period (again, provided that their affected EGUs still meet the interim performance rates or interim goal over the interim period as a whole). As a result, if the affected EGUs in those states need to incur any expenses before the adoption of the final state plans, those expenses need not be more than minimal. It is worth noting that an earlier state plan submission date provides regulated sources with more certainty and time to plan for compliance, but has no effect on the time when compliance must be achieved, as the mandatory compliance period begins in 2022 for all states. Some states that already have established programs for limiting CO_2 emissions from power plants may adopt and submit to the EPA state plans by September 6, 2016. In those states, sources will already have developed compliance approaches to meet state law requirements. Other states that submit plans by September 6, 2016, may be expected to work with their affected EGUs to determine a reasonable compliance approach, in light of the fact that compliance is not required to begin until 2022. It is also possible that some states will submit neither final state plans nor initial submittals by September 6, 2016, and that the EPA will promulgate federal plans. Sources in those states will have more than five years to meet their 2022 compliance obligations, a lengthy period that will afford them the opportunity to plan before incurring significant expenditures.

These periods of time are consistent with current industry practice in changing generation or adding new generation. For example, in June 2015, Alabama Power Company announced plans to acquire 500 MW of REgeneration over the next six years. This amount would make up between four and five percent of Alabama Power's generation mix.[416] In addition, the study of utility IRPs

[416] Alabama Power Co., "Petition for a Certificate of Convenience and Necessity," submitted to the Alabama Public Service Commission (June 25, 2015) (petition requests "a certificate of convenience and necessity for the construction or acquisition of renewable energy and environmentally specialized generating resources and the acquisition of rights and the assumption of payment obligations under power purchase arrangements pertaining to renewable energy and environmentally specialized generating resources, together with all transmission facilities, fuel

placed in the docket for this rulemaking[417] shows that sources are able to replace coal-fired generation with natural-gas fired generation and add incremental amounts of RE (as well as take other actions, such as implement demand-side EE programs), on a gradual basis, after a several-year lead time, over an extended period, as provided for under the final rule.

h. Refinements to stringency for individual building blocks. For each individual building block, the EPA has reexamined the data and assumptions used at proposal in light of comments solicited and has made a number of refinements in the final rule based on that information. The refinements are discussed in the preamble sections for each building block (sections V.C., V.D., and V.E.) and emission performance rate computation (section VI) and in the GHG Mitigation Measures TSD for the CPP Final Rule and the CO2 Emission Performance Rate and Goal Computation TSD for the CPP Final Rule. As previously noted, viewed in terms of projected nationwide emission reductions (but not necessarily with respect to each individual state), these refinements generally tend to make the interim goals somewhat less stringent

supply and transportation arrangements, appliances, appurtenances, equipment, acquisitions and commitments necessary for or incident thereto") (included in the docket for this rulemaking). *See* Swartz, Kristi, "Alabama Power plan would dramatically boost its renewables portfolio," E&E Publishing, July 16, 2015.

[417] See memo entitled "Review of Electric Utility Integrated Resource Plans" (May 7, 2015) available in the docket.

than at proposal and the 2030 goals somewhat more stringent than at proposal. In addition to the changes described above, the refinements include the following:

- Use of regional rates ranging from 2.1 percent to 4.3 percent (rather than 6 percent) as the average heat rate improvement opportunity achievable by steam units under building block 1.
- Use of 75 percent of summer capacity (rather than 70 percent of nameplate capacity) as the target capacity factor for existing NGCC units under building block 2.
- Use of updated information from the National Renewable Energy Laboratory (NREL) on RE costs and potential, and revision of the list of quantified RE technologies to exclude landfill gas under building block 3.

4. Determination of the BSER

In this rule, the EPA is finalizing as the BSER a combination of building blocks 1, 2, and 3, with refinements as discussed below. The building blocks constitute the BSER from the perspective of the source category as a whole. Each building block can be implemented through standards of performance set by the states and includes a set of actions that individual sources can use to achieve the emission limitations reflecting the BSER. These actions and mechanisms, which include reduced generation and emissions trading approaches where the state-set standards of performance incorporate trading and which may be understood as part of the BSER, will be discussed below in section V.A.5. Each of the building blocks consists of measures that the source category and individual affected EGUs have already demonstrated the ability to implement. In quantifying the application of each building block, the EPA has identified reasonable levels of stringency rather than the maximum possible levels.

As discussed above, one of the modifications being made in this rule is the establishment of uniform performance rates by technology subcategory, which enhances the rule’s achievability and flexibility and facilitates coordination among the states and across the industry. However, in the first instance, the emission reductions achievable through use of the building blocks are being evaluated on a regional basis that reflects the regional nature of the interconnected electricity system and the region-wide scope of opportunities available for affected EGUs to access emission reduction measures. The EPA recognizes that the emission reduction opportunities under these building blocks vary by region because of regional differences in the existing mix of types of fossil fuel-fired EGUs and the available opportunities to increase low- and zero-carbon generation. Consequently, in order to achieve uniform performance rates by technology subcategory, while respecting these regional differences in emission reduction opportunities, we have determined that it is reasonable not to establish the stringency of the BSER separately by region based on the maximum emission reduction that would be achievable in that region, but instead to establish uniform stringency across all regions at a level that is achievable at reasonable cost in any region. Thus, for each technology subcategory, the BSER is the combination of the elements described above at the combined stringency that is reasonably achievable in the region where the CO_2 emission performance rates determined to be achievable at reasonable cost by the EGUs in that subcategory through application of the building blocks were least stringent.[418]

This approach is consistent with the EPA’s efforts to enhance the achievability and flexibility of the rule and to promote interstate and industry coordination and reflects the regional strategies emphasized in the proposal and the Notice of Data Availability. It is also consistent with the approach we

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[418] The determinations of stringency for each source subcategory were made independently for each year from 2022 through 2030, and in the case of the NGCC category, the limiting region changed over time. Thus, for the NGCC category, the uniform CO_2 emission performance rate is based on the stringency achievable in the Texas Interconnection for the years from 2022 through 2026 and the stringency achievable in the Eastern Interconnection for the years from 2027 through 2030. For the steam EGU subcategory, the uniform CO_2 emission performance rate is based on the stringency achievable in the Eastern Interconnection in all years.

have taken in other NSPS rulemakings, where the degree of emission limitation achievable through the application of the BSER for each subcategory of affected sources generally has been determined not on the basis of what is achievable by the sources that can reduce emissions most easily, but instead on the basis of what is reasonably achievable through the application of the BSER across a range of sources. This approach also provides compliance headroom -- in addition to the headroom provided by our approach to setting the stringency for each individual building block -- for affected EGUs in regions where additional emission reductions can be achieved at reasonable cost, thereby promoting nationwide compliance flexibility. Further, because we are authorizing states to establish standards of performance that incorporate trading without geographic restrictions, the opportunity of affected EGUs to engage in emissions trading, to the extent allowed under the relevant section 111(d) plans, ensures the availability of additional, lower-cost emission reduction opportunities in other regions that will also promote compliance flexibility and reduce compliance costs.

As discussed in section XI of the preamble and the Regulatory Impact Analysis, application of the BSER determined as summarized above is projected to result in substantial and meaningful reductions of CO_2 emissions.

Briefly, the elements of the BSER are:

Building block 1: Improving heat rate at affected coal-fired steam EGUs in specified percentages.

Building block 2: Substituting increased generation from existing affected NGCC units for reduced generation from affected steam EGUs in specified quantities.

Building block 3: Substituting generation from new zero-emitting RE generating capacity for reduced generation from affected EGUs in specified quantities.

a. Building block 1. Building block 1 -- improving heat rate at affected coal-fired steam EGUs -- is a component of the BSER with respect to coal-fired steam EGUs[419] because the measures the affected EGUs may undertake to achieve heat rate improvements are technically feasible and of reasonable cost, and perform well with respect to other factors relevant to a determination of the "best system of emission reduction ... adequately demonstrated." Building block 1 is a "system of emission reduction" for steam EGUs because owners of these EGUs can take actions that will improve their heat rates and thereby reduce their rates of CO_2 emissions with respect to generation.

[419] For the reasons discussed in the proposal, the EPA is not determining that heat rate improvements at other types of affected EGUs, such as NGCC units and oil-fired and natural gas-fired steam EGUs, are components of the BSER. However, all types of affected EGUs would be able to employ heat rate improvements as measures to help achieve compliance with their assigned standards of performance.

The EPA has analyzed the technical feasibility, costs, and magnitude of CO_2 emission reductions achievable through heat rate improvements at coal-fired steam EGUs based on engineering studies and on these EGUs' reported operating and emissions data. We conclude that taking action to improve heat rates is a common and well-established practice within the industry that is capable of achieving meaningful reductions in CO_2 emissions at reasonable cost, although, as discussed earlier, we also conclude that the quantity of emission reductions achievable through heat rate improvement measures is insufficient for these measures alone to constitute the BSER. Specifically, we have determined that an average heat rate improvement ranging from 2.1 to 4.3 percent by all affected coal-fired EGUs, depending on the region, is an element of the BSER, based on the inclusion of those amounts of improvement in the three regions, determined through our regional analysis. Our analysis and conclusions are discussed in Section V.C. below and in the GHG Mitigation Measures TSD for the CPP Final Rule. Additional analysis and conclusions with respect to cost reasonableness are discussed in section V.A.4.d. below.

Consideration of other BSER factors also favors a conclusion that building block 1 is a component of the BSER. For example, with respect to non-air health and environmental impacts, heat rate improvements cause fuel to be used more efficiently, reducing the volumes of, and therefore the adverse impacts associated with, disposal of coal combustion solid waste products. By definition, heat rate improvements do not cause increases in net energy usage. Although we are justifying building block 1 as part of the BSER without reference to technological innovation, we also consider technological innovation in the alternative, and we note that building block 1 encourages the spread of more advanced technology to EGUs currently using components with older designs.

As noted in the June 2014 proposal, the EPA is concerned about the potential "rebound effect" associated with building block 1 if applied in isolation. More specifically, we noted that in the context of the integrated electricity system, absent other incentives to reduce generation and CO_2 emissions from coal-fired EGUs, heat rate improvements and consequent variable cost reductions at those EGUs would cause them to become more competitive compared to other EGUs and increase their generation, leading to smaller overall reductions in CO_2 emissions (depending on the CO_2 emission rates of the displaced generating capacity). Unless mitigated, the occurrence of a rebound effect would reduce the emission reductions achieved by building block 1, exacerbating the inadequacy of emission reductions that is the basis for our conclusion that building block 1 alone would not represent the BSER for this industry.

However, we believe that our concern about the potential rebound effect can be readily addressed by ensuring that the BSER also reflects other CO_2 reduction strategies that encourage increases in generation from lower- or zero-carbon EGUs, thereby allowing building block 1 to be considered an appropriate part of the BSER for CO_2 emissions at affected EGUs as long as the building block is applied in combination with other building blocks.

b. Building block 2. Building block 2 --substituting generation from less carbon-intensive affected EGUs (specifically NGCC units that are currently operating or under construction) for generation from the most carbon-intensive affected EGUs -- is a component of the BSER for steam EGUs because generation shifts that will reduce the amount of CO_2 emissions at higher-emitting EGUs and from the source category as a whole are technically feasible, are of reasonable cost, and perform well with respect to other factors relevant to a determination of the "best system of emission reduction ... adequately demonstrated." Building block 2 is a "system of emission reduction" for steam EGUs because incremental generation from existing NGCC units will result in reduced generation and emissions from steam EGUs, and owners of steam EGUs can, and many do, invest in incremental generation from NGCC units through a variety of possible mechanisms. A steam EGU investing in incremental generation from NGCC units may choose to reduce its own generation or may maintain its generation level and choose to allow the reduction in generation to occur at other steam EGUs through the coordinated planning and operation of the interconnected electricity system. An affected EGU may also invest in emission reductions from building block 2 through the mechanism of engaging in emissions trading where the EGU is operating under a standard of performance that incorporates trading.

The EPA’s analysis and conclusions regarding the technical feasibility, costs, and magnitude of CO_2 emission reductions achievable at high-emitting EGUs through generation shifts to lower-emitting affected EGUs are discussed in Section V.D. below. Additional analysis and conclusions with respect to cost reasonableness are discussed in section V.A.4.d. below. We consider generation shifts among the large number of diverse EGUs that are linked to one another and to customers by extensive regional transmission grids to be a routine and well-established operating practice within the industry that is used to facilitate the achievement of a wide variety of objectives, including environmental objectives, while meeting the demand for electricity services. In the interconnected and integrated electricity industry, fossil fuel-fired steam EGUs are able to reduce their generation and NGCC units are able to increase their generation in a coordinated manner through mechanisms -- in some cases centralized and in others not -- that regularly deal with such changes on both a short-term and a longer-term basis. Our analysis demonstrates that the emission reductions that can be achieved or supported by such generation shifts are substantial and of reasonable cost. Further, both the achievability of this building block and the reasonableness of its costs are supported by the fact that there has been a long-term trend in the industry away from coal-fired generation and toward NGCC generation for a variety of reasons.

Building block 2 is adequately demonstrated as a “system of emission reduction” for affected steam EGUs. As discussed in section V.B., since the time of the 1970 CAA Amendments, the utility power sector has recognized that generation shifts are a means of controlling air pollutants; in the 1990 CAA Amendments, Congress recognized that generation shifts among EGUs are a means of reducing emissions from this sector; and generation shifts similarly have been recognized as a means of reducing emissions under trading programs established by the EPA to implement the Act’s provisions. It is common practice in the industry to account for the cost of emission allowances as a variable cost when making security-constrained, cost-based dispatch decisions; doing so integrates generation shifts into the operating practices used to achieve compliance with environmental requirements in an economical manner. These industry trends are further discussed in section V.D. Thus, legislative history, regulatory precedent, and industry practice support interpreting the broad term “system of emission reduction” as including substituting lower-emitting generation for higher-emitting generation through generation shifts among affected EGUs.

An important additional consideration supporting the determination that building block 2 is adequately demonstrated as a “system of emission reduction” is that owners of affected steam EGUs have the ability to invest in generation shifts as a way of reducing emissions. The owner of an affected EGU could invest in such generation shifts in several ways, including by increasing operation of an NGCC unit that it already owns or by purchasing an existing NGCC unit and increasing operation of that unit. Increases in generation by NGCC units over baseline levels can also serve as the basis for creation of CO_2 ERCs -- that is, instruments representing the ability of incremental electricity generated by NGCC units to cause emission reductions at affected steam EGUs, as distinct from the incremental electricity itself. Again, it is important to note that the acquisition of such ERCs represents an investment in the actions of the facility or facilities whose alteration of utilization levels generated the emissions rate improvement or reduction. In the context of the BSER, purchase of instruments representing the emissions-reducing benefit of an action is simply a medium of investment in the underlying emissions reduction action. These mechanisms are discussed further in section V.A.5. In this rule, the EPA is establishing minimum criteria for the creation of valid ERCs by NGCC units and for the use of such ERCs by affected steam EGUs for demonstrating compliance with emission rate-based standards of performance established under state plans. The existence of minimum criteria will ensure that crediting mechanisms are feasible and will facilitate the development of organized markets to simplify the process of buying and selling ERCs. The minimum criteria are discussed in section VIII of this preamble.

We note that an affected EGU investing in building block 2 to reduce emissions may, but need not, also choose to reduce its own generation as part of its approach for meeting the standard of performance assigned to it by its state. Through the coordinated operation of the integrated electricity system, subject to the collective emission reduction requirements that will be imposed on affected EGUs in order to meet the emissions standards representing the BSER, an increase in NGCC generation will be offset elsewhere in the interconnection by a decrease in other generation. Because of the need to meet the collective emission reduction requirements, the decrease in generation resulting from that coordinated operation is most likely to be generation from an affected steam EGU. Measures taken by affected EGUs that result in emission reductions from other EGUs in the source category may appropriately be deemed measures to implement or apply the "system of emission reduction" of substituting lower-emitting generation for higher-emitting generation.

Consideration of other BSER factors also supports a determination to include building block 2 as a component of the BSER. For example, we expect that building block 2 would have positive non-air health and environmental impacts. Coal combustion for electricity generation produces large volumes of solid wastes that require disposal, with some potential for adverse environmental impacts; these wastes are not produced by natural gas combustion. The intake and discharge of water for cooling at many EGUs also carries some potential for adverse environmental impacts; NGCC units generally require less cooling water than steam EGUs.[420] With respect to energy impacts, building block 2 represents replacement of electrical energy from one generator with electrical energy from another generator

[420] For example, according to a DOE/NETL study, the relative amount of water consumption for a new pulverized coal plant is 2.5 times the consumption for a new NGCC unit of similar size. "Cost and Performance Baseline for Fossil Energy Plants: Volume 1: Bituminous Coal and Natural Gas to Electricity," Rev 2a, September 2013, National Energy Technology Laboratory Report DOE/NETL-2010/1397. EPA believes the difference would on average be even more pronounced when comparing existing coal and NGCC units.

that consumes less fuel, so the overall energy impact should be a reduction in fuel consumption by the overall source category as well as by individual affected coal-fired steam EGUs. Although for purposes of this rule we consider the incentive for technological innovation only in the alternative, we note that building block 2 promotes greater use of the NGCC technology installed in the existing fleet of NGCC units, which is newer and more advanced than the technology installed in much of the older existing fleet of steam EGUs. For all these reasons, the measures in building block 2 qualify as a component of the "best system of emission reduction ... adequately demonstrated."

It should be observed that, by definition of the elements of this building block, the shifts in generation taking place under building block 2 occur entirely among existing EGUs subject to this rulemaking.[421] Through application of this building block considered in isolation, some affected EGUs -- mostly coal-fired steam EGUs -- would reduce their generation and CO_2 emissions, while other affected EGUs -- NGCC units -- would increase their generation and CO_2 emissions. However, because for each MWh of generation, NGCC units produce fewer CO_2 emissions than coal-fired steam EGUs, the total quantity of CO_2

[421] For purposes of this rulemaking, "existing" EGUs include units under construction as of January 8, 2014, the date of publication in the Federal Register of the Carbon Pollution Standards for new fossil fuel-fired EGUs.

emissions from all affected EGUs in aggregate would decrease without a reduction in total electricity generation. In the context of the integrated electricity system, where the operation of affected EGUs of multiple types is routinely coordinated to provide a highly substitutable service, and in the context of CO_2 emissions, where location is not a consideration (in contrast with other pollutants), a measure that takes advantage of that integration to reduce CO_2 emissions from the overall set of affected EGUs is readily understood as a means to implement a "system of emission reduction" for CO_2 emissions at affected EGUs even if the measure would increase CO_2 emissions from a subset of those affected EGUs. Indeed, some industry participants are already moving in this direction for this purpose (while other participants are moving in the same direction for other purposes). Standards of performance that incorporate emissions trading can facilitate the implementation of such a "system" and such approaches have already been used in the electricity industry to address CO_2 as well as other pollutants, as discussed above.

c. Building block 3. Building block 3 --substituting generation from expanded RE generating capacity for reduced generation from affected EGUs -- is a component of the BSER because the expansion and use of renewable generating capacity to reduce emissions from affected EGUs is technically feasible, is of reasonable cost, and performs well with respect to other factors relevant to a determination of the "best system of emission reduction ... adequately demonstrated." Building block 3 is a "system of emission reduction" for all affected EGUs because incremental RE generation will result in reduced generation and emissions from affected EGUs, and owners or operators of affected EGUs can apply or implement building block 3 through a number of actions. For example, they can invest in incremental RE generation either directly or through the purchase of ERCs. An affected EGU investing in incremental RE generation may choose to reduce its own generation by a corresponding amount or may choose to allow the reduction in generation to occur at other affected EGUs through the coordinated planning and operation of the interconnected electricity system. An affected EGU can also invest in RE generation by means of engaging in emissions trading where the EGU is operating under a standard of performance that incorporates trading.

The EPA's analysis and conclusions regarding the technical feasibility, costs, and magnitude of the measures in building block 3 are discussed in Section V.E. below. Additional analysis and conclusions with respect to cost reasonableness are discussed in section V.A.4.d. below. We consider construction and operation of expanded RE generating capacity to be proven, well-established practices within the industry consistent with recent industry trends. States are already pursuing policies that encourage production of greater amounts of RE, such as the establishment of targets for procurement of renewable generating capacity. Moreover, as discussed earlier, markets are likely to develop for ERCs that would facilitate investment in increased RE generation as a means of helping sources comply with their standards of performance; indeed, markets for RECs, which similarly facilitate investment in RE for other purposes, are already well-established. As noted in Section V.A.5. below, an allowance system or tradable emission rate system would provide incentives for affected EGUs to reduce their emissions as much as possible where such reductions could be achieved economically (taking into account the value of the emission credits or allowances), including by substituting generation from new RE generating capacity for their own generation, or could provide a mechanism, as stated above, for such sources to invest in or acquire such generation.

Building block 3 is adequately demonstrated as a “system of emission reduction” for all affected EGUs. As discussed in section II, RE generation has been relied on since the 1970s to provide energy security by replacing some fossil fuel-fired generation. Both Congress and the EPA have previously established frameworks under which RE generation could be used as a means of achieving emission reductions from the utility power sector, as discussed in section V.B. Investment in RE generation has grown rapidly, such that in recent years the amount of new RE generating capacity brought into service has been comparable to the amount of new fossil fuel-fired capacity. Rapid growth in RE generation is projected to continue as costs of RE generation fall relative to the costs of other generation technologies. These trends are further discussed in section V.E. Interpretation of a "system of emission reduction" as including RE generation for purposes of this rule is thus supported by legislative history, regulatory precedent, and industry practice.

Also supporting the determination that building block 3 is adequately demonstrated as a "system of emission reduction" is the fact that owners of affected EGUs have the ability to invest in RE generation as a way of reducing emissions. As with building block 2, this can be accomplished in several ways. For example, the owner of an affected EGU could invest in new RE generating capacity and operate that capacity in order to obtain ERCs. Alternatively, the affected EGU could purchase ERCs created based on the operation of an unaffiliated RE generating facility, effectively investing in the actions at another site that allow CO_2 emission reductions to occur. These mechanisms are discussed further in section V.A.5. As with building block 2, in this rule the EPA is establishing minimum criteria for the creation of valid ERCs by new RE generators and for the use of such ERCs by affected EGUs for demonstrating compliance with emission rate-based standards of performance established under state plans. The existence of minimum criteria will ensure that crediting mechanisms are feasible and will facilitate the development of organized markets to simplify the process of buying and selling credits. The minimum criteria are discussed in section VIII of the preamble.

As with building block 2, an affected EGU investing in building block 3 to reduce emissions may, but need not, also choose to reduce its own generation as part of its approach for meeting the standard of performance assigned to it by its state. Through the coordinated operation of the integrated electricity system, subject to the collective requirements that will be imposed on affected EGUs in order to meet the emissions standards representing the BSER, an increase in RE generation will be offset elsewhere in the interconnection by a decrease in other generation. Because of the need to meet the collective requirements, the decrease in generation resulting from that coordinated operation is most likely to be generation from an affected EGU. Measures taken by affected EGUs that result in emission reductions from other sources in the source category may appropriately be deemed methods to implement the "system of emission reduction."

The renewable capacity measures in building block 3 generally perform well against other BSER criteria. Generation from wind turbines and solar voltaic installations, two common renewable technologies, does not produce solid waste or require cooling water, a better environmental outcome than if that amount of generation had instead been produced at a typical range of fossil fuel-fired EGUs. With respect to energy impacts, fossil fuel consumption will decrease both for the source category as a whole and for individual affected EGUs. Although the variable nature of generation from renewable resources such as wind and solar units requires special consideration from grid operators to address possible changes in operating reserve requirements, renewable generation has grown quickly in recent years, as discussed above, and grid planners and operators have proven capable of addressing any consequent changes in requirements through ordinary processes. The EPA believes that planners and operators will be similarly capable of addressing any changes in requirements due to future growth in renewable generation through ordinary processes, but notes that in addition, the reliability safety valve in this rule, discussed in section VIII.G.2, will ensure the absence of adverse energy impacts. With respect to technological innovation, which we consider for the BSER only in the alternative, incentives for expansion of renewable capacity encourage technological innovation in improved renewable technologies as well as more extensive deployment of current advanced technologies. For all these reasons, the measures in building block 3 qualify as a component of the "best system of emission reduction ... adequately demonstrated."

d. Combination of all three building blocks. The final BSER includes a combination of all three building blocks. For the reasons described below, and similar to each of the building blocks, the combination must be considered a "system of emission reduction." Moreover, as also discussed below, the combination qualifies as the "best" system that is "adequately demonstrated." The combination is technically feasible; it is capable of achieving meaningful reductions in CO_2 emissions from affected EGUs at a reasonable cost; it also performs well against the other BSER factors; and its components are well-established. The combination of the three building blocks will achieve greater CO_2 emission reductions at reasonable costs than possible combinations with fewer building blocks and will also perform better against other BSER factors. We therefore find the combination of all three building blocks to be the "best system of emission reduction ... adequately demonstrated" for reducing CO_2 emissions at affected EGUs.

As already discussed, each of the individual building blocks generally performs well with respect to the BSER factors identified by the statute and the D.C. Circuit. (The exception, which we have pointed out above, is that building block 1, if implemented in isolation, would achieve an insufficient magnitude of emission reductions to be considered the BSER.) The EPA expects that combinations of the building blocks would perform better than the individual building blocks. Beginning with the most obvious and important advantage, combinations of the building blocks will achieve greater emission reductions than the individual building blocks would in isolation, assuming that the building blocks are applied with the same stringency. Because fossil fuel-fired EGUs generally have higher variable costs than other EGUs, it will generally be fossil fuel-fired generation that is replaced when low-variable cost RE generation is increased. At the levels of stringency determined to be reasonable in this rule, opportunities to deploy building block 2 to replace higher-emitting generation and to deploy building block 3 to replace any emitting generation are not exhausted. Thus, as the system of emission reduction is expanded to include each of these building blocks, the emission reductions that will be achieved increase.

Because the stringency and timing of emission reductions achievable through use of each individual building block have been set based on what is achievable at reasonable cost rather than the maximum achievable amount, the stringency of the combination of building blocks is also reasonable, and the combination provides headroom and additional flexibility for states in setting standards of performance and for sources in complying with those standards to choose among multiple means of reducing emissions.

With respect to the quantity of emission reductions expected to be achieved from building block 1 in particular, the BSER encompassing all three building blocks is a substantial improvement over building block 1 in isolation. As noted earlier, the EPA is concerned that implementation of building block 1 in isolation not only would achieve insufficient emission reductions assuming generation levels from affected steam EGUs were held constant, but also has the potential to result in a "rebound effect." The nature of the potential rebound effect is that by causing affected steam EGUs to improve their heat rates and thereby lower their variable operating costs, building block 1 if implemented in isolation would make those EGUs more competitive relative to other, lower-emitting fossil fuel-fired EGUs, possibly resulting in increased generation and higher emissions from the affected steam EGUs in spite of their lower emission rates. Combining building block 1 with the other building blocks addresses this concern by ensuring that owner/operators of affected steam EGUs as a group would have appropriate incentives not only to improve the steam

EGUs’ efficiency but also to reduce generation from those EGUs consistent with replacement of generation by low- or zero-emitting EGUs. While combining building block 1 with either building block 2 or 3 should address this concern, the combination of all three building blocks addresses it more effectively by strengthening the incentives to reduce generation from affected steam EGUs.

The combination of all three building blocks is also of reasonable cost, for a number of independent reasons described below. The emission reductions associated with the BSER determined in this rule are significant, necessary, and achievable. As discussed in section V.A.1. above, the Administrator must take cost into account when determining that the measures constituting the BSER are adequately demonstrated, and the Administrator has done so here. Below, we summarize information on the cost of the building block measures and discuss the several independent reasons for the Administrator’s determination that the costs of the building block 1, 2, and 3 measures, alone or in combination, are reasonable. In considering whether these costs are reasonable, the EPA considered the costs in light of both the observed and projected effects of GHGs in the atmosphere, their effect on climate, and the public health and welfare risks and impacts associated with such climate change, as described in Section II.A. The EPA focused on public health and welfare impacts within the U.S., but the impacts in other world regions strengthen the case for action because impacts in other world regions can in turn adversely affect the U.S. or its citizens. In looking at whether costs were reasonable, the EPA also considered that EGUs are by far the largest emitters of GHGs among stationary sources in the U.S., as more fully set forth in section II.B.

As described in sections V.C. through V.E. and the GHG Mitigation Measures TSD, the EPA has determined that the cost of each of the three building blocks is reasonable. In summary, these cost estimates are \$23 per ton of CO_2 reductions for building block 1, \$24 per ton for building block 2, and \$37 per ton for building block 3. The EPA estimates that, together, the three building blocks are able to achieve CO_2 reductions at an average cost of \$30 per ton, which the EPA likewise has determined is reasonable. The \$30 per ton estimate is an average of the estimates for each building block, weighted by the total estimated cumulative CO_2 reductions for each of these building blocks over the 2022-2030 period. While it is possible to weight each building block by other amounts, the EPA believes that weighting by cumulative CO_2 reductions best reflects the average cost of total reduction potential across the three building blocks. The EPA considers each of these cost levels reasonable for purposes of the BSER established for this rule.

The EPA views the weighted average cost estimate as a conservatively high estimate of the cost of deploying all three building blocks simultaneously. The simultaneous application of all three building blocks produces interactive dynamics, some of which could increase the cost and some of which could decrease the cost represented in the individual building blocks. For example, one dynamic that would tend to raise costs (and whose omission would therefore make the weighted average understate costs) is that the emission reduction measures associated with building blocks 2 and 3 both prioritize the replacement of higher-cost generation (from affected steam EGUs in the case of building block 2 and from all affected EGUs in the case of building block 3). The EPA recognizes that the increased magnitude of generation replacement when building blocks 2 and 3 are implemented together necessitates that some of the generation replacement will occur at more efficient affected EGUs, at a relatively higher cost; however, this is a consequence of the greater emission reductions that can be achieved by combining building blocks, not an indication that any individual building block has become more expensive because of the combined deployment.

Also, the EPA recognizes that when building block 1 is combined with the other building blocks, the combination has the potential to raise the cost of the portion of the overall emission reductions achievable through heat rate improvements relative to the cost of those same reductions if building block 1 were implemented in isolation (assuming for purposes of this discussion that the rebound effect is not an issue and that the affected steam EGUs would in fact reduce their emissions if building block 1 were implemented in isolation).[422] However, we believe that the cost of emission reductions achieved through heat rate improvements in the context of a three-building block BSER will remain reasonable for two reasons. First, as discussed in section V.C. below, even when conservatively high investment costs are assumed, the cost of CO_2 emission reductions achievable through heat rate improvements is low enough that the cost per ton of CO_2 emission reductions will remain reasonable even if that cost is substantially increased. Second, although under a BSER encompassing all three building blocks the volume of coal-

[422] If an EGU produces less generation output, then an improvement in that EGU's heat rate and rate of CO_2 emissions per unit of generation produces a smaller reduction in CO_2 emissions. If the investment required to achieve the improvement in heat rate and emission rate is the same regardless of the EGU's generation output, then the cost per unit of CO_2 emission reduction will be higher when the EGU's generation output is lower. Commenters have also stated that operating at lower capacity factors may cause units to experience deterioration in heat rates.

fired generation will decrease, that decrease is unlikely to be spread uniformly among all coal-fired EGUs. It is more likely that some coal-fired EGUs will decrease their generation slightly or not at all while others will decrease their generation by larger percentages or cease operations altogether. We would expect EGU owners to take these changes in EGU operating patterns into account when considering where to invest in heat rate improvements, with the result that there will be a tendency for such investments to be concentrated in EGUs whose generation output is expected to decrease the least. This enlightened bias in spending on heat rate improvements -- that is, focusing investments on EGUs where such improvements will have the largest impacts and produce the highest returns, given consideration of projected changes in dispatch patterns -- will tend to mitigate any deterioration in the cost of CO_2 emission reductions achievable through heat rate improvements.

In contrast with those prior examples, combining the building blocks also produces interactive dynamics that significantly reduce the cost for CO_2 reductions represented in the individual building blocks (and whose omission would therefore make the weighted average overstate costs). Foremost among these dynamics is the stabilization of wholesale power prices. When assessed individually, building blocks 2 and 3 have opposite impacts on wholesale power prices, although in each case, the direction of the wholesale power price impact corresponds to an increasing cost of that building block in isolation. For example, building block 2 promotes more utilization of existing NGCC capacity, which (assessed on its own) would increase natural gas consumption and therefore price, in turn raising wholesale power prices (which are often determined by gas-fired generators as the power supplier on the margin); this dynamic puts upward pressure on the cost of achieving CO_2 reductions through shifting generation from steam EGUs to NGCC units.[423] Meanwhile, building block 3 increases RE deployment; because RE generators have very little variable cost, an increase in RE generation replaces other supply with higher variable cost, which would yield lower wholesale power prices. Lower wholesale power prices would make further RE deployment less competitive against generation from existing emitting sources; while this dynamic would generally reduce electricity prices to consumers, it also puts upward pressure on the cost of achieving CO_2 reductions through increased RE deployment.[424] Applying building blocks 2 and 3 together produces significantly more CO_2 reductions at a relatively lower cost

[423] The EPA’s cost-effectiveness estimate of $24 per ton for building block 2 reflects these market dynamics.

[424] The EPA’s cost-effectiveness estimate of $37 per ton for building block 3 reflects these market dynamics.

because the countervailing nature of these wholesale power price dynamics mitigates the primary cost drivers for each building block.[425]

The EPA believes the dynamics tending to cause the weighted average above to overstate costs of the combination of building blocks are greater than the dynamics tending to cause costs to be understated, and that the weighted average costs are therefore conservatively high. Analysis performed by the EPA at an earlier stage of the rulemaking supports this conclusion. At proposal, the EPA evaluated the cost of increasing NGCC utilization (building block 2) and deploying incremental RE generation (building block 3) independently, as well as the cost of simultaneously increasing NGCC utilization and incremental RE generation. The average cost (in dollars per ton of CO_2 reduced) was less for the combined building block scenario, showing that the net outcome of the interactivity effects described above is

[425] Notwithstanding the interactive dynamics that improve the cost effectiveness of emission reductions when building blocks 2 and 3 are implemented together, we also consider each of these building blocks to be independently of reasonable cost, so that either building block 2 or 3 alone, or combinations of the building blocks that include either but not both of these two building blocks, could be the BSER if a court were to strike down the other building block, as discussed in section V.A.7. below. (We also note in section V.A.7. that a combination of building blocks 2 and 3 without building block 1 could be the BSER if a court were to strike down building block 1.)

a reduction in cost per ton when compared to cost estimates that do not incorporate this interactivity.[426]

A final reason why the EPA considers the weighted-average cost above conservatively high is that simply combining the building blocks at their full individual stringencies overstates the stringency of the BSER. As discussed in section V.A.3.f and section VI, the BSER reflects the combined degree of emission limitation achieved through application of the building blocks in the least stringent region. By definition, in the other two regions, the BSER is less stringent than the simple combination of the three building blocks whose stringency is represented in the weighted-average cost above.

The cost estimates for each of the three building blocks cited above -- \$23, \$24, and \$37 per ton of CO_2 reductions from building blocks 1, 2, and 3, respectively – are each conservatively high for the reasons discussed in section V.C., V.D., and V.E. below. Likewise, the \$30 per ton weighted-average cost of all three building blocks is a conservatively high estimate of the cost of the combination of the three individual building block costs, as described above. While conservatively

[426] Specifically, at proposal the EPA quantified the average cost, in dollar per ton of CO_2 reduced, of building blocks 1, 2, and 3 (\$22.5 per ton) to be less than the cost of either building block 2 (\$28.9 per ton) or building block 3 (\$23.4 per ton) alone.

high, and especially so in the case of the $30 per ton weighted-average cost, these estimates fall well within the range of costs that are reasonable for the BSER for this rule.

In assessing cost reasonableness for the BSER determination for this rule, the EPA has compared the estimated costs discussed above to two types of cost benchmark. The first type of benchmark comprises costs that affected EGUs incur to reduce other air pollutants, such as SO_2 and NO_X. In order to address various environmental requirements, many coal-fired EGUs have been required to decide between either shutting down or installing and operating flue gas desulfurization (FGD) equipment – that is, wet or dry scrubbers – to reduce their SO_2 emissions. The fact that many of these EGUs have chosen scrubbers in preference to shutting down is evidence that scrubber costs are reasonable, and we believe that the cost of these controls can reasonably serve as a cost benchmark for comparison to the costs of this rule. We estimate that for a 300-700 MW coal-fired steam EGU with a heat rate of 10,000 Btu per kWh and operating at a 70 percent utilization rate, the annualized costs of installing and operating a wet scrubber are approximately $14 to $18 per MWh and the annualized costs of installing and operating a dry scrubber are approximately \$13 to \$16 per MWh.[427]

In comparison, we estimate that for a coal-fired steam EGU with a heat rate of 10,000 Btu per kWh, assuming the conservatively high cost of \$30 per ton of CO_2 removed through the combination of all three building blocks, the cost of reducing CO_2 emissions by the amount required to achieve the uniform CO_2 emission performance rate for steam EGUs of 1,305 lbs. CO_2 per MWh would be equivalent to approximately \$11 per MWh. The comparable costs for achieving the required emission performance rate for steam EGUs through use of the individual building blocks range from \$8 to \$14 per MWh. For an NGCC unit with a heat rate of 7,800 Btu per kWh, assuming a conservatively high cost of \$37 per ton of CO_2 removed through the use of building block 3,[428] the cost of reducing CO_2 emissions by the amount required to achieve the uniform CO_2 emission performance rate for NGCC units of 771 lbs. CO_2 per MWh would be equivalent to approximately \$3 per MWh.[429] These estimated CO_2 reduction costs of \$3 to \$14 per MWh to achieve the CO_2 emission performance rates are either less than the ranges of \$14 to \$18

[427] For details of these computations, see the memo "Comparison of building block costs to FGD costs" available in the docket.
[428] The comparison for an NGCC unit considers only building block 3 because building blocks 1 and 2 do not apply to NGCC units.
[429] For details of these computations, see the memo "Comparison of building block costs to FGD costs" available in the docket.

and $13 to $16 per MWh to install and operate a wet or dry scrubber, or in the case of CO_2 emission reductions at a steam unit achieved through building block 3, near the low end of the ranges of scrubber costs. This comparison demonstrates that the costs associated with the BSER in this rule are reasonable compared to the costs that affected EGUs commonly face to comply with other environmental requirements.

The second type of benchmark comprises CO_2 prices that owners of affected EGUs use for planning purposes in their IRPs. Utilities subject to requirements to prepare IRPs commonly include assumptions regarding future environmental regulations that may become effective during the time horizon covered by the IRP, and assumptions regarding CO_2 regulations are often represented in the form of assumed prices per ton of CO_2 emitted or reduced. A survey of the CO_2 price assumptions from 46 recent IRPs shows a range of CO_2 prices in the IRPs' reference cases of $0 to $30 per ton, and a range of CO_2 prices in the IRPs' high cases from $0 to $110 per ton.[430] In comparison, the conservatively high, weighted-average cost of $30 per ton removed described above is at the high end of the range of

[430] *See* Synapse Energy Economics Inc., 2015 Carbon Dioxide Price Forecast (March 3, 2015) at 25-28, *available at* http://www.synapse-energy.com/sites/default/files/2015%20Carbon%20Dioxide%20Price%20Report.pdf.

reference case assumptions but at the low end of the range of the high case assumptions. The costs of the individual building blocks are likewise well within the range of the high case assumptions, and either at or slightly above the high end of the reference case assumptions. This comparison demonstrates that the costs associated with the BSER in this rule are reasonable compared to the expectations of the industry for the potential costs of CO_2 regulation.

In addition to comparison to these benchmarks, there is a third independent way in which EPA has considered cost. In light of the severity of the observed and projected climate change effects on the U.S., U.S. interests, and U.S. citizens, combined with EGUs' large contribution to U.S. GHG emissions, the costs of the BSER measures are reasonable when compared to other potential control measures for this sector available under section 111. Given EGUs' large contribution to U.S. GHG emissions, any attempt to address the serious public health and environmental threat of climate change must necessarily include significant emission reductions from this sector. The agency would therefore consider even relatively high costs – which these are not – to be reasonable. Imposing only the lower cost reduction measures in building block 1 would not achieve sufficient reductions given the scope of the problem and EGUs' contribution to it. While the EPA also considered measures such as CCS retrofits for all fossil-fired EGUs or co-firing at all steam units, the EPA determined that these costs were too high when considered on a sector-wide basis. Furthermore, the EPA has not identified other measures available under section 111 that are less costly and would achieve emission reductions that are commensurate with the scope of the problem and EGUs' contribution to it. Thus, the EPA determined that the costs of the measures in building blocks 1, 2 and 3, individually or in combination, are reasonable because they achieve an appropriate balance between cost and amount of reductions given the other potential control measures under section 111.

As required under Executive Order 12866, the EPA conducts benefit-cost analyses for major Clean Air Act rules.[431] While benefit-cost analysis can help to inform policy decisions, as permissible and appropriate under governing statutory provisions, the EPA does not use a benefit-cost test (i.e., a determination of whether monetized benefits exceed costs) as the sole or primary decision tool when required to consider costs or to determine whether to issue regulations under the Clean Air

[431] The EPA's regulatory impact analysis for this rule, which appropriately includes a representation of the flexibility available under the rule to comply using a combination of BSER and non-BSER measures (such as demand-side energy efficiency) is discussed in section XI of the preamble.

Act, and is not using such a test here.[432] Nonetheless, the EPA observes that the costs of the building block 1, 2 and 3 measures, both individually and combined as discussed in this section above, are less than the central estimates of the social cost of carbon. Developed by an interagency workgroup, the social cost of carbon (SC-CO_2) is an estimate of the monetary value of impacts associated with marginal changes in CO_2 emissions in a given year.[433] It is typically used to assess the avoided damages as a result of regulatory actions (i.e., benefits of rulemakings that lead to an incremental reduction in cumulative global CO_2 emissions).[434] The central values for the SC-CO_2 range from $40 per short ton in 2020 to $48 per short ton

[432] See memo entitled "Consideration of Costs and Benefits Under the Clean Air Act" available in the docket.

[433] Estimates are presented in the *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (May 2013, Revised July 2015)*, Interagency Working Group on Social Cost of Carbon, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Environmental Protection Agency, National Economic Council, Office of Energy and Climate Change, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (May 2013, Revised July 2015). Available at: <https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf> Accessed 7/11/2015.

[434] The SC-CO_2 estimates do not include all important damages because of current modeling and data limitations. The IPCC Fifth Assessment report observed that SC-CO_2 estimates omit various impacts that would likely increase damages.

in 2030.[435] The weighted-average cost estimate of $30 per ton is well below this range.

Finally, the EPA notes that the combination of all three building blocks would perform consistently with the individual building blocks with respect to non-air energy and environmental impacts. There is no reason to expect an adverse non-air environmental or energy impact from deployment of the combination of the three building blocks, whether considered on a source-by-source basis, on a sector-wide or national basis, or both. In fact, the combination of the building blocks, like the building blocks individually, as discussed above, would be expected to produce non-air environmental co-benefits in the form of reduced water usage and solid waste production (and, in addition to these non-air environmental co-benefits, would also be expected to reduce emissions of non-CO_2 air pollutants such as SO_2, NO_X, and mercury). Likewise, with respect to technological innovation, which we consider only in the alternative, the building blocks in combination would have the same positive effects that they would have if implemented independently.

[435] The 2010 and 2013 TSDs present SC-CO_2 in 2007$ per metric ton. The unrounded estimates from the current TSD were adjusted to (1) 2011$ using GDP Implicit Price Deflator (1.061374), http://www.bea.gov/iTable/index_nipa.cfm and (2) short tons using the conversion factor of 0.90718474 metric tons in a short ton. These estimates were rounded to two significant digits.

e. <u>Other combinations of the building blocks</u>. The EPA has considered whether other combinations of the building blocks, such as a combination of building blocks 1 and 2 or a combination of building blocks 1 and 3, could be the BSER. We believe that any such combination is technically feasible and would be a "system of emission reduction" capable of achieving meaningful reductions in CO_2 emissions from affected EGUs at a reasonable cost. As with the combination of three building blocks discussed above, any combination of building blocks would achieve greater emission reductions than the individual building blocks encompassed in that combination would achieve if implemented in isolation. Further, the cost of any combination would be driven principally by the combined stringency and would remain reasonable in aggregate, such that the conclusions on cost reasonableness discussed in section V.A.4.d. would continue to apply. We have already noted our determination that building block 1 in isolation is not the BSER because it would not produce a sufficient quantity of emission reductions. A combination of building block 1 with one of the other building blocks would produce greater emission reductions and would not be subject to this concern. Any combination of building blocks including building block 1 and at least one other building block would also address the concern about potential "rebound effect," discussed above, that could occur if building block 1 were implemented in isolation. Finally, there is no reason to expect any combination of the building blocks to have adverse non-air energy or environmental impacts, and the implications for technological innovation, which we consider only in the alternative, would likewise be positive for any combination of the building blocks because those implications are positive for the individual building blocks and there is no reason to expect negative interaction from a combination of building blocks.

For these reasons, any combination of the building blocks (but not a BSER comprising building block 1 in isolation) could be the BSER if it were not for the fact that a BSER comprising all three of the building blocks will achieve greater emission reductions at a reasonable cost and is therefore “better.” As discussed below in section V.A.7., we intend for the individual building blocks to be severable, such that if a court were to deem building block 2 or 3 defective, but not both, the BSER would comprise the remaining building blocks.

f. Achievability of emission limits. As noted, based on the BSER, the EPA has established a source subcategory-specific emission performance rate for fossil steam units and one for NGCC units. As discussed in section V.A.1.c., for new sources, standards of performance must be “achievable” under CAA section 111(a)(1), and the D.C. Circuit has identified criteria for achievability.[436] In this rule, the EPA is taking the approach that while the states are not required to adopt those source subcategory-specific emission performance rates as the standards of performance for their affected EGUs, those rates must be achievable by the steam generator and NGCC subcategories, respectively. In addition, the EPA is assuming that the achievability criteria in the case law for new sources apply to existing sources under section 111(d). For the reasons discussed next, for this rule, the source subcategory-specific emission performance rates are achievable in accordance with those criteria in the case law.

As noted, the building blocks include several features that assure that affected EGUs may implement them. The building blocks may be implemented through a range of methods, including through the purchase of ERCs and emission trading. In addition, the building blocks incorporate "headroom." Moreover, the source subcategory-specific emission performance rates apply on an annual basis, so that short-term issues need not jeopardize compliance. In addition, we quantify the emission performance rates based on the degree of emission limitation achievable by

[436] *See Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433-34 (D.C. Cir. 1973), *cert. denied*, 416 U.S. 969 (1974); *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 433, n.46 (D.C. Cir. 1980); *Sierra Club v. Costle*, 657 F.2d 298, 377 (D.C. Cir. 1981) (citing *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416 (D.C. Cir. 1980).

affected EGUs in the region where application of the combined building blocks results in the least stringent emission rate. Because the means to implement the building blocks are widely available and because of the just-noted flexibilities and approaches to the emission performance rates, all types of affected steam generating units, operating throughout the lower-48 states and under all types of regulatory regimes, are able to implement building blocks 1, 2 and 3 and thereby achieve the emission performance rate for fossil steam units, and all types of NGCC units operating in all states under all types of regulatory requirements are able to implement building block 3 and thereby achieve the emission performance rate for NGCC units.[437]

Commenters have raised questions about whether particular circumstances could arise, such as the sudden loss of certain generation assets, that would cause the implementation of the building blocks to cause reliability problems, and have cautioned that these circumstances could preclude implementation of the building blocks and thus achievement of the emission performance rates. Commenters have also raised concerns about whether affected EGUs with limited remaining useful lives can

[437] We discuss the ability of affected EGUs to implement the building blocks in more detail in sections V.C., V.D., and V.E. and the accompanying support documents.

implement the building blocks and achieve the emission performance rates. We address those concerns in section VIII, where we authorize state plans to include a reliability mechanism and discuss affected EGUs with limited remaining useful lives. Accordingly, we conclude that the source subcategory specific emission performance standards are achievable in accordance with the case law.

5. Actions under the BSER that sources can take to achieve standards of performance

Based on the determination of the BSER described above, the EPA has identified a performance rate of 1305 lbs. per net MWh for affected steam EGUs and a performance rate of 771 lbs. per net MWh for affected stationary combustion turbines. The computations of these performance rates and the determinations of state goals reflecting these rates are described in sections VI and VII of the preamble, respectively.

Under section 111(d), states determine the standards of performance for individual sources. The EPA is authorizing states to express the standards of performance applicable to affected EGUs as either emission rate-based limits or mass-based limits. As described above, the sets of actions that sources can take to comply with these standards implement or apply the BSER and, in that sense, may be understood as part of the BSER.

A source to which a state applies an emission rate-based limit can achieve the limit through a combination of the following set of measures (to the extent allowed by the state plan), all of which are components of the BSER, again, in the sense that they implement or apply it:

- Reducing its heat rate (building block 1).
- Directly investing in, or purchasing ERCs created as a result of, incremental generation from existing NGCC units (building block 2).
- Directly investing in, or purchasing ERCs created as a result of, generation from new or uprated RE generators (building block 3).
- Reducing its utilization, coupled with direct investment in or purchase of ERCs representing building blocks 2 and 3 as indicated above.
- Investing in surplus emission rate reductions at other affected EGUs through the purchase or other acquisition of rate-based emission credits.

A source to which a state applies a mass-based limit can achieve the limit through a combination of the following set of measures (to the extent allowed by the state plan), all of which are likewise components of the BSER:

- Reducing its heat rate (building block 1).

- Reducing its utilization and allowing its generation to be replaced or avoided through the routine operation of industry reliability planning mechanisms and market incentives.
- Investing in surplus emission reductions at other affected EGUs through the purchase or other acquisition of mass-based emission allowances.

The EPA has determined appropriate CO_2 emission performance rates for each of the two source subcategories as a whole achievable through application of the building blocks. The wide ranges of measures included in the BSER and available to individual sources as indicated above provide assurance that the source category as a whole can achieve standards of performance consistent with those emissions standards using components of the BSER, whether states choose to establish emission rate-based limits or mass-based limits. The wide ranges of measures included in the BSER also provide assurance that each individual affected EGU could achieve the standard of performance its state establishes for it using components of the BSER. Of course, sources may also employ measures not included in the BSER, to the extent allowed under the applicable state plan.

In the remainder of this subsection, we discuss further how affected EGUs can use each of the measures listed above to achieve emission rate-based forms of performance standards and mass-based forms of performance standards, indicating that all types of owner/operators of affected EGUs -- i.e., vertically integrated utilities and merchant generators; investor-owned, government-owned, and customer-owned (cooperative) utilities; and owner/operators of large, small, and single-unit fleets of generating units -- have the ability to implement each of the building blocks in some way. In the following subsection we discuss the use of measures not in the BSER that can help sources achieve the standards of performance.

a. <u>Use of BSER measures to achieve an emission rate-based standard</u>. Under an emission-rate based form of performance standards, compliance is nominally determined through a comparison of the affected EGU’s emission rate to the emission rate standard. The emissions-reducing impact of BSER measures that reduce CO_2 emissions through reductions in the quantity of generation rather than through reductions in the amount of CO_2 emitted per unit of generation would not be reflected in an affected EGU’s emission rate computed solely based on measured stack emissions and measured electricity generation but can readily be reflected in an emission rate computation by averaging ERCs acquired by the affected EGU into the rate computation.

In section VIII.K., we discuss the processes for issuance and use of ERCs that can be included in the emission rate computations that affected EGUs perform to demonstrate compliance with an emission rate standard. This ERC mechanism is analogous to the approach the EPA has used to reflect building blocks 2 and 3 in the uniform emission rates representing the BSER, as discussed in section VI below. As summarized below and as discussed in greater detail in section VIII.K., the existence of a clearly feasible path for usage of ERCs ensures that emission reductions achievable through implementation of the measures in building blocks 2 and 3 are available to assist all affected EGUs in achieving compliance with standards of performance based on the BSER.

(1) Building block 1.

The owner/operator of an affected steam EGU can take steps to reduce the unit's heat rate, thereby lowering the unit's CO_2 emission rate. Examples of actions in this category are included in section V.C. below and in the GHG Mitigation Measures TSD for the CPP Final Rule. Any type of owner/operator can take advantage of this measure.

(2) Building block 2.

The owner/operator of an affected EGU can average the EGU's emission rate with ERCs issued on the basis of incremental generation from an existing NGCC unit. As permitted under the

EGU's state's section 111(d) plan, the owner/operator of the affected EGU could accomplish this through either common ownership of the NGCC unit, a bilateral transaction with the owner/operator of the NGCC unit, or a transaction for ERCs through an intermediary, which could but need not involve an organized market.[438] As discussed earlier, based on observation of market behavior both inside and outside the electricity industry, we expect that intermediaries will seek opportunities to participate in such transactions and that organized markets are likely to develop as well if section 111(d) plans authorize the use of ERCs. While the opportunity to acquire ERCs through common ownership of NGCC facilities might not extend to owner/operators of single EGUs or small fleets, all owner/operators would have the ability to engage in bilateral or intermediated purchase transactions for ERCs just as they can engage in transactions for other kinds of goods and services.

In section VIII.K. below, the EPA sets out the minimum criteria that must be satisfied for generation and issuance of a valid ERC based upon incremental electricity generation by an

[438] Each of these methods of implementing building block 2 meets the criteria for the BSER in that (i) as we discuss in section V.D. and supporting documents, each of these methods is adequately demonstrated;(ii) the costs of each of these methods on a source-by-source basis are reasonable, as discussed above; and (iii) none of these methods causes adverse energy impacts or non-quality environmental impacts.

existing NGCC unit. Those criteria generally concern ensuring that the physical basis for the ERC -- i.e., qualifying generation by an existing NGCC unit and the NGCC unit CO_2 emissions associated with that qualifying generation -- is adequately monitored and that there is an adequate administrative process for tracking credits to avoid double-counting. In the case of ERCs related to building block 2, the monitoring criteria would generally be satisfied by standard 40 CFR part 75 monitoring.

The owner/operator of an affected steam EGU would use the ERCs it has acquired for compliance -- whether acquired through ownership of NGCC capacity, a bilateral transaction, or an intermediated transaction -- by adding the ERCs to its measured net generation when computing its CO_2 emission rate for purposes of demonstrating compliance with its emission rate-based standard of performance.

(3) Building block 3.

The owner/operator of an affected EGU can average the EGU's emission rate with ERCs issued on the basis of generation from new (i.e., post-2012) RE generating capacity, including both newly constructed capacity and new uprates to existing RE generating capacity. As permitted under the EGU's state's section 111(d) plan, the owner/operator of the affected EGU could accomplish this through either common ownership of the RE generating capacity, a bilateral transaction with the owner/operator of the RE generating capacity, or a transaction for ERCs through an intermediary, which could, but need not, involve an organized market.[439] As discussed earlier, based on observation of market behavior both inside and outside the electricity industry, we expect that intermediaries will seek opportunities to participate in such transactions and that organized markets are likely to develop as well if section 111(d) plans authorize the use of ERCs. While the opportunity to acquire ERCs through common ownership of RE generating facilities might not extend to owner/operators of single EGUs or small fleets, all owner/operators would have the ability to engage in bilateral or intermediated purchase transactions for ERCs just as they can engage in transactions for other kinds of goods and services.

In section VIII.K. below, the EPA sets out the minimum criteria that must be satisfied for generation and issuance of a valid ERC based upon generation from new RE generating capacity.

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[439] As with building block 2, each of these methods of implementing building block 3 meets the criteria for the BSER in that (i) as we discuss in section V.E. and supporting documents, each of these methods is adequately demonstrated;(ii) the costs of each of these methods on a source-by-source basis are reasonable, as discussed above; and (iii) none of these methods causes adverse energy impacts or non-quality environmental impacts.

Those criteria generally concern assuring that the physical basis for the ERC -- i.e., generation by from qualifying new RE capacity -- is adequately monitored and that there is an adequate administrative process for tracking credits to avoid double-counting and to facilitate enforceability of emission limits.[440]

As with building block 2, the owner/operator of an affected EGU would use the ERCs it has acquired for compliance -- whether acquired through ownership of qualifying RE generating capacity, a bilateral transaction, or an intermediated transaction -- by adding the ERCs to its measured net generation when computing its CO_2 emission rate for purposes of demonstrating compliance with its emission rate-based standard of performance.

(4) Reduced generation.

The owner/operator of an affected EGU can reduce the unit's generation and reflect that reduction in the form of a lower emission rate provided that the owner/operator also acquires some amount of ERCs to use in computing the unit's emission rate for purposes of demonstrating compliance. As permitted under the EGU's state's section 111(d) plan, the ERCs could be acquired through investment in incremental generation from existing NGCC

[440] The possible use of types of RE generating capacity that are not included in the BSER is discussed in section V.A.6. and section VIII of the preamble.

capacity, generation from new RE generating capacity, or purchase from an entity with surplus ERCs. If the owner/operator does not average any ERCs into the unit's emission rate, reducing the unit's own generation will proportionately reduce both the numerator and denominator of the fraction and therefore will not affect the computed emission rate (unless the unit retires, reducing its emission rate to zero). However, if the owner/operator does average ERCs into the unit's emission rate, then a proportional reduction in both the numerator and the portion of the denominator representing the unit's measured generation will amplify the effect of the acquired ERCs in the computation, with the result that the more the unit reduces its generation, the fewer ERCs will be needed to reach a given emission rate-based standard of performance. All owner/operators have the ability to reduce generation, and as discussed above all also would be capable of acquiring ERCs, so all would be capable of reflecting reduced utilization in their emission rates for purposes of demonstrating compliance.

(5) Emissions trading approaches.

To the extent allowed under standards of performance that incorporate emissions trading or otherwise through the relevant section 111(d) plans, the owner/operator of an affected EGU can acquire tradable rate-based emission credits representing an investment in surplus emission rate reductions not needed by another affected EGU and can average those credits into its own emission rate for purposes of demonstrating compliance with its rate-based standard of performance. The approach would have to be authorized in the appropriate section 111(d) plan and would have to conform to the minimum conditions for such approaches described in section VIII below. As we have repeatedly noted, we read the comment record and the discussions that occurred during the outreach process, it is reasonable to presume that such authorization will be forthcoming from states that submit plans establishing rate-based standards of performance for their affected EGUs.

Under a rate-based emissions trading approach, credits are initially created and issued according to processes defined in the state plan. After credits are initially issued, the owner/operator of an affected EGU needing additional credits can acquire credits through common ownership of another affected EGU or through a bilateral transaction with the other affected EGU, or the owner/operator of the affected EGU can acquire credits in a transaction through an intermediary, which could, but need not, involve an organized market. As discussed earlier, based on observation of market behavior both inside and outside the electricity industry, we expect that intermediaries will seek opportunities to participate in such transactions and that organized markets are likely to develop as well if section

111(d) plans and/or standards of performance established thereunder authorize emissions trading. While the opportunity to acquire credits through common ownership might not extend to owner/operators of single EGUs or small fleets, all owner/operators would have the ability to engage in bilateral or intermediated purchase transactions for credits just as they can engage in transactions for other kinds of goods and services.

Further details regarding the possible use of rate-based emission credits in a state plan (using ERCs issued on the basis of investments in building blocks 2 and 3 and potentially other measures as the credits) are provided in section VIII.K.

b. Use of BSER measures to achieve a mass-based standard. Under a mass-based form of the standard, compliance is determined through a comparison of the affected EGU's monitored mass emissions to a mass-based emission limit. Although a state could choose to impose specific mass-based limits that each EGU would be required to meet on a physical basis, in past instances where mass-based limits have been established for large numbers of sources it has been typical for the limit on each affected EGU to be structured as a requirement to periodically surrender a quantity of emission allowances equal to the source's monitored mass emissions. The EPA believes that section 111(d) encompasses the flexibility for plans to impose mass-based standards in the typical manner where the standard of performance for each affected EGU consists of a requirement to surrender emission allowances rather than a requirement to physically comply with a unit-specific emissions cap.

Measurements of mass emissions at a given affected EGU capture reductions in the EGU's emissions arising from both reductions in generation and reductions in the emission rate per MWh. Accordingly, under a mass-based standard there is no need to provide a mechanism such as the ERC mechanism described above in order to properly account for emission reductions attributable to particular types of BSER measures. The relative simplicity of the mechanics of monitoring and determining compliance are significant advantages inherent in the use of mass-based standards rather than emission rate-based standards.

(1) Building block 1.

The owner/operator of an affected steam EGU can take steps to reduce the unit's heat rate, thereby lowering the unit's CO_2 mass emissions. Examples of actions in this category are included in section V.C. below and in the GHG Mitigation Measures TSD for the CPP Final Rule. Any type of owner/operator can take advantage of this measure.

(2) Reduced generation.

The owner/operator of an affected EGU can reduce its generation, thereby lowering the unit's CO_2 mass emissions. Any type of owner/operator can take advantage of this measure.

Although some action or combination of actions to increase lower-carbon generation or reduce electricity demand somewhere in the interconnected electricity system of which the affected EGU is a part will be required to enable electricity supply and demand to remain in balance, the affected EGU does not need to monitor or track those actions in order to use its reduction in generation to help achieve compliance with the mass-based standard. Instead, multiple participants in the interconnected electricity system will act to ensure that supply and demand remain in balance, subject to the complex and constantly changing set of constraints on operation of the system, just as those participants have routinely done for years.

Of course, if the owner/operator of the affected EGU wishes to play a direct role in driving the increase in lower-carbon generation or demand-side EE required to offset a reduction in the affected EGU’s generation, the owner/operator may do so as part of whatever role it happens to play as a participant in the interconnected electricity system. However, the owner/operator will achieve the benefit that reduction in generation brings toward compliance with the mass-based standard whether it takes those additional actions itself or instead allows other participants in the interconnected electricity system to play that role.

(3) Emissions trading approaches.

To the extent allowed under the relevant section 111(d) plans -- as the record indicates that it is reasonable to expect it will be -- the owner/operator of an affected EGU can acquire tradable mass-based emission allowances representing investment in surplus emission reductions not needed by another affected EGU and can aggregate those allowances with any other allowances it already holds for purposes of demonstrating compliance with its mass-based standard of performance. The approach would have to be authorized in the appropriate section 111(d) plan and would have to conform to the minimum conditions for such approaches described in section VIII below.

Under a mass-based emissions trading approach, the total number of allowances to be issued is defined in the state plan, and affected EGUs may obtain an initial quantity of allowances through an allocation or auction process. After that initial process, the owner/operator of an affected EGU needing additional allowances can acquire allowances through common ownership of another affected EGU or through a bilateral transaction with the other affected EGU, or the owner/operator of the affected EGU can acquire allowances in a transaction through an intermediary, which could but need not involve an organized market. As discussed earlier, based on observation of market behavior both inside and outside the electricity industry, we expect that intermediaries will seek opportunities to participate in such transactions and that organized markets are likely to develop as well if section 111(d) plans authorize the use of emissions trading. While the opportunity to acquire allowances through common ownership might not extend to owner/operators of single EGUs or small fleets, all owner/operators would have the ability to engage in bilateral or intermediated purchase transactions for allowances just as they can engage in transactions for other kinds of goods and services.

Further details regarding the possible use of mass-based emission allowances in a state plan are provided in section VIII.J.

6. Use of non-BSER measures to achieve standards of performance

In addition to the BSER-related measures that affected EGUs can use to achieve the standards of performance set in section 111(d) plans, there are a variety of non-BSER measures that could also be employed (to the extent permitted under a given plan). This final rule does not limit the measures that affected EGUs may use for achieving standards of performance to measures that are included in the BSER; thus, the existence of these non-BSER measures provides flexibility allowing the individual affected EGUs and the source category to achieve emission reductions consistent with application of the BSER at the levels of stringency reflected in this final rule even if one or more of the building blocks is not implemented to the degree that the EPA has determined to be reasonable for purposes of quantifying the BSER. In this way, non-BSER measures provide additional flexibility to states in establishing standards of performance for affected EGUs through section 111(d) plans and to individual affected EGUs for achieving those standards.

Any of the non-BSER measures described below would help the affected source category as a whole achieve emission limits consistent with the BSER. The non-BSER measures either reduce the amount of CO_2 emitted per MWh of generation from the set of affected EGUs or reduce the amount of generation, and therefore associated CO_2 emissions, from the set of affected EGUs. However, the manner in which the various non-BSER measures would help individual affected EGUs meet their individual standards of performance varies according to the type of measure and the type of standard of performance -- i.e., whether the standard is emission rate-based or mass-based.

In general, a non-BSER measure that reduces the amount of CO_2 emitted per MWh of generation at an affected EGU will reduce the amount of CO_2 emissions monitored at the EGU's stack (assuming the quantity of generation is held constant). Measures of this type can help the EGU meet either an emission rate-based or mass-based standard of performance.

Other non-BSER measures do not reduce an affected EGU's CO_2 emission rate but rather facilitate reductions in CO_2 emissions by reducing the amount of generation from affected EGUs. Under a mass-based standard, the collective reduction in emissions from the set of affected EGUs is reflected in the collective monitored emissions from the set of affected EGUs. An individual EGU that reduces its generation and emissions will be able to use the measure to help achieve its mass-based limit. Individual EGUs that do not reduce their generation and emissions will be able to use the measure, if the relevant section 111(d) plans provide for allowance trading, by purchasing emission allowances no longer needed by EGUs that have reduced their emissions.

Under an emission rate-based standard, non-BSER measures that reduce generation from affected EGUs but do not reduce an affected EGU's emission rate generally can facilitate compliance by serving as the basis for ERCs that affected EGUs can average into their emission rates for purposes of demonstrating compliance. Section VIII.K. includes a discussion of the issuance of ERCs based on various non-BSER measures. Affected EGUs could use such ERCs to the extent permitted by the relevant section 111(d) plans.

The remainder of this section discusses some specific types of non-BSER measures. The first set discussed includes measures that can reduce the amount of CO_2 emitted per MWh of generation, and the second set discussed includes measures that can reduce CO_2 emissions by reducing the amount of generation from affected EGUs. In some cases, considerations related to use of these measures for compliance are discussed below in section VIII on state plans. The EPA notes that this is not an exhaustive list of non-BSER measures that could be employed to reduce CO_2 emissions from affected EGUs, but merely a set of examples that illustrate the extent of the additional flexibility such measures provide to states and affected EGUs under the final rule.

a. <u>Non-BSER measures that reduce CO_2 emissions per MWh generated</u>. In the June 2014 proposal, the EPA discussed several potential measures that could reduce CO_2 emissions per MWh generated at affected EGUs but that were not proposed to be part of the BSER. The measures discussed included heat rate improvements at affected EGUs other than coal-fired steam EGUs; fuel switching from coal to natural gas at affected EGUs, either completely (conversion) or partially (co-firing); and carbon capture and storage by affected EGUs. One reason for not proposing to consider these measures to be part of the BSER was that they were more costly than the BSER measures. Another reason was that the emission reduction potential was limited compared to the potential available from the measures that were proposed to be included in the BSER. However, we also noted that circumstances could exist where these measures could be sufficiently attractive to deploy, and that the measures could be used to help affected EGUs achieve emission limits consistent with the BSER.

In the final rule, the EPA has reached determinations consistent with the proposal with respect to these measures: namely, that they do not merit inclusion in the BSER, but that they are capable of helping affected EGUs achieve compliance with standards of performance and are likely to be used for that purpose by some units. To the extent that they are selectively employed, they provide flexibility for the source category as a whole and for individual affected EGUs to achieve emission limits reflective of the BSER, as discussed above.

(1) Heat rate improvement at affected EGUs other than coal-fired steam EGUs.

Building block 1 reflects the opportunity to improve heat rate at coal-fired steam EGUs but not at other affected EGUs. As the EPA stated at proposal, the potential CO_2 reductions available from heat rate improvements at coal-fired steam EGUs are much larger than the potential CO_2 reductions available from heat rate improvements at other types of EGUs, and comments offered no persuasive basis for reaching a different conclusion. Nevertheless, we recognize that there may be instances where an owner/operator finds heat rate improvement to be an attractive option at a particular non-coal-fired affected EGU, and nothing in the rule prevents the owner/operator from implementing such a measure and using it to help achieve a standard of performance.

(2) Carbon capture and storage at affected EGUs.

Another approach for reducing CO_2 emissions per MWh of generation from affected EGUs is the application of carbon capture and storage (CCS) technology. Consistent with the June 2014 proposal, we are determining that use of full or partial CCS technology should not be part of the BSER for existing EGUs because it would be more expensive than the measures determined to be part of the BSER, particularly if applied broadly to the overall source category. At the same time, we note that retrofit of CCS technology may be a viable option at some individual facilities, particularly where the captured CO_2 can be used for enhanced oil recovery (EOR). For example, construction of one CCS retrofit application with EOR has already been completed at a unit at the Boundary Dam plant in Canada, and construction of another CCS retrofit application with EOR is underway at the W.A. Parish plant in Texas. We expect the costs of CCS to decline as implementation experience increases. CO_2 emission rate reductions achieved through retrofit of CCS technology would be available to help affected EGUs achieve emission limits consistent with the BSER. State plan considerations related to CCS are discussed in section VIII.I.2.a.

(3) Fuel switching to natural gas at affected EGUs.

In the proposal we discussed the opportunity to reduce CO_2 emissions at an individual affected EGU by switching fuels at the EGU, particularly by switching from coal to natural gas. Most coal-fired EGUs could be modified to burn natural gas instead, and the potential CO_2 emission reductions from this measure are large – approximately 40 percent in the case of conversion from 100 percent coal to 100 percent natural gas, and proportionately smaller for partial co-firing of coal with natural gas. The primary reason for not considering this measure part of the BSER, both at proposal and in this final rule, is that it is more expensive than the BSER measures. In particular, combusting natural gas in a steam EGU is less efficient and generally more costly than combusting natural gas in an NGCC unit. For the category as a whole, CO_2 emissions can be achieved far more cheaply by combusting additional natural gas in currently underutilized NGCC capacity and reducing generation from coal-fired steam EGUs (building block 2) than by combusting natural gas instead of coal in steam EGUs.

Some owner/operators are already converting some affected EGUs from coal to natural gas, and it is apparent that the measure can be attractive compared to alternatives in certain circumstances, such as when a unit must meet tighter unit-specific limits on emissions of non-GHG pollutants, the options for meeting those emission limits are costly, and retirement of the unit would necessitate transmission upgrades that are costly or cannot be completed quickly. CO_2 emission reductions achieved in these situations are available to help achieve emission limits consistent with the BSER.

(4) Fuel switching to biomass at affected EGUs.

Some affected EGUs may seek to co-fire qualified biomass with fossil fuels. The EPA recognizes that the use of some biomass-derived fuels can play an important role in controlling increases of CO_2 levels in the atmosphere. As with the other non-BSER measures discussed in this section, the EPA expects that use of biomass may be economically attractive for certain individual sources even though on a broader scale it would likely be more expensive or less achievable than the measures determined to be part of the BSER. Section VIII.I.2.c. describes the process and considerations for states proposing to use different kinds of biomass in state plans.

(5) Waste heat-to-energy conversion at affected EGUs.

Certain affected EGUs in urban areas or located near industrial or commercial facilities with needs for thermal energy may be able add new equipment to capture some of the waste heat from their electricity generation processes and use it to create useful thermal output, thereby engaging in combined heat and power (CHP) production. While the set of affected EGUs in locations making this measure feasible may be limited, where feasible the potential CO_2 emission rate improvements can be substantial: depending on the process used, the efficiency with which fuel is converted to useful energy can be increased by 25 percent or more. The final rule allows an owner/operator applying CHP technology to an affected EGU to account for the increased efficiency by counting the useful thermal output as additional MWh of generation, thereby lowering the unit's computed emission rate and assisting with achievement of an emission rate-based standard of performance. (The EPA notes that unless the unit also reduced its fuel usage, the addition of the capability to capture waste heat and produce useful thermal output would not reduce the unit's mass emissions and therefore would not directly help the unit achieve a mass-based standard of performance.[441])

b. Non-BSER measures that reduce CO_2 emissions by reducing fossil fuel-fired generation. A second group of non-BSER measures has the potential to reduce CO_2 emissions from affected EGUs by reducing the amount of generation from those EGUs. As discussed above, under a section 111(d) plan with mass-based standards of performance, no special action is required to enable measures of

[441] However, the EPA notes that a state could establish a mechanism for encouraging affected EGUs to apply CHP technology under a mass-based plan, for example, through awards of emission allowances to CHP projects.

this nature to help the source category as a whole and individual affected EGUs achieve their emission limits, because the CO_2-reducing effects are captured in monitored stack emissions. However, under a section 111(d) plan with rate-based standards of performance, affected EGUs would need to acquire ERCs based on the non-BSER activities that could be averaged into their emission rate computations for purposes of determining compliance with their standards of performance.

(1) Demand-side EE.

One of the major approaches available for achieving CO_2 emission reductions from the utility power sector is demand-side EE. In the June 2014 proposal, the EPA identified demand-side EE as one of the four proposed building blocks for the BSER. We continue to believe that significant emission reductions can be achieved by the source category through use of such measures at reasonable costs. In fact, we believe that the potential emission reductions from demand-side EE rival those from building blocks 2 and 3 in magnitude, and that demand-side EE is likely to represent an important component of some state plans, particularly in instances where a state prefers to develop a plan reflecting the state measures approach discussed in section VIII below. We also expect that many sources would be interested in including demand-side EE in their compliance strategies to the extent permitted, and we received comment that it should be permitted.

For the reasons discussed in section V.B.3.c.(8) below, the EPA has determined not to include demand-side EE in the BSER in this final rule. However, the final rule authorizes generation avoided through investments in demand-side EE to serve as the basis for issuance of ERCs when appropriate conditions are met. In section VIII.K. below, the EPA sets out the minimum criteria that must be satisfied for generation and issuance of a valid ERC based upon implementation of new demand-side EE programs. Those criteria generally concern ensuring that the physical basis for the ERC -- in this case, generation avoided through implementation of demand-side EE measures -- is adequately evaluated, measured, and verified and that there is an adequate administrative process for tracking credits.

Through their authority over legal requirements such as building codes, states have the ability to drive certain types of demand-side EE measures that are beyond the reach of private-sector entities. The EPA recognizes that, by definition, this type of measure is beyond the ability of affected EGUs to invest in either directly or through bilateral arrangements. However, the final rule also authorizes generation avoided through such state policies to serve as the basis for issuance of ERCs that in turn can be used by affected EGUs. The section 111(d) plan would need to include appropriate provisions for evaluating, measuring, and verifying the avoided MWh associated with the state policies, consistent with the criteria discussed in section VIII.K. below.

(2) New or uprated nuclear generating capacity.

In the June 2014 proposal, the EPA included generation from the five nuclear units currently under construction as part of the proposed BSER. As discussed above in section V.A.3.c., upon consideration of comments, we have determined that generation from these units should not be part of the BSER. However, we continue to observe that the zero-emitting generation from these units would be expected to replace generation from affected EGUs and thereby reduce CO_2 emissions, and the continued commitment of the owner/operators to completion of the units is essential in order to realize that result. Accordingly, a section 111(d) plan may rely on ERCs issued on the basis of generation from these units and other new nuclear units. For the same reason, a plan may rely on ERCs issued on the basis of generation from uprates to the capacity of existing nuclear units. Requirements for state plan provisions intended to serve this purpose are discussed in section VIII.K.

(3) Zero-emitting RE generating technologies not reflected in the BSER.

The range of available zero-emitting RE generating technologies is broader than the range of RE technologies determined to be suitable for use in quantification of building block 3 as an element of the BSER. Examples of additional zero-emitting RE technologies not included in the BSER that could be used to achieve emission limits consistent with the BSER include offshore wind, distributed solar, and fuel cells. These technologies were not included in the range of RE technologies quantified for the BSER because they are generally more expensive than the measures that were included and the other measures in the BSER. However, these technologies are equally capable of replacing generation from affected EGUs and thereby reducing CO_2 emissions. Further, as with any technology, there are likely to be certain circumstances where the costs of these technologies are more attractive relative to alternatives, making the technologies likely to be deployed to some extent. Indeed, distributed solar is already being widely deployed in much of the U.S. and offshore wind, while still unusual in this country, has been extensively deployed in some other parts of the world. We expect innovation in RE generating technologies to continue, making such technologies even more attractive over time. A section 111(d) plan may rely on ERCs issued on the basis of generation from new and uprated installations of these technologies. The necessary state plan provisions are discussed in section VIII.K.

(4) Non-zero-emitting RE generating technologies.

Generation from new or expanded facilities that combust qualified biomass or biogenic portions of municipal solid waste (MSW) to produce electricity can also replace generation from affected EGUs and thereby control CO_2 levels in the atmosphere.[442] While the EPA believes it is reasonable to consider generation from these fuels and technologies to be forms of RE generation, the fact that they can produce stack emissions containing CO_2 means that a section 111(d) plan seeking to permit use of such generation to serve as the basis for issuance of ERCs must include appropriate consideration of feedstock characteristics and climate benefits. Specifically, the use of some kinds of biomass has the potential to offer a wide range of environmental benefits, including carbon benefits. However these benefits can only be realized if biomass feedstocks are sourced responsibly and attributes of the carbon cycle related to the biomass feedstock are taken into account. Section VIII.I.2.c. describes the process and considerations for states proposing to use

[442] The EPA and many states have recognized the importance of integrated waste materials management strategies that emphasize a hierarchy of waste prevention and all other productive uses of waste materials to reduce the volume of disposed waste materials (see section VIII for more discussion of waste to energy strategies).

biomass in state plans. Section VIII.K. describes additional provisions related to ERCs.

(5) Waste heat-to-electricity conversion at non-affected facilities.

Industrial facilities that install new equipment to capture waste heat from an existing combustion process and then use the waste heat to generate electricity -- a form of combined heat and power (CHP) production -- can produce generation that replaces generation from affected EGUs and thereby reduces CO_2 emissions. A section 111(d) plan may rely on ERCs issued on the basis of generation of this nature provided that the facility does not generate and sell sufficient electricity to qualify as a new EGU for purposes of section 111(b) and is not covered under section 111(d) for another source category. More information is provided in section VIII.K.

(6) Reduction in transmission and distribution line losses.

Reductions of electricity line losses incurred from the transmission and distribution system between the points of generation and the points of consumption by end-users allow the same overall demand for electricity services to be met with a smaller overall quantity of electricity generation. Such reductions in generation quantities would tend to reduce generation by affected EGUs, thereby reducing CO_2 emissions. The opportunity for improvement is large because, on average, line losses account for approximately seven percent of all electricity generation. The EPA recognizes that, in general, only the owner/operators of the transmission and distribution facilities have the ability to undertake line loss reduction investments, and that merchant generators may have little opportunity to engage a contractor to pursue such opportunities on a bilateral basis. Nevertheless, for entities that do have the opportunity to make such investments, generation avoided through investment that reduces transmission and distribution line losses may serve as the basis for issuance of ERCs that in turn can be used by affected EGUs. Further information is provided in section VIII.K.

7. Severability.

The EPA intends that the components of the BSER summarized above be severable. It is reasonable to consider the building blocks severable because the building blocks do not depend on one another. Building blocks 2 and 3 are feasible and demonstrated means of reducing CO_2 emissions from the utility power sector that can be implemented independently of the other building blocks. If implemented in combination with at least one of the other building blocks, building block 1 is also a feasible and demonstrated means of reducing CO_2 emission from the utility power sector.[443] As discussed in sections V.C. through V.E. below, we have determined that each building block is independently of reasonable cost whether or not the other building blocks are applied, and that alternative combinations of the building blocks are likewise of reasonable cost, and we have determined reasonable schedules and stringencies for implementation of each building block independently, based on factors that generally do not vary depending on the implementation of other building blocks.

Further, building block 2, building block 3, and all combinations of the building blocks (implemented on the schedules and at the stringencies determined to be reasonable in this rule) would achieve meaningful degrees of emission reductions,[444] although less than the combination of all three building blocks. No combination of the building blocks would lead to adverse non-air environmental or energy impacts or impose a risk to the reliability of electricity supplies.

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[443] The heat rate improvement measures included in building block 1 are capable of being implemented independently of the measures in the other building blocks but, as discussed earlier, unless at least one other building block is also implemented, a "rebound effect" arising from improved competitiveness and increased generation at the EGUs implementing heat rate improvements could weaken or potentially even eliminate the ability of building block 1 to achieve CO_2 emission reductions.

[444] This conclusion would not extend to a BSER comprising solely building block 1 because of the possibility of rebound effects discussed earlier.

In the event that a court should deem building block 2 or 3 defective, but not both, the standards and state goals can be recomputed on the basis of the remaining building blocks. All of the data and procedures necessary to determine recomputed state goals using any combination of the building blocks are set forth in the CO_2 Emission Performance Rate and Goal Computation TSD for the CPP Final Rule available in the docket.

B. Legal Discussion of Certain Aspects of the BSER

This section includes a legal analysis of various aspects of EPA's determination of the BSER, including responses to some of the major adverse comments. These aspects include (1) the EPA's authority to determine the BSER; (2) the approach to subcategorization; (3) the EPA's basis for determining that building blocks 2 and 3 qualify as part of the BSER under CAA sections 111(d)(1) and (a)(1), notwithstanding commenters' arguments that these building blocks cannot be considered part of the BSER because they are not based on measures integrated into the design or operation of the affected source's own production processes or methods or because they are dependent on actions by entities other than the affected source; (4) the relationship between an affected EGU's implementation of building blocks 2 and 3 and CO_2 emissions reductions; (5) how reduced generation relates to the BSER; (6) reasons why, contrary to assertions by commenters, this rule is within the

EPA's statutory authority, is not inconsistent with the Federal Power Act or state laws governing public utility commissions, and does not result in what the U.S. Supreme Court described as "an enormous and transformative expansion in [the] EPA's regulatory authority";[445] and (7) reasons that, contrary to assertions by commenters, the stringency of the BSER for this rule for CO_2 emissions from existing affected EGUs is not inconsistent with the stringency of the BSER for the rules the EPA is promulgating at the same time for CO_2 emissions from new or modified affected EGUs.

1. The EPA's authority to determine the BSER.

In this section, we explain why the EPA, and not the states, has the authority to determine the BSER and, therefore, the level of emission limitation required from the existing sources in the source category in section 111(d) rulemaking and the associated state plans.

CAA section 111(d)(1) requires the EPA to establish a section 110-like procedure under which each state submits a plan that "establishes standards of performance for any existing source of air pollutant" and "provides for the implementation and enforcement of such standards of performance." As CAA section 111(d) was originally adopted in the 1970 CAA

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[445] *Util. Air Reg. Group v. EPA*, 134 S. Ct. 2427, 2444 (2014).

Amendments, however, state plans were required to establish "emission standards" -- an undefined term -- rather than "standards of performance," a term that was limited to CAA section 111(b).[446] The 1970 provision was in effect when the EPA issued the 1975 implementing regulations for CAA section 111(d),[447] which remain in effect to this day.

These regulations establish a cooperative framework that is similar to that under CAA section 110. First, the EPA develops "emission guidelines" for source categories, which are defined as a final guideline document reflecting "the degree of emission reduction achievable through the application of the best system of emission reduction ... which the Administrator has determined has been adequately demonstrated." Then, the states submit implementation plans to regulate any existing sources.[448]

The preamble to these regulations carefully considered the allocation of responsibilities as between the EPA and the states for purposes of CAA section 111(d), and concluded that the EPA is responsible for determining the level of emission limitation

[446] *See* 1970 CAA Amendments, § 4, 84 Stat. at 1683-84. Subsequently, in 1977, Congress replaced the term "emission standard" with "standards of performance." *See* 1977 CAA Amendments, § 109, 91 Stat. at 699.
[447] *See* "State Plans for the Control of Certain Pollutants From Existing Facilities," 40 FR 53340 (Nov. 17, 1975).
[448] *See* "State Plans for the Control of Certain Pollutants From Existing Facilities," 40 FR 53340 (Nov. 17, 1975).

from the source category, while the states have the responsibility of assigning emission requirements to their sources that assured their achievement of that level of emission limitation.[449] The EPA explained "that some substantive criterion was intended to govern not only the Administrator's promulgation of standards but also [her] review of state plans."[450] The EPA added, "it would make no sense to interpret [CAA] section 111(d) as requiring the Administrator to base approval or disapproval of state plans solely on procedural criteria. Under that interpretation, states could set extremely lenient standards -- even standards permitting greatly increased emissions -- so long as [the] EPA's procedural requirements were met."[451] The EPA concluded that "emission guidelines, each of which will be subjected to public comment before final adoption, will serve [the] function" of providing substantive criteria "in advance to the states, to industry, and to the general public" to aid states in "developing and enforcing control plans under [CAA]

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[449] As we made clear in the proposed rulemaking, we are not re-opening these regulations (on the issue of the authority to determine the BSER or any other issue, unless specifically indicated otherwise) in this rulemaking, and our discussion of these regulations in responding to comments does not constitute a re-opening.

[450] "State Plans for the Control of Certain Pollutants From Existing Facilities," 40 FR 53340, 53342 (Nov. 17, 1975).

[451] "State Plans for the Control of Certain Pollutants From Existing Facilities," 40 FR 53340, 53343 (Nov. 17, 1975).

section 111(d)."[452] Thus, the implementing regulations make clear that the EPA is responsible for determining the level of emission limitation that the state plans must achieve.

In 1977, Congress revised CAA section 111(d) to require that the states adopt "standards of performance," as defined under CAA section 111(a)(1). As noted above, a standard of performance is defined as "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which ... *the Administrator determines* has been adequately demonstrated." (Emphasis added.) By its terms, this provision provides that the EPA has the responsibility of determining whether the "best system of emission reduction" is "adequately demonstrated." By giving the EPA this responsibility, this provision is clear that Congress assigned the role of determining the "best system of emission reduction" to the EPA. Even if the provision may be considered to be silent or ambiguous on that question, the EPA reasonably interprets the provision to assign the responsibility of identifying the "best system of emission reduction" to the Administrator for the same reasons discussed in the preamble to the 1975 implementing regulations.

[452] "State Plans for the Control of Certain Pollutants From Existing Facilities," 40 FR 53340, 53343 (Nov. 17, 1975).

In addition, in the legislative history of the 1977 CAA Amendments, when Congress replaced the term "emission standards" under CAA section 111(d)(1) with the term "standards of performance," Congress endorsed the overall approach of the implementing regulations, which lends further credence to the proposition that the EPA has the responsibility for determining the "best system of emission reduction" and the amount of emission limitation from the existing sources. Specifically, in the House report that introduced the substantive changes to CAA section 111, the Committee explained that "[t]he Administrator would establish *guidelines as to what the best system* for each category of existing sources *is*."[453] States, on the other hand, "would be responsible for determining the applicability of such *guidelines* to any particular source or sources."[454] The use of the term "guidelines," which does not appear in CAA section 111(d), indicates Congress was aware of and approved of the approach taken in the EPA's implementing regulations for establishing guidelines, which determine the BSER. At a minimum, if Congress disapproved of the EPA's implementing regulations, we would not expect the House report to adopt the EPA's terminology to clarify CAA section 111(d).

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[453] H.R. Rep. No. 95-294, at 195 (May 12, 1977) (emphasis added).
[454] H.R. Rep. No. 95-294, at 195 (May 12, 1977) (emphasis added).

In addition, Congress expressly referred to our "guidelines" in CAA section 129, added as part of the 1990 CAA Amendments. Congress added CAA section 129 to address solid waste combustion and specifically directed the Administrator to establish "*guidelines* (under section 111(d) and this section) and other requirements applicable to existing units."[455] This reference also indicates that Congress was aware of and approved the EPA's regulations under section 111(d).

The EPA has followed the same approach described in the implementation regulations in all its rulemakings under section 111(d). Thus, in all cases, the EPA has identified the type of emission controls for the source category and the level of emission limitation based on those controls.[456] The EPA's

[455] CAA section 129(a)(1)(A) (emphasis added).
[456] *See* 40 CFR Part 60, Subpart Ca (large municipal waste combustors), 56 FR 5514 (Feb. 11, 1991), 40 CFR 60.30a-.39a (subsequently withdrawn and superseded by Subpart Cb, see 60 FR 65387 (Dec. 19, 1995)); Subpart Cb (large municipal waste combustors constructed on or before September 20, 1994), 60 FR 65387 (Dec. 19, 1995), 40 CFR 60.30b-.39b (as amended in 1997, 2001, and 2006); Subpart Cc (municipal solid waste landfills), 61 FR 9905 (Mar. 12, 1996), 40 CFR 60.30c-.36c (as amended in 1998, 1999, and 2000); Subpart Cd (sulfuric acid production units), 60 FR 65387 (Dec. 19, 1995), 40 CFR 60.30d-.32d; Subpart Ce (hospital/medical/infectious waste incinerators), 62 FR 48348 (Sept. 15, 1997), 40 CFR 60.30e-.39e (as amended in 2009 and 2011); Subpart BBBB (small municipal waste combustion units constructed on or before August 30, 1999), 65 FR 76738 (Dec. 6, 2000), 40 CFR 60.1500-.1940; Subpart DDDD (commercial and industrial solid waste incineration units that commenced construction on or before November 30, 1999), 65 FR 75338 (Dec. 1, 2000), 40 CFR 60.2500-.2875 (as amended in 2005, 2011, and

longstanding and consistent interpretation of CAA section 111(d) is also "evidence showing that the statute is in fact not ambiguous," and that the EPA's interpretation should be adopted.[457]

Lastly, this interpretation is consistent with the Supreme Court's reading of CAA section 111(d) in *American Electric Power Co*. There, the Court explained that "EPA issues emissions guidelines, see 40 C.F.R. § 60.22, .23 (2009); in compliance with those guidelines and subject to federal oversight, the States then issue performance standards for stationary sources within their jurisdiction, § 7411(d)(1)."[458]

As noted in the response to comment document, some commenters agreed with our interpretation, just discussed, while

2013); Subpart FFFF (other solid waste incineration units that commenced construction on or before December 9, 2004), 70 FR 74870 (Dec. 16, 2005), 40 CFR 60.2980-.3078 (as amended in 2006); Subpart HHHH (coal-electric utility steam generating units), 70 FR 28606 (May 18, 2005) (subsequently vacated by the D.C. Circuit in *New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008)); Subpart MMMM (existing sewage sludge incineration units), 76 FR 15372 (Mar. 21, 2011), 40 CFR 60.5000-.5250; "Phosphate Fertilizer Plants, Final Guideline Document Availability," 42 FR 12022 (Mar. 1, 1977) (not codified); "Kraft Pulp Mills; Final Guideline Document; Availability," 44 FR 29828 (May 22, 1979) (not codified); and "Primary Aluminum Plants; Availability of Final Guideline Document," 45 FR 26294 (Apr. 17, 1980) (not codified).

[457] Scalia, Antonin, *Judicial Deference to Administrative Interpretations of Law*, 1989 Duke L.J. 511, 518; see *Riverkeeper v. Entergy,* 556 U.S. 208, 235 (2009).

[458] *Am. Elec. Power Co. v. Connecticut*, 131 S. Ct. 2527, 2537-38 (2011).

others argued that the states should be given the authority to determine the best system of emission reduction and, therefore, the level of emission limitation from their sources. For the reasons just discussed, this latter interpretation is an incorrect interpretation of CAA section 111(d)(1) and (a)(1), and we are not compelled to abandon our longstanding practice.

2. Approach to subcategorization.

As noted above, in this rule, we are treating all fossil fuel-fired EGUs as a single category, and, in the emission guidelines that we are promulgating with this rule, we are treating steam EGUs and combustion turbines as separate subcategories. We are determining the BSER for steam EGUs and the BSER for combustion turbines, and applying the BSER to each subcategory to determine a performance rate for that subcategory. We are not further subcategorizing among different types of steam EGUs or combustion turbines.

This approach is fully consistent with the provisions of section 111(d), which simply require the EPA to determine the BSER, do not prescribe the method for doing so, and are silent as to subcategorization. This approach is also fully consistent with other provisions in CAA section 111, which require the EPA first to list source categories that may reasonably be expected to endanger public health or welfare[459] and then to regulate new sources within each such source category,[460] and which grant the EPA discretion whether to subcategorize new sources for purposes of determining the BSER.[461]

For this rule, our approach of subcategorizing between steam EGUs and combustion turbines is reasonable because building blocks 1 and 2 apply only to steam EGUs. No further subcategorization is appropriate because each affected EGU can achieve the performance rate by implementing the BSER. Specifically, as noted, each affected EGU may take a range of actions including investment in the building blocks, replacing or reducing generation, and emissions trading, as enabled or facilitated by the implementation programs the states adopt. Further, in the case of a rate-based state plan, several other compliance options not included in the BSER for this rule are also available to all affected sources, including investment in demand-side EE measures. Such compliance options help affected sources achieve compliance under a mass-based plan, even if indirectly. Our approach to subcategorization in this rule is consistent with our approach to subcategorization in previous section 111 rules for this industry, in which we determined

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[459] CAA section 111(b)(1)(A).
[460] CAA section 111(b)(1)(B).
[461] CAA section 111(b)(2).

whether or not to subcategorize on the basis of the ability of affected EGUs with different characteristics (e.g., size or type of fuel used) to implement the BSER and achieve the emission limits).[462]

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[462] *Compare* "Revision of Standards of Performance for Nitrogen Oxide Emissions From New Fossil-Fuel Fired Steam Generating Units; Revisions to Reporting Requirements for Standards of Performance for New Fossil-Fuel Fired Steam Generating Units: Final Rule," 63 FR 49442 (Sept. 16, 1998) *and* "Proposed Revision of Standards of Performance for Nitrogen Oxide Emissions From New Fossil-Fuel Fired Steam Generating Units: Proposed Revisions," 62 FR 36948, 36943 (July 9, 1997) (establishing a single NOx emission limit for new fossil-fuel fired steam generating units, and not subcategorizing, because the affected units could implement the BSER of SCR and achieve the promulgated emission limits) *with* "National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units: Final Rule," 77 FR 9304 (Feb. 16, 2012) (MATS rule) *and* "National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units: Proposed Rule," 76 FR 24976, 25036-37 (May 3, 2011) (subcategorizing coal fired units designed to burn coal with greater than or equal to 8,300 Btu/lb (for Hg emissions only), coal-fired units designed to burn coal with less than 8,300 Btu/lb (for Hg emissions only), IGCC units, liquid oil units, and solid oil-derived units; evaluating "subcategorization of lignite coal vs. other coal ranks; subcategorization of Fort Union lignite coal vs. Gulf Coast lignite coal vs. other coal ranks; subcategorization by EGU size (i.e., MWe); subcategorization of base load vs. peaking units (e.g., low capacity utilization units); subcategorization of wall-fired vs. T fired units; and subcategorization of small, non-profit-owned units vs. other units;" but deciding not to adopt those latter subcategorizations).

In addition, there are numerous possible criteria to use in subcategorizing, including, among others, subcategorizing on the basis of age; size; steam conditions (i.e., subcritical or supercritical); type of fuel, including type of coal (i.e., lignite, bituminous, and sub-bituminous), and coal refuse; and method of combustion (i.e., fluidized bed combustion, pulverized coal combustion, and gasification). In addition, there are different possible combinations of those categories. At least some of those criteria do not have logical cut-points. Furthermore, we have not been presented with, nor can we discern, a method of subcategorizing based on these or other criteria that is appropriate in light of the BSER for the affected EGUs and their ability to meet the emission limits. Moreover, our approach of not further subcategorizing as between different types of steam EGUs or combustion turbines reflects the reasonable policy that affected EGUs with higher emission rates should reduce their emissions by a greater percentage than affected EGUs with lower emission rates, and can do so by implementing the BSER we are identifying.

In addition, a section 111(d) rule presents less of a need to subcategorize because the states retain great flexibility in assigning standards of performance to their affected EGUs. Thus, a state can, if it wishes, impose different emission reduction obligations on its sources, as long as the overall level of emission limitation is at least as stringent as the emission guidelines, as discussed below. This means that if a state is concerned that its different sources have different capabilities for compliance, it can adjust the standards of performance in imposes on its sources accordingly.

3. Building blocks 2 and 3 as a "system of emission reduction"

a. Overview. As we explain above, the emission performance rates that we include in this rule's emission guidelines are achievable by the affected EGUs through the application of the BSER, which includes the three building blocks. Commenters object that building blocks 2 (generation shift) and 3 (RE) cannot, as a legal matter, be considered part of the BSER under CAA section 111(d)(1) and (a)(1). These commenters explain that in their view, under CAA section 111, the emission performance rates must be based on, and therefore the BSER must be limited to, methods for emission control that the owner/operator of the affected source can integrate into the design or operation of the source itself, and cannot be based on actions taken beyond the source or actions involving third-party entities.[463] For

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[463] *See, e.g.,* comments by UARG at 6-7 ("Standards promulgated under section 111 must be source-based and reflect measures that the source's owner can integrate into the design or operation of the source itself. A standard cannot be based on actions taken beyond the source itself that somehow reduce the source's utilization."); comments by UARG at 31 (the building blocks other than building block 1 take a "'beyond-the-source'

these reasons, these commenters argue that the phrase "system of emission reduction" cannot be interpreted to include building blocks 2 and 3.

We disagree with these comments, and note that other commenters were supportive of our determination to include building blocks 2 and 3. Under CAA section 111(d)(1) and (a)(1), the EPA's emission guidelines must establish achievable emission limits based on the "best system of emission reduction ... adequately demonstrated." While some commenters assert that emission guidelines must be limited in the manner summarized above, the phrase "system of emission reduction," by its terms and when read in context, contains no such limits. To the contrary, its plain meaning is deliberately broad and is capacious enough to include actions taken by the owner/operator of a stationary source designed to reduce emissions from that

approach" and "impermissibly rely on measures that go beyond the boundaries of individual affected EGUs and that are not within the control of individual EGU owners and operators"); comments by UARG at 33 (the "system" of emission reduction "can refer only to reductions resulting from measures that are incorporated into the source itself;" section 111 is "designed to improve the emissions performance of new and existing sources in specific categories based on the application of achievable measures implemented in the design or production process of the source at reasonable cost."); comments by American Chemistry Council et al. ("Associations") at 60-61 (EPA's proposed BSER analysis is unlawful because it "looks beyond the fence line of the fossil fuel-fired EGUs that are the subject of this rulemaking;" "the standard of performance must ... be limited to the types of actions that can be implemented directly by an existing source within [the appropriate] class or category.").

affected source, including actions that may occur off-site and actions that a third party takes pursuant to a commercial relationship with the owner/operator, so long as those actions enable the affected source to achieve its emission limitation. Such actions include the measures in building blocks 2 and 3, which, when implemented by an affected source, enable the source to achieve their emission limits because of the unique characteristics of the utility power sector. For purposes of this rule, we consider a "system of emission reduction" -- as defined under CAA section 111(a)(1) and applied under CAA section 111(d)(1) -- to encompass a broad range of pollution-reduction actions, which includes the measures in building blocks 2 and 3. Furthermore, the measures in building blocks 2 and 3 fall squarely within EPA's historical interpretation of section 111, pursuant to which the focus for the BSER has been on how to most cleanly produce a good, not on how much of the good should be produced.

Our interpretation that a "system of emission reduction" is broad enough to include the measures in building blocks 2 and 3 is supported by the following: our interpretation of the phrase "system of emission reduction" is consistent with its plain meaning and statutory context; our interpretation accommodates the very design of CAA section 111(d)(1), which covers a range of source categories and air pollutants;[464] our interpretation is supported by the legislative history of CAA section 111(d)(1) and (a)(1), which indicates Congress's intent to give the EPA broad discretion in determining the basis for CAA section 111 control requirements, particularly for existing sources, and Congress's intent to authorize the EPA to consider measures that could be carried out by parties other than the affected sources; and our interpretation is reasonable in light of comparisons to CAA provisions that give the EPA similar authority to consider such measures and to CAA provisions that would preclude the EPA from considering such measures.

In addition to the reasons stated above, the EPA's interpretation is also reasonable for the following reasons: (i) Building blocks 2 and 3 fit well within the structure and economics of the utility power sector. (ii) Fossil fuel-fired EGUs are already implementing the measures in these building blocks for various reasons, including for purposes of reducing CO_2 emissions. (iii) Interpreting the phrase "system of emission reduction" to incorporate building blocks 2 and 3 is consistent with (a) other provisions in the CAA, including the acid rain

[464] Because it is designed to apply to a range of air pollutants not regulated under other provisions, CAA section 111(d) may be described as a "catch-all" or "gap-filler." As such, a "system of emission reduction" as applied under CAA section 111(d) should be interpreted flexibly to accommodate this role.

provisions in Title IV and the SIP provisions in CAA section 110, along with the EPA's regulations implementing the CAA SIP requirements concerning interstate transport and regional haze, each of which is based on at least some of the same measures included in building blocks 2 and 3; (b) prior EPA action under CAA section 111(d), including the 2005 Clean Air Mercury Rule,[465] which is based on some of the same measures in building blocks 2 and 3; (c) the various provisions of the CAA that authorize emissions trading, because emissions trading entails a source meeting its emission limitation based on the actions of another entity; and (d) the pollution prevention provisions of the CAA, which make clear that a primary goal of the CAA is to encourage federal and state actions that reduce or eliminate, through any measures, the amount of pollution produced at the source.[466] (iv) Lastly, interpreting the phrase "system of emission reduction" to authorize the EPA, in formulating its BSER determination, to weigh a broad range of emission-reducing measures that includes building blocks 2 and 3 is consistent with Congress's intent to

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[465] This rule was vacated by the D.C. Circuit on other grounds. *New Jersey v. EPA*, 517 F.3d 574, 583-84 (D.C. Cir. 2008), *cert. denied sub nom. Util. Air Reg. Group v. New Jersey*, 555 U.S. 1169 (2009).

[466] As noted in the Legal Memorandum, in several of these rulemakings and in the course of litigation, the fossil fuel-fired electric power sector has taken positions that are consistent with the EPA's interpretation that the BSER may include building blocks 2 and 3.

address urgent environmental problems and to protect public health and welfare against risks, as well as Congress's expectation that American industry would be able to develop the innovative solutions necessary to protect public health and welfare.

Congress passed the CAA, including its several amendments, to protect public health and welfare from "mounting dangers," including "injury to agricultural crops and livestock, damage to and the deterioration of property, and hazards to air and ground transportation."[467] In doing so, Congress established numerous programs to address air pollution problems and provided the EPA with guidance and flexibility in carrying out many of those programs. Even if we were to accept commenters' view that the system of emission reduction identified as best here is not integrated into the design or operation of the regulated sources, in the context of this industry and this pollutant it is reasonable to reject the narrow interpretation urged by some commenters that the "system of emission reduction" applicable to the affected EGUs must be limited to only those measures that can be integrated into the design or operation of the source itself. The plain language of the statute does not support such an interpretation, and to adopt it would limit the "system of

[467] CAA section 101(a)(2).

emission reduction” to measures that are either substantially more expensive or substantially less effective at reducing emissions than the measures in building blocks 2 and 3, notwithstanding the absence of any statutory language imposing such a limit. Such a result would be contrary to the goals of the CAA and would ignore the facts that sources in the electric generation industry routinely address planning and operating objectives on a broad, multi-source basis using the measures in building blocks 2 and 3 and would seek to use building blocks 2 and 3 (as well as non-BSER measures) to comply with whatever emission standards are set as a result of this rule. Indeed, as already observed, building blocks 2 and 3 are already being used to reduce emissions, and to do so specifically by operation of the industry’s inherent multi-source functions.

Although the BSER provisions are sufficiently broad to include, for affected EGUs, the measures in building blocks 2 and 3, they also incorporate significant constraints on the types of measures that may be included in the BSER. We discuss those constraints at the end of this section. They include the section 111(d)(1) and (a)(1) requirements that emission reductions occur from the affected sources; that the emission performance standards for which the BSER forms the basis be achievable; that the system of emission reduction be adequately demonstrated; and that the EPA account for cost, non-air quality impacts, and energy requirements in determining the "best" system of emission reduction that is adequately demonstrated. The constraints included in these statutory requirements do not preclude building blocks 2 and 3 from the BSER. In interpreting these statutory requirements for determining the BSER, the EPA is consistent with past practice and current policy for both section 111 regulatory actions as well as regulatory actions under other CAA provisions for the electric power sector, under which the EPA has generally taken the approach of basing regulatory requirements on controls and measures designed to reduce air pollutants from the production process without limiting the aggregate amount of production. This approach has been inherent in our past interpretation and application of section 111 and we maintain this interpretation in this rulemaking.[468] While inclusion of building blocks 2 and 3 is consistent with our interpretation of the statutory requirements, inclusion of building block 4 is not, and for that

[468] As we note in section V.A., this rulemaking presents a unique set of circumstances, including the global nature of CO_2 and the emission control challenges that CO_2 presents (which limit the availability and effectiveness of control measures), combined with the facts that the electric power industry (including fossil fuel-fired steam generators and combustion turbines) is highly integrated, electricity is fungible, and generation is substitutable (which all facilitate the generation shifting measures encompassed in building blocks 2 and 3). Our interpretation of section 111 as focusing on limiting emissions without limiting aggregate production must take into account those unique circumstances.

reason, we are declining to include building block in the BSER. Finally, we briefly note additional constraints that focus the BSER identified for new sources under section 111(b) on controls that assure that sources are well-controlled at the the time of construction.

b. <u>System of emission reduction as a broad range of measures</u>.

(1) <u>Plain meaning and context of "system of emission reduction."</u>

The phrase "system of emission reduction" appears in the definition of a "standard of performance" under CAA section 111(a)(1). That definition reads:

> a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

Pursuant to this definition, it is clear that a "system of emission reduction" serves as the basis for emission limits embodied by CAA section 111 standards. For this reason, emission limits must be "achievable" through the "application" of the "best" "system of emission reduction" "adequately demonstrated." Under CAA section 111(d)(1), such a limit is established for "any existing source," which is defined as any existing "building, structure, facility, or installation which emits or may emit any air pollutant."[469]

Although a "system of emission reduction" lays the groundwork for CAA section 111 standards, the term "system" is not defined in the CAA. As a result, we look first to its ordinary meaning.

Abstractly, the term "system" means a set of things or parts forming a complex whole; a set of principles or procedures according to which something is done; an organized scheme or method; and a group of interacting, interrelated, or interdependent elements.[470] As a phrase, "system of emission reduction" takes a broad meaning to serve a singular purpose: it is a set of measures that work together to reduce emissions.

[469] *See* CAA section 111(d)(1) (applying a standard of performance to any existing source); (a)(6) (defining the term "existing source" as any stationary source other than a new source); and (a)(3) (defining the term "stationary source" as "any building, structure, facility, or installation which emits or may emit any air pollutant," however, explaining that "[n]othing in subchapter II [*i.e.*, Title II] of this chapter relating to nonroad engines shall be construed to apply to stationary internal combustion engines.")

[470] *Oxford Dictionary of English* (3rd ed.) (2010), *available at* http://www.oxforddictionaries.com/us/definition/american_english/system; *see also* American Heritage Dictionary (5th ed.) (2013), *available at* http://www.yourdictionary.com/system#americanheritage; and The American College Dictionary (C.L. Barnhart, ed. 1970) ("an assemblage or combination of things or parts forming a complex or unitary whole").

When read in context, the phrase "system of emission reduction" carries important limitations: because the "degree of emission limitation" must be "*achievable* through the *application* of the best system of emission reduction," (emphasis added), the "system of emission reduction" must be limited to a set of measures that work together to reduce emissions and that are implementable by the sources themselves.

As a practical matter, the "source" includes the "owner or operator" of any building, structure, facility, or installation for which a standard of performance is applicable. For instance, under CAA section 111(e), it is the "owner or operator" of a source who is prohibited from operating "in violation of any standard of performance applicable to such source."[471]

Thus, a "system of emission reduction" for purposes of CAA section 111(d) means a set of measures that source owners or operators can implement to achieve an emission limitation applicable to their existing source.[472]

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[471] While this section provides for enforcement in the context of new sources, a CAA section 111(d) plan must provide for the enforcement of a standard of performance for existing sources.

[472] Some commenters read the proposed rulemaking as taking the position that the phrase "system of emission reduction" includes anything whatsoever that reduces emissions, and criticized that interpretation as too broad. *See* UARG comment, at 3-4. We are not taking that interpretation here. In this final rule, we agree that the phrase should be limited to exclude, *inter alia*, actions beyond the ability of the owners/operators to control.

In contrast, a "system of emission reduction" does not include actions that only a state or other governmental entity could take that would have the effect of reducing emissions from the source category, and that are beyond the ability of the affected sources' owners/operators to take or control. Additionally, actions that a source owner or operator could take that would not have the effect of reducing emissions from the source category, such as purchasing offsets, would also not qualify as a "system of emission reduction."

Building blocks 2 and 3 each fall within the meaning of a "system of emission reduction" because they consist of measures that the owners/operators of the affected EGUs can implement to achieve their emission limits. In doing so, the affected EGUs will achieve the overall emission reductions the EPA identifies in this rule. We describe these building block 2 and 3 measures in detail elsewhere in this rule, including the specific actions that owners/operators of affected EGUs can take to implement the measures.

It should be noted that defining the scope of a "system of emission reduction" is not the end of our inquiry under CAA section 111(a)(1); rather, as noted above, a standard of performance must reflect the application of the "*best* system of emission reduction ... *adequately demonstrated*." (Emphasis added.) Thus, in determining the BSER, the Administrator must first determine whether the available systems of emission reduction are “adequately demonstrated,” based on the criteria, described above, set out by Congress in the legislative history and the D.C. Circuit in case law. After identifying the “adequately demonstrated” systems of emission reduction, the Administrator then selects the “best” of these, based on several factors, including amount of emission reduction, cost, non-air quality health and environmental impact and energy requirements. Only after the Administrator weighs all of these considerations can she determine the BSER and, based on that, establish a standard of performance under CAA section 111(b) or an emission guideline under CAA section 111(d).

For purposes of this final rule, it is not necessary to enumerate all of the types of measures that do or do not constitute a “system of emission reduction.” What is relevant is that building blocks 2 and 3 each qualify as part of the “system of emission reduction.” As noted, they focus on supply-side activities and they each constitute measures that the affected EGUs can implement that will allow those EGUs to achieve the degree of emission limitation that the EPA has identified based on those building blocks. Further, these building blocks also satisfy the other statutory criteria enumerated in CAA section 111(a)(1).

(2) Other indications that the BSER provisions encompass a broad range of measures.

The EPA's plain meaning interpretation that the BSER provisions in CAA section 111(d)(1) and (a)(1) are designed to include a broad range of measures, including building blocks 2 and 3, is supported by several other indications in the CAA and the legislative history of section 111.

(a) Scope of CAA section 111(d)(1).

First, the broad scope of CAA section 111(d)(1) supports our interpretation of the BSER because a wide range of control measures is appropriate for the wide range of source categories and air pollutants covered under CAA section 111(d).

In the 1970 CAA Amendments, Congress established a regulatory regime for existing stationary sources of air pollutants that may be envisioned as a three-legged stool, designed to address "three categories of pollutants emitted from stationary sources": (1) criteria pollutants (identified under CAA section 109 and regulated under section 110); (2) hazardous air pollutants (identified and regulated under section 112); and (3) "pollutants that are (or may be) harmful to public health or welfare but are not" criteria or hazardous air pollutants.[473] Congress enacted CAA section 111(d) to cover this third category

[473] 40 FR 53340, 53340 (Nov. 17, 1975) (EPA regulations implementing CAA section 111(d)).

of air pollutants and, in this sense, Congress designed it to apply to any air pollutants that were not otherwise regulated as toxics or NAAQS pollutants.[474] This would include air pollutants that the EPA might later, when more information became available, designate as NAAQS or hazardous air pollutants, as well as air pollutants that Congress may not have been aware of at the time.[475] In addition, the indications are that Congress expected CAA section 111(d) to be a significant source of regulatory activity, by some measures, more active than CAA section 112. This is evident because Congress expected that CAA section 111(d) would cover more air pollutants than either CAA section 109/110 (criteria pollutants) or CAA section 112 (hazardous air pollutants).[476] In addition, in the 1990 CAA

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[474] *See* S. Rep. No. 91-1196, at 20 (Sept. 17, 1970), 1970 CAA Legis. Hist. at 420 ("It should be noted that the emission standards for pollutants which cannot be considered hazardous (as defined in section 115 [*i.e.*, the bill's version of CAA section 112] could be established under section 114 [*i.e.*, the bill's version CAA section 111]. Thus, there should be no gaps in control activities pertaining to stationary source emissions that pose any significant danger to public health or welfare.").

[475] *See* S. Rep. No. 91-1196, at 20 (Sept. 17, 1970), 1970 CAA Legis. Hist. at 420.

[476] *See* S. Rep. No. 91-1196, at 9; 18-20, 1970 CAA Legis. Hist. at 418-20. The Senate Committee Report identified 14 substances as subject to the provision that became section 111(d), four substances as hazardous air pollutants that would be regulated under the provision that became section 112, and 5 substances as criteria pollutants that would be regulated under the provisions that became sections 109-110 (and more "as knowledge increases"). In particular, the Report recognized that in particular, relatively few air pollutants may qualify as

Amendments, Congress enacted CAA section 129 to achieve emission reductions from a major source category, solid waste incinerators, and established CAA section 111(d) as the basic mechanism for that provision. The EPA subsequently promulgated a number of CAA section 129/111(d) rulemakings.[477] Finally, it should be noted that Congress designed CAA section 111(d) to cover a wide range of source categories -- including any source category that the EPA identifies under subsection 111(b)(1)(A) as meeting the criteria of, in general, causing or contributing significantly to air pollution that may reasonably be anticipated to endanger public health or welfare -- along with the wide range of air pollutants.

Because Congress designed CAA section 111(d) to cover a wide range of air pollutants -- including ones that Congress may not have been aware of at the time it enacted the provision -- and a wide range of industries, it is logical that Congress intended that the BSER provision, as applied to CAA section

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hazardous air pollutants, but that other air pollutants that did not qualify as hazardous air pollutants would be regulated under what became section 111(d).

[477] *See, e.g.*, Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Hospital/Medical/Infectious Waste Incinerators, 62 FR 48348, 48359 (Sept. 15, 1997); Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Commercial and Industrial Solid Waste Incineration Units, 65 FR 75338, 75341 (Dec. 1, 2000).

111(d), have a broad scope so as to accommodate the range of air pollutants and source categories.

(b) Legislative history of CAA section 111.

(i) Breadth of "system of emission reduction."

The phrase "system of emission reduction," particularly as applied under CAA section 111(d), should be broadly interpreted consistent with its plain meaning but also in light of its legislative history. The version of CAA section 111(d)(1) that Congress adopted as part of the 1970 CAA Amendments read largely as CAA section 111(d)(1) does at present, except that it required states to impose "emission standards" on any existing source. (Congress replaced that term with "standards of performance" in the 1977 CAA Amendments.) The 1970 CAA Amendments version of CAA section 111(d)(1) neither defined "emission standards" nor imposed restrictions on the EPA in determining the basis for the emission standards.[478]

[478] Although not defined under CAA section 111, the term was used in other provisions and defined in some of them. The term was defined under the CAA's citizen suit provision. *See* 1970 CAA Amendments, Pub. L. 91-604, § 12, 84 Stat. 1676, 1706 (Dec. 31, 1970) (defined as "(1) a schedule or timetable of compliance, emission limitation, standard of performance or emission standard, or (2) a control or prohibition respecting a motor vehicle fuel or fuel additive…."). Congress also used it in the CAA's NAAQS provisions and in CAA section 112. Under the CAA's NAAQS provisions (i.e., the "Ambient Air Quality and Emission Standards" provisions), Congress directed the EPA to issue information on "air pollution control techniques," and include data on "available technology and alternative methods of

For new sources, CAA section 111(b)(1)(B), as enacted in the 1970 CAA Amendments (and as it largely still reads), required the EPA to promulgate "standards of performance," and defined that term, much like the present definition, as emission standards based on the "best system of emission reduction ... adequately demonstrated." This quoted phrase was not included in either the House or Senate versions of the provision, and, instead, was added during the joint conference between the House and Senate. The conference report accompanying the text offers no clarifications.

The House and Senate bills do, however, provide some insights. The House bill, H.R. 17255, would have required new sources of non-hazardous air pollutants to "prevent and control such emissions to the fullest extent compatible with the available technology and economic feasibility, as determined by the Secretary."[479] The Senate bill, S. 4358, would have

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prevention and control of air pollution" as well as on "alternative fuels, processes, and operating methods which will result in elimination or significant reduction of emissions." *Id.*, § 4, 84 Stat. at 1679. Similarly, under CAA section 112, the Administrator was required to "from time to time, issue information on pollution control techniques for air pollutants" subject to emission standards. *Id.*, 84 Stat. at 1685. These statements provide additional context for the term's broad intent.

[479] H.R. 17255, § 5, 1970 CAA Legis. Hist. at 921-22. The reference to "Secretary" was to the Secretary of Health Education and Welfare, which, at the time, was the agency with responsibility for air pollution regulations.

established "Federal standards of performance for new sources," which, in turn, were to "reflect the greatest degree of emission control which the Secretary determines to be achievable through application of the latest available control technology, processes, operating methods, *or other alternatives*."[480] The Senate Committee Report explains that "performance standards should be met through application of the latest available emission control technology or through *other means of preventing or controlling air pollution*."[481] This Report further elaborates that the term "standards of performance"

> refers to the degree of emission control which can be achieved through process changes, operation changes, direct emission control, *or other methods*. The Secretary should not make a technical judgment as to how the standard should be implemented. He should determine the achievable limits and let the owner or operator determine the most economic, acceptable *technique* to apply.[482]

Thus, the Senate bill clearly envisioned that standards of performance would not be based on a particular technology or even a particular method to prevent or control air pollution.[483]

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[480] S. 4358, § 6, 1970 Legis. Hist. at 554-55 (emphasis added).
[481] S. Rep. No. 91-1196, at 15-16 (Sept. 17, 1970), 1970 CAA Legis. Hist. at 415-16 (emphasis added).
[482] S. Rep. No. 91-1196, at 15-16 (Sept. 17, 1970), 1970 CAA Legis. Hist. at 415-16 (emphasis added).
[483] Notably, the Senate report identifies pollution control *and* pollution prevention as objectives of the Senate provision. Pollution prevention is discussed more generally below as a "primary purpose" of the CAA, however, the report makes clear that pollution prevention measures – which the EPA understands

This vision contrasted with the House bill, which would have restricted performance standards to economically feasible technical controls.

Following the House-Senate Conference, the enacted version of the legislation defined a "standard of performance" to mean

> a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the *best system of emission reduction* which (taking into account the cost of achieving such reduction) the Administrator determines has been adequately demonstrated.[484]

While the phrase "system of emission reduction" was not discussed in the Conference Report, an exhibit titled "Summary of the Provisions of Conference Agreement on the Clean Air Amendments of 1970" was added to the record during the Senate's consideration of the Conference Report and sheds some light on the phrase. According to the summary, "[t]he agreement authorizes regulations to require that new major industry plants such as power plants, steel mills, and cement plants achieve a standard of emission performance based on the latest available control technology, processes, operating methods, and other alternatives."[485] In light of this summary, the phrase "system of

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to include such measures as building blocks 2 and 3 -- are appropriate under CAA section 111.

[484] CAA section 111(a)(1) under the 1970 CAA Amendments (emphasis added).

[485] Sen. Muskie, S. Consideration of H.R. Conf. Rep. No. 91-1783 (Dec. 17, 1970), 1970 CAA Legis. Hist. at 130.

emission reduction" appears to blend the broad spirit of S. 4358 (which required the "latest available control technology, processes, operating methods, or other alternatives") with the cost concerns identified in H.R. 17255 (which required consideration of "economic feasibility" when establishing federal emission standards for new stationary sources). This history strongly suggests that Congress intended to authorize the EPA to consider a wide range of measures in calculating a standard of performance for stationary sources. At a minimum, there is no indication that Congress intended to preclude measures or actions such as the ones in building blocks 2 and 3 from the EPA's assessment of the BSER.

Notwithstanding this broad approach, as we discuss in the Legal Memorandum, the legislative history of the 1970 CAA Amendments also indicates that Congress intended that new sources be well-controlled at the source, in light of their expected lengthy useful lives.

In 1977, Congress amended CAA section 111(a)(1) to limit the types of controls that could be the basis of standards of performance for new sources to technological controls. Congress was clear, however, that existing source standards, which were no longer developed as "emission standards," would not be limited to technological measures. Specifically, the 1977 CAA Amendments revised CAA section 111(a)(1) to require all new sources to meet emission standards based on the reductions achievable through the use of the ”best technological system of continuous emission reduction.”[486] According to the legislative history, [t]his mean[t] that new sources may not comply merely by burning untreated fuel, either oil or coal.” [487] The new requirement stemmed in part from Congress’s concern over the shocks that the country experienced during the 1973-74 Arab Oil Embargo, which led Congress to revise CAA section 111 to “encourage and facilitate the increased use of coal, and to reduce reliance (by new and old sources alike), upon petroleum to meet emission requirements.”[488] Imposing a new technological requirement (along with a new percentage reduction requirement) under CAA section 111 was designed to “force new sources to burn high-sulfur fuel thus freeing low-sulfur fuel for use in existing sources where it is harder to control emissions and where low-sulfur fuel is needed for compliance.” [489] Congress nonetheless recognized that despite narrowing new source standards to the best “technological system of continuous

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[486] CAA section 111(a)(1) (1977).
[487] H.R. Rep. No. 95-294 (May 12, 1977), 1977 CAA Legis. Hist. at 2659.
[488] H.R. Rep. No. 95-294 (May 12, 1977), 1977 CAA Legis. Hist. at 2659.
[489] *New Stationary Sources Performance Standards; Electric Utility Steam Generating Units*, 44 FR 33580, 33581-33582 (June 11, 1979).

emission reduction," many "innovative approaches may in fact reduce the economic and energy impact of emissions control," and the Administrator should still be encouraged to consider other technologically based techniques for emissions reduction, including "precombustion cleaning or treatment of fuels."[490] This is discussed in more detail below.

Despite these changes with respect to new sources, the 1977 CAA Amendments further reinforce the notion that with respect to existing sources, the BSER was never intended to be narrowly applied. In 1977, Congress changed CAA section 111(d)(1) to require that states adopt "standards of performance" and made clear that such standards were to be based on the "best system of continuous emission reduction ... adequately demonstrated,"[491] but generally maintained the breadth of that term. Although Congress inserted the word "continuous" into the phrase, Congress explained that "standards in the Section 111(d) state plan would be based on the *best available means (not necessarily technological)* for categories of existing sources to reduce emissions."[492] This was intended to distinguish existing source

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[490] H.R. Rep. No. 95-294, at 189 (May 12, 1977), 1977 CAA Legis. Hist. at 2656.
[491] CAA section 111(a)(1)(C) under the 1977 CAA Amendments.
[492] H.R. Rep. No. 95-294 (May 12, 1977), 1977 CAA Legis. Hist. at 2662 (emphasis added). Congress also endorsed the EPA's practice of establishing "emission guidelines" under CAA section 111(d). *See* H.R. Rep. No. 95-294 (May 12, 1977), 1977 CAA Legis. Hist.

standards from new source standards, for which "the requirement for [BSER] has been more narrowly redefined as best technological system of continuous emission reduction."[493,494]

In the 1990 CAA Amendments, Congress restored the 1970s vintage definition of a standard of performance as applied to both new and existing sources. With respect to existing sources, this had the effect of no longer requiring that the BSER be "continuous."[495] Further, nothing in the 1990 CAA Amendments or their legislative history indicates that Congress intended to

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at 2662 ("The Administrator would establish guidelines as to what the best system for each such category of existing sources is. However, the state would be responsible for determining the applicability of such guidelines to any particular source or sources.").

[493] Sen. Muskie, S. Consideration of the H.R. Conf. Rep. No. 95-564 (Aug. 4, 1977), 1977 CAA Legis. Hist. at 353.

[494] In 1977, Congress added a new substantive definition for "emission standard" generally applicable throughout the CAA. 1977 CAA Amendments, Pub. L. 95-95, § 301, 91 Stat. 685, 770 (Aug. 7, 1977) (defining "emission limitation" and "emission standard" as "a requirement established by the State or the Administrator which limits the quantity, rate, or concentration of emissions of air pollutants on a continuous basis, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction."). Congress also added a generally applicable definition of standard of performance, defined as "a requirement of continuous emission reduction, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction." *Id.*

[495] We note that the general definition of a standard of performance at CAA section 302(l) still uses "continuous." Even if this provision applies to section 111, it does not affect our analysis in this rule, including our interpretation that BSER includes building blocks 2 and 3.

impose new constraints on the types of systems of emission reduction that could be considered under CAA section 111(d)(1) and (a)(1). In contrast, Congress retained the definition of the term "technological system of continuous emission reduction," which means

(A) a technological process for production or operation by any source which is inherently low-polluting or nonpolluting, or
(B) a technological system for continuous reduction of the pollution generated by a source before such pollution is emitted into the ambient air, including precombustion cleaning or treatment of fuels.

That term continues to be used in reference to new sources in certain circumstances, under CAA section 111(b), (h), and (j).[496]

[496] There are numerous reasons to find that particular CAA section 111(b) standards of performance should be based on controls installed at the source at the time of new construction. This is due in part to the recognition that new sources have long operating lives over which initial capital costs can be amortized, as recognized in the legislative history for section 111. Thus, new construction is the preferred time to drive capital investment in emission controls. *See, e.g.*, S. Rep. No. 91-1196, at 15-16, 1970 CAA Legis. Hist. at 416 ("[t]he overriding purpose of this section [concerning new source performance standards] would be to prevent new air pollution problems, and toward that end, maximum feasible control of new sources at the time of their construction is seen by the committee as the most effective and, in the long run, the least expensive approach."); *see also* 1977 CAA Amendments, § 109, 91 Stat. at 700, (redefining, with respect to new sources, CAA section 111(a)(1) to reflect the best "technological system of continuous emission reduction" and adding CAA section 111(a)(7) to define this new term). However, as a result of the 1990 revisions to CAA section 111(a)(1), which replaced the phrase "technological system of continuous emission reduction" with "system of emission reduction," new source standards would not be restricted to being based on technological control measures.

However, it is not and never has been used to regulate existing sources. In this manner, the 1990 CAA Amendments further reinforce the breadth and flexibility of the phrase "system of emission reduction," particularly as it applies to existing sources under CAA section 111(d).

For these reasons, the 1970, 1977, and 1990 legislative histories support the EPA's interpretation in this rule that the term is sufficiently broad to encompass building blocks 2 and 3.

(ii) <u>Reliance on actions taken by other entities</u>.

The legislative history supports the EPA's interpretation of "system of emission reduction" in another way as well: The legislative history makes clear that Congress intended that standards of performance for electric power plants could be based on measures implemented by other entities, for example, entities that "wash," or desulfurize, coal (or, for oil-fired EGUs, that desulfurize oil). This legislative history is consistent with the EPA's view that the "system of emission reduction" may include actions taken by an entity with whom the owner/operator of the affected source enters into a contractual relationship as long as those actions allow the affected source to meet its emission limitation. By the same token, this legislative history directly refutes commenters' assertions that the phrase "system of emission reduction" must not include actions taken by entities other than the affected sources.[497]

As noted above, in the 1977 CAA Amendments, Congress revised the basis for standards of performance for new fossil fuel-fired stationary sources to be a "technological system of continuous emission reduction," including "precombustion cleaning or treatment of fuels."[498] Precombustion cleaning or treatment reduces the amount of sulfur in the fuel, which means that the fuel can be combusted with fewer SO_2 emissions, and that in turn means that the source can achieve a lower emission limit. Congress understood that these fuel cleaning techniques would not necessarily be accomplished at the affected source and, in revising CAA section 111(a)(1), wanted to ensure that such techniques would not be overlooked. For example, the 1977 House Committee report indicates that an assessment of the best

[497] *See, e.g.*, comments by UARG at 31 (the building blocks other than building block 1 take a "'beyond-the-source' approach" and "impermissibly rely on measures that go beyond the boundaries of individual affected EGUs and that are not within the control of individual EGU owners and operators"); comments by American Chemistry Council et al. ("Associations") at 60-61 (EPA's proposed BSER analysis is unlawful because it "looks beyond the fence line of the fossil fuel-fired EGUs that are the subject of this rulemaking;" "the standard of performance must ... be limited to the types of actions that can be implemented directly by an existing source within [the appropriate] class or category.").
[498] 1977 CAA Amendments, § 109, 91 Stat. at 700; *see also* CAA section 111(a)(7).

technological system of continuous emission reduction for fossil fuel-fired power plants would include off-site or third-party pre-combustion techniques for reducing emissions at the source ("*e.g.*, various coal-cleaning technologies such as solvent refining, oil desulfurization *at the refinery*").[499] Thus, the standard of performance reflecting the best technological system implementable by an affected source could be based, in part, on technologies used at off-site facilities owned and operated by third-parties.

In the 1990 CAA Amendments, Congress eliminated many of the restrictions and other provisions added in the 1977 CAA Amendments by largely reinstating the 1970 CAA Amendments' definition of "standard of performance." Nevertheless, there is no indication that in doing so, Congress intended to preclude the EPA from considering coal cleaning by third parties (which had been considered within the scope of the best system of

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[499] H.R. Rep. No. 95-294 (May 12, 1977), 1977 CAA Legis. Hist. at 2655 (emphasis added). Generally speaking, coal cleaning activities also are conducted by third parties. For instance, EPA recognized in a regulatory analysis of new source performance standards for industrial-commercial-institutional steam generating units that the technology "requires too much space and is too expensive to be employed at individual industrial-commercial-institutional steam generating units." U.S. EPA, *Summary of Regulatory Analysis for New Source Performance Standards: Industrial-Commercial-Institutional Steam Generating Units of Greater than 100 Million Btu/hr Heat Input*, EPA-450/3-86-005, p. 4-4 (June 1986).

emission reduction even under the 1970 CAA Amendments),[500] and in fact, the EPA's regulations promulgated after the 1990 CAA Amendments continue to impose standards of performance that are based on third-party coal cleaning.[501]

(c) <u>Consistency of a broad interpretation of CAA section 111 with the overall structure of the CAA</u>.

Interpreting CAA section 111(d)(1) and (a)(1) to authorize the EPA's consideration of the building block 2 and 3 measures is consistent with the overall structure of the CAA, particularly as it was amended in 1970, when Congress added CAA section 111 in much the same form that it reads today.

In the 1970 CAA Amendments, for the most part, and particularly for stationary source provisions, Congress painted with broad brush strokes, giving broad authority to the EPA or the states. That is, Congress established general requirements that were intended to produce stringent results, but gave the

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[500] *See* U.S. EPA, *Background Information for Proposed New-Source Performance Standards: Steam Generators, Incinerators, Portland Cement Plants, Nitric Acid Plants, Sulfuric Acid Plants*, Office of Air Programs Tech. Rep. No. APTD-0711, p. 7 (Aug. 1971) (indicating the "desirability of setting sulfur dioxide standards that would allow the use of low-sulfur fuels *as well as fuel cleaning*, stack-gas cleaning, and equipment modifications" (emphasis added)).

[501] 40 CFR 60.49b(n)(4); see also *Amendments to New Source Performance Standards (NSPS) for Electric Utility Steam Generating Units and Industrial-Commercial-Institutional Steam Generating Units; Final Rule*, 72 FR 32742 (June 13, 2007).

EPA or the states great discretion in fashioning the types of measures to achieve those results.

For example, under CAA section 109, Congress authorized the EPA to promulgate national ambient air quality standards (NAAQS) for air pollutants, and Congress established general criteria and procedural requirements, but left to the EPA discretion to identify the air pollutants and select the standards. Under CAA section 110, Congress required the states to submit to the EPA SIPs, required that the plans attain the NAAQS by a date certain, and established procedural requirements, but allowed the states broad discretion in determining the substantive requirements of the SIPs.

Under CAA section 111(b), Congress directed the EPA to list source categories that endanger public health or welfare and established procedural requirements, but did not include other substantive requirements, and instead gave the EPA broad discretion to determine the criteria for endangerment.

Under CAA section 112, Congress required the EPA to regulate certain air pollutants and to set "emission standards" that meet general criteria, and established procedural requirements, but did not include other substantive requirements and, instead, gave the EPA broad discretion in identifying the types of pollutants and in determining the standards.[502] By and large, Congress left these provisions intact in the 1977 CAA Amendments.[503,504]

Congress drafted the CAA section 111(d) requirements in the 1970 CAA Amendments, and revised them in the 1977 CAA Amendments, in a manner that is similar to the other stationary source requirements, just described, in CAA sections 109, 110, 111(b), and 112. The CAA section 111(d) requirements are broadly phrased, include procedural requirements but no more than very general substantive requirements, and give broad discretion to the EPA to determine the basis for the required emission limits and to the states to set the standards. It should be noted that

[502] By comparison, under the 1990 CAA Amendments, Congress substantially transformed CAA section 112 to be significantly more prescriptive in directing EPA rulemaking, which reflected Congress's increased knowledge of hazardous air pollutants and impatience with the EPA's progress in regulating.
[503] In the 1977 CAA Amendments, Congress applied the same broad drafting approach to the stratospheric ozone provisions it adopted in CAA sections 150-159. There, Congress authorized the EPA to determine whether, "in the Administrator's judgment, any substance, practice, process, or activity may reasonably be anticipated to affect the stratosphere, especially ozone in the stratosphere, and such effect may reasonably be anticipated to endanger public health or welfare," and then directed the EPA, if it made such a determination, to "promulgate regulations respecting the control of such process practice, process, or activity…." CAA section 157(a). This provision does not further specify requirements for the regulations.
[504] On the other hand, in those instances in which Congress had a clear idea as to the emission limitations that it thought should be imposed, it mandated those emission limits, e.g., in Title II concerning motor vehicles.

this drafting approach is not unique to the CAA; on the contrary, Congress "usually does not legislate by specifying examples, but by identifying broad and general principles that must be applied to particular factual instances."[505]

In light of this statutory framework, it is clear that Congress delegated to the EPA the authority to administer CAA section 111, including by authorizing the EPA to apply the “broad and general principles” contained in CAA section 111(a)(1) to the particular circumstances we face today.

(3) Comments and responses.

While some commenters support the EPA’s interpretation of section 111 to authorize the inclusion of building blocks 2 and 3 in the BSER, other commenters assert that the emission standards must be based on measures that the sources subject to CAA section 111 -- in this rule, the affected EGUs -- apply to their own design or operations, and, as a result, in this rule, cannot include measures implemented at entities other than the affected EGUs that have the effect of reducing generation, and therefore emissions, from the affected EGUs. The commenters assert that various provisions in CAA section 111 make this limitation clear. We do not find those arguments persuasive.

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[505] *Pub. Citizen v. U.S. Dept. of Justice*, 491 U.S. 440, 475 (1989) (Kennedy, J., concurring).

First, some commenters state that under CAA section 111(d)(1) and (a)(1), the existing sources subject to the standards of performance must be able to achieve their emission limit, but that they are able to do so only through measures integrated into the source's own design and operation. As a result, according to these commenters, those are the only types of measures that may qualify as a "system of emission reduction" that may form the basis of the emissions standards. We disagree. We see nothing in CAA section 111(d)(1) or (a)(1) which by its terms limits CAA section 111 to measures that must be integrated into the sources' own design or operation. Rather, we recognize that in order for an emission limitation based on the BSER to be "achievable," the BSER must consist of measures that can be undertaken by an affected source -- that is, its owner or operator. As noted elsewhere in the preamble, the affected sources subject to this rule are fully able to meet their emission standards by undertaking the measures described in all three building blocks. Moreover, as discussed, the measures in building blocks 2 and 3 are highly effective in achieving CO_2 emission reductions from these affected EGUs, given the unique characteristics of the industry. This reinforces the conclusion that the term "system of emission reduction" is broad enough to include these measures.

The broad nature of CAA section 111(d)(1) and (a)(1) is also confirmed by comparing it to CAA provisions that explicitly require controls on the design or operations of an affected source. The most notable comparison is at CAA section 111(a)(7). The term "technological system of continuous emission reduction," which was added in 1977 and remains as a separately defined term means, in part, "a technological process *for production or operation* by any source *which is inherently* low-emitting or nonpolluting." (Emphasis added.) With respect to this portion of the definition (and ignoring the additional text, which includes "precombustion cleaning or treatment of fuels" and clearly encompasses off-site activities), it could be argued that between 1977 and 1990 new source performance standards should be restricted to measures that could be integrated into the design or operation of a source. However, commenters' assertion that the BSER must be limited in a similar fashion ignores the deliberate change in 1990 to restore the broader definition of a standard of performance (*i.e.*, that it be based on the BSER and not the TSCER). In any case, the narrower scope of CAA section 111(a)(7) was never applicable to the regulation of existing sources under CAA section 111(d).

Several other examples of standard setting in the CAA shed light on ways in which Congress has constrained the EPA's review. CAA section 407(b)(2) provides that the EPA base NO_x

emission limits for certain types of boilers "on the degree of reduction achievable through the *retrofit* application of the best system of continuous emission reduction." (Emphasis added.) Likewise, in determining best available retrofit technology under CAA section 169A, the state (or Administrator) must "take into consideration the costs of compliance, the energy and nonair quality environmental impacts, any existing pollution control technology *in use at the source*, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result *from the use of such technology*."[506] (Emphasis added.) These provisions make clear that Congress knew how to constrain the basis for emission limits to measures that are integrated into the design or operation of the affected source, and that its choice to base CAA section 111(d)(1) and (a)(1) standards of performance on a "system of emission reduction" indicates Congress' intent to authorize a broader basis for those standards.

Some commenters also argue that other provisions in CAA section 111 indicate that Congress intended that CAA section 111(d)(1) and (a)(1) be limited to measures that are integrated

[506] Even under BART, the EPA is authorized to allow emissions trading between sources. *See, e.g.*, 40 CFR 51.308(e)(1) & (2); *Util. Air Reg. Group v. EPA*, 471 F.3d 1333 (D.C. Cir. 2006); *Ctr. for Econ. Dev. v. EPA*, 398 F.3d 653 (D.C. Cir. 2005); and *Cent. Ariz. Water Dist. v. EPA*, 990 F.2d 1531 (9th Cir. 1993).

into the source's design or operations. This argument is unpersuasive for several reasons. First, it would be unreasonable to presume that Congress intended to limit the BSER, indirectly through these other provisions, to measures that are integrated into the affected source's design or operations, when Congress could have done so expressly, as it did for the above-discussed CAA section 407(b)(2) NO_x requirements.

Second, the interpretations that commenters offer for these various provisions misapply the text. For example, commenters note that under CAA section 111(d)(1), (a)(3), and (a)(6), the standards of performance apply to "any existing source," and an "existing source" is defined to include "any stationary source," which, in turn, is defined as "any building, structure, facility, or installation which emits or may emit any air pollutant." Commenters assert that these applicability and definitional provisions indicate that the BSER provisions in CAA section 111(d)(1) and (a)(1) must be interpreted to require that the control measures must be integrated into the design or operations of the source itself.

We disagree. These applicability and definitional provisions are jurisdictional in nature. Their purpose is simply to identify the types of sources whose emissions are to be addressed under CAA section 111(d), *i.e.*, stationary sources, as opposed to other types of sources, *e.g.*, mobile sources, whose emissions are addressed under other CAA provisions (such as CAA Title II). This purpose is made apparent by the terms of CAA section 111(a)(3), which contains two sentences (the second of which commenters seem to ignore). The first sentence provides: "The term 'stationary source' means any building, structure, facility, or installation which emits or may emit any air pollutant." The second sentence provides: "Nothing in subchapter II of this chapter relating to nonroad engines shall be construed to apply to stationary internal combustion engines." This second sentence explains that stationary internal combustion engines are to be regulated under CAA section 111, and not Title II (relating to mobile sources), which confirms that the purpose of the definition of stationary source is jurisdictional in nature -- to identify the emissions that are to be regulated under section 111, as opposed to other CAA provisions.

These applicability and definitional provisions say nothing about the system of emission reduction -- whether it is limited to measures integrated into the design or operation of the source itself or may be broader -- that may form the basis of the standards for those emissions that are to be promulgated under CAA section 111.

Third, this argument by commenters does not account for the commonsense proposition that it is the owner/operator of the stationary source, not the source itself, who is responsible for taking actions to achieve the emission rate, so that actions that the owner/operator is able to take should be considered in determining the appropriate standards for the source's emissions. Again, it is common sense that buildings, structures, facilities, and installations can take no actions -- only owners and operators can install and maintain pollution control equipment; only owners and operators can solicit precombustion cleaning or treatment of fuel services; and only owners and operators can apply for a permit or trade allowances.[507] Other provisions in CAA section 111 make clear the role of the owner/operator. CAA section 111(e) provides that for new sources, the burden of compliance falls on the "owner or operator."[508] The same is necessarily true for existing sources. This supports the EPA's view that the basis for whether a control measure qualifies as a "system of emission reduction"

[507] Industry commenters also acknowledged that it is the owner or operator that implements the control requirements. See UARG comment at 19 (section 111(d) "provides for the regulation of individual emission sources through performance standards that are based on what design or process changes an individual source's owner can integrate into its facility").
[508] CAA section 111(e) provides: ("[I]t shall be unlawful for any owner or operator of any new source to operate such source in violation of any [applicable] standard of performance.")

under CAA section 111(d)(1) and (a)(1) is whether it is something that the owner/operator can implement in order to achieve the emissions standard assigned to the source -- if so, the control measure should qualify as a "system of emission reduction" -- and not whether the control measure is integrated into the source's own design or operation.

Commenters also argue that CAA section 111(h), which authorizes "design, equipment, work practice or operational standard[s]" (together, "design standards") only when a source's emissions are not emitted through a conveyance or cannot be measured, makes clear that CAA section 111 standards of performance must be based on measures integrated into a source's own design or operations. We disagree. CAA section 111(h) concerns the relatively rare situation in which an emission standard, which entails a numerical limit on emissions, *is not* appropriate because emissions cannot be measured, due either to the nature of the pollutant (i.e., the pollutant is not emitted through a conveyance) or the nature of the source category (i.e., the source category is not able to conduct measurements). CAA section 111(h) provides that in such cases, the EPA may instead impose design standards rather than establish an emission standard (i.e., the EPA can require sources to implement a particular design, equipment, work practice, or operational standard). When an emissions standard *is* appropriate, as in the present rule, CAA section 111(h) is silent as to what types of measures –- whether limited to a source's own design or operations -- may be considered as the system of emission reduction.[509] In any event, CAA section 111(h) applies only to standards promulgated by the Administrator, and therefore appears by its terms to be limited to CAA section 111(b) rulemakings for new, modified, or reconstructed sources, not CAA section 111(d) rulemakings for existing sources.

Some commenters identify other provisions of CAA section 111 that, in their view, prove that CAA section 111 is limited to control measures that are integrated within the design or operations of the source. We do not find those arguments persuasive, for the reasons discussed in the supporting documents for this rule.

Commenters also argue, more generally, that Congress knew how to authorize control measures such as RE, as indicated by Congress's inclusion of those measures in Title IV (relating to acid rain), so the fact that Congress did not explicitly include these measures in the BSER provisions of CAA section 111(d)(1) and (a)(1) indicates that Congress did not intend that they be

[509] For this same reason, the fact that CAA section 111(h) authorizes the EPA to impose certain types of standards –- such as, among others, work practice or operational standards -- only in limited circumstances not present in this rulemaking, does not mean that the EPA cannot consider those same measures as the BSER in promulgating a standard of performance.

included as part of the BSER, and instead intended that the BSER be limited to measures integrated into the sources' design or operations. This argument misses the mark. The provisions of CAA section 111(d)(1) and (a)(1) do not explicitly include *any* specific emission reduction measures -- neither RE measures (like the ones Congress wanted to incentivize under Title IV), nor measures that are integrated into the sources' design or operations (like the retrofit control measures Congress required under CAA section 407(b)). But this contrast with other CAA provisions does not mean that Congress did not intend the BSER to include any of those types of measures. Rather, this contrast supports viewing a "system of emission reduction" under CAA section 111 as sufficiently broad to encompass a wide range of measures for the purpose of emission reduction of a wide range of pollutants from a wide range of stationary sources.[510]

c. <u>Deference to interpret the BSER to include building blocks 2 and 3.</u> To the extent that it is not clear whether the phrase "system of emission reduction" may include the measures in building blocks 2 and 3, the EPA's interpretation of CAA section

[510] It should also be noted that Title IV is limited to particular pollutants (i.e., SO_2 and NO_x) and particular sources -- fossil fuel-fired EGUs -- and as a result, lends itself to greater specificity about the types of control measures. Section 111(d), in contrast, applies to a wide range of source types, which, as discussed above, supports reading it to authorize a broad range of control measures.

111(d) and (a) is reasonable[511] in light of our discretion to determine "whether *and how* to regulate carbon-dioxide emissions from power plants...."[512]

Our interpretation that a "system of emission reduction" for the affected EGUs may include building blocks 2 and 3 is a reasonable construction of the statute for the reasons described above and in this section below.

(1) Consistency of building blocks 2 and 3 with the structure of the utility power sector.

(a) Integration of the utility power sector.

Certain characteristics of the utility power sector are of central importance for understanding why the measures of building blocks 2 and 3 qualify as part of the system of emission reduction. As discussed above, electricity is highly substitutable and the utility power sector is highly integrated, so much so that it has been likened to a "complex machine."[513] Specifically, the utility power sector is characterized by physical, as well as operational, interconnections between electricity generators themselves, and between those generators

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[511] *EPA v. EME Homer City Generation, L.P.*, 134 S. Ct. 1584, 1603 (2014) ("We routinely accord dispositive effect to an agency's reasonable interpretation of ambiguous statutory language.").

[512] *American Electric Power Co. v. Connecticut*, 131 S. Ct. 2527, 2538 (2011) ("*AEP*") (emphasis added).

[513] S. Massoud Amin, "Securing the Electricity Grid," The Bridge, Spring 2010, at 13, 14; Phillip F. Schewe, The Grid: A Journey Through the Heart of Our Electrified World 1 (2007).

and electricity users. Because of the physical properties of electricity and the current low availability of large scale electricity storage, generation and load (or use) must be instantaneously balanced in real time. As a result, the utility power sector is uniquely characterized by extensive planning and highly coordinated operation. These features have been present for decades, and in fact, over time, the sector has become more highly integrated. Another important characteristics of the utility power sector is that although the states have developed both regulated and de-regulated markets, the generation of electricity reflects a least-cost dispatch approach, under which electricity is generated first by the generators with the lowest variable cost.

These characteristics of the sector have facilitated the overall objective of providing reliable electric service at least cost subject to a variety of constraints, including environmental constraints. Moreover, in each type of market, the sector has developed mechanisms, including the participation of institutional actors, to safeguard reliability and to assure least cost service.

Congress,[514] the Courts,[515] the EPA in its regulatory actions,[516] and states in their regulatory actions[517] have recognized the integrated nature of the utility power sector.

(b) <u>Significance of integrated utility power sector for the BSER</u>.

The fungibility of electricity, coupled with the integration of the utility power sector, means that, assuming that demand is held constant, adding electricity to the grid from one generator will result in the instantaneous reduction in generation from other generators. Similarly, reductions in generation from one generator lead to the instantaneous increase in generation from other generators. Thus, the operation of individual EGUs is integrated and coordinated with the

[514] *See* CAA section 404(f)(2)(B)(iii)(I) (conditioning a utility's eligibility for certain allowances on implementing an energy conservation and electric power plan that evaluates a range of resources to meet expected future demand at least cost); *see also* S. Rep. No. 101-228, at 319-20 (Dec. 20, 1989)(recognizing that "utilities already engage in power-pooling arrangements to ensure maximum flexibility and efficiency in supplying power" to support the establishment of an allowance system under Title IV).

[515] *New York v. Federal Energy Regulatory Commission*, 535 U.S. 1, at 7 (2002) (citing Brief for Respondent FERC 4-5).

[516] "Stack Heights Emissions Balancing Policy," 53 FR 480, 482 (Jan. 7, 1988).

[517] See 79 FR 34830, 34880 (June 18, 2014) (discussing State of California Global Warming Solutions Act of 2006, Assembly Bill 32, http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.pdf, and quoting December 27, 2013 Letter from Mary D. Nichols, Chairman of California Air Resources Board, to EPA Administrator Gina McCarthy).

operations of other EGUs and other sources of generation, as well as with electricity users. This allows for locational flexibility across the sector in meeting demand for electricity services. The institutions that coordinate planning and operations routinely use this flexibility to meet demand for electricity services economically while satisfying constraints, including environmental constraints. Because of these characteristics, EGU owner/operators have long conducted their business, including entering into commercial arrangements with third parties, based on the premise that the performance and operations of any of their facilities is substantially dependent on the performance and operation of other facilities, including ones they neither own nor operate. For example, when an EGU goes off-line to perform maintenance, its customer base is served by other EGUs that increase their generation. Similarly, if an EGU needs to assure that it can meet its obligations to supply a certain amount of generation, it may enter into arrangements to purchase that generation, if it needs to, from other EGUs.

Because of this structure, fossil fuel-fired EGUs can reduce their emissions by taking the actions in building blocks 2 and 3. Specifically, fossil fuel-fired EGUs may generate or cause the generation of increased amounts of lower- or zero-emitting electricity –- through contractual arrangements, investment, or purchase -- which will back out higher-emitting generation, and thereby lower emissions. In addition, fossil fuel-fired EGUs may reduce their generation, which, given the overall emission limits this rule requires, will have the effect of stimulating lower- or zero-emitting generation.

It should also be noted that CO_2 is particularly well-suited for building blocks 2 and 3 because it is a global, not local, air pollutant, so that the location where it is emitted does not affect its environmental impact. The U.S. Supreme Court in the *UARG* case highlighted the importance of taking account of the unique characteristics of CO_2.[518]

In light of these characteristics of the utility power sector, as well as the characteristics of CO_2 pollution, it is reasonable for the EPA to reject an interpretation of the term "system of emission reduction" that would exclude building blocks 2 and 3 from consideration in this rule and instead restrict consideration to measures integrated into each individual affected source's design or operation, especially since the record and other publicly available information makes clear that the measures in the two building blocks are effective in reducing emissions and are already widely used.

As discussed above, no such restriction on the measures that can be considered part of a "system of emission reduction"

[518] *See Util. Air. Reg. Group v. EPA,* 134 S. Ct. 2427, 2441 (2014).

is required by the statutory language, and the legislative history demonstrates that Congress intended an interpretation of the phrase broad enough to encompass building blocks 2 and 3. The narrow interpretation advocated by some commenters would permit consideration only of potential CO_2 reduction measures that are either more expensive than building blocks 2 and 3 (such as the use of natural gas co-firing at affected EGUs or the application of CCS technology) or measures capable of achieving far less reduction in CO_2 emissions (such as the heat rate improvement measures included in building block 1). Imposing such a restrictive interpretation -- one which is not called for by the statute -- would be inconsistent with CAA section 111's specific requirement that standards be based on the "best" system of emission reduction and, as discussed below, would be inconsistent with Congressional design that the CAA be comprehensive and address the major environmental issues.[519]

The unique characteristics of the sector described above require coordinated action in the fundamental, primary function of EGUs – and in meeting current pollution control requirements to the extent that EGUs operate in dispatch systems that apply variable costs in determining dispatch -- and affected EGUs

[519] *See King v. Burwell*, No. 14-114 (2015) (slip op., at 21) ("But in every case we must respect the role of the Legislature, and take care not to undo what it has done.").

necessarily already plan and operate on a multi-unit basis. In doing so, they already make use of building blocks 2 and 3 to meet operational and environmental objectives in a cost-effective manner, as further described below. CO_2 is a global pollutant that is exceptionally well-suited to emission reduction efforts optimized on a broad geographic scale rather than on a unit-by-unit basis. It is also clear from both comments and communications received through the Agency's outreach efforts that affected EGUs will seek to use building blocks 2 and 3 to achieve compliance with the emission standards set in the section 111(d) plans following promulgation of this rule. For these reasons -- and the additional reasons discussed below -- interpreting "system of emission reduction" so as to allow consideration in this rule of only the individual pieces of the "complex machine," and to forbid consideration of the ways in which the pieces actually fit and work together as parts of that machine, such as building blocks 2 and 3, cannot be justified. This is particularly so in light of the dilemma presented by the types of control options that commenters argue are the only ones authorized under section 111(a)(1), which are controls that apply to the design or operation of the affected EGUs themselves. On the one hand, the control measures in building block 1 yield only a small amount of emission reductions. On the other hand, control measures such as carbon capture and storage, or co-firing with natural gas, could yield much greater emission reductions, but are substantially more expensive than building blocks 2 and 3.

(2) <u>Current implementation of measures in building blocks 2 and 3</u>.

The requirement that the "system of emission reduction" be "adequately demonstrated" suggests that we begin our review under CAA section 111(d)(1) and (a)(1) with the systems that sources are already implementing to reduce their emissions. As noted above, fossil fuel-fired EGUs have long implemented, and are continuing to implement, the measures in building blocks 2 and 3 for various purposes, including for the purpose of reducing CO_2 emissions[520] -- and certainly always with the effect of reducing emissions. This is a strong indicator that these measures should be considered part of a "system of emission reduction" for CO_2 emissions from these sources. The requirement that the "system of emission reduction" be "adequately

[520] A number of utilities have climate mitigation plans. Examples include National Grid, http://www2.nationalgrid.com/responsibility/how-were-doing/grid-data-centre/climate-change/; Exelon, http://www.exeloncorp.com/newsroom/pr_20140423_EXC_Exelon2020.aspx; PG&E, http://www.pge.com/about/environment/pge/climate/; and Austin Energy, http://austinenergy.com/wps/portal/ae/about/environment/austin-climate-protection-plan/!ut/p/a0/04_Sj9CPykssy0xPLMnMz0vMAfGjzOINjCyMPJwNjDzdzY0sDBzdnZ28TcP8DAMMDPQLsh0VAU4fG7s!/.

demonstrated" indicates that the implementation of control mechanisms or other actions that the sources are already taking to reduce their emissions are of particular relevance in establishing the emission reduction requirements of CAA section 111(d)(1) and (a)(1). As a result, such measures are a logical starting point for consideration as a "system of emission reduction" under CAA section 111.

(3) Reliance in CAA Title IV on building block measures.

Some of the building block approaches to reducing emissions in the utility power sector were first tested around the time that Congress adopted the 1970 CAA Amendments.[521] Over time, these techniques have become more established within the industry, and by the 1990 CAA Amendments, Congress based the Title IV acid rain program for existing fossil fuel-fired EGUs in part on the same measures that are considered here.

(a) Overview.

It is logical that in determining whether the "system of emission reduction" that Congress established in CAA section 111(d)(1) and (a)(1) is broad enough to include the measures in building blocks 2 and 3 as the basis for establishing emission guidelines for fossil fuel-fired EGUs, an inquiry should be made

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[521] *See, e.g.*, Shepard, Donald S., *A Load Shifting Model for Air Pollution Control in the Electric Power Industry*, Journal of the Air Pollution Control Association, Vol. 20:11, pp. 756-761 (November 1970).

into the tools that Congress relied on in other CAA provisions to reduce emissions from those same sources. The most useful CAA provision to examine for this purpose is Title IV, which includes a nationwide cap-and-trade program under which coal-fired power plants must have allowances for their SO_2 emissions.

Title IV includes several signals that it is especially relevant for interpreting and implementing CAA section 111(d) for purposes of this rule. Title IV applies to most of the same sources that this rule applies to -- existing coal-fired EGUs and other utility boilers, as well as NGCC units. In addition, Congress added Title IV in the 1990 CAA Amendments at the same time that Congress largely reinstated the 1970-vintage reading of section 111(a)(1) to adopt the currently applicable definition of a "standard of performance," which is based on the "best system of emission reduction ... adequately demonstrated." Moreover, Congress linked Title IV and CAA section 111 in certain respects. Specifically, Congress conditioned the revisions to CAA section 111(a)(1), i.e., eliminating the percentage reduction and most of the other limitations under the 1977 CAA Amendments, on the continued applicability of the Title IV SO_2 cap, so that if the cap were eliminated, the changes would, by operation of law, also be eliminated, and the 1977 version of section 111(a)(1) would be reinstated.[522] Additionally, Congress authorized the EPA to establish standards of performance for new *and* existing industrial (non-EGU) sources of SO_2 emissions if emissions from these sources might exceed 1985 levels and failed to decline at the expected rate.[523] While industrial sources were not required to participate under Title IV -- they could elect to do so, under CAA section 410(a) -- Congress believed SO_2 reductions from these sources were "an essential component of the reductions sought under [Title IV]" and intended that Title IV would "assure[] that these projected reductions occur and will not be overcome by future growth in emissions."[524] As such, Congress viewed federal standards of performance as the appropriate backstop to Title IV even for sources that could not otherwise be regulated under CAA section

[522] 1990 CAA Amendments, § 403, 104 Stat. at 2631 (requiring repeal of amendments to CAA section 111(a)(1) upon any cessation of effectiveness of CAA section 403(e), which requires new units to hold allowances for each ton of SO_2emitted). Congress believed that mandating a technological standard through the percentage reduction requirement in section 111(a)(1) would ensure the continued availability of low sulfur coal for existing sources. In other words, the percentage reduction requirement discouraged compliance with new source performance standards based solely on fuel shifting because it was much more costly to achieve the percentage reduction with lower sulfur coal. This belief was expressed during the 1977 CAA Amendments and is discussed above as part of the legislative history of section 111.

[523] 1990 CAA Amendments, § 406, 104 Stat. at 2632-33; *see also* S. Rep. No. 101-228, at 282 (industrial source emissions totaled 5.6 million tons of SO_2 in 1985).

[524] S. Rep. No. 101-228, at 345 (Dec. 20, 1989).

111(d).[525] Together, these signals suggest that it is reasonable for the EPA to consider Title IV when interpreting and implementing CAA section 111.

For present purposes, the essential features of Title IV are that it regulates SO_2 emissions from coal-fired EGUs by adopting a nationwide cap of 8.95 million tons to be achieved through a tradable allowance system. As we explain below, the provisions of Title IV and its legislative history make clear that Congress based the stringency of the emission limitation requirement (8.95 million tons) and the overall structure of the approach (a cap-and-trade system) on Congress's recognition that the affected EGUs had a set of tools available to them to reduce their emissions, including through a shift to lower emitting generation and use of RE, along with add-on controls and other measures. Thus, Title IV provides a close analogy to CAA section 111: generation shift and RE were part of Congress's basis for the Title IV emission requirements, and that is analogous to building blocks 2 and 3 serving as part of the "system of emission reduction" that is the EPA's basis for the section 111(d) emission guidelines. For this reason, the fact that in Title IV, Congress relied on generation shift and RE as the

[525] To reiterate, ordinarily, standards of performance cannot be used to regulate SO_2 emissions from existing sources because of the pollutant exclusions in CAA section 111(d).

basis for the SO_2 emission limitations for affected EGUs strongly supports interpreting CAA section 111(d)(1) and (a)(1) to include use of those same measures as part of the "system of emission reduction" as the basis for CO_2 emission limitations for those same sources.

(b) Title IV provisions.

Several provisions of Title IV make explicit Congress's reliance on some of the same measures as are in building blocks 2 and 3. Title IV begins with a statement of congressional "findings," including the following:

> §401(a). Findings
>
> The Congress finds that –
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> * * * *
>
> (4) *strategies and technologies* for the control of precursors to acid deposition exist now that are economically feasible, and improved methods are expected to become increasingly available over the next decade.

(Emphasis added.) Title IV then includes the following statement of its "purposes:"

> §401(b). Purposes
>
> The purpose of this subchapter [Title IV] is to reduce the adverse effects of acid deposition through reductions in annual emissions of sulfur dioxide … and nitrogen oxides…. It is the intent of this subchapter to effectuate such reductions by requiring compliance by affected EGUs with prescribed emission limitations by specified deadlines which limitations may be met through alternative methods of compliance provided by an emission allocation and transfer system. *It is also*

> *the purpose of this subchapter to encourage* energy conservation, *use of renewable* and clean alternative technologies, and pollution prevention as a long-range strategy, consistent with the provisions of this subchapter, *for reducing air pollution* and other adverse impacts of energy production and use.

(Emphasis added). By its terms, this statement of Title IV's purposes explicitly embraces the use of RE. Moreover, the legislative history makes clear that the reference in the "findings" section quoted above to "strategies and technologies" includes generation shift to lower-emitting generation. Specifically, the Senate Report stated that an "allowance system"[526] would encourage such "technologies and strategies" as

> energy efficiency; enhanced emissions reduction or control technologies—like sorbent injection, cofiring with natural gas, integrated gasification combined cycles; fuel-switching and *least-emissions dispatching* in order to maximize emissions reductions."[527]

Congress's reliance on generation shifting and REto reduce acid rain precursors from affected EGUs in Title IV strongly supports the EPA's authority to identify those same measures as part of the CAA section 111 "system of emission reduction" to reduce CO_2 emissions from those same sources.

In addition, Title IV includes other provisions expressly concerning RE. In CAA section 404(f) and (g), Congress set aside a special pool of allowances to encourage use of RE. In order to

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[526] *See* S. Rep. No. 101-228, at 320 (Dec. 20, 1989).
[527] *See* S. Rep. No. 101-228, at 316 (Dec. 20, 1989) (emphasis added).

obtain a special allowance (which would authorize emissions from a coal-fired utility), an electric utility needed to pay for qualifying RE sources "directly or through purchase from another person."[528] These measures confirm Congress's recognition that REwas available to the industry, was desirable to encourage from a policy perspective, and was appropriate to consider in determining the amount of pollution reduction the law should require.

(c) Title IV legislative history.

Numerous statements in the legislative history confirm that Congress based the Title IV requirements on the fact that affected EGUs could reduce their SO_2 emissions through a set of measures, including shifting to lower-emitting generation as well as reliance on RE.

For example, the Senate Committee Report[529] and Senator Baucus,[530] a member of the Senate Committee on Environment and Public Works and Chairman of the House and Senate Clean Air Conferees, both emphasized that affected EGUs could rely on, among other things, "least-emissions dispatching in order to

[528] CAA section 404(f)(2)(B)(i).
[529] S. Rep. No. 101-228 (Dec. 20, 1989), 1990 CAA Legis. Hist. at 8656.
[530] S. Debates on Conf. Rep. to accompany S. 1630, H.R. Rep. No. 101-952 (Oct. 27, 1990), 1990 CAA Legis. Hist. at 1033-35 (statement of Senator Baucus, inserting "the Clean Air Conference Report" into the record).

maximize emissions reductions." Similarly, statements supporting the RE reserve were included in the legislative history on the House side.

> We believe that this provision of the bill will establish a balanced and workable approach that will provide certainty for utility companies that are considering conservation and renewables, while at the same time strengthening the environmental goals of this legislation.[531]

(4) Reliance on RE measures to reduce CO_2.

The Title IV legislative history also makes clear that Congress viewed RE measures as a means to reduce CO_2 for the purpose of mitigating climate change. By the time of the 1990 CAA Amendments, Congress had long been aware that emissions of CO_2 and other GHGs put upward pressure on world temperatures and threatened to change the climate in destructive ways. In 1967, President Lyndon Johnson sent a letter to Congress recognizing that carbon dioxide was changing the composition of the

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[531] H.R. Rep. No. 101-490, at 368-69; 674-76 (May 17, 1990) (additional views of Reps. Markey and Moorhead) ("We believe that H.R. 3030, as amended, will create a strong and effective incentive for utilities to immediately pursue energy conservation and renewable energy sources as key components of their acid rain control strategies."); *see also* Rep. Collins, H. Debates on H.R. Conf. Rep. No. 101-952 (Oct. 26, 1990), 1990 CAA Legis. Hist. at 1307 ("The bottom line is that our Nation's utilities and production facilities must reach beyond coal, oil, and fossil fuels. The focus must shift instead toward conservation and renewables such as hydropower, solar thermal, photovoltaics, geothermal, and wind. These clean sources and energy, available in virtually limitless supply, are the way of the future.").

atmosphere.[532] The record for the 1970 CAA Amendments include hearings[533] and a report by the National Academy of Sciences noting that carbon dioxide emissions could heat the atmosphere.[534] A 1976 report noting the phenomenon was included in the record for the 1977 CAA Amendments.[535] A 1977 Report by the National Academy of Sciences warned that average

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532 "Special Message to the Congress on Conservation and Restoration of Natural Beauty (Feb. 8, 1965). http://www.presidency.ucsb.edu/ws/?pid=27285 ("This generation has altered the composition of the atmosphere on a global scale through radioactive materials and a steady increase in carbon dioxide from the burning of fossil fuels.").

533 Testimony of Charles Johnson, Jr., Administrator of the Consumer Protection and Environmental Health Service (Administration Testimony), Hearing of the House Subcommittee on Public Health and Welfare (Mar. 16, 1970), 1970 CAA Legis. Hist. at 1381 (stating that "the carbon dioxide balance might result in the heating up of the atmosphere whereas the reduction of the radiant energy through particulate matter released to the atmosphere might cause reduction in radiation that reaches the earth").

534 1970 CAA Legis. Hist. at 244, 257 S. Debate on S. 4358 (Sept. 21, 1970) (statement of Sen. Boggs) (replicating Chapter IV of the Council on Environmental Quality's first annual report, which states, "the addition of particulates and carbon dioxide in the atmosphere could have dramatic and long-term effects on world climate.").

535 122 Cong. Rec. S25194 (daily ed. Aug. 3, 1976) (statement of Sen. Bumpers) (inserting into the record, "Summary of Statements Received from Professional Societies for the Hearings on Effects of Chronic Pollution (in the Subcommittee on the Environment and the Atmosphere)," which stated, "there is near unanimity that carbon dioxide concentrations in the atmosphere are increasing rapidly. Though even the direction (warming or cooling) of the climate change to be caused by this is unknown, very profound changes in the balance of climate factors that determine temperature and rainfall on the earth are almost certain within 100 years").

temperatures would rise due to the burning of fossil fuel.[536] By the time of the 1990 CAA Amendments, the dangers had become more clearly evident. Senate hearings beginning in 1988 had presented testimony from Dr. James E. Hansen of the National Aeronautics and Space Administration and other scientists that described the dangers of climate change caused by anthropogenic carbon dioxide and other GHG emissions and asserted that as a result of those emissions, the climate was in fact already changing.[537]

In enacting the 1990 CAA Amendments, Congress identified reductions in carbon dioxide emissions as an important co-benefit of the reductions in coal use and stressed that the RE measures would achieve those reductions. Senator Fowler, the author of the provision that established a RE technology reserve within the allowance system, noted that RE technologies, "can

[536] National Academy of Sciences, "Energy and Climate: Studies in Geophysics" viii (1977), http://www.nap.edu/openbook.php?record_id=12024 (noting that a fourfold to eightfold increase in carbon dioxide by the latter part of the twenty-second century would increase average world temperature by more than 6 degrees Celsius).

[537] S. Rep. No. 101-228, at 322 (Dec. 20, 1989), at 1990 Legis. Hist. at 8662 ("In the last several years, the Committee has received extensive scientific testimony that increases in the human-caused emissions of carbon dioxide and other GHGs will lead to catastrophic shocks in the global climate system."); History, Jurisdiction, and a Summary of Activities of the Committee on Energy and Natural Resources During the 100th Congress, S. Rep. No. 101-138, at 5 (Sept. 1989); "Global Warming Has Begun, Expert Tells Senate," New York Times, June 24, 1988, http://www.nytimes.com/1988/06/24/us/global-warming-has-begun-expert-tells-senate.html.

greatly reduce emissions of ... global warming gases. That makes them a potent weapon against catastrophic climate change....”[538]

In addition, the 1990 CAA Amendments required EGUs covered by the monitoring requirements of the Title IV acid rain program to report their CO_2 emissions.[539]

(5) Other EPA actions that rely on the building block measures.

Another indication that it is reasonable to interpret the CAA section 111(d)(1) and (a)(1) provisions for the BSER to include the measures in building blocks 2 and 3 is that the EPA and states have relied on these measures to reduce emissions in a number of other CAA actions.

For example, in 2005, the EPA promulgated a rule to control mercury emissions from fossil fuel-fired power plants under section 111(d): the Clean Air Mercury Rule (CAMR).[540] The EPA established a nationwide cap-and-trade program that took effect in two phases: In 2010, the cap was set at 38 tons per year, and in 2018, the cap was lowered to 15 tons per year. The EPA expected, on the basis of modeling, that sources would achieve the second phase, 15-ton per year cap cost-effectively by

[538] Sen. Fowler, S. Debate on S. 1630 (Apr. 3, 1990), 1990 CAA Legis. Hist. at 7106.
[539] 1990 CAA Amendments, § 821, 104 Stat. at 2699.
[540] 70 FR 28606 (May 18, 2005).

choosing among a set of measures that included shifting generation to lower-emitting units.[541] CAMR was vacated by the D.C. Circuit on other grounds,[542] but it shows that in the only other section 111(d) rule that the EPA attempted for affected EGUs, the EPA relied on shifting generation as part of the BSER in a CAA section 111(d) rulemaking for fossil fuel-fired EGUs.

In 2011, the EPA promulgated the Cross State Air Pollution Rule (CSAPR),[543] in which it set statewide emission budgets for NO_x and SO_2 emitted by fossil fuel-fired EGUs, and based those standards in part on shifts to lower-emitting generation. CSAPR established state-wide emissions budgets based on a range of cost-effective actions that EGUs could take, and set the stringency of the deadlines for some required reductions in part because of the availability of "increased dispatch of lower-emitting generation which can be achieved by 2012."[544] The EPA developed a federal implementation plan (FIP) that established a

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[541] 70 FR 28606, 28619 (May 18, 2005) ("Under the CAMR scenario modeled by EPA, units [were] projected to meet their SO_2 and NO_x requirements and take additional steps to address the remaining [mercury] reduction requirements under CAA section 111, including adding [mercury]-specific control technologies (model applies [activated carbon injection]), additional scrubbers and [selective catalytic reduction], *dispatch changes*, and coal switching.").
[542] *New Jersey v. EPA*, 517 F.3d 574, 583-84 (D.C. Cir. 2008), *cert. denied sub nom. Util. Air Reg. Group v. New Jersey*, 555 U.S. 1169 (2009).
[543] 76 FR 48208 (Aug. 8, 2011).
[544] 76 FR at 48452.

trading program to meet the state-wide emission budgets set by CSAPR. The EPA projected that sources would meet their emission reduction obligations by implementing a range of emission control approaches, including the operation of add-on controls, switches to lower-emitting coal, and "changes in dispatch and generation shifting from higher emitting units to lower emitting units."[545] The U.S. Supreme Court upheld CSAPR in *EPA v. EME Homer City Generation, L.P.*[546]

With respect to RE, in 2004, the EPA provided guidance to states for adopting attainment SIPs under CAA section 110 that include RE measures.[547] Some states have done so. For example,

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[545] 76 FR at 48279-80. The exact mix of controls varied for different air pollutants and different time periods, but in all cases, shifting generation from higher to lower emitting units was one of the expected control strategies for the fossil fuel-fired power plants. Prior to CSAPR, the EPA promulgated two other transport rules, the NO_x SIP Call (1998) and the Clean Air Interstate Rule (CAIR) (2005), which similarly established standards based on analysis of the availability and cost of emission reductions achievable through the use of add-on controls and generation shifting, and also authorized and encouraged the implementation of RE and demand-side EE measures. CAIR: 70 FR 25162, 25165, 25256, 25279 (May 12, 2005) (allowing use of allowance set-asides for renewables and energy efficiency); NO_x SIP Call: 63 FR 57356, 57362, 57436, 57438, 57449 (Oct. 27, 1998) (authorizing and encouraging SIPs to rely on renewables and energy efficiency to meet the state budgets).

[546] 134 S. Ct. 1584 (2014).

[547] *See, e.g.,* Guidance on SIP Credits for Emission Reductions from Electric-Sector Energy Efficiency and Renewable Energy Measures (Aug. 2004), *http://www.epa.gov/ttn/oarpg/t1/memoranda/ereseerem_gd.pdf;* Incorporating Emerging and Voluntary Measures in a State

Connecticut included in its SIP reductions from solar photovoltaic installations.[548] In 2012, the EPA provided additional guidance on this topic.[549] In addition, the EPA has partnered with the Northeast States for Coordinated Air Use Management (NESCAUM) and three states (Maryland, Massachusetts, and New York) to identify opportunities for including RE in a SIP and to provide real-world examples and lessons learned through those states' case studies.[550]

(6) <u>Other rules that relied on actions by other entities</u>.

The EPA has promulgated numerous actions that establish control requirements for affected sources on the basis of actions by other entities or actions other than measures integrated into the design or operations of the affected sources. This section summarizes some of those actions. First,

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Implementation Plan (SIP) (Sept. 2004), *http://www.epa.gov/ttn/oarpg/t1/memoranda/evm_ievm_g.pdf*.

[548] CT 1997 8-hour ozone SIP Web site, http://www.ct.gov/deep/cwp/view.asp?a=2684&q=385886&depNav_GID=1619 (see Attainment Demonstration TSD, Chapter 8 at 31, *http://www.ct.gov/deep/lib/deep/air/regulations/proposed_and_reports/section_8.pdf*).

[549] "Roadmap for Incorporating EE/RE Policies and Programs into SIPs/TIPs" (July 2012), *http://epa.gov/airquality/eere/manual.html.*

[550] States' Perspectives on EPA's Roadmap to Incorporate Energy Efficiency/Renewable Energy in NAAQS State Implementation Plans: Three Case Studies, Final Report to the U.S. Environmental Protection Agency (Dec. 2013), *http://www.nescaum.org/documents/nescaum-final-rept-to-epa-ee-in-naaqs-sip-roadmap-case-studies-20140522.pdf*.

virtually all pollution control requirements require the affected sources to depend in one way or another on other entities, such as control technology manufacturers. Second, the EPA has promulgated numerous regulatory actions that are based on trading of mass-based emission allowances or rate-based emission credits, in which many sources meet their emission limitation requirements by purchasing allowances or credits from other sources that reduce emissions.

(a) Third-party transactions.

To reiterate, commenters argue that the "system of emission reduction" must be limited to measures taken by the affected source itself because only those measures are under the control of the affected source, as opposed to third parties, and therefore only those measures can assure that the affected source will achieve its emission limits. But this argument is belied by the fact that for a wide range of pollution control measures – including many that are indisputably part of a "system of emission reduction" – affected sources are in fact dependent on third parties. For example, to implement any type of add-on pollution control equipment that is available only from a third-party manufacturer, the affected source is dependent upon that third party for developing and constructing the necessary controls, and for offering them for sale. Indeed, the affected sources may be dependent upon third parties to install (and in some cases to operate) the controls as well, and in fact, in the CAIR rule, the EPA established the compliance date based on the limited availability of the specialized workforce needed to install the controls needed by the affected EGUs.[551] In addition, EGU owners and operators may be dependent on the actions of third parties to finance the controls and third-party regulators to assure the mechanism for repaying that financing. However, this dependence does not mean that the emission limit based on that equipment is not achievable. Rather, the fact that the owner or operator of the affected source can arrange with the various third parties to acquire, install, and pay for the equipment means that emission limit is achievable.

In this rule, as noted, the affected EGUs may, in many cases, implement the measures in building blocks 2 and 3 directly, and, in other cases, implement those measures by engaging in market transactions with third parties that are as much within the affected EGUs' control as engaging in market transactions with the range of third parties involved in pollution control equipment. By the same token, the market transactions that the affected EGUs engage in with third parties

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[551] 70 FR 25162, 25216-25225 (May 12, 2005). The EPA noted that its view was "based on the NO_X SIP Call experience." *Id.* at 25217.

to implement the measures in building blocks 2 and 3 are comparable to the market transactions that affected EGUs engage in as part of their normal course of business, which include, among many examples, transactions with RTOs/ISOs or balancing authorities, entities in organized markets.

(b) Emissions trading.

Additional precedent that the "system of emission reduction" may include the measures in building blocks 2 and 3 and is not limited to measures that a source can integrate into its own design or operations, without being dependent on other entities, is found in the many rules that Congress has enacted or that the EPA has promulgated that allow EGUs and other sources to meet their emission limits by trading with other sources. In a trading rule, the EPA authorizes a source to meet its emission limit by purchasing mass-based emission allowances or rate-based emission credits generated from other sources, typically ones that implement controls that reduce their emissions to the point where they are able to sell allowances or credits. As a result, the availability of trading reduces overall costs to the industry by focusing the controls on the particular sources that have the least cost to implement controls. For present purposes, what is relevant is that in a trading program, some affected sources choose to meet their emission limits not by implementing emission controls integrated into their own design or operations, but rather by purchasing allowances or credits. These affected sources, therefore, are dependent on the actions of other entities, which are the ones that choose to meet their emission limits by implementing emission controls, which permits them to sell allowances or credits. They are dependent, however, in the same way that a source acquiring pollution control technology for the purposes of meeting a NSPS is dependent on a vendor of that technology to fulfill its contractual obligations. That is, the source operator purchasing a credit or an allowance is acquiring an equity in the technology or action applied to the credit-selling source for purposes of achieving a reduction in emissions occurring at the selling source. Trading programs have been commonplace under the CAA, particularly for EGUs, for decades. They include the acid rain trading program in Title IV of the CAA, the trading programs in the transport rules promulgated by the EPA under the "good neighbor provision" of CAA section 110(a)(2)(D)(i)(I), the Clean Air Mercury Rule, and the regional haze rules. In each of these actions, the Congress or the EPA recognized that some of the affected EGUs would implement controls or take other actions that would lower their emissions and thereby allow them to sell allowances to other EGUs, which were dependent on the purchase of those allowances to meet their obligations.[552] For the reasons just described, these trading rules refute commenters' arguments for limiting the scope of the "system of emission reduction."

(c) NSPS rules for EGUs that depend on the integrated grid.

The EPA has promulgated NSPS for EGUs that include requirements based on the fact that an EGU may reduce its generation, and therefore its emissions, because the integration of the grid allows another EGU to increase generation and thereby avoid jeopardizing the supply of electricity. For example, in 1979, the EPA finalized new standards of performance to limit emissions of SO_2 from new, modified, and reconstructed EGUs. In evaluating the best system against concerns of electric service reliability, the EPA took into account the unique

[552] For example, in the enacting the acid rain program under CAA Title IV, Congress explicitly recognized that some sources would comply by purchasing allowances instead of implementing controls. S. Rep. No. 101-228, at 303 (Dec. 20, 1989). Similarly, in promulgating the NOx SIP Call in 1998, the EPA stated, "Since EPA's determination for the core group of sources is *based on the adoption of a broad-based trading program*, average cost-effectiveness serves as an adequate measure across sources because sources with high marginal costs will be able to take advantage of this program to lower their costs." 63 FR at 57399 (emphasis added). By the same token, in promulgating the Cross State Air Pollution Rule, the EPA stated, "the preferred trading remedy will allow source owners to choose among several compliance options to achieve required emission reductions in the most cost effective manner, such as installing controls, changing fuels, reducing utilization, *buying allowances*, or any combination of these actions." 76 FR at 48272 (emphasis added).

features of power transmission along the interconnected grid and the unique commercial relationships that rely on those features.[553]

Additionally, in 1982, the EPA recognized that utility turbines could meet a NO_x emission limit without unacceptable economic consequences because "other electric generators on the grid can restore lost capacity caused by turbine down time."[554] We describe the relevant parts of these rules in greater detail in the Legal Memorandum.

(7) Consistency with the purposes of the Clean Air Act.

Interpreting the term "system of emission reduction" broadly to include building blocks 2 and 3 (so that the "best system of emission reduction ... adequately demonstrated" may include those measures as long as they meet all of the applicable requirements) is also consistent with the purposes of the CAA. Most importantly, these purposes include protecting public health and welfare by comprehensively addressing air pollution, and, particularly, protecting against urgent and

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[553] *See* 44 FR 33580, 33597-33600 (taking into account "the amount of power that could be purchased from neighboring interconnected utility companies" and noting that "[a]lmost all electric utility generating units in the United States are electrically interconnected through power transmission lines and switching stations" and that "load can usually be shifted to other electric generating units").

[554] 47 FR 3767, 3768 (Jan. 27, 1982).

severe threats. In addition, these purposes include promoting pollution prevention measures, as well as the advancement of technology that reduces air pollution.

(a) <u>Purpose of protecting public health and welfare</u>.

The first provisions in the Clean Air Act set out Congress's findings and the CAA's purposes. They provide as follows, in relevant part:

> Section 101. Congressional findings and declaration of purpose
>
> (a) The Congress finds—
>
> * * * *
>
> (2) that the growth in the amount and complexity of air pollution brought about by urbanization, industrial development, and the increasing use of motor vehicles, has resulted in mounting dangers to the public health and welfare * * * *
>
> (3) that air pollution prevention (that is, the reduction or elimination, through any measures, of the amount of pollutants produced or created at the source) and air pollution control at its source is the primary responsibility of States and local governments; and
>
> (4) that Federal financial assistance and leadership is essential for the development of cooperative Federal, State, regional, and local programs to prevent and control air pollution.
>
> (b) The purposes of this title are—
>
> (1) to protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare and the productive capacity of its population;

(2) to initiate and accelerate a national research and development program to achieve the prevention and control of air pollution;

(3) to provide technical and financial assistance to State and local governments in connection with the development and execution of their air pollution prevention and control programs; and

(4) to encourage and assist the development and operation of regional air pollution prevention and control programs.

(c) POLLUTION PREVENTION.—A primary goal of this Act is to encourage or otherwise promote reasonable Federal, State, and local governmental actions, consistent with the provisions of this Act, for pollution prevention.

As just quoted, these provisions are explicit that the purpose of the CAA is "to protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare and the productive capacity of its population." Moreover, Congress designed the CAA to be "the comprehensive vehicle for protection of the Nation's health from air pollution"[555] and, in fact, designed CAA section 111(d) to address air pollutants not covered under other provisions, specifically so that "there should be no gaps in control activities pertaining to stationary source emissions that pose

[555] H.R. Rep. No. 95-294, at 42 (May 12, 1977), 1977 CAA Legis. Hist. at 2509 (discussing a provision in the House Committee bill that became CAA section 122, requiring the EPA to study and regulate radioactive air pollutants and three other air pollutants).

any significant danger to public health or welfare."[556] Furthermore, in these purpose provisions, Congress recognized that while pollution prevention and control are the primary responsibility of the States, "federal leadership" would be essential.

At its core, Congress designed the CAA to address urgent and severe threats to public health and welfare. This purpose is evident throughout 1970 CAA Amendments, which authorized stringent remedies that were necessary to address those problems. By 1970, Congress viewed the air pollution problem, which had been worsening steadily as the nation continued to industrialize and as automobile travel dramatically increased after World War II,[557] as nothing short of a national crisis.[558]

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[556] S. Rep. No. 91-1196, at 20 (Sept. 17, 1970), 1970 CAA Legis. Hist. at 420 (discussing section 114 of the Senate Committee bill, which was the basis for CAA section 111(d)).

[557] *See* Dewey, Scott Hamilton, *Don't Breathe the Air: Air Pollution and U.S. Environmental Politics, 1945-1970* (Texas A&M University Press 2000).

[558] 1970 was a significant year in environmental legislation, but it was also marked as "a year of environmental concern." Sen. Muskie, S. Debate on S. 4358 (Sept. 21, 1970), 1970 CAA Legis. Hist. at 223. By mid-1970, Congress recognized that "[o]ver 200 million tons of contaminants [were] spilled into the air each year in America.... And each year these 200 million tons of pollutants endanger the health of [the American] people." *Id.* at 224. "Cities up and down the east coast were living under clouds of smog and daily air pollution alerts." Sen. Muskie, S. Consideration of the Conference Rep. (Dec. 18, 1970), 1970 CAA Legis. Hist. at 124. Put simply, America faced an "environmental crisis." Sen. Muskie, S. Debate on S. 4358 (Sept. 21, 1970), 1970 CAA Legis. Hist. at 224. The conference agreement, it was

With the 1970 CAA Amendments, Congress enacted a stringent response, designed to match the severity of the problem. At the same time, Congress did not foreclose the EPA's ability to address new environmental concerns; in fact, Congress largely deferred to the EPA's expertise in identifying pollutants and sources that adversely affect public health or welfare. In doing so, Congress authorized the EPA to establish national ambient air quality standards for the most pervasive air pollutants -- including the precursors for the choking smog that blanketed urban areas[559] --to protect public health with an ample margin of safety. Disappointed that the states had not taken effective action to that point to curb air pollution, "Congress reacted by taking a stick to the States"[560] and including within the 1970

reported, "faces the air pollution crisis with urgency and in candor. It makes hard choices, provides just remedies, requires stiff penalties." Sen. Muskie, S. Consideration of the Conference Rep. (Dec. 18, 1970), 1970 CAA Legis. Hist. at 123. "[I]t represents [Congress'] best efforts to act with the knowledge available ... in an affirmative but constructive manner." *Id.* at 150.

[559] *See* Dewey, Scott Hamilton, *Don't Breathe the Air: Air Pollution and U.S. Environmental Politics, 1945-1970* (Texas A&M University Press 2000) at 230 ("By the mid-1960s, top federal officials showed an increasing sense of alarm regarding the health effects of polluted air. In June, 1966, Secretary of Health, Education, and Welfare John W. Gardner testified before the Muskie subcommittee: "We believe that air pollution at concentrations which are routinely sustained in urban areas of the United States is a health hazard to many, if not all, people.").

[560] *Train v. NRDC*, 421 U.S. 60, 64 (1975).

CAA Amendments both the requirement that the states develop plans to assure that their air quality areas would meet those standards by no later than five years, and the threat of imposition of federal requirements if the states did not timely adopt the requisite plans. Congress also required the EPA to establish standards for hazardous air pollutants that could result in shutting sources down. Congress added stringent controls on automobiles, overriding industry objections that the standards were not achievable. In addition, Congress added CAA section 111(b), which required the EPA to list categories based on harm to public health and regulate new sources in those categories. Congress then designed CAA section 111(d) to assure, as the Senate Committee Report for the 1970 CAA Amendments noted, that "there should be no gaps in control activities pertaining to stationary source emissions that pose any significant danger to public health or welfare."[561]

Similarly, the 1977 and 1990 CAA Amendments were also designed to respond to new and/or pressing environmental issues.

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[561] S. Rep. No. 91-1196, at 20 (Sept. 17, 1970), 1970 CAA Legis. Hist. at 420 (discussing section 114 of the Senate Committee bill, which was the basis for CAA section 111(d)). Note that in the 1977 CAA Amendments, the House Committee Report made a similar statement. H.R. Rep. No. 95-294, at 42 (May 12, 1977), 1977 CAA Legis. Hist. at 2509 (discussing a provision in the House Committee bill that became CAA section 122, requiring EPA to study and then take action to regulate radioactive air pollutants and three other air pollutants).

For example, in 1977 then-EPA Administrator Costle testified before Congress that the expected increase in coal use (in response to various energy crises, including the 1973-74 Arab Oil Embargo) "will make vigorous and effective control even more urgent."[562] Similarly, by 1990, Congress recognized that "many of the Nation's most important air pollution problems [had] failed to improve or [had] grown more serious."[563] Indeed, President George H. W. Bush said that "'progress has not come quickly enough and much remains to be done.'"[564]

Climate change has become the nation's most important environmental problem. We are now at a critical juncture to take meaningful action to curb the growth in CO_2 emissions and forestall the impending consequences of prior inaction. CO_2 emissions from existing fossil fuel-fired power plants are by far the largest source of stationary source emissions. They emit

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[562] Statement of Administrator Costle, Hearings before the Subcommittee on Energy Production and Supply of the Senate Committee on Energy and Natural Resources (Apr. 5, 7, May 25, June 24 and 30, 1977), 1977 CAA Legis. Hist. at 3532 (discussing the relationship between the National Energy Plan and the Administration's proposed CAA amendments). Some of the specific changes to the CAA include the addition of the PSD program, visibility protections, requirements for nonattainment areas, and stratospheric ozone provisions.

[563] H.R. Rep. No. 101-490, at 144 (May 17, 1990).

[564] H.R. Rep. No. 101-490, at 144 (May 17, 1990). Some of the changes adopted in 1990 include revisions to the NAAQS nonattainment program, a more aggressive and substantially revised CAA section 112, the new acid rain program, an operating permits program, and a program for phasing out of certain ozone depleting substances.

almost three times as much CO_2 as do the next nine stationary source categories combined, and approximately the same amount of CO_2 emissions as all of the nation's mobile sources. The only controls available that can reduce CO_2 emissions from existing power plants in amounts commensurate with the problems they pose are the measures in building blocks 2 and 3, or far more expensive measures such as CCS.

Thus, interpreting the "system of emission reduction" provisions in CAA section 111(d)(1) and (a)(1) to allow the nation to meaningfully address the urgent and severe public health and welfare threats that climate change pose is consistent with what the CAA was designed to do.[565] This interpretation is also consistent with the cooperative purpose of section 111(d) to assure that the CAA comprehensively address

[565] In addition, as we have noted, in designing the 1970 CAA Amendments, Congress was aware that carbon dioxide increased atmospheric temperatures. In 1970, when Congress learned that "the carbon dioxide balance might result in the heating up of the atmosphere" and that particulate matter "might cause reduction in radiation," the Nixon Administration assured Congress that "[w]hat we are trying to do, however, in terms of our air pollution effort should have a very salutary effect on either of these." Testimony of Charles Johnson, Jr., Administrator of the Consumer Protection and Environmental Health Service (Administration Testimony), Hearing of the House Subcommittee on Public Health and Welfare (Mar. 16, 1970), 1970 CAA Legis. Hist. at 1381. Many years later, scientific consensus has formed around the particular causes and effects of climate change; and the tools put in place in 1970 can be read fairly to address these concerns.

those threats through the mechanism of state plans, where the states assume primary responsibility under federal leadership. *See King v. Burwell*, 576 U.S. (2015), No. 14-114 (2015), slip op. at 15 ("We cannot interpret federal statutes to negate their own stated purposes" (quoting *New York State Dept. of Social Servs. v. Dublino*, 413 U.S. 405, 419-20 (1973)); *id*. at 21 ("A fair reading of legislation demands a fair understanding of the legislative plan.").[566]

(b) Purpose of encouraging pollution prevention. Interpreting "system of emission reduction" to include building blocks 2 and 3 is also consistent with the CAA's purpose to encourage pollution prevention. CAA section 101(c) states that

[566] This final rule is also consistent with the CAA's purpose of protecting health and welfare. For example, the CAA authorizes the EPA to regulate air pollutants as soon as the EPA can determine that those pollutants pose a risk of harm, and not to wait until the EPA can prove that those pollutants actually cause harm. *See* H.R. Rep. No. 95-294, at 49 (May 12, 1977), 1977 CAA Legis. Hist. at 2516 (describing the CAA as being designed... to assure that regulatory action can effectively prevent harm before it occurs; to emphasize the predominant value of protection of public health").The protective spirit of the CAA extends to the present rule, in which the EPA regulates on the basis of building blocks 2 and 3 because the range of available and cost-effective measures in those building blocks achieves more pollution reduction than building block 1 alone. Indeed, add-on controls that are technically capable of reducing CO_2 emissions at the scale necessitated by the severity of the environmental risk -- for example, CCS technology -- are not as cost-effective as building blocks 2 and 3 on an industry-wide basis, and while the costs of the add-on controls can be expected to be reduced over time, it is not consonant with the protective spirit of the CAA to wait.

"[a] primary goal of [the CAA] is to encourage or otherwise promote reasonable federal, state, and local governmental actions, consistent with the provisions of this chapter, for pollution prevention." Indeed, in the U.S. Code, in which the CAA is codified as chapter 85, the CAA is entitled, "Air Pollution Prevention and Control."[567] CAA section 101(a)(3) describes "air pollution prevention" as "the reduction or elimination, through *any* measures, of the amount of pollutants produced or created at the source". (Emphasis added.) The reference to "any measures" highlights the breadth of what Congress considered to be pollution prevention, that is, any and all measures that reduce or eliminate pollutants at the source.[568]

The measures in building blocks 2 and 3 qualify as "pollution prevention" measures because they are "any measures" that "reduc[e] or eliminate[e] ... the amount of pollutants

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[567] *See* Air Quality Act of 1967, Pub. L. 90-148, § 2, 81 Stat. 485 (Nov. 21, 1967) (adding "Title I—Air Pollution Prevention and Control" to the CAA, along with Congress' initial findings and purposes under CAA section 101).

[568] Section 101 emphasizes the importance of air pollution prevention in two other provisions: CAA section 101(b)(4) states that one of "the purposes of [title I of the CAA, which includes section 111] are ... (b) to encourage and assist the development and operation of regional air pollution prevention and control programs." CAA section 101(a)(3) adds: "The Congress finds -- ... (3) that air pollution prevention … and air pollution control at its source is the primary responsibility of states and local governments." In fact, section 101 mentions pollution prevention no less than 6 times.

produced or created at the [fossil fuel-fired affected] source[s].” Thus, consistent with the CAA’s primary goals, it is therefore reasonable to interpret a “system of emission reduction,” as including the pollution prevention measures in building blocks 2 and 3.

(c) Purpose of advancing technology to control air pollution.

This final rule is also consistent with CAA section 111’s purpose of promoting the advancement of pollution control technology based on the expectation that American industry will be able to develop innovative solutions to the environmental problems.

The legislative history and case law of CAA section 111 identify three different ways that Congress designed CAA section 111 to authorize standards of performance that promote technological improvement: (i) the development of technology that may be treated as the “best system of emission reduction ... adequately demonstrated;” under CAA section 111(a)(1);[569] (ii) the expanded use of the best demonstrated technology;[570] and

[569] *See Portland Cement Ass’n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973) (the best system of emission reduction must “look[] toward what may fairly be projected for the regulated future, rather than the state of the art at present”).
[570] *See* S. Rep. No. 91-1196, at 15 (“The maximum use of available means of preventing and controlling air pollution

(iii) the development of emerging technology.[571] This rule is consistent with the second of those ways -- it expands the use of the measures in building blocks 2 and 3, which are already established and provide substantial reductions at reasonable cost. As discussed below, the use of the measures in these building blocks will be most fully expanded when organized markets develop, and our expectation that those markets will develop is consistent with the Congress's view, just described, that CAA section 111 should promote technological innovation.

This final rule is also consistent with Congress's overall view that the CAA Amendments as a whole were designed to promote technological innovation. In enacting the CAA, Congress articulated its expectation that American industry would be creative and come up with innovative solutions to the urgent and severe problem of air pollution. This is manifest in the well-recognized technology-forcing nature of the CAA, and was expressed in numerous, sometimes ringing, statements in the legislative history about the belief that American industry will be able to develop the needed technology. For example, in the 1970 floor debates, Congress recalled that the nation had put a

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is essential to the elimination of new pollution problems").

[571] *See Sierra Club v. Costle*, 657 F.2d at 351 (upholding a standard of performance designed to promote the use of an emerging technology).

man on the moon a year before and had won World War II a quarter century earlier, and attributed much of the credit for those singular achievements to American industry and its ability to be productive and innovative. Congress expressed confidence that American industry could meet the challenges of developing air pollution controls as well.[572]

(d) Response to commenters concerning purpose.

Commenters have stated that the proposed rule "would transform CAA section 111 into something untethered to its statutory language and unrecognizable to the Congress that created it."[573] Commenters with this line of comments focused on the ramifications of building block 4, which the EPA has decided does not belong in BSER using EPA's historical interpretation of BSER. Regardless of whether the comments are accurate with

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[572] Sen. Muskie, S. Debates on S. 4358 (Sept. 21, 1970), 1970 CAA Legis. Hist. at 227 ("At the beginning of World War II industry told President Roosevelt that his goal of 100,000 planes each year could not be met. The goal was met, and the war was won. And in 1960, President Kennedy said that America would land a man on the moon by 1970. And American industry did what had to be done. Our responsibility in Congress is to say that the requirements of this bill are what the health of the Nation requires, and to challenge polluters to meet them."). *See* Blaime, A.J., *The Arsenal of Democracy: FDR, Detroit, and an Epic Quest to Arm an America at War* (Houghton Mifflin Harcourt 2014); Carew, Michael G., *Becoming the Arsenal: The American Industrial Mobilization for World War II, 1938-1942* (University Press of America, Inc. 2010).

[573] UARG comment at 31. *See id.* at 18, 29, 49. This comment appears to be a reference to the Supreme Court's statement in *UARG*. *See Util. Air Reg. Group v. EPA*, 134 S. Ct. 2427, 2444 (2014).

respect to building block 4 measures, they are certainly not accurate with respect to the three building blocks that the EPA is defining as the BSER. This rule would be recognizable to the Congresses that created and amended CAA section 111 and is carefully fashioned to the statutory text in CAA section 111(d) and (a)(1). This final rule would be recognizable to the Congress that adopted CAA section 111 in 1970 as part of a bold, far-reaching law designed to address comprehensively an air pollution crisis that threatened the health of millions of Americans; to have EPA and the States work cooperatively to develop state-specific approaches to address a national problem; to challenge industry to meet that crisis with creative energy; and to give the EPA broad authority -- under section 111 and other provisions -- to craft the needed emission limitations. This final rule would be recognizable to the Congress that revised CAA section 111 in 1977 to explicitly authorize that standards be based on actions taken by third parties (fuel cleaners). And this final rule would be recognizable to the Congress that revised CAA section 111 in 1990 to be linked to the Acid Rain Program that Congress adopted at the same time, which regulated the same industry (fossil fuel-fired EGUs) through some of the same measures (generation shifts and RE), and that explicitly acknowledged that those measures (RE) would also reduce CO_2 and thereby address the dangers of climate change. To reiterate, for the reasons explained in this preamble, this rule is grounded in our reasonable interpretation of CAA section 111(d) and (a)(1).

(8) Constraints on the BSER – treatment of building block 4 and response to comments concerning precedents.

Although the BSER provisions are sufficiently broad to include, for affected EGUs, the measures in building blocks 2 and 3, they also incorporate significant constraints on the types of measures that may be included in the BSER. We discuss those constraints in this section. These constaints explain why we are not including building block 4 in the BSER. In addition, these constraints explain why our reliance on building blocks 2 and 3 will have limited precedential effect for other rulemakings, and serve as our basis for responding to commenters who expressed concern that reliance on building blocks 2 and 3 would set a precedent for the EPA to rely on similar measures in promulgating future air pollution controls for other sectors.[574]

As discussed above, the emission limits in the CAA section 111(d) emission guidelines that this rule promulgates are based

[574] Commenters offered hypothetical examples to illustrate their concerns over precedential effects, discussed below. Some commenters objected that our proposed interpretation of the BSER failed to include limiting principles. In the Legal Memorandum, we discuss the relevance of limiting principles and note that the statutory constraints discussed in this section of the preamble constitute limits on the type of the BSER that the EPA is authorized to determine.

on the EPA's determination, for the affected EGUs, of the "system of emission reduction" that is the "best," taking into account "cost" and other factors, and that is "adequately demonstrated." Those components include certain interpretations and applications and provide constraints on the types of measures or controls that the EPA may determine to include in the BSER.

(a) Emission reductions from affected sources.

The first constraint is that the BSER must assure emission reductions from the affected sources. Under section 111(d)(1), the states must submit state plans that "establish[] standards of performance for any existing source," and, under section 111(a)(1) and the EPA's implementing regulations, those standards are informed by the EPA's determination of the best system of emission reduction adequately demonstrated. Because the emission standards must apply to the affected sources, actions taken by affected sources that do not result in emission reductions from the affected sources -- for example, offsets (e.g., the planting of forests to sequester CO_2) -- do not qualify for inclusion in the BSER. Building blocks 2 and 3 achieve emission reductions from the affected EGUs, and thus are not precluded under this constraint.

(b) Controls or measures that affected EGUs can implement.

The second constraint is that because the affected EGUs must be able to achieve their emission performance rates through the application of the BSER, the BSER must be controls or measures that the EGUs themselves can implement. Moreover, as noted, the D.C. Circuit has established criteria for achievability in the section 111(b) case law; *e.g.*, sources must be able to achieve their standards under a range of circumstances. If those criteria are applicable in a section 111(d) rule, the BSER must be of a type that allows sources to meet those achievability criteria. As noted, under this rule, affected EGUs can achieve their emission performance rates in the various circumstances under which they operate, through the application of the building blocks.

(c) "Adequately demonstrated."

The third constraint is that the system of emission reduction that the EPA determines to be the best must be "adequately demonstrated." To qualify as the BSER, controls and measures must align with the nature of the regulated industry and the nature of the pollutant so that implementation of those controls or measures will result in emission reductions from the industry and allow the sources to achieve their emission performance standards. The history of the effectiveness of the controls or other measures, or other indications of their effectiveness, are important in determining whether they are adequately demonstrated.

More specifically, the application of building blocks 2 and 3 to affected EGUs has a number of unique characteristics. Building blocks 2 and 3 entail the production of the same amount of the same product -- electricity, a fungible product that can be produced using a variety of highly substitutable generation processes -- through the cleaner (that is, less CO_2-intensive) processes of shifting dispatch from steam generators to existing NGCC units, and from both steam generators and NGCC units to renewable generators.

The physical properties of electricity and the highly integrated nature of the electricity system allow the use of these cleaner processes to generate the same amount of electricity. In addition, the electricity sector is primarily domestic -- little electricity is exported outside the U.S. -- and there is low capacity for storage. In addition, the electricity sector is highly regulated, planned, and coordinated. As a result, holding demand constant, an increase in one type of generation will result in a decrease in another type of generation. Moreover, the higher-emitting generators, which are fossil fuel-fired, have higher variable costs than renewable generators, so that increased renewable generation will generally back out fossil fuel-fired generation.

Because of these characteristics, the electricity sector has a long and well-established history of substituting one type of generation for another. This has occurred for a wide variety of reasons, many of which are directly related to the system's primary purposes and functions, as well as for environmental reasons. As a result, at present, there is a well-established network of business and operational relationships and past practices that supports building blocks 2 and 3. As noted elsewhere, a large segment of steam generators already have business relationships with existing NGCC units, and a large segment of all fossil fuel-fired EGUs already own, co-own, or have invested in RE.

Many of these characteristics are unique to the utility power sector. Moreover, this complex of characteristics, ranging from the physical properties of electricity and the integrated nature of the grid to the institutional mechanisms that assure reliability and the existing practices and business relationships in the industry, combine to facilitate the implementation of building blocks 2 and 3 in a uniquely efficient manner. This supports basing the emission limits on the ability of owners and operators of fossil fuel-fired EGUs to replace their generation with cleaner generation in other locations, sometimes owned by other entities.

As noted above, commenters offered hypothetical examples to illustrate their concerns over precedential effects. Most of their concerns focused on building block 4, and most of their hypothetical examples concerned reductions in demand for various types of products. We address these concerns in the response to comments document, but we note here that, in any event, these concerns are mooted because we are not finalizing building block 4. Some commenters offered hypothetical examples for building blocks 2 and 3 as well. For example, some commenters asserted that the EPA could "develop standards of performance for tailpipe emissions from motor vehicles" by "requiring car owners to shift some of their travel to buses," which the commenters considered analogous to building block 2; or by "requiring there to be more electric vehicle purchases," which the commenters considered analogous to building block 3.[575]

Commenters' concerns over precedential impact cannot be taken to mean that the building blocks should not be considered to meet the requirements of the BSER or that the affected EGUs cannot be considered to meet the emission limits by implementing those measures. Moreover, because many of these individual characteristics, and their inherent complexity, are unique to the utility power sector, building blocks 2 and 3 as applied to

[575] UARG comment at 2-3.

fossil fuel-fired EGUs will have a limited precedent for other industries and other types of rulemakings. For example, the commenter's hypothetical examples noted above are inapposite for several reasons. The hypotheticals appear to be premised on government action mandating actions not implementable by emitting sources (e.g., that a government would "require[e] car owners to shift some of their travel to buses, or ... require[e] there to be more electric vehicle purchases"), whereas the measures in building blocks 2 and 3 can be implemented by the affected EGUs. Nor have commenters attempted to address how car owners shifting travel to buses or purchasing more electric vehicles could be translated into lower tailpipe standards for motor vehicles.[576]

(d) "Best" in light of "cost ... nonair quality health and environmental impact and energy requirements" and EPA's past practice and current policy.

The fourth constraint, or set of constraints, is that the system of emission reduction must be the "best," "taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements." As noted, in light of the D.C. Circuit case law,

[576] In any event, it is questionable whether measures such as those hypothesized by the commenters would be consistent with the provisions of Title II.

the EPA has considered cost and energy factors on both an individual source basis and on the basis of the nationwide electricity sector. In determining what is "best," the EPA has broad discretion to balance the enumerated factors.[577] In interpreting and applying these provisions in this rulemaking to regulate CO_2 emissions from affected EGUs under section 111(d), we are acting consistently with our past practice for applying these provisions in previous section 111 rulemakings and for regulating air pollutants from the electricity sector under other provisions of the CAA, as well as current policy.

The great majority of our regulations under section 111 have been 111(b) regulations for new sources. As discussed in the Legal Memorandum and briefly below, the BSER identified under section 111(b) is designed to assure that affected sources are well controlled at the time of construction, and that approach is consistent with the design expressed in the legislative history for the 1970 CAA Amendments that enacted the provision.

Traditionally, CAA section 111 standards have been rate-based, allowing as much overall production of a particular good as is desired, provided that it is produced through an appropriately clean (or low-emitting) process. CAA section 111

[577] *See Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999).

performance standards have primarily targeted the means of production in an industry and not consumers' demand for the product. Thus, the focus for the BSER has been on how to most cleanly produce a good, not on limiting how much of the good can be produced.

One example of the focus under section 111 on clean production, not limitation of product is provided by the revised new source performance standards for electric utility steam generating units that we promulgated in 1979 following the 1977 CAA Amendments to limit emissions of SO_2, PM, and NOx. In relevant part, the revised standards limited SO_2 emissions to 1.20 lb/million BTU heat input and imposed a 90 percent reduction in potential SO_2 emissions. This was based on the application of flue gas desulfurization (FGD) together with coal preparation techniques. In the preamble, we explain that "[t]he intent of the final standards is to encourage power plant owners and operators to install the best available FGD systems and to implement effective operation and maintenance procedures but not to create power supply disruptions."[578,579] EPA has taken the same overall approach in its section 111(d) rules,[580] including the CAMR rule noted below.

Similarly, in a series of rulemakings regulating air pollutants from EGUs under several provisions of the CAA, we have focused our efforts on assuring that electricity is

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[578] *See, e.g.*, 44 FR 33580, at 33599 (June 11, 1979). In this rulemaking, the EPA recognized the ability of the integrated grid to minimize power disruptions: "When electric load is shifted from a new steam-electric generating unit to another electric generating unit, there would be no net change in reserves within the power system. Thus, the emergency condition provisions prevent a failed FGD system from impacting upon the utility company's ability to generate electric power and prevents an impact upon reserves needed by the power system to maintain reliable electric service." *Id.*

[579] The EPA's 1982 revised new source performance standards for certain stationary gas turbines provide another example of a rulemaking that focused controls on reducing emissions, as well as reliance on the integrated grid to avoid power disruptions. 44 FR 33580 (June 11, 1979). In response to comments that requested a NOx emission limit exemption for base load utility gas turbines, the EPA explained that "for utility turbines ... since other electric generators on the grid can restore lost capacity caused by turbine down time" the NOx emission limit of 1150 ppm for such turbines would not be rescinded. 44 FR 33580, at 33597-98.

[580] *See* "Phosphate Fertilizer Plants; Final Guideline Document Availability," 42 FR 12022 (Mar. 1, 1977); "Standards of Performance for New Stationary Sources; Emission Guideline for Sulfuric Acid Mist," 42 FR 55796 (Oct. 18, 1977); "Kraft Pulp Mills, Notice of Availability of Final Guideline Document," 44 FR 29828 (May 22, 1979); "Primary Aluminum Plants; Availability of Final Guideline Document," 45 FR 26294 (Apr. 17, 1980); "Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills, Final Rule," 61 FR 9905 (Mar. 12, 1996).

generated through cleaner or lower-emitting processes, and we have not sought to limit the aggregate amount of electricity that is generated. We describe those rules in section II, elsewhere in this section V.B.3., and in the Legal Memorandum.

For example, as discussed in the Legal Memorandum, in the three transport rules promulgated under CAA section 110(a)(2)(D)(i)(I) – the NOx SIP Call, CAIR, and CSAPR – which regulated precursors to ozone-smog and particulate matter, the EPA based certain aspects of the regulatory requirements on the fact that fossil fuel-fired EGUs could shift generation to lower-emitting sources. In CAMR, the 2005 rulemaking under section 111(d) regulating mercury emissions from coal-fired EGUs, the EPA based the first phase of control requirements on the actions the affected EGUs were required to take under CAIR, including shifting generation to lower-emitting sources. In addition, as also discussed in the Legal Memorandum, in the EPA's 2012 MATS rule regulating mercury from coal-fired EGUs under section 112, at industry's urging, the EPA allowed compliance deadlines to be extended for coal-fired EGUs that desired to substitute replacement power of any type, including NGCC units or RE, for compliance purposes.

While these and other rulemakings for fossil fuel-fired EGUs took different approaches towards lower-emitting generation and renewable generation, they all were based on control measures that reduced emissions without reducing aggregate levels of electricity generation. It should be noted that even though some of those rules established overall emission limits in the form of budgets implemented through a cap-and-trade program, the EPA recognized that the fossil fuel-fired EGUs that were subject to the rules could comply by shifting generation to lower-emitting EGUs, including relying on RE. In this manner, the rules limited emissions but on the basis that the industry could implement lower-emitting processes, and not based on reductions in overall generation.

We are applying the same approach to this rulemaking. Our basis for this rulemaking is that affected EGUs can implement a system of emission reduction that will reduce the amount of their emissions without reducing overall electricity generation. This approach takes into account costs by minimizing economic disruption as well as the nation’s energy requirements by avoiding the need for environmental-based reductions in the aggregate amount of electricity available to the consumer, commercial, and industrial sectors.

This approach is a reasonable exercise of the EPA’s discretion under section 111, consistent with the U.S. Supreme Court’s statements in its 2011 decision, *American Electric Power Co. v. Connecticut*, that the CAA and the EPA actions it authorizes displace any federal common law right to seek abatement of CO_2 emissions from fossil-fuel fired power plants. There, the Court emphasized that CAA section 111 authorizes the EPA -- which the Court identified as the "expert agency" -- to regulate CO_2 emissions from fossil fuel-fired power plants based an "informed assessment of competing interests…. Along with the environmental benefit potentially achievable, our Nation's energy needs and the possibility of economic disruption must weigh in the balance."[581]

Similarly, the D.C. Circuit, in a 1981 decision upholding the EPA's section 111(b) standards for air pollutants from fossil fuel-fired EGUs, stated that section 111 regulations concerning the electric power sector "demand a careful weighing of cost, environmental, and energy considerations."[582] This exercise of policy discretion is consistent with Congress's expectation that the Administrator "should determine the achievable limits"[583] and "would establish guidelines as to what the best system for each such category of existing sources

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[581] *American Electric Power Co. v. Connecticut*, 131 S. Ct. 2527, 2539-40 (2011).

[582] *Sierra Club v. EPA*, 657 F.2d 298, 406 (D.C. Cir. 1981). *Id.* at 406 n. 526.

[583] S. Rep. No. 91-1196, at 15-16 (Sept. 17, 1970), 1970 CAA Legis. Hist. at 415-16 (explaining that the "[Administrator] should determine the achievable limits and let the owner or operator determine the most economic, acceptable technique to apply.").

is."[584] As the D.C. Circuit explained, "[i]t seems likely that if Congress meant ... to curtail EPA's discretion to weigh various policy considerations it would have explicitly said so in section 111, as it did in other parts of the statute."[585]

Our interpretation that CAA section 111 targets supply-side activities that allow continued production of a product through use of a cleaner process, rather than targeting consumer-oriented behavior, also furthers Congress' intent of promoting cleaner production measures "to protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare and the productive capacity of its population."[586] This principle is also consistent with promoting "reasonable ... governmental actions ... for pollution prevention."[587]

In this rule, we are applying that same approach in interpreting the BSER provisions of section 111. That is, we are basing the regulatory requirements on measures the affected EGUs can implement to assure that electricity is generated with lower emissions, taking into account the integrated nature of the industry and current industry practices. Building blocks 1, 2 and 3 fall squarely within this paradigm; they do not require reductions in the total amount of electricity produced.

[584] H.R. Rep. No. 95-294, at 195 (May 12, 1977).
[585] *Sierra Club v. Costle*, 657 F.2d 298, 330 (D.C. Cir. 1981).
[586] CAA section 101(b)(1).
[587] CAA section 101(c).

We recognize that commenters have raised extensive legal concerns about building block 4. We recognize that building block 4 is different from building blocks 1, 2, and 3 and the pollution control measures that we have considered under CAA section 111. Accordingly, under our interpretation of section 111, informed by our past practice and current policy, today's final action excludes building block 4 from the BSER. Building block 4 is outside our paradigm for section 111 as it targets consumer-oriented behavior and demand for the good, which would reduce the amount of electricity to be produced.

Although numerous commenters urged us to include demand-side EE measures as part of the BSER, as we had proposed to do, we conclude that we cannot do so under our historical practice, current policy, and current approach to interpreting section 111 as well as our historical practice in regulating the electricity sector under other CAA provisions. While building blocks 2 and 3 are rooted in our past practice and policy, building block 4 is not and would require a change (which we are not making) in our interpretation and implementation and application of CAA section 111.

Excluding demand-side EE measures from the BSER has the benefit of allaying legal and other concerns raised by commenters, including concerns that individuals could be "swept into" the regulatory process by imposing requirements on "every household in the land."[588] While building block 4 could have been implemented without imposing requirements on individual households, this final rule resolves any doubt on this matter and is not based on the inclusion of demand-side EE as part of the BSER.

By the same token, we are not finalizing reduced generation of electricity overall as the BSER. Instead, components of the BSER focus on shifting generation to lower- or zero-emitting processes for producing electricity.[589]

(e) Constraints for new sources.

For new sources, practical and policy concerns support the interpretation of basing the BSER on controls that new sources can install at the time of construction, so that they will be well-controlled throughout their long useful lives. This approach is consistent with the legislative history. We discuss this at greater length in the Legal Memorandum.

4. Relationship between a source's implementation of building blocks 2 and 3 and its emissions.

In this section, we discuss the relationship between an affected EGU's implementation of the measures in building blocks

[588] *See Util. Air Reg. Group v. EPA*, 134 S. Ct. 2427, 2436 (2014).

[589] As discussed below, however, reduced generation remains important to this rule in that it is one of the methods for implementing the building blocks.

2 and 3 and that affected EGU's own generation and emissions. As discussed above, an affected EGU subject to a CAA section 111(d) state plan that imposes an emission rate-based standard may achieve that standard in part by implementing the measures in building block 2 (for a steam generator) and building block 3 (for a steam generator or combustion turbine). That is, an affected EGU may invest in low- or zero-emitting generation and may apply credits from that generation against its emission rate. Those credits reduce the affected EGU's emission rate and thereby help it to achieve its emission limit.

In addition, the additional low- or zero-emitting generation that results from the affected EGU's investment will generally displace higher-emitting generation. This is because, as described above, higher-emitting generation generally has higher variable costs, reflecting its fuel costs, than, at least, zero-emitting generation. Displacement of higher-emitting generation will lower overall CO_2 emissions from the source category of affected EGUs.

If an affected EGU implements building block 2 or 3 by reducing its own generation, it will reduce its own emissions. However, the affected EGU may also or alternatively choose to implement building block 2 or 3 by investing in lower- or zero-emitting generation that does not, in and of itself, reduce the amount of its own generation or emissions. Even so, implementation of building blocks 2 and 3 will reduce CO_2 from some affected EGUs, and therefore reduce CO_2 on a source category-wide basis.

This outcome is, however, consistent with the requirements of CAA section 111(d)(1) and (a)(1). To reiterate, CAA section 111(d)(1) requires that "any existing source" have a "standard of performance," defined under CAA section 111(a)(1) as "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction ... adequately demonstrated [BSER] ...." These provisions require by their terms that "any existing source" must have a "standard of performance," but nothing in these provisions requires a particular amount -- or, for that matter, any amount -- of emission reductions from each and every existing source. That the "standard of performance" is defined on the basis of the "degree of emission limitation achievable through the application of the [BSER]" does not mean that each affected EGU must achieve some amount of emission reduction, for the following reasons.

The cornerstone of the definition of the term "standard of performance" is the BSER. In determining the BSER, the EPA must consider the amount of emission reduction that the system may achieve, and must consider the ability of the affected EGUs to achieve the emission limits that result from the application of the BSER. The EPA is authorized to include in the BSER, for this source category, the measures in building blocks 2 and 3 because, when applied to the source category, these measures result in emission standards that may be structured to ensure overall emission reductions from the source category and remain achievable by the affected EGUs. This remains so regardless of whether the "degree of emission limitation achievable through the application of the [BSER]" by any particular source results in actual emission reductions from that source.

The application of the building blocks has an impact that is similar to that of an emissions trading program, under which, overall, the affected sources reduce emissions, but any particular source does not need to reduce its emissions and, in fact, may increase its emissions, as long as it purchases sufficient credits or allowances from other sources. In fact, we expect that that many states will carry out their obligations under this rule by imposing standards of performance that incorporate trading or other multi-entity generation-replacement strategies. Indeed, any emission rate-based standard may not necessarily result in emission reductions from any particular affected source (or even all of the affected sources in the category) as a result of the ability of the particular source (or even all of them) to increase its production and, therefore, its emissions, even while maintaining the required emission rate.

5. Reduced generation and implementation of the BSER

In the proposed rulemaking, we described the BSER as the measures included in building block 1 as well the set of measures included in building blocks 2, 3 and 4 or, in the alternative, reduced generation or utilization by the affected EGUs in the amount of building blocks 2, 3 and 4. In this final rule, based on the comments and further evaluation, we are refining our approach to the BSER. Specifically, we are determining the BSER as the combination of measures included in building blocks 1, 2, and 3.Building blocks 2 and 3 entail substitution of lower-emitting generation for higher-emitting generation, which ensures that aggregate production levels can continue to meet demand even where an individual affected EGU decreases its own output to reduce emissions. The amount of generation from the increased utilization of existing NGCC units determines a portion of the amount of reduced generation that affected fossil fuel-fired steam EGUs could undertake to achieve building block 2, and the amount of generation from the use of expanded lower- or zero-emitting generating capacity that could be provided, determines a portion of the amount of reduced generation that affected fossil fuel-fired steam EGUs, as well as the entire amount of reduced generation that affected NGCC units could undertake to implement building blocks 2 and 3. This section discusses the reasons that reduced generation is one of the set of reasonable and well-established actions that an affected EGU can implement to achieve its emission limits. We are not finalizing our proposal that reduced overall generation of electricity may by itself be considered the BSER, for the reason that reduced generation by itself does not fit within our historical and current interpretation of the BSER. Specifically, reduced generation by itself is about changing the amount of product produced rather than producing the same product with a process that has fewer emissions.

a. Background. As noted, for both rate-based and mass-based state plans, affected EGUs may take a set of actions to comply with their emission standards. An affected EGU may comply with an emission rate-based standard (*e.g.,* a limit on the amount of CO_2 per MWh) by acquiring, through one means or another, credits from lower- or zero-emitting generation (building blocks 2 or 3) to reduce its emission rate for compliance purposes. In addition, the affected EGU may reduce its generation, and if it does so, it then needs to acquire fewer of those credits to meet its emission rate.[590] Under these circumstances, the affected EGU

[590] An affected EGU that is subject to an emission rate, e.g., pounds of CO_2 per MWh generated, cannot achieve that rate simply by reducing its generation (unless it shuts down, in which case

would in effect replace part of its higher-emitting generation with lower- or zero-emitting generation. On the other hand, an affected EGU that is subject to a mass-based standard -- for example, a requirement to hold enough allowances to cover its emissions (*e.g.*, one allowance for each ton of emissions in any year) -- may comply at least in part by reducing its generation and, thus, its emissions. Therefore, one type of action that an affected EGU may take to achieve either of these emission limits is to reduce its generation. Further, reduced generation by individual sources offers a pathway to compliance in and of itself. That is, a state may adopt a mass-based goal, assign mass-based standards to its sources, and those sources may comply with their mass-based limits by, in addition to implementing building block 1 measures, reducing their generation in the appropriate amounts, and without taking any other actions.

b. <u>Well-established use of reduced generation to comply with environmental requirements.</u> Reduced generation is a well-established method for individual fossil fuel-fired power plants to comply with their emission limits.

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it would achieve a zero emission rate). This is because although reducing generation results in fewer emissions, it does not, by itself, result in fewer emissions per MWh generated.

Reduced generation in the amounts contemplated in this rule, as undertaken by individual sources to achieve their emission limits, reduces emissions from the affected sources, but because of the integrated and interconnected nature of the power sector, can be accommodated without significant cost or disruption. The electric transmission grid interconnects the nation's generation resources over large regions. Electric system operators coordinate, control, and monitor the electric transmission grid to ensure cost-effective and reliable delivery of power. These system operators continuously balance electricity supply and demand, ensuring that needed generation and/or demand resources are available to meet electricity demand. Diverse resources generate electricity that is transmitted and distributed through a complex system of interconnected components to end-use consumers.

The electricity system was designed to meet these core functions. The three components of the electricity supply system -- generation, transmission and distribution -- coordinate to deliver electricity from the point of generation to the point of consumption. This interconnectedness is a fundamental aspect of the nation's electricity system, requiring a complicated integration of all components of the system to balance supply and demand and a federal, state and local regulatory network to oversee the physically interconnected network. Electricity from a diverse set of generation resources such as natural gas, nuclear, coal and renewables is distributed over high-voltage transmission lines. The system is planned and operated to ensure that there are adequate resources to meet electricity demand plus additional available capacity over and above the capacity needed to meet normal peak demand levels. System operators have a number of resources potentially available to meet electricity demand, including electricity generated by electric generation units of various types as well as demand-side resources. Importantly, if generation is reduced from one generator, safeguards are in place to ensure that adequate supply is still available to meet demand. We describe these safeguards in the background section of this preamble.

Both Congress and the EPA have recognized reduced generation as one of the measures that fossil fuel-fired EGUs may implement to reduce their emissions of air pollutants and thereby achieve emission limits. Congress, in enacting the allowance requirements in CAA Title IV, under which fossil fuel-fired EGUs must hold an allowance for each ton of SO_2 emitted, explicitly recognized that fossil fuel-fired EGUs could meet this requirement by reducing their generation. In fact, Congress anticipated that fossil fuel-fired EGUs may choose to comply with the SO_2 emission limits by reducing utilization, and included provisions that specifically addressed reduced utilization. For example, CAA section 408(c)(1)(B) includes requirements for an owner or operator of an EGU that meets the Phase 1 SO_2 reduction obligations and the NO_x reduction obligations "by reducing utilization of the unit as compared with its baseline or by shutting down the unit."

The EPA has also recognized in several rulemakings limiting emissions from fossil fuel-fired EGUs that reduced generation is one of the methods of emission reduction that an EGU was expected to rely on to achieve its emission limitations. Examples include rulemakings to impose requirements that sources implement BART to reduce their emissions of air pollutants that cause or contribute to visibility impairment. As explained earlier, for certain older stationary sources that cause or contribute to visibility impairment, including fossil fuel-fired EGUs, states must determine BART on the basis of five statutory factors, such as costs and energy and non-air quality impacts.[591] In 1980, the EPA promulgated a regulatory definition of BART: "an emission limitation based on the degree of reduction achievable through the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility."[592] Both the statutory factors and the regulatory definition resemble the definition of the BSER under

591 CAA section 169A(g)(2).
592 40 CFR 51.301.

CAA section 111(a)(1) (although, as noted, the statutory definition of BART is more technology focused than the definition of BSER). In its regional haze SIP, the State of New York determined that BART for the NO_X emissions from two coal-fired boilers that served as peaking units was caps on baseline emissions rates and annual capacity factors of 5 percent and 10 percent, respectively.[593]

There have been numerous other instances in which fossil fuel-fired EGUs have reduced their individual generation, or placed limits on their generation, in order to achieve, or obviate, emission standards. In fact, there are numerous examples of EGUs that take restrictions on hours of operation in their permits for the purpose of avoiding CAA obligations, including avoiding triggering the requirements of the Prevention of Significant Deterioration (PSD), Nonattainment New Source Review (NNSR), or Title V programs (including Title V fees), and avoiding triggering HAP requirements. Such restrictions may also be taken to limit emissions of pollutants, such as limiting emissions of criteria pollutants for attainment purposes.

More specifically, EPA's regulations for a number of air programs expressly recognize that certain sources may take enforceable limits on hours of operation in order to avoid

[593] 77 FR 24794, 24810 (Apr. 25, 2012).

triggering CAA obligations that would otherwise apply to the source. Stationary sources that emit or have the *potential to emit* a pollutant at a level that is equal to or greater than specified thresholds are subject to major source requirements.[594] A source may voluntarily obtain a synthetic minor limitation -- that is, a legally and practicably enforceable restriction that has the effect of limiting emissions below the relevant level -- to avoid triggering a major stationary source requirement.[595] Such synthetic minor limits may be based on restrictions on the hours of operation, as provided in EPA's regulations defining "potential to emit," as well as on air pollution control equipment. "Potential to emit" is defined, for instance, in the regulations for the PSD program for permits issued under federal authority as: "the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any

[594] *See, e.g.*, CAA sections 112(a)(1), 112(d)(1), 165(a), 169(1), 172(c)(5), 173(a) &(c), 501(2), 502(a), 302(j).

[595] *See, e.g.*, Memorandum from Terrell Hunt, Assoc. Enforcement Counsel, U.S. EPA, & John Seitz, Director, Stationary Source Compliance Div., U.S. EPA, *Guidance on Limiting Potential to Emit in New Source Permitting,* at 1-2, 6 (June 13, 1989), available at http://www.epa.gov/region07/air/nsr/nsrmemos/lmitpotl.pdf ("Restrictions on production or operation that will limit potential to emit include limitations on quantities of raw materials consumed, fuel combusted, *hours of operation*, or conditions which specify that the source must install and maintain controls that reduce emissions to a specified emission rate or to a specified efficiency level.") (emphasis added).

physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and *restrictions on hours of operation* … shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable,"[596] or "legally and practicably enforceable by a state or local air pollution control agency."[597] The regulations for other air programs similarly recognize that potential to emit may be limited through restrictions on hours of operations in their corresponding definitions of "potential to emit."[598] These regulatory provisions make clear that restrictions on potential to emit include both "air pollution control equipment" and "restrictions on hours of operation," and indicate that these are equally cognizable means of restricting emissions to comply with, or avoid, CAA requirements.[599]

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[596] 40 CFR 52.21(b)(4)(emphasis added).
[597] John Seitz, Director, Office of Air Quality Planning and Standards, and Robert Van Heuvelen, Director, Office of Regulatory Enforcement, *Release of Interim Policy on Federal Enforceability of Limitations on Potential to Emit*, at 3 (Jan. 22, 1996), available at http://www.epa.gov/region07/air/nsr/nsrmemos/pottoemi.pdf.
[598] *See* 40 CFR 51.166(b)(4) (addressing SIP approved PSD programs), 51.165(a)(1)(iii) (addressing SIP approved NNSR programs), 70.2 (addressing Title V operating permit programs), and 63.2 (addressing hazardous air pollutants).
[599] *See, e.g.,* 40 CFR 52.21(b)(4).

As one of many examples of a fossil-fuel fired EGU taking restrictions on hours of operation for the purpose of avoiding CAA obligations, Manitowoc Public Utilities in Wisconsin obtained a Title V renewal permit that limited the operating hours of the single simple-cycle combustion turbine to not more than 194 hours per month, averaged over any consecutive 12 month period, as part of limiting its potential to emit for volatile organic compounds below the Title V threshold of 100 tpy, and carbon monoxide, $NO_x$and SO_2below the PSD threshold of 250 tpy.[600] As another example, Sunbury Generation LP in Pennsylvania obtained a minor new source preconstruction permit, called a plan approval, for a repowering project from the Pennsylvania

[600] *See* Final Operation Permit No. 436123380-P10 for Manitowoc Public Utilities -- Custer Street (Wis. Dept. Nat. Res., 8/19/2013), Condition ZZZ.1.a(1) at p. 9 (Limiting potential to emit) and n. 11 ("These conditions are established so that the potential emissions for volatile organic compounds will not exceed 99 tons per year and potential emissions for carbon monoxide, nitrogen oxides and sulfur dioxide emissions from the facility will not exceed 249 tons per year."). *See also* Analysis and Preliminary Determination for the Renewal of Operation Permit 436123380-P01 (Wis. Dept. Nat. Res., 5/21/2013) at p. 5 (noting that the "existing facility is a major source under Part 70 because potential emissions of sulfur dioxide, nitrogen oxides and carbon monoxide exceed 100 tons per year. The existing facility is a minor source under PSD and an area source of federal HAP" and further noting that after renewal, "the facility will continue to be a major source under Part 70 because potential emissions of sulfur dioxide, nitrogen oxides and carbon monoxide exceed 100 tons per year. The facility will also continue to be a minor source under PSD and an area source of federal HAP.").

Department of Environmental Protection in 2013 that limited the hours of operation of three combined cycle combustion turbines that were planned for construction in order to remain below the significance threshold for GHGs.[601] The Legal Memorandum includes numerous other examples of power plants accepting permit limits that reduce generation to meet, or avoid the need to meet, emission limits.

There are several ways that an affected EGU may implement reduced generation. For example, an EGU may accept a permit requirement that specifically limits its operating hours. In addition, an EGU may treat the cost of its generation as including an additional amount associated with environmental impacts, which requires it to raise its bid price, so that the EGU is dispatched less.

c. Other aspects of reduced generation. The amounts of increased existing NGCC generation and new renewables, in the amounts reflected in building blocks 2 and 3, can be substituted for

[601] *See* Plan Approval No. 55-00001E for Sunbury Generation LP (Pa. Dept. Env. Protection, 4/1/2013), Conditions #016 on pp. 24, 32 and 40 (limiting turbine units to operating no more than 7955, 6920, or 8275 hours in any 12 consecutive month period depending on which of three turbine options was selected); Memorandum from J. Piktel to M. Zaman, *Addendum to Application Review Memo for the Repowering Project* (Pa. Dept. Env. Protection, 4/1/2013) at p. 2 of 10 (noting that source had "calculated a maximum hours per year (12 consecutive month period) of operation for the sources proposed for each of the turbine options in order to remain below the significance threshold for GHGs.").

generation at affected EGUs at reasonable cost. The NGCC capacity necessary to accomplish the levels of generation reduction proposed for building block 2 is already in operation or under construction. Moreover, it is reasonable to expect that the incremental resources reflected in building block 3 will develop at the levels requisite to ensure an adequate and reliable supply of electricity at the same time that affected EGUs may choose to reduce their CO_2 emissions by means of reducing their generation.

Reduced generation by affected EGUs, in the amounts that affected EGUs may rely on to implement the selected building blocks, will not have adverse effects on the utility power sector and will not reduce overall electricity generation. In light of the emission limits of this rule, because of the availability of the measures in building blocks 2 and 3, and because the grid is interconnected and the electricity system is highly planned, reductions in generation by fossil fuel-fired EGUs in the amount contemplated if they were to implement the building blocks, and occurring over the lengthy time frames provided under this rule, will result in replacement generation that generally is lower- or zero-emitting. Mechanisms are in place in both regulated and deregulated electricity markets to assure that substitute generation will become available and/or steps to reduce demand will be taken to compensate for reduced generation by affected EGUs. As a result, reduced generation will not give rise to reliability concerns or have other adverse effects on the utility power sector and are of reasonable cost for the affected source category and the nationwide electricity system.[602] All these results come about because the operation of the electrical grid through integrated generation, transmission, and distribution networks creates substitutability for electricity and electricity services, which allows decreases in generation at affected fossil fuel-fired steam EGUs to be replaced by increases in generation at affected NGCC units (building block 2) and allows decreases in generation at all affected EGUs to be replaced by increased generation at new lower- and zero-emitting EGUs (building block 3). Further, this substitutability increases over longer timeframes with the

[602] Although, as discussed in the text in this section of the preamble, we are not treating reduced overall generation of electricity as the BSER (because it does not meet our historical and current approach of defining the BSER to include methods that allow the same amount of production but with a lower-emitting process) we note that reduced generation by individual higher-emitting EGUs to implement building blocks 2 and 3 meets the following criteria for the BSER: as the examples in the text and in the Legal Memorandum make clear, reduced generation is "adequately demonstrated" as a method of reducing emissions (because Congress and the EPA have recognized it and on numerous occasions, power plants have relied on it); it is of reasonable cost; it does not have adverse effects on energy requirements at the level of the individual affected source (because it does not require additional energy usage by the source) or the source category or the U.S.; and it does not create adverse environmental problems.

opportunity to invest in infrastructure improvements, and as noted elsewhere, this rule provides an extended state plan and source compliance horizon.

d. Comments concerning limiting principles. A commenter stated that "an interpretation of ['system of emission reduction'] that relies primarily on reduced utilization has no clear limiting principle."[603] We disagree with this concern, for the following reasons.

As discussed, in this final rule, we are identifying the BSER as the combination of the three building blocks. Building blocks 2 and 3 entail substitution of lower- or zero-emitting generation for higher-emitting generation, and one component of that substitution is reduced generation, which is limited in several respects discussed below. Accordingly, our identification of the BSER in this final rule does not "rel[y] primarily" on reduced utilization in and of itself (and therefore reduced generation of the product overall, electricity) as the BSER. Rather, the BSER is, in addition to building block 1, the substitution of lower- or zero-emitting generation for higher emitting generation, and reduced utilization may be a way to implement that substitution and is one of numerous methods that affected EGUs may employ to achieve

[603] EEI comment, at 284.

or help achieve the emission limits established by these emission guidelines.[604] The commenter's concerns over a perceived lack of a limiting principle cannot be taken to mean that reduced generation by higher-emitting EGUs cannot be considered to be a method for affected EGUs to achieve their emission limits.

Moreover, reduced generation, as applied to affected EGUs in this rule, is limited in a number of respects. The amount of

[604] Indeed, load shifting -- as substitute generation is sometimes called -- is an "easy and fairly inexpensive strategy" that "may be used in conjunction with other control measures" for "emission reduction." Donald S. Shepard, "A Load Shifting Model for Air Pollution Control in the Electric Power Industry," Journal of the Air Pollution Control Association, Vol. 20, No. 11, p. 760 (Nov. 1970). In fact, load shifting has been recognized as a pollution control technique as early as 1968, when it was included in the "Chicago Air Pollution System Model" for controlling incidents of extremely high pollution. E.J. Croke, et al., "Chicago Air Pollution System Model, Third Quarterly Progress Report," Chicago Department of Air Pollution Control, p. 186 (1968) (discussing the feasibility of "Control by Load Reduction" in combination with load shifting as applied to the Commonwealth Edison Company), *available at* http://www.osti.gov/scitech/servlets/purl/4827809. The report also considered "combining fuel switching and load reduction" as a possible air pollution abatement technique. *See id.* at 188. The report recognized, as an initial matter, that the Commonwealth Edison Company (CECO) was "constrained to meet the total load demand" but that "load reduction at one plant or even a number of plants is usually feasible by shifting the power demand to other plants in the system." *Id.* As a result, the report noted, "load shifting within the physical limits of the CECO system ... may be a highly desirable control mechanism." *Id.* The report also predicted that "[i]n the future, it may be possible to form reciprocal agreements to obtain 'pollution abatement' power from neighbor companies during a pollution incident and return this borrowed power at some later date." *Id.* at 187.

reduced generation is the amount of replacement generation that is lower- or zero- emitting, that is of reasonable cost, that can be generated without jeopardizing reliability, and that meets the other requirements for the BSER. As discussed, that amount is the amount of generation in building blocks 2 and 3.[605]

Finally, as discussed, the integrated nature of the electricity system, coupled with the high substitutability of electricity, allows EGUs to reduce their generation without adversely affecting the availability of their product. Those characteristics facilitate replacement of generation that has been reduced, and for that reason, EGUs have a long history of reducing their generation and either replacing it directly or having it replaced through the operation of the interconnected electricity system through measures similar to those in building blocks 2 and 3. Thus, an EGU can either directly replace its generation, or simply reduce its generation, and in the latter case, the integrated grid, combined with the high degree of planning and various reliability safeguards, will result in entities providing replacement generation. This means that

[605] The EPA notes that affected EGUs are not actually required to collectively reduce generation by the amount represented in the BSER, and may collectively reduce generation by more or less than that amount. Individual affected EGUs are free to choose reduced generation or other means of reducing emissions, as permitted by their state plans, in order to achieve the standards of performance established for them by their states.

consumers receive exactly the same amount of the same product, electricity, after the reduced generation that they received before it. No other industry is both physically interconnected in this manner and manufactures such a highly substitutable product; as a result, the use of reduced generation is not easily transferrable to another industry.

6. Reasons that this rule is within the EPA’s statutory authority and does not represent over-reaching.

In this section, we respond to adverse comments that the EPA is overreaching in this rulemaking by attempting to direct the energy sector. These commenters construed the proposed rulemaking as the EPA proposing to mandate the implementation of the measures in the building blocks, including investment in RE and implementation of a broad range of state and utility demand-side EEprograms. Commenters added that in some instances, the affected EGUs and states would have no choice but to take the actions in the building blocks because they would not otherwise be able to achieve their emission standards. Commenters also emphasized that with the proposed portfolio approach, the rule would impose federally enforceable requirements on a wide range of entities that do not emit CO_2 and have not previously been subject to CAA regulation. Commenters cite the U.S. Supreme Court’s statements in *Utility Air Regulatory Group v. EPA*

(UARG)[606] that caution an agency against interpreting its statutory authority in a way that "would bring about an enormous and transformative expansion in [its] regulatory authority without clear congressional authorization," and that add, "When an agency claims to discover in a long-extant statute an unheralded power to regulate 'a significant portion of the American economy,' ... we typically greet its announcement with a measure of skepticism."[607] Commenters assert that in this rule, the EPA is taking the actions that the *UARG* opinion cautioned against. For the reasons discussed below, these comments are incorrect and misunderstand fundamental aspects of this rule. In addition, to the extent these comments address either building block 4 or the portfolio approach they are moot, because the EPA is not finalizing those elements of the proposal.

In this rule, the EPA is following the same approach that it uses in any rulemaking under CAA section 111(d), which is designed to regulate the air pollutants from the source category at issue. First, the EPA identifies the BSER to reduce harmful air pollution. Second, based on the BSER, the EPA promulgates emission guidelines, which generally take the form of emission rates applicable to the affected sources. In this case, the EPA

[606] 134 S. Ct. 2427 (2014).
[607] *Utility Air Regulatory Group v. EPA*, 134 S. Ct. 2427, 2444 (2014) (citations omitted).

is promulgating a uniform CO_2 emission performance rate for steam-generating EGUs and a uniform CO_2 emission performance rate for combustion turbines, and the EPA is translating those rates into a combined emission rate and equivalent mass limit for each state. These emission guidelines serve as the guideposts for state plan requirements. The states, in turn, promulgate standards of performance and, in doing so, retain significant flexibility either to promulgate rate-based emission standards that mirror the emission performance rates in the guidelines, promulgate rate-based emission standards that are equivalent to the emission performance rates in the guidelines, or promulgate equivalent mass-based emission standards. The sources, in turn, are required to comply with their emission standards, and may do so through any means they choose. Alternatively, the state may adopt the state-measures approach, which provides additional flexibility.

Thus, the EPA is not requiring that the affected EGUs take any particular action, such as implementation of the building blocks. Rather, as just explained, the EPA is regulating the affected EGUs' emissions by requiring that the state submit state plans that achieve specified emission performance levels. The states may choose from a wide range of emission limits to impose on their sources, and the sources may choose from a wide range of compliance options to achieve their emission limits.

Those options include various means of implementing the building blocks as well as numerous other compliance options, ranging from -- depending in part on whether the state imposes a rate-based or mass-based emission limit -- implementation of demand-side EE measures to natural gas co-firing.[608]

As some indication of the diverse set of actions we expect to comply with the requirements of this rule, we note that demand-side EE programs, in particular, are expected to be a significant compliance method, in light of their low costs. In addition, the National Association of Clean Air Agencies (NACAA) has issued a report that provides a detailed discussion of 25 approaches to CO_2 reduction in the electricity sector.[609] In addition, we note that the nine RGGI states -- Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New

[608] In fact, the EPA is expressly precluded from mandating specific controls except in certain limited circumstances. *See* 42 U.S.C. § 7411(b)(5). For instance, the EPA is authorized to mandate a particular "design, equipment, work practice, or operational standard, or combination thereof," when it is "not feasible to prescribe or enforce a standard of performance" for new sources. 42 U.S.C. § 7411(h)(1). CAA section 111(h) also highlights for us that while "design, equipment, work practice, or operational standards" may be directly mandated by the EPA, CAA section 111(a)(1) encompasses a broader suite of measures for consideration as the BSER.
[609] NACAA, "Implementing EPA's Clean Power Plan: A Menu of Options (May 2015), http://www.4cleanair.org/NACAA_Menu_of_Options. NACAA describes itself as "the national, non-partisan, non-profit association of air pollution control agencies in 41 states, the District of Columbia, four territories and 116 metropolitan areas." *Id.*

York, Rhode Island and Vermont -- have indicated that they intend to maintain their current state programs, which this rule would allow, and there are reports that other states may seek to join RGGI.[610] Similarly, California has indicated that it intends to maintain its current state program, which this rule would allow. Other states could employ the types of methods used in Oregon, Washington, Colorado, or Minnesota, described in the background section of this preamble.

As a practical matter, we expect that for some affected EGUs, implementation of the building blocks will be the most attractive option for compliance. This does not mean, contrary to the adverse comments noted above, that this rule constitutes a redesign of the energy sector. As discussed above, the building blocks meet the criteria to be part of the best system of emission reduction ... adequately demonstrated. The fact that some sources will implement the building blocks and that this may result in changes in the electricity sector does not mean that the building blocks cannot be considered the BSER under CAA section 111(d).

[610] Martinson, Erica, "Cap and trade lives on through the states," Politico (May 27, 2014), http://www.politico.com/story/2014/05/cap-and-trade-states-107135.html.

In this rule, as with all CAA section 111(d) rules, the EPA is not directly regulating any entities. Moreover, the EPA is not finalizing the proposed portfolio approach. Accordingly, the EPA is neither requiring nor authorizing the states to regulate non-affected EGUs in their CAA section 111(d) plans.[611]

Moreover, contrary to adverse comments, this rule does not require the states to adopt a particular type of energy policy or implement particular types of energy measures. Under this rule, a state may comply with its obligations by adopting the emission standards approach to its state plan and imposing rate-based or mass-based emission standards on its affected EGUs. In this manner, this rule is consistent with prior section 111(d) rulemaking actions, in which the states have complied by promulgating one or both of those types of standards of performance. In this rulemaking, as an alternative, the state may adopt the state measures approach, under which the state could, if it wishes, adopt particular types of energy measures that would lead to reductions in emissions from its EGUs. But again, this rule does not require the state to implement a particulate type of energy policy or adopt particular types of energy measures.

[611] A state may regulate non-EGUs as part of a state measures approach, but those measures would not be federally enforceable.

It is certainly reasonable to expect that compliance with these air pollution controls will have costs, and those costs will affect the electricity sector by discouraging generation of fossil fuel-fired electricity and encouraging less costly alternative means of generating electricity or reducing demand. But for affected EGUs, air pollution controls necessarily entail costs that affect the electricity sector and, in fact, the entire nation, regardless of what BSER the EPA identifies as the basis for the controls. For example, had some type of add-on control such as CCS been identified as the BSER for coal-fired EGUs, sources that complied by installing that control would incur higher costs. As a result, generation from coal-fired EGUs would be expected to decrease and be replaced at least in part by generation from existing NGCC units and new renewables because those forms of generation would see their competitive positions improved.

This basic fact that EPA regulation of air pollutants from affected EGUs invariably affects the utility sector is well-recognized and in no way indicates that such regulation exceed the EPA's authority. In revising CAA section 111 in the 1977 CAA Amendments, Congress explicitly acknowledged that the EPA's rules under CAA section 111 for EGUs would significantly impact the energy sector.[612] The Courts have recognized that, too. The U.S. Supreme Court, in its 2011 decision that the CAA and the EPA actions it authorizes displace any federal common law right to seek abatement of CO_2 emissions from fossil fuel-fired power plants, emphasized that CAA section 111 authorizes the EPA -- which the Court identified as the "expert agency" -- to regulate CO_2 emissions from these sources in a manner that balances "our Nation's energy needs and the possibility of economic disruption:"

> The appropriate amount of regulation in any particular greenhouse gas-producing sector cannot be prescribed in a vacuum: as with other questions of national or international policy, informed assessment of competing interests is required. Along with the environmental benefit potentially achievable, our Nation's energy needs and the possibility of economic disruption must weigh in the balance.
>
> The [CAA] entrusts such complex balancing to EPA in the first instance, in combination with state regulators. Each "standard of performance" EPA sets must "tak[e] into account the cost of achieving [emissions] reduction and any nonair quality health and environmental impact and energy requirements." §

[612] The D.C. Circuit acknowledged this legislative history in *Sierra Club v. EPA*, 657 F.2d 298, 331 (D.C. Cir. 1981). There, the Court stated:

> [T]he Reports from both Houses on the Senate and House bills illustrate very clearly that Congress itself was using a long-term lens with a broad focus on future costs, environmental and energy effects of different technological systems when it discussed section 111. [Citing S. Rep. No. 95-127, 95th Cong., 1st Sess. (1977), 3 Legis. Hist. 1371; H.R. Rep. No. 95-294, 95th Cong., 1st Sess. 188 (1977), 4 Legis. Hist. 2465.]

> 7411(a)(1), (b)(1)(B), (d)(1); see also 40 C.F.R. § 60.24(f) (EPA may permit state plans to deviate from generally applicable emissions standards upon demonstration that costs are "[u]n-reasonable"). EPA may "distinguish among classes, types, and sizes" of stationary sources in apportioning responsibility for emissions reductions. § 7411(b)(2), (d); see also 40 C.F.R. § 60.22(b)(5). And the agency may waive compliance with emission limits to permit a facility to test drive an "innovative technological system" that has "not [yet] been adequately demonstrated." § 7411(j)(1)(A). The Act envisions extensive cooperation between federal and state authorities, see § 7401(a), (b), generally permitting each state to take the first cut at determining how best to achieve EPA emissions standards within its domain, see § 7411(c)(1), (d)(1)-(2).
>
> It is altogether fitting that Congress designated an expert agency, here, EPA, as best suited to serve as primary regulator of greenhouse gas emissions. The expert agency is surely better equipped to do the job than individual district judges issuing ad hoc, case-by-case injunctions.[613]

Similarly, the D.C. Circuit, in its 1981 decision upholding the EPA's rules to reduce SO_2 emissions from new coal-fired EGUs under the version of CAA section 111(b) adopted in the 1977 CAA Amendments, stated:

> [S]ection 111 most reasonably seems to require that EPA identify the emission levels that are "achievable" with "adequately demonstrated technology." After EPA makes this determination, it must exercise its discretion to choose an achievable emission level which represents the best balance of economic, environmental, and energy considerations. It follows that to exercise this discretion EPA must examine the effects of technology on the grand scale in order to decide which level of control is best…. The standard

[613] *American Electric Power Co. v. Connecticut*, 131 S. Ct. 2527, 2539-40 (2011).

> is, after all, a national standard with long-term effects.[614]

The D.C. Circuit added: "Regulations such as those involved here demand a careful weighing of cost, environmental, and energy considerations. They also have broad implications for national economic policy."[615] This rule has "economic, environmental, and

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[614] *Sierra Club v. EPA*, 657 F.2d 298, 330 (D.C. Cir. 1981).
[615] *Sierra Club v. EPA*, 657 F.2d 298, 406 (D.C. Cir. 1981). The Court supported this statement with a lengthy quotation from a scholarly article, which stated, in part:

> Consider for a moment the chain of collective decisions and their effects just in the case of electric utilities. Petroleum imports can be conserved by switching from oil-fired to coal-fired generation. But barring other measures, burning high-sulfur Eastern coal substantially increases pollution. Sulfur can be "scrubbed" from coal smoke in the stack, but at a heavy cost, with devices that turn out huge volumes of sulfur wastes that must be disposed of and about whose reliability there is some question. Intermittent control techniques (installing high smokestacks and switching off burners when meteorological conditions are adverse) can, at lower cost, reduce local concentrations of sulfur oxides in the air, but cannot cope with the growing problem of sulfates and widespread acid rainfall. Use of low-sulfur Western coal would avoid many of these problems, but this coal is obtained by strip mining. Strip-mining reclamation is possible, but substantially hindered in large areas of the West by lack of rainfall. Moreover, in some coal-rich areas the coal beds form the underground aquifer and their removal could wreck adjacent farming or ranching economies. Large coal-burning plants might be located in remote areas far from highly populated urban centers in order to minimize the human effects of pollution. But such areas are among the few left that are unspoiled by pollution and both environmentalists and the residents (relatively few in

energy" impacts, as Congress and the Courts expect in a CAA section 111 rule, but those impacts do not mean that the EPA is precluded from promulgating the rule.

As noted above, in this rule, to control CO_2 emissions from affected EGUs, the EPA first considered more traditional air pollution control measures, including supply-side efficiency improvements, fuel-switching (for CO_2 emissions, that entails co-firing with natural gas), and add-on controls (for CO_2 emissions, that entails CCS). However, it became apparent that even if the EPA could have finalized those controls as the BSER[616] and established the same uniform CO_2 emission performance rates, the affected EGUs would rely on less expensive ways to achieve their emission limits. Specifically, instead of relying on co-firing and CCS, the affected EGUs generally would replace their generation with lower- or zero-emitting generation– the measures in building blocks 2 and 3 -- because those measures are significantly less expensive and already well-established as pollution control measures. Indeed, some affected EGUs have

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> number compared with those in metropolitan localities but large among the voting population in the particular states) strongly object to this policy.

Id. at 406 n. 526.

[616] For the reasons explained, we did not finalize those measures because significantly less expensive control measures -- building blocks 2 and 3 -- are available for these affected EGUs.

stated that while they oppose including in the BSER generation shifts to lower- or zero-emitting sources (or, as proposed, demand-side EE), they request that those measures be available for compliance, which indicates their interest in implementing those measures.[617]

We expect that many sources will choose to comply with their emission limits through the measures in building blocks 2 and 3, but contrary to the assertions of some commenters, this will not result in unprecedented and fundamental alterations to the energy sector. As discussed above, Congress relied on the same measures as those the EPA is including in building blocks 2 and 3 as essential parts of the basis for the Title IV emission limits for fossil fuel-fired EGUs, and the EPA did the same for the emission limits in various rules for those same sources.

In addition, reliance on the measures in building blocks 2 and 3 is fully consistent with the recent changes and current trends in electricity generation, and as a result, would by no means entail fundamental redirection of the energy sector. As indicated in the RIA for this rule, we expect that the main

[617] See the proposal for this rule, 79 FR at 34888 ("during the public outreach sessions, stakeholders generally recommended that state plans be authorized to rely on, and that affected sources be authorized to implement, re-dispatch, renewable energy measures, and demand-side energy efficiency measures in order to meet states' and sources' emission reduction obligations.").

impact of this rule on the nation’s mix of generation will be to reduce coal-fired generation, but in an amount and by a rate that is consistent with recent historical declines in coal-fired generation. Specifically, from approximately 2005 to 2014, coal-fired generation declined at a rate that was greater than the rate of reduced coal-fired generation that we expect to result from this rulemaking from 2015 to 2030. In addition, under this rule, the trends for all other types of generation, including natural gas-fired generation, nuclear generation, and renewable generation, will remain generally consistent with what their trends would be in the absence of this rule. In addition, this rule is expected to result in increases in demand-side EE.

In addition, contrary to claims of some commenters, in this rule, the EPA is not attempting to expand its authorities by attempting to expand the jurisdiction of the CAA to previously unregulated sectors of the economy, in contravention of the *UARG* decision. In *UARG*, the U.S. Supreme Court struck down the EPA’s interpretation of the PSD provisions of the CAA because the interpretation had the effect of applying the PSD requirements to large numbers of small sources that previously had not been subject to PSD, and because, according to the Court, the EPA acknowledged that Congress did not intend that such sources be subject to the PSD requirements.[618] Commenters appear to interpret this decision to preclude the EPA from including at least building block 3 in the BSER because it includes measures that involve entities (such as RE developers) that do not emit CO_2 and have not previously been subject to the CAA. However, in this rule, the EPA is not attempting to subject any entity other than the affected EGUs in the source category to CAA section 111 requirements. As discussed below, the EPA is not finalizing the proposed portfolio approach, under which states were authorized to include, in their CAA section 111(d) state plans, federally enforceable requirements on entities other than affected EGUs. Thus, as noted above, this final rule does not require or authorize the states to include entities other than affected EGUs in their CAA section 111(d) state plans, and as a result, those entities will not come under CAA jurisdiction[619] and the parts of the economy that they represent will not be regulated by the EPA.

7. Relative stringency of requirements for existing sources and new, modified, and reconstructed sources.

Commenters also objected that the proposed CAA section 111(d) standards are more stringent than the standards for new,

[618] *Util. Air Reg. Group v. EPA*, 134 S. Ct. 2427, 2443 (2014).
[619] States may regulate non-affected EGUs through a state measures approach, but those regulations would not be federally enforceable.

modified or reconstructed sources, and they assert that setting section 111(d) standards that are more stringent than 111(b) standards would be illogical, contrary to precedent, contrary to the intent of the remaining useful life exception, and arbitrary and capricious.[620] We disagree with these comments. Comparing the control requirements of the two sets of rules, CAA section 111(d) and 111(b), is an "apples-to-oranges" comparison and, as a result, it is not possible – and it is overly simplistic - to conclude that the 111(d) requirements are more stringent that the 111(b) requirements.

Most importantly, the two sets of rules become applicable at different points in time and have significantly different compliance periods. The CAA section 111(b) rule becomes applicable for new, modified and reconstructed sources immediately upon construction, modification, or reconstruction and, in fact, by operation of section 111(e) and (a)(2), new, modified, or reconstructed sources that commenced construction prior to the effective date of the section 111(b) rule must also be in compliance upon the effective date of the rule. In contrast, the requirements under the CAA section 111(d) rule do not become applicable to existing affected EGUs until seven years after promulgation of the rule, when the interim

[620] ACC et al. (Associations) comments at 40, Luminant comments at 89.

compliance period begins in 2022, and the final compliance period does not begin until 2030. Moreover, the compliance period for the interim requirements is eight years. This later applicability date and longer compliance period for existing sources accommodates a requirement that, on average, those sources have a lower nominal emission limit than the standards for new or modified sources, which those latter sources must comply with immediately.

In addition, the timetables for compliance with the section 111(b) and 111(d) rules should be considered in light of the 8-year review schedule required for section 111(b) rules under CAA section 111(b)(1)(B). Under CAA section 111(b)(1)(B), the EPA is required to "review and, if appropriate, revise" the section 111(b) standards "at least every 8 years." This provision obligates the EPA to review the section 111(b) rule for CO_2 emissions from new, modified, and reconstructed power plants by the year 2023. That mandatory review will reassess the BSER to determine the appropriate stringency for emission standards for new, modified, and reconstructed sources into the future. Therefore, for present purposes of comparing the stringency of the section 111(b) and 111(d) rules, the year 2023 presents an important point of comparison.

Specifically, as noted above, the section 111(b) standards apply to new, modified and reconstructed sources beginning in

2015, while the section 111(d) rule does not take effect until 2022, which happens to fall on the cusp of the 8-year review for the 111(b) standards.

Even after the section 111(d) rule takes effect in 2022, the flexibility that this rule offers the states has important implications for its stringency and for any comparison to the section 111(b) rule. Although the requirements for the 111(d) rule begin in 2022, they are phased in, in a flexible manner, over the 2022-2030 period. That is, states are required to meet interim goals for the 2022-2029 period by 2029, and the final goals by 2030, but states are not required to impose requirements on their sources that take effect in 2022. In fact, states may, if they prefer, impose business-as-usual emission standards on their sources that do not require emission reductions in 2022 and apply emission standards on their sources that do require emission reductions and that take effect no earlier than 2023. Moreover, because emission standards may have an annual compliance period, the states may allow their sources to delay having to comply with any emission reduction requirements until the end of 2023.[621]

[621] A state that chooses to allow its sources to remain uncontrolled through 2023 would still be able to meet its interim goal by 2029, although it would need to impose more stringent requirements on its sources over the 2024-2029 period than it would if it had imposed requirements beginning in 2022.

Therefore, while the section 111(b) standards apply to new, modified, and reconstructed sources beginning in 2015, the section 111(d) standards may not apply to existing sources until 2023.As a result, by 2023 – the year that the 111(b) standards are required to be reviewed for possible revision – affected EGUs subject to the 111(d) standards may remain uncontrolled. Under those circumstances, the 111(d) rule cannot be said to be more stringent than the 111(b) rule.[622]

Another reason why the section 111(d) rule cannot be said to be more stringent than the section 111(b) rule is that for any individual source, the 111(d) rule is applied more flexibly and includes more flexible means of compliance. Whereas the section 111(b) rule entails an emission rate that each affected

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It should also be noted that in fact, most states could allow their sources to remain uncontrolled for 2022 and 2023, and require controls beginning in 2024, and still be able to meet their interim goal.

[622] In addition, because the section 111(d) requirements are phased in, states may choose to apply a gradual phase-in of the reductions. This means that the nominal emission rates for section 111(d) sources would be significantly less stringent for the first several years of the compliance period. We estimate that if states choose to impose the section 111(d) requirements in a proportional amount each year, beginning in 2022, the requirements for steam generators by 2022 would result in an average emission performance rate of 1,764 lb. CO_2/MWh net and by 2023, an average emission rate of 1,698 lb. CO_2/MWh net (In 2030, the rate falls to 1,305 lb. CO_2/MWh net.) For existing NGCC units, if states choose to implement the section 111(d) requirements proportionally, in 2022, the average rate would be 910 lb. CO_2/MWh net, and in 2023 it would be 899 lb. CO_2/MWh net. (In 2030, this rate falls to 771 lb. CO_2/MWh net.)

EGU must meet on a 12-month (rolling) basis, the section 111(d) is more flexible. For example, states may adopt the state measures approach and refrain from imposing any requirements on their affected EGUs. In addition, under the section 111(d) rule, sources have more flexible means of compliance. For an emission standards approach, depending on the form of the state requirements (mass-based or rate-based), the state may be expected to authorize trading of mass-based emission allowances or rate-based emission credits, and in addition, the purchase of ERCs. These flexibilities are not included in the section 111(b) rule, rather, as noted, each new, modified, and reconstructed EGU must individually meet its emission standard on a 12-month (rolling) basis. The EPA has frequently required that sources meet a more stringent nominal limit when they are allowed compliance flexibility, particularly, the opportunity to trade.[623] In addition, states have the discretion to allow their

[623] *See, e.g.*, EPA, "Improving Air Quality with Economic Incentive Programs," EPA-452/R-01-001, at 82 (2001) (requiring that Economic Incentive Programs show an environmental benefit, such as "reducing emission reductions generated by program participants by at least 10 percent"), *available at* http://www.epa.gov/airquality/advance/pdfs/eipfin.pdf; "Economic Incentive Program Rules: Final Rule," 59 FR 16690 (April 7, 1994) (same); "Certification Programs for Banking and Trading of NOx and PM Credits for Heavy-Duty Engines: Final Rule," 55 FR 30584 (July 26, 1990) (requiring that for programs for banking and trading of NOx and PM credits for gasoline, diesel and methanol powered engines, all trading and banking of credits must be subject to a

sources to meet emission standards over a longer time period. This distinction between the two rules is another reason why the section 111(d) rule cannot be said to be more stringent in fact than the section 111(b) rule.

There are other reasons why the section 111(d) rule cannot be said to be more stringent. With respect to the 111(d) and 111(b) rules for existing and new NGCC units, we note the following: as explained in the section 111(b) preamble, the standard for new NGCC units is designed to accommodate a wide range of unit types, including small units and rapid-start units, which are a small part of the expected new NGCC generation capacity. As such, the 111(b) standard (1,000 lb CO_2/MWh gross, which equates to 1,030 lb CO_2/MWh net) will not constrain the emissions of the great majority of expected new NGCC generation capacity, which is expected to consist of larger base load units (with a capacity of 100 MW or greater) that are not intended to cycle frequently. Their initial emissions are expected to be below 800 lb. CO_2/MWh gross, their emissions over time may be somewhat higher due to equipment deterioration, and as a result, their PSD permits are expected to include emission

20 percent discount "as an added assurance that the incentives created by the program will not only have no adverse environmental impact but also provide an environmental benefit.").

limits at approximately the 800 lb. CO_2/MWh gross level. A very small amount of the new NGCC generation is expected to be small units (with a capacity of approximately 25 MW) or rapid-start units. Their initial emissions are expected to be approximately 950 lb. CO_2/MWh gross, their emissions over time are expected to be somewhat higher due to equipment deterioration, and it these units that the standard of 1,000 lb. CO_2/MWh gross is designed to constrain.[624] As a result, the 1,000 lb. CO_2/MWh gross limit applies to all new NGCC units, including the great majority of the expected new capacity consisting of larger, non-rapid start units, even though, as just noted, the great majority of the units are expected to emit at significantly lower emission rates. The section 111(d) standard for existing sources, in contrast, is generally expected to constrain existing NGCC units on average. Moreover, very little of the existing NGCC generation includes small units or, in particular, rapid-start units because the latter are a recently developed technology. To some extent, the same is true for the 111(b) standard for reconstructed NGCC units. The average NGCC rate was approximately 850 lb CO_2/MWh gross in 2014 and, as a result, most sources are emitting below the section 111(b) standard for

[624] As explained in the 111(b) preamble, any attempt to subcategorize and assign a lower emission limit to larger, non-rapid start NGCC units could cause market distortions.

reconstructed sources. For these reasons, too, the 111(b) standards for new and reconstructed NGCC units cannot be compared to the 111(d) standards for existing NGCC units.[625]

Moreover, even if commenters were correct that the section 111(d) requirements for existing sources are more stringent than the section 111(b) requirements for new sources, that would not, by itself, call into question the reasonableness of either standard. The stringency of the requirements for each source subcategory is, of course, a direct function of the BSER identified for that source subcategory. In this rulemaking, we explain the basis for the BSER for existing sources, and why we do not include certain measures, such as CCS; and in the section 111(b) rulemaking, we explain the basis for the BSER for new sources, and why we do not include certain measures, such as the building blocks. As long as the BSER determination is reasonable and the resulting emission limits meet other applicable requirements, those emission limits are valid, even if the one for new sources is less stringent than the one for existing sources. No provision in section 111, nor any statement in its legislative history, nor any of its case law, indicates that the

[625] The section 111(b) standards for modified and reconstructed steam generation units are generally lower than the emission rates of existing stream generation units, but for the reasons explained earlier, those standards cannot be compared to the section 111(d) standards for existing steam generation units.

standards for new sources must be more stringent than the standards for existing sources.

C. Building Block 1—Efficiency Improvements at Affected Coal-Fired Steam EGUs

The first category of approaches to reducing CO_2 emissions at affected fossil fuel-fired EGUs consists of measures that improve heat rate at coal-fired steam EGUs. Heat rate improvements are changes implemented at an EGU that increase the efficiency with which the EGU converts fuel energy to electric energy, thereby reducing the amount of fuel needed to produce the same amount of electricity and consequently lowering the amount of CO_2 produced as a byproduct of fuel combustion. Heat rate improvements yield important economic benefits to affected EGUs by reducing their fuel costs.

An EGU's heat rate is the amount of fuel energy input needed (Btu, higher heating value basis) to produce 1 kWh of net electrical energy output.[626] In 2012, the generation-weighted average annual heat rate of the 884 coal-fired EGUs included in EPA's building block 1 analysis was approximately 9,732 Btu per

[626] Typically, the units of measure used for heat rate (*e.g.*, Btu/kWh-net) indicate whether a given value is based on the gross output or net output. Net heat rate is always higher than gross heat rate; in coal-steam units, net heat rate can be 5–10% higher than gross heat rate.

gross kWh.[627] Because an EGU's CO_2 emissions are driven primarily by the amount of fuel consumed, improving (*i.e.*, decreasing) heat rate at a coal-fired EGU inherently reduces the carbon-intensity of generation.

As discussed above in section V.A and in the June 2014 proposal,[628] it is critical to recognize that affected coal-fired EGUs operate in the context of the integrated electricity system. Because of this reality, applying building block 1 in isolation can result in a "rebound effect" that undermines the emissions reductions otherwise achieved by heat rate improvements. As already noted, the building block 1 measures described below cannot by themselves constitute the BSER because the quantity of emission reductions achieved -- which is a factor that the courts have required EPA to consider in determining the BSER -- would be of insufficient magnitude in the context of this pollutant and this industry. The potential rebound effect, if it occurred, would exacerbate the insufficiency of the emission reductions. However, applying building block 1 in combination with other building blocks can address this concern for the reasons stated in section V.A.4.

[627] Similarly, within each interconnection, the generation-weighted average annual heat rates for those coal-fired EGUs in our study population were 9,700 Btu per gross kWh (Eastern); 9,888 Btu per gross kWh (Western); and 9,789 Btu per gross kWh (Texas).

[628] *See, e.g.*, 79 FR 34830, 34859 (June 18, 2014).

We conducted several analyses to assess the potential for heat rate improvements from the coal-fired EGU fleet. As in the proposal, we employed a unit-specific approach that compared each EGU's performance against its own historical performance in lieu of directly comparing an EGU's performance against other EGUs with similar characteristics. Accordingly, as described below, our method effectively controls for the characteristics and factors of an EGU that typically remain constant over time (*e.g.*, a unit is unlikely to dramatically increase or decrease in size). Our methodology for determining the amount of heat rate improvement appropriately included in the BSER as building block 1 is discussed in the next section, below.

1. Summary of measures comprising the BSER in building block 1

a. <u>Measures under building block 1 - heat rate improvements</u>. In finalizing the building block 1 portion of this rule, we considered over a thousand individual comments from the public, including individual EGUs and state agencies, on heat rate improvement, which are discussed below and also in the responses to comments document and the GHG Mitigation Measures TSD for the CPP Final Rule [Docket ID No. EPA-HQ-OAR-2013-0602]. Based on these public comments, we have refined the statistical analyses used in the proposal to identify the potential heat rate improvement that can be achieved on average by affected coal-fired EGUs.

In the proposal, we used two approaches to analyze the variability of an EGU’s gross heat rate using a robust dataset comprised of 11 years of hourly gross heat rate data for 884 coal-fired EGUs -- over 11 million hours of data collected between 2002 and 2012. The foundation of our first approach was an analysis of the variability of each EGU’s gross heat rate, which was accomplished in large part by grouping each EGU’s hourly data by similar ambient temperature and capacity factor (*i.e.*, hourly operating level as a percentage of nameplate capacity) conditions. The second approach analyzed the difference between an EGU’s average gross heat rate and its best historical gross heat rate performance. We proposed that, on a nationwide basis, affected coal-fired EGUs should be able to achieve 6-percent heat rate improvement: 4-percent improvement from best practices, and an additional 2-percent improvement from equipment upgrades.

We received many comments asserting that the 11-year dataset we had used to determine the 4-percent best practices figure likely reflected some portion of the 2-percent equipment upgrades figure we had separately identified. Accordingly, these commenters claim that the EPA double-counted equipment upgrades in arriving at the full estimate of 6-percent heat rate improvement. Commenters also noted the difficulty, in some cases, of determining whether a heat rate improvement measure is an “equipment upgrade” or “best practice,” such as optimizing soot blowing with intelligent systems, using CO monitors for optimizing combustion, or applying air heater and duct leakage controls.

As noted below in sections V.C.1.b and V.C.3, the EPA acknowledges that some equipment upgrades implemented by EGUs during the 11-year study period are reflected in the hourly heat rate data. Therefore, we made two refinements to our analyses of heat rate improvement potential. First, we refined our statistical approaches to use each EGU’s gross heat rate from 2012 -- the final year of the 11-year study period -- as the baseline for calculating heat rate improvement potential. By comparing each EGU’s best historical gross heat rate with its 2012 gross heat rate, our analyses account for the enduring effects on heat rate of any equipment upgrades or best practices that an EGU implemented during the study period. Heat rate improvement measures that an EGU maintains in 2012 are reflected in that baseline, and thus are not treated as evidence that the EGU can further improve heat rate. Additionally, in part because of limitations on the information available to us regarding which equipment upgrades have been or could be implemented at individual EGUs, as well concerns about double-counting, we have conservatively decided not to add a separate equipment upgrade component to our estimate of heat rate improvement potential.

Nonetheless, we remain confident that additional equipment upgrades (including measures that are unambiguously equipment upgrades, such as turbine overhauls) are possible at many coal-fired EGUs, as supported by numerous commenters, the Sargent & Lundy study[629] (S&L) and other industry reports and studies. Many of these reports and studies are referenced in the TSD developed for the proposed rule, as well as in the GHG Mitigation Measures TSD supporting the final CPP.

Several commenters criticized the fact that the proposal assessed potential heat rate improvement on a nationwide basis. These commenters suggested instead that we narrow the geographic scope of our analysis, generally identifying a state-by-state approach as a preferred alternative. In light of commenters' concerns about using a single nationwide approach, as well as for reasons described in Section V.A and elsewhere in this preamble, the final rule assesses potential heat rate improvement regionally, within the Eastern, Western and Texas Interconnections.[630]

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[629] Sargent and Lundy 2009, Coal-Fired Power Plant Heat Rate Reductions, SL-009597, Final Report, January 2009, Docket ID No. EPA–HQ–OAR–2013–0602-XXXX, available at: http://www.epa.gov/airmarkets/documents/ipm/coalfired.pdf.

[630] The geographic area within the Texas Interconnection generally corresponds to the portion of the state of Texas covered by ERCOT (the Electric Reliability Council of Texas). Additional portions of the state of Texas are located within the Eastern and Western Interconnections.

For the final rule, we performed several analyses to determine what heat rate improvement was achievable in each interconnection from best practices and equipment upgrades. As in the proposal, these analyses used the 11-year dataset of EGU hourly gross heat rate data from 2002 to 2012. As discussed further in the GHG Mitigation Measures TSD, our reliance on these gross heat rate data was reasonable given that (1) these data are the only comprehensive data available to the EPA, and (2) heat rate is proportional to CO_2 emission rate.

As in the proposal, we used more than one analytical method to evaluate the opportunity for EGUs to reduce their CO_2 emissions through heat rate improvements. Our final methodology uses three different analytical approaches based on refinements of the two approaches described at the proposal stage. We call these final approaches: (1) the "efficiency and consistency improvements under similar conditions" approach; (2) the "best historical performance" approach; and (3) the "best historical performance under similar conditions" approach. As described below and in the GHG Mitigation Measures TSD, each approach provides an independently reasonable way to estimate the potential for heat rate improvements by EGUs in each region. However, rather than select a potential heat rate improvement value supported by one or only some of these independently reasonable analytical approaches, we conservatively based our final determination for each region on the value for that region supported by all three approaches.

The "efficiency and consistency improvements under similar conditions" approach is a slight refinement of an approach discussed at length in the proposal. As in the proposal, we distributed each hour of gross heat rate data for each EGU into a matrix comprised of 168 bins, based on the ambient temperature and hourly capacity factor of the EGU at the time that hour of gross heat rate data was generated. Each bin represented a 10-degree Fahrenheit (°F) range in ambient temperature (from -20°F to greater than 110°F), and a 10-percent range in capacity factor (from 0 percent to greater than 110 percent[631]). Thus, for example, one bin would contain all of an EGU's hourly gross heat rate data generated during the 11-year study period while that EGU was operating at 80- to 89-percent capacity while ambient temperatures were between 70°F and 79°F.

As we explained at proposal and as discussed further in the GHG Mitigation Measures TSD, ambient temperature and hourly capacity factor are important conditions that influence heat rate at individual EGUs. By separating the EGU-specific data into bins based on these variables, and only directly comparing

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[631] Because an EGU's rated nameplate capacity is based on a maximum continuous rating, EGUs may operate for periods of time "over" 100 percent of their capacity factor. The EPA's dataset of hourly operating data reflected some such instances.

data within a bin, we were largely able to control for the influence of those variables on an EGU's heat rate. Accordingly, having controlled for these two external factors, and having already controlled for unit-specific factors affecting heat rate by analyzing the data for each EGU in isolation, we are confident that the remaining variation in each bin's data was primarily driven by factors under the EGU operator's control.

After allocating an individual EGU's data across the bins, we next established a benchmark for each bin based on the best hourly gross heat rate accounting for outliers (*i.e.*, we set the benchmark at the 10th percentile hourly gross heat rate value) during any consecutive two-year period.[632] We compared the hourly gross heat rate data within each bin to the EGU's benchmark value. Similar to the proposal, within each bin we assessed the effect on heat rate of improving the consistency of that EGU by reducing hourly gross heat rate values that were greater than the benchmark by a percentage of the distance between each of those higher hourly values and the benchmark.[633] We refer to this percentage improvement value as the "consistency factor,"

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[632] As described below, we also conducted this regionalized approach using a benchmark based on the best hourly gross heat rate accounting for outliers during any one-year period. See the GHG Mitigation Measures TSD supporting the final CPP for more details.

[633] In the proposal, we used heat input values rather than gross heat rate values. See the GHG Mitigation Measures TSD supporting the final CPP for more details.

because applying it results in values for heat rate that are more consistent with the EGU's benchmark for that bin. In our proposal we evaluated the heat rate improvement that would result from applying consistency factors of 10, 20, 30, 40 and 50 percent of the distance between those less-efficient hourly gross heat rate values and the benchmark; using engineering judgment, we selected a consistency factor of 30 percent, which produced results comparable to those obtained using other approaches for analyzing heat rate. For our final analysis under this approach, we refined the consistency factor based on a statistical assessment of the overall variability of heat rate in that EGU's region, as described in the GHG Mitigation Measures TSD.[634] As in the proposal, we applied the consistency factor to each bin of each EGU's hourly gross heat rate data, and averaged the result across all bins in that EGU's matrix. The net result was an improved gross heat rate reflecting what that EGU would have achieved between 2002 and 2012 if, under certain ambient temperature and capacity factor conditions, the

[634] For the Eastern Interconnection, the consistency factor is 38.1 percent. For the Western Interconnection, the consistency factor is 38.4 percent. For the Texas Interconnection, the consistency factor is 37.1 percent. Conducting this analysis on a nationwide basis would have resulted in application of a consistency factor of 38.2 percent. As described below, we also conducted this regionalized approach using consistency factors determined based on one-year figures. See the GHG Mitigation Measures TSD supporting the final CPP for more details.

EGU had improved its gross heat rate during less-efficient hours to be slightly more consistent with the relevant benchmark value. We then compared the improved gross heat rate for each EGU to its actual 2012 historical average gross heat rate. We chose 2012 as the year of comparison because 2012 was the latest year for which the EPA had data at the time of the proposal, and because using the most recent data reflects the EGU's current operating level and accounts for improvements the EGU may have undertaken over the 11-year study period.

Applying this procedure to all units in our database and averaging the generation-weighted results, we determined that it would be reasonable to conclude that, through application of best practices and equipment upgrades, EGUs on average are at least capable of reducing their CO_2 emissions by improving heat rate 4.3 percent in the Eastern Interconnection, 2.1 percent in the Western Interconnection, and 2.3 percent in the Texas Interconnection.[635]

In addition to the statistical approach described above, we employed a "best historical performance" approach refined from

[635] Conducting this analysis on a nationwide basis would have resulted in a finding that EGUs nationwide are capable on average of reducing their CO_2 emissions by improving heat rate 4.0 percent. See the table in this section and the GHG Mitigation Measures TSD for the results of this approach using benchmarks and consistency factors based on one-year averages.

the proposal, which compared each EGU's best two-year rolling average gross heat rate to that EGU's 2012 average annual gross heat rate.[636] We then calculated the differences across all EGUs in a region to determine the potential heat rate improvement that would result if, in 2012, each EGU had performed at the best two-year rolling average gross heat rate that the EGU achieved between 2002 and 2012. Under this analysis of historical gross heat rate, we determined that it would be reasonable to conclude that the average heat rate improvement potential from best practices and equipment upgrades is at least 4.9 percent in the Eastern Interconnection, 2.6 percent in the Western Interconnection and 3.1 percent in the Texas Interconnection.[637]

Finally, we employed the "best historical performance under similar conditions" approach, which combines aspects of the other two approaches. First, as with the "efficiency and consistency improvements under similar conditions approach," we

[636] As described below, we also conducted this regionalized approach using each EGU's best one-year rolling average. See the GHG Mitigation Measures TSD supporting the final CPP for more details.

[637] Conducting this approach on a nationwide basis would have resulted in a finding that EGUs nationwide are capable on average of reducing their CO_2 emissions by improving heat rate 4.6 percent. As described below, we also conducted this regionalized approach using one-year averages. See the GHG Mitigation Measures TSD supporting the final CPP for more details.

grouped hourly data for each EGU by ambient temperature conditions and hourly capacity factor. Next, we calculated each EGU's best two-year gross heat rate for each of the 168 ambient temperature-capacity factor bins.[638] Similar to the "best historical performance" approach, to calculate the potential heat rate improvement, the EPA then compared each EGU's 2012 gross heat rate for each of the ambient temperature-capacity factor bins to the EGU's best two-year gross heat rate for the corresponding bin. Accounting for differences in ambient temperature and capacity factor, we determined that under this analytical approach the average heat rate improvement potential from best practices and equipment upgrades was at least 5.3 percent in the Eastern Interconnection, 3.1 percent in the Western Interconnection and 3.5 percent in the Texas Interconnection.[639]

As in the proposal, we additionally analyzed the data with our analytical approaches using one-year averaging periods in

[638] As described below, we also conducted this approach using one-year averages for each EGU instead of two-year averages. See the GHG Mitigation Measures TSD supporting the final CPP for more details.

[639] Conducting this approach on a nationwide basis would have resulted in a finding that EGUs nationwide are capable on average of reducing their CO_2 emissions by improving heat rate 5.0 percent.

place of the two-year averaging periods described above.[640] However, because our conservative overall methodology adopts the lowest value that is identified for a region by any of our reasonable analytical approaches, the inherently less conservative results obtained with one-year averaging periods (reproduced below) could not influence the outcome of our methodology as a whole. Overall, applying these three analytical approaches resulted in six heat rate improvement values generated for each region, each of which represents a reasonable estimate of the potential for heat rate improvements by EGUs in that region. Those values ranged from 4.3 to 6.9 percent in the Eastern Interconnection, from 2.1 to 4.7 percent in the Western Interconnection, and from 2.3 to 4.9 percent in the Texas Interconnection. In all three regions, the most conservative values were generated using the "efficiency and consistency improvements under similar conditions" approach with two-year averaging periods and consistency factors. As shown in Table 6, the values produced by that approach were the minimum values for each region produced by any of the three approaches:

Table 6. Heat Rate Improvement Potential by Region and Averaging Period.

Analytical approach	Heat rate improvement potential (percent)

[640] The GHG Mitigation Measures TSD describes in more detail our rationale for using one- and two-year averaging periods in our analytical approaches and methodology as a whole.

	by region and averaging period					
	Western		**Texas**		**Eastern**	
	1 year	**2 year**	**1 year**	**2 year**	**1 year**	**2 year**
Efficiency and consistency improvements under similar conditions	3.5%	2.1%	3.7%	2.3%	5.6%	4.3%
Best historical performance	4.1%	2.6%	4.2%	3.1%	6.3%	4.9%
Best historical performance under similar conditions	4.7%	3.1%	4.9%	3.5%	6.9%	5.3%

Accordingly, we have concluded that a well-supported and conservative estimate of the potential heat rate improvements (and accompanying reductions in CO_2 emission rates) that EGUs can achieve on average through best practices and equipment upgrades is a 4.3-percent improvement in the Eastern Interconnection, a 2.1-percent improvement in the Western Interconnection and a 2.3-percent improvement in the Texas Interconnection. The decision to use these values as the building block 1 potential in each region is based on the weight of evidence that these are conservative values; for each region, each of the three analytical approaches in our methodology supports our determination that the heat rate improvement value we selected is achievable. Taken individually, each approach provides an independently reasonable estimate of the potential for heat rate improvement. Furthermore, as described in the GHG Mitigation

Measures TSD, these approaches are conservative on even an individual basis because they do not account for the full extent of heat rate improvements available through additional equipment upgrades and best practices. Some EGUs may have faced difficulties achieving significant heat rate improvement in the past and EGU owners may feel they face challenges in the future. Nevertheless, our methodology as a whole indicates that, on average, coal-fired EGUs can at least achieve the percentage heat rate improvement selected for their region through application of best practices and some of the available equipment upgrades. A more detailed discussion of the EPA's analysis in determining the heat rate improvement potential for existing coal-fired EGUs may be found in the GHG Mitigation Measures TSD supporting the final CPP.

No affected coal-fired EGU is specifically required to improve heat rate by any amount as a result of this rule. Rather, as described in section VI, the potential for heat rate improvement is used to determine a CO_2 emission performance rate. Those affected EGUs that have done the most to reduce their heat rate will tend to be closer to that CO_2 emission rate. In this sense, our approach to determining potential CO_2 reductions through heat rate improvements is similar to the way EPA ordinarily approaches standards of performance.[641]

In this final analysis, we do not delineate what proportion of the potential heat rate improvement can be expected from equipment upgrades versus best practices;[642] only that these heat

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[641] To give an illustrative example, imagine a population of sources that emit Pollutant X. Half of the sources emit Pollutant X at 2500 lbs/hour, while the other half of the sources have scrubbers installed that reduce their emission rates to 1500 lbs/hour. Because the sources are evenly divided between those with and without scrubbers, the average emission rate for the population as a whole is 2000 lbs/hour. In this hypothetical, EPA decides to base requirements on the emission rate achievable through use of a scrubber, meaning that all sources will have to meet an emission rate of 1500 lbs/hour. Because the fleet as a whole has an average emission rate of 2000 lbs/hour, it would be accurate for EPA to say that the fleet as a whole can reduce its emission rate by 25 percent -- from 2000 lbs/hour on average (only half the sources with scrubbers), to 1500 lbs/hour on average (all the sources with scrubbers). This description of what is possible *for the fleet as a whole* -- a 25-percent reduction in emission rate -- should not be misinterpreted as a statement that every *individual* source is capable of further reducing its emissions by 25 percent. The sources that have already installed scrubbers, and which are thus already operating at 1500 lbs/hour, would not be required to further improve their emission rate.

[642] Examples of the many types of best practices and equipment upgrades available to coal-fired EGUs include adopting sliding pressure operation to reduce turbine throttling losses; installing intelligent sootblowing system software; upgrading the combustion control/optimization system; installing heat rate optimization software; installing a production cost optimization program that benchmarks plant thermal performance using historical plant data; establishing centralized remote monitoring centers with thermal performance software for monitoring heat rates systemwide; repairing steam and water leaks; automating steam system drains; performing an on-site performance appraisal to identify potential areas for improved performance; developing heat rate improvement procedures and

rate improvements are achievable in the regions through a combination of these methods. As discussed in section V.C.3 below, we believe that a single heat rate improvement goal for each region incorporating both best practices and upgrades, based on the 11 years of hourly heat rate data for 884 coal-fired EGUs available to the EPA, is a reasonable approach that is supported by our analysis, and is particularly conservative given that it does not account for the full range of heat rate improvements achievable through additional equipment upgrades and best practices.

The performance rates quantified in section VI, below, reflect the region-specific values for heat rate improvement. Although the performance rates are based on the least stringent overall performance rate determined to be reasonable for any region, and are thus based in part on the percentage heat rate improvement identified for the region, this rule does not itself

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training O&M staff on their use; aligning the cycle to isolate or capture high-energy fluid leakage from the steam cycle; repairing utility boiler air in-leakage; performing utility boiler chemical cleaning; installing condenser tube cleaning system; retubing condenser; repairing/upgrading flue gas desulfurization systems; cleaning air preheater coils; adjusting/replacing worn air heater seals; replacing corroded air heater baskets; replacing feed pump turbine steam seals; overhauling high pressure feedwater pumps; installing fan and pump variable speed/frequency drives; upgrading turbine steam seals; upgrading all turbine internals; and installing coal drying systems. These and additional heat rate improvement measures are discussed further in the GHG Mitigation Measures TSD for the CPP Final Rule.

require any specific EGU to implement measures resulting in a specific percentage heat rate improvement. Rather, the percentage heat rate improvement value is merely reflected in the CO_2 emission performance rates and corresponding mass-based and rate-based state goals. Each state has the flexibility to develop a plan that achieves those CO_2 performance rates or emission goals by assigning the emission standards the state considers appropriate to its affected coal-fired EGUs. Similarly, depending on the content of the applicable plan, affected EGUs may achieve their emission standards through use of any of the building block measures described in this rule or any other measures permitted under the plan.

b. <u>Changes from the proposal</u>. In the proposed rule, we determined that building block 1 measures could on average achieve a 6-percent heat rate improvement from coal-fired EGUs in the U.S. based on a 4-percent heat rate improvement from implementation of best practices and a 2-percent heat rate improvement from equipment upgrades. Based on comments received and refinements made to our methodology for determining potential heat rate improvement from the hourly gross heat rate dataset of 884 coal-fired EGUs, we have conducted our analysis on a regional basis and reduced the overall expected percent heat rate improvement for coal-fired EGUs to 4.3 percent in the Eastern Interconnection, 2.1 percent in the Western

Interconnection, and 2.3 percent in the Texas Interconnection.[643] These values reflect improvements achievable through both best practices and equipment upgrades because, as described above, we also no longer include a separate estimation of the potential heat rate improvement achievable solely through equipment upgrades.

We received comments on our proposed statistical methodology for determining the CO_2 emission reductions opportunities achievable by coal-fired EGUs through heat rate improvements. We have closely reviewed those comments and, for the final rule, have made refinements to our methodology, as described above and explained in more detail in the GHG Mitigation Measures TSD supporting the final CPP.

In the final rule, the EPA extends the implementation deadline from 2020 to 2022. This additional time will be helpful to the states seeking to conduct more targeted analyses of the nature and extent of heat rate improvements that specific coal-fired EGUs can make, considering specific recent improvements or upgrades, planned retirements of older coal-fired EGUs, and other relevant considerations. The extended deadline will also provide additional time to accommodate changes to heat rate

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[643] Had the EPA maintained a nationwide approach to analyzing the potential reductions under building block 1, the result would have been 4.0 percent.

monitoring methods at EGUs and for the installation of new pollution controls that comply with other rules, as discussed below in the summary of key comments.

2. Costs of heat rate improvements

By definition, any heat rate improvement made by EGUs for the purpose of reducing CO_2 emissions will also reduce the amount of fuel that EGUs consume to produce the same electricity output. The cost attributable to CO_2 emission reductions, therefore, is the net cost of achieving heat rate improvements after any savings from reduced fuel expenses. As summarized below, we estimate that, on average, the savings in fuel cost associated with the percentage heat rate improvements we identified for each region would be sufficient to cover much of the associated costs. Accordingly, the net costs of heat rate improvements associated with reducing CO_2 emissions from affected EGUs are relatively low. We recognize that this cost analysis will represent the costs for some EGUs better than others because of differences in individual circumstances. We further recognize that reduced generation from coal-fired EGUs due to the implementation of other building block measures would tend to reduce the fuel savings associated with heat rate improvements, thereby raising the effective cost of achieving the CO_2 emission reductions from the heat rate improvements. Nevertheless, we still expect that a significant fraction of the investment required to capture the technical potential for CO_2 emission reductions from heat rate improvements would be offset by fuel savings, and that the net costs of implementing heat rate improvements as an approach to reducing CO_2 emissions from affected EGUs are reasonable. Even if we conservatively estimate that EGUs will largely rely on equipment upgrades rather than cheaper best practices to reduce heat rate, those reductions can generally be achieved at $100 or less per kW, or approximately $23 per ton of CO_2 removed, as described in detail in the GHG Mitigation Measures TSD supporting the final CPP.[644] Depending on the balance between equipment upgrades and best practices, improving heat rate would even result in a net savings for some EGUs.

Based on the analyses of technical potential and cost summarized above and in Chapter 2 of the GHG Mitigation Measures TSD, we find that heat rate improvements of 4.3, 2.1 and 2.3 percent are reasonable and conservative estimates of what coal-fired EGUs in the Eastern, Western and Texas Interconnections, respectively, can achieve at a reasonable cost.

3. Response to key comments

[644] The $100/kW cost figure from the proposal is now particularly conservative because it included the cost of significant equipment upgrades that improve heat rate, whereas building block 1 is now largely quantified based on low- or no-cost best practices, with a smaller portion of the remainder comprised of equipment upgrades.

Many commenters said that the EPA should have subcategorized by EGU design or operating characteristics for purposes of evaluating potential heat rate improvements under building block 1.

Several studies categorize EGUs broadly by capacity, thermodynamic cycle, fuel rank or other characteristics. We considered subcategorizing the EGUs by their design and fuel characteristics under building block 1. Although grouping by categories does not account for all of the factors that may affect heat rate, it can provide a useful way of understanding the operating profile of classes of coal-fired EGUs and the fleet as a whole. However, we have declined to subcategorize among affected coal-fired EGUs for both technical and practical reasons. First, as discussed above, our assessment of heat rate improvement potential uses a unit-specific data methodology that compares each EGU’s performance against its own historical performance. By substantially basing our analysis on these unit-specific assessments, we inherently factor in the effect of numerous design conditions. We also conducted a regression analysis that evaluated the effect of numerous factors on heat rate, and found that subcategorizing would generally make little difference in our analysis. Additionally, subdividing the EGUs into subcategories would reduce the quantity of EGUs used to calculate each average, which would increase the influence of random and atypical variations in the data on the overall averages, and would thus decrease our confidence in the results. Furthermore, as a practical matter, states are free to apportion reductions in a way that reflects any subcategories of their choosing when determining the emission standards for individual affected EGUs. Additionally, commenters assert that because building block 1 is calculated on an average basis, some affected EGUs will have greater potential than others to reduce CO_2 emissions through heat rate improvements. If an affected EGU cannot meet its particular emission standard because it has below-average potential to reduce emissions through heat rate improvements, then in instances where the EGU's state plan allows emissions trading, the EGU can acquire credits or allowances from affected EGUs that have above-average potential. For a further discussion of our reasonable decision not to subcategorize among coal-fired EGUs for purposes of determining building block 1, see the GHG Mitigation Measures TSD supporting the final CPP.

Many commenters told the EPA that EGUs already have undertaken significant efforts to operate efficiently to provide reliable electric service at the lowest reasonable cost; that they believe they cannot significantly improve heat rate; that best practice maintenance activities are performed on a daily basis, including during maintenance outages that allow for the inspection, cleaning and repair of all equipment; that extensive capital investments have been made to install state-of-the art equipment and replace equipment that is beyond repair; and that their employees continuously monitor and control operating levels in the combustion process to maintain maximum combustion of fuel and to avoid wasting available heat energy. In summary, these commenters say they have expended considerable effort and resources to maintain peak boiler efficiency at all times and, therefore, the 6-percent heat rate improvement proposed for building block 1 is unreasonable to apply to EGUs across the board; the EPA should develop a rule that allows treatment of affected EGUs on a case-by-case basis.

We commend the efforts of those who strive to operate and maintain EGUs in the best possible manner to minimize heat loss and CO_2 emissions. This rule does allow for treatment of EGUs on a case-by-case basis. States may believe that individual considerations are appropriate in some cases and, accordingly, we have purposely allowed states to make decisions about how to implement specific CO_2 reductions. Our determinations of 4.3-, 2.1- and 2.3-percent heat rate improvement for EGUs in the Eastern, Western and Texas Interconnection, respectively, are conservatively based on the lowest value identified by any of our reasonable statistical analyses. If states choose to set limits on individual affected EGUs based in part on the availability of heat rate improvements, the states are free to assess heat rate improvements on a more targeted, case-by-case basis that takes into account an EGU's previous heat rate improvement efforts, or lack thereof. The fact that states (or EGUs complying with state requirements) can make case-by-case decisions about how to achieve goals does not contradict our conservative estimates -- which are based on millions of hours of operating data reported to the EPA by EGUs -- of how much EGUs are capable of improving their heat rate in each region overall. Opportunities to improve heat rate abound for affected EGUs as a whole, as evidenced by the fact that the approaches in our statistical methodology each included a comparison of an EGU's historical heat rate to its 2012 heat rate. Our estimates of the potential heat rate improvement are additionally conservative because they are based purely on comparisons among historical gross heat rate data, and thus do not reflect available, cost-effective opportunities to improve heat rate that affected EGUs never implemented during the study period. Finally, to the extent that an affected EGU was in 2012 fully implementing every possible best practice for improving heat rate, it may still be capable of improving heat rate through equipment upgrades.

Other commenters said that a 6-percent heat rate improvement overall is too high; that the heat rate improvement from upgrades are double-counted within the data used to determine heat rate improvements from best practices; and that the 2-percent heat rate improvement specifically for upgrades was inappropriately based on "conceptual" improvements from only one study.

We have reduced the 6-percent heat rate improvement from the proposed rule to three regionalized figures of 4.3 percent (Eastern), 2.1 percent (Western) and 2.3 percent (Texas), as discussed above and described in detail in the GHG Mitigation Measures TSD supporting the final CPP. We expect that, on average, affected coal-fired EGUs can at a minimum improve heat rate in these amounts by implementing best practices and equipment upgrades identified in the GHG Mitigation Measures TSD. These overall heat rate improvement figures do not include an estimated percent heat rate improvement attributable specifically to upgrades. Although we are no longer including in our calculation of building block 1 a separate 2-percent heat rate improvement attributable solely to equipment upgrades, this decision is not because we believe that our initial 2-percent assessment of equipment upgrades was incorrect. To the contrary, the information presented in the S&L study was similar to that in other industry reports and studies -- many of which were referenced in the proposal TSD -- describing potential heat rate improvements at EGUs from all types of equipment upgrades.

However, we recognized that the possibility existed that some limited portion of that 2 percent was also reflected in our statistical analyses of historical gross heat rate data. In order to ensure that our methodology did not double-count an indeterminate amount of heat rate improvement available through equipment upgrades, we conservatively set aside the entire additional 2 percent attributable solely to equipment upgrades. Accordingly, we determined the amount of potential heat rate improvement in the BSER solely from the heat rate analyses described above, which account for improvements through best practices and equipment upgrades that were at some point achieved by an EGU, but not for the full range of best practices and equipment upgrades that are actually available.

Commenters also said that the EPA did not look at important factors that affect heat rate such as coal type, boiler type, cooling water temperature, age, nameplate capacity or the use of post-combustion pollution controls.

Our statistical methodology compared each unit to its own historical performance and, therefore, largely accounts for the effects that a unit’s design or fuel characteristics would have on heat rate. As discussed above, our methodology used hourly data from 884 units over an 11-year period (2002-2012) and compared the variability in the heat rate of each individual unit to that unit’s own performance. By assessing potential heat rate improvement by first looking at unit-specific data, our methodology inherently factors in the possible effects of design and fuel characteristics (*e.g.*, coal type, boiler type, nameplate capacity, age, cooling water system, air pollution controls) on heat rate and heat rate variability.

Although cooling water temperature likely plays an important role in a coal-fired EGU’s heat rate, as stated by commenters, there are no consistent quality-assured hourly cooling water temperature data available to the EPA. However, in an effort to determine the potential effect of cooling water temperature on heat rate, we looked at a sample of 45 coal-fired EGUs at 19 facilities for which we had hourly surface water temperature data (used as a surrogate for cooling water) from monitors located nearby and upstream of cooling water intake points. Our analysis found that surface water temperature did explain some of the variation in heat rate, but that surface water temperature is strongly correlated with ambient air temperature -- a variable we did control for in our methodology. Because of the strong correlation between ambient air temperature and surface water temperature, the availability of a comprehensive dataset of nationwide hourly ambient air temperature, and the similar explanatory power of surface water temperature and ambient air temperature, it is unlikely that separately addressing cooling water temperature would significantly change the results. Rather, we are confident that our use of hourly ambient air temperature in our analyses adequately addressed any significant impact of cooling water temperature. See the GHG Mitigation Measures TSD supporting the final CPP for further details about this analysis. As described further in that TSD, the other potentially relevant variables for which we did not directly control are unlikely to significantly affect the average heat rate.

Commenters said that the heat rate improvement attributable to upgrades will degrade over time or require repeated and costly further upgrades.

We are aware that some heat rate improvement measures can degrade over time. Like most power plant components, some heat rate improvement technologies require maintenance in order to sustain their efficacy over time. Therefore, to avoid degradation, personnel at EGUs will need to diligently apply "best practices" on a regular basis, a practice that numerous commenters say is standard operating procedure. The S&L study includes estimates of associated O&M costs for each heat rate improvement method that is discussed. As we explained in the proposal, the related O&M costs of diligently applying best practices are relatively small compared to the associated capital costs and would, therefore, have little effect on the economics of heat rate improvements.

Commenters stated that heat rate improvement should be set on a basis that is narrower than nationwide -- for example, state-by-state or unit-by-unit.

The EPA did not propose and is not finalizing a rule that sets heat rate improvement goals for individual states or for individual coal-fired EGUs. Instead, in the approved state plans developed under this rule, each state will set the emission standards for its various coal-fired EGUs. In doing so, the state may take into account its own view of the amount of heat rate improvement needed (if any) at specific EGUs, and may look to the EPA's analysis of heat rate improvement potential in the applicable region as a guide, while keeping in mind the CO_2 emission performance rate. This broad-based approach is consistent with the traditional rules evaluating the potential for emission reductions on a source-category basis, and is consistent with the broader goal-setting purpose of this rule. Furthermore, the final rule establishes a uniform national performance rate based on the least stringent regional performance rate calculated with the building blocks. Accordingly, affected EGUs in regions not setting the national level have emission reduction opportunities beyond those reflected in the applicable performance rate.

The heat rate improvement measures comprising building block 1 would ordinarily be evaluated on a nationwide basis.

However, in this instance there are two good reasons to calculate building block 1 on a regionalized basis. First, a regionalized approach is consistent with the EPA's approach to determining the other building blocks. For building block 1, this means that the heat rate improvement should reflect only as much potential for emission reduction from building block 1 as our analyses indicate can be achieved on average by the affected coal-fired EGUs in that region. This ensures that the BSER for each region is representative of the characteristics and opportunities available within that region, rather than a less logical combination of opportunities in the region and opportunities nationwide. Second, a regionalized approach provides a more representative average of the potential heat rate improvement that EGUs in a given region are capable of achieving. The populations of affected coal-fired EGUs in each region differ in some respects, as discussed in the GHG Mitigation Measures TSD, and the more nuanced regionalized approach thus indirectly accounts for some of those systemic differences. For these and other reasons described in Section V.A. of the preamble with respect to the BSER as a whole, we have reasonably based building block 1 on a regionalized approach. Applying this regionalized approach to building block 1 strikes an appropriate balance between the proposed nationwide analysis and commenters' suggested state-specific analysis, which does not fully reflect the interconnected nature of the system within which affected coal-fired EGUs operate.

The practical consequence of calculating building block 1 on a regionalized versus nationwide basis is minimal. This is because the CO_2 emission performance rates are based on the overall performance rate determined to be reasonable for EGUs in the Eastern Interconnection. Our methodology identifies a 4.3 percent potential improvement in the Eastern Interconnection, compared to a 4.0 percent figure across all three interconnections.

We further note, along with some commenters, that site-specific engineering studies or unit-by-unit analyses of heat rate improvement potential for coal-fired EGUs are not available to the EPA; only a small number of site-specific case studies are available in the public literature. We considered that for the EPA to develop a comprehensive, unit-by-unit heat rate improvement study of nearly 900 coal-fired EGUs from scratch, it would likely cost the Agency $50,000 to $100,000 to study each EGU (almost $50 to $100 million total) and require three to four years to complete. Such a granular analysis would not serve the broader goal-setting purpose of this rulemaking. We agree with commenters who have pointed out that a heat rate improvement-estimating effort of that magnitude and duration would be unnecessarily lengthy and expensive. Nor would such a granular analysis be a necessary predicate for states to develop emission standards, or for EGUs to comply with those emission standards. Rather, our methodology's reliance on individualized, unit-by-unit hourly performance data from 884 EGUs provides conservative and reasonable regional estimates of heat rate improvement potential. Indeed, given the conservative nature of our methodology, a unit-specific approach that evaluates the full range of best practices and equipment upgrades available at individual EGUs -- including upgrades not accounted for here -- would be more likely to result in higher overall heat rate improvement figures than we are finalizing for building block 1. Furthermore, site-specific information forms the foundation of the EPA's estimated heat rate improvement potential, and similar data likely would be used in any site-specific heat rate improvement engineering study. Finally, EGU-specific detailed design and operation information is not consistently available for all the factors that influence heat rate. The EPA has used the comprehensive data that are available to reasonably and conservatively estimate potential heat rate improvement in each region.

Commenters also said that shifting electricity generation from coal-fired EGUs to other EGUs because of measures implemented under other building blocks will lower the capacity factors of coal-fired EGUs, and thus increase, not decrease, their heat rates.

We expect that most states will develop plans that optimize the operation of existing coal-fired EGUs while utilizing the other building blocks and other measures to reduce emissions from carbon-intensive generation. From our IPM projections, the average annual capacity factor of existing coal-fired EGUs that are expected to remain in operation in 2030 will actually increase compared to 2012. This projection -- which is further described in the GHG Mitigation Measures TSD -- incorporates expected retirements of inefficient units and generation shifts away from using coal-fired EGUs as peaking units.

Commenters also noted that the EPA used net heat rate in state goals, but used gross heat rate in its heat rate improvement analysis -- potentially ignoring the detrimental effect that parasitic load from air pollution control devices (APCD) and other equipment can have on net heat rate.

The EPA's variability analysis necessarily and reasonably used gross output data for each of the 884 EGUs in the EPA's database because they are the only publicly available, unit-specific, hourly performance data. By definition, improvement in gross heat rate would be reflected in the net heat rate. Gross heat rate is the total heat output from the EGU, in units of Btu/gross kWh, and includes the power used by auxiliary equipment required to operate the EGU itself. By contrast, net heat rate is the remaining Btu/kWh after subtracting the power used by the EGU's own auxiliary equipment from the gross heat rate value, *i.e.*, what the EGU is able to provide to the grid. Improvements in net heat rate alone (*e.g.*, reducing parasitic load of on-site equipment) may be possible on many units. Therefore, our use of gross heat rate to estimate potential heat rate improvement was conservative because of the additional opportunities to achieve the uniform performance rate through improvements in net heat rate alone.

Commenters also raised concerns that the EPA was not taking into account net heat rate increases due to additional add-on pollution controls that may, for some units, be required by other rules.[645]

The results of our statistical analysis are based on gross heat rates and would not change with installation of emission controls for CSAPR, MATS, or other rules because these controls will add parasitic load requirements and thereby have an impact on the net heat rates only. Furthermore, we conservatively consider region-wide net heat rate improvement potential to be the same as that indicated for the region-wide gross heat rate, when in fact it is not. In order to check our assumptions

[645] See above for an explanation of gross versus net heat rate.

concerning gross versus net heat rate, we used the IPM Power Sector Modeling Platform (version 5.14) and National Electric Energy Data System (NEEDS) (version 5.14) to analyze the anticipated incremental heat input required to operate additional add-on controls to comply with various EPA rules, including CSAPR, MATS, effluent guidelines for EGUs, and coal combustion residuals. From this analysis, we project that between 2012 and 2025, existing coal-fired EGUs are expected to install approximately 18.6 GW of wet flue gas desulphurization (FGD), 16.6 GW of dry FGD, 24.9 GW of selective catalytic reduction (SCR), and 3.9 GW of selective noncatalytic reduction (SNCR). The resulting impact from new pollution controls on existing coal-fired EGUs' heat rate is expected to be very small, at conservatively less than 31 Btu/kWh, or less than 0.3 percent in 2025.[646] After 2025, this estimate is particularly conservative because the EPA's cost performance models overestimate the parasitic load from individual add-on controls for future years. Furthermore, at some EGUs these newer pollution control devices will replace existing pollution control devices. Accordingly, for these EGUs, the minimal increase in net heat rate due to power required to operate new

[646] When considered on a regional basis, we expect these controls to impact heat rate by approximately 0.3 percent in both the Eastern and Western Interconnections, and by less than 0.1 percent in the Texas Interconnection.

controls will be at least partially offset by the decrease in net heat rate caused by removal of the control devices currently in place. For more information about this analysis, see the GHG Mitigation Measures TSD supporting the final CPP.

Commenters contended that the 11 years of data used to evaluate potential heat rate improvement is too broad, and that the population of domestic coal-fired EGUs has changed significantly over this time period.

The 11-year span for the hourly gross heat rate data is appropriate because it represents a wide variety of economic conditions, market conditions and fleet composition, while also capturing the relatively recent historical performance of affected coal-fired EGUs. We also noted in the proposal TSD that the population of coal-fired EGUs used in the analytical approaches to determine potential heat rate improvement is made up of coal-fired EGUs that operated in 2012. The gross heat rate data of any coal-fired EGUs that retired prior to 2012 were not included in the dataset.

Commenters stated that many of the changes in heat rate reflected in the 11-year hourly gross heat rate dataset are attributable to changes in monitoring methodology, and thus do not represent heat rate improvements attributable to best practices or equipment upgrades. In addition, commenters are concerned that changes to the monitoring methodology in the future could artificially alter the measured heat rate.

Different stack gas flow monitoring methods can yield more or less accurate measurements of heat input and CO_2 emissions. These differences depend on the characteristics of the stack gas flow where the monitoring and reference method measurements are taken, and which options under the Part 75 emission measurement rules are chosen in the application of the various flow rate reference methods. In general, more accurate stack gas flow monitoring methodologies yield lower values that, when used to calculate emissions or heat input, may lower the heat rate values reported to the EPA.

Some EGUs adopted monitoring methodologies that have the potential to affect the exactness of the data we used for assessing heat rate improvements. However, as discussed in detail in the GHG Mitigation Measures TSD supporting the final CPP, our review of the data shows that a relatively small amount of the data are affected by these changes; we are confident that the values adopted for building block 1 are conservative and reasonable estimates of the potential for heat rate improvement in each region. Some changes in monitoring methodology would have the result of tending to cause us to underestimate the potential for heat rate improvement. Furthermore, because our methodology analyzes percentage heat rate improvement based on

2012 gross heat rate data, our results are unaffected by EGUs that used more accurate monitoring methodologies in 2012 or used the same monitoring methodologies consistently throughout the 11-year study period. For these and other reasons discussed in detail in the GHG Mitigation Measures TSD, we remain confident in our results despite the marginal differences attributable to monitoring methodologies in some of the heat rate data for a subset of EGUs.[647]

In terms of concerns with future methodological changes, the overwhelming majority of the 884 EGUs in the dataset we used to assess heat rate improvement have already changed their stack gas flow monitoring methodology in 2012 or earlier. Furthermore, extension of the compliance date to 2022 for this rule, as discussed above, more than adequately allows enough time for EGUs to determine how to actually improve their heat rates and lower CO_2 emissions while accommodating future changes to monitoring methodologies. For a more detailed explanation, see the GHG Mitigation Measures TSD supporting the final CPP.

Commenters said that there is no proof that lowering the heat rate will reduce variability or that reduced variability

[647] Furthermore, on a fundamental level, our methodology accounts for a certain amount of any residual inexactness because we have conservatively adopted the lowest value identified by any of our reasonable approaches -- all three of which are themselves conservative because they do not account for the full extent of heat rate improvements achievable through equipment upgrades.

will reduce heat rate, *i.e.*, correlation does not prove causation.

As an initial matter, it is important to note that for the final rule the EPA used three types of statistical analyses to evaluate and estimate potential heat rate improvements of coal-fired EGUs, and only one of these analyses involved any consideration of heat rate variability. All three types of statistical analyses are described in the GHG Mitigation Measures TSD supporting the final CPP.

These commenters are correct that, in the abstract, reducing heat rate variability only means that heat rate will be more consistent -- not necessarily lower or higher. However, our analysis is not an abstract evaluation of the potential to reduce variability, as commenters suggest, but rather is an evaluation of the potential heat rate *improvement* achievable through reducing variability -- *i.e.*, reducing variability to achieve a more consistently low heat rate. See the more detailed discussion of the statistical procedures used for the final rule, above. In particular, the application of a “consistency factor” in the analyses performed for both the proposed and final rule demonstrates the potential results if each individual EGU operated slightly more consistently with the lower heat rates that the EGU had itself previously achieved under similar conditions.

The consequence of a reduced heat rate is, of course, a lower rate of CO_2 emissions, which is the purpose of the BSER for building block 1. This way of thinking about reduced variability is consistent with the utility power sector's own efforts to reduce variability, which are aimed at securing the economic benefits of a more consistently *lower* overall heat rate.

Some commenters expressed concern that heat rate improvements could trigger applicability of new source review (NSR) provisions. The relationship of this final rule to other regulatory provisions, including NSR, is discussed in section X of the preamble.

D. Building Block 2—Generation Shifts Among Affected EGUs

The second element of the foundation for the EPA's BSER determination for reducing CO_2 emissions at affected fossil fuel-fired EGUs entails an analysis of the extent to which fossil steam EGUs can shift generation to existing NGCC EGUs. In this section, we define building block 2 as the gradual shifting of generation from existing fossil steam to existing NGCC within each region up to a maximum NGCC utilization of 75 percent on a net summer basis. In each year of the interim period, this 75 percent net summer maximum potential is subject to a regional limit informed by historical growth rates.

This section summarizes the EPA's analysis supporting that definition. We begin by discussing the sector's ability to reduce CO_2 emissions by shifting generation, including selected background information, data on trends toward greater NGCC generation, and various mechanisms for executing or facilitating generation shifts. Next, we describe the amount and timing of generation shift we have determined to be achievable through the building block. We then discuss various elements supporting our quantification of achievable generation shift, including the technical feasibility of NGCC units to increase generation; historical shifts to NGCC generation; considerations related to reliability, natural gas transmission infrastructure, natural gas production, and electricity transmission infrastructure; and regulatory flexibility. A discussion of costs follows. Finally, we respond to certain comments not addressed in the preceding discussions.

1. Demonstration of ability to reduce CO_2 emissions through shifting generation

a. Background of utility power sector. The ability to shift generation from higher- to lower-emitting sources is compatible with the way EGUs are generally dispatched.[648] The standard approach to dispatching generation is through Security Constrained Economic Dispatch (SCED), a well-established

[648] See preamble section II.C.1, History of the Power Sector, for background to this discussion.

practice in the electric power industry.[649] As the name indicates, SCED has two defining components: economic operation of generating facilities and assurance that the electric system remains reliable and secure.[650] Economic dispatch generally refers to shorter-term planning and operations from a day ahead through real time. During this period, generating units are committed – a process known as "unit commitment," in which units are committed to be ready to provide generation to the system when they will be needed – and then dispatched in real time to meet the electricity demand of the system. Overall changes in the level of generation from different facilities are also planned over time periods longer than this 2-day dispatch period. Over a calendar year, for example, units are planned and scheduled seasonally or monthly to ensure that sufficient capacity and energy will be available to meet expected loads in an area. Over a period of a week, units are committed to be prepared to start up or shut down to meet forecast loads, and dispatch is coordinated within this planning and unit commitment framework. This process enables system operators to respond

[649] "Economic Dispatch: Concepts, Practices and Issues", FERC Staff Presentation to the Joint Board for the Study of Economic Dispatch", Palm Springs, California, November 13, 2005. A copy of this presentation is available in the docket for this rule.
[650] "Security Constrained Economic Dispatch: Definitions, Practices, Issues and Recommendations: A Report to Congress", Federal Energy Regulatory Commission, July 31, 2006.

quickly to short-term changes in demand, and also to shift generation among different generation types to match longer-term requirements and goals.

EGUs using technologies with relatively low variable costs, such as nuclear units, are for economic reasons generally operated at their maximum output whenever they are available. Renewable EGUs such as wind and solar units also have low variable costs, but the magnitude and timing of their output generally depend on wind and sun conditions rather than the operators' discretion. In contrast, fossil fuel-fired EGUs have higher variable costs and are also relatively flexible to operate. Fossil fuel-fired EGUs are therefore generally the units that operators use to respond to intra-day and intra-week changes in demand. Because of these typical characteristics of the various EGU types, the primary opportunities for switching generation among existing units available to EGU owners and grid operators generally consist of opportunities to shift generation among various fossil fuel-fired units, in particular between coal-fired EGUs (as well as oil- and gas-fired steam EGUs) and NGCC units. In the short term — that is, over time intervals shorter than the time required to build a new electric generation unit — fossil fuel-fired units consequently tend to compete more with one another than with nuclear and renewable EGUs. The amount of generation shifting from coal-fired EGUs to

NGCC units that takes place as a result of this competition is highly relevant to overall power sector GHG emissions, because a typical NGCC unit produces less than half as much CO_2 per MWh of electricity generated as a typical coal-fired EGU.

b. Trends in generation shifts from coal-fired to natural gas-fired sources. Since at least 2000, fossil fuel-fired generation has been shifting from coal- and oil-fired EGUs to NGCC units, both as a result of construction of additional NGCC units, and also as a result of dispatch of pre-existing NGCC units at higher capacity factors. As a result, generation from NGCC EGUs in 2012 reached over four times the level of NGCC generation in 2000, while generation from coal and oil/gas steam EGUs decreased by around one third.[651] As we demonstrate in the GHG Mitigation Measures TSD, NGCC units are capable of operating at higher annual capacity factors than they have historically, so there remains considerable opportunity for increased use of existing NGCC units to replace generation currently supplied by higher-emitting coal and oil/gas steam units. The electric utility industry is thus well-positioned to address the requirements of this building block by increasing use of existing NGCC units and correspondingly decreasing use of steam units. The electric industry has been shifting generation to

[651] Ventyx Electric Power Database.

NGCC units in recent years and is expected to continue to retire coal capacity and add new NGCC capacity. In the reference case without implementation of CO_2 emission limitations, EIA forecasts 40 GW of coal retirements and 53 GW of NGCC capacity additions from 2014 to 2030.[652] An EPA review of state Integrated Resource Plans (IRPs) shows a pattern of shifting away from coal steam capacity to NGCC capacity and, in some cases, conversion of coal steam capacity to natural gas steam capacity. For example, Ameren plans to add 600 MW of NGCC capacity and convert two coal units to natural gas steam units, and Duke plans to add 680 MW of NGCC capacity and convert one coal unit to a natural gas steam unit.[653]

c. Mechanisms for dispatch shifts from coal-fired to natural gas-fired generation. There are a variety of patterns of ownership and operational control of EGUs; these ownership and operational structures influence how EGUs will respond to this building block. However, all owners and operators have the ability to comply by using this building block. In terms of ownership, investor-owned utilities (IOUs) serve about 75 percent of the US population, while consumer-owned utilities

[652] Energy Information Administration, Annual Energy Outlook 2015 reference case, ref2015.d021915a.
[653] For further examples, see the memo entitled "Review of Electric Utility Integrated Resource Plans" (May 7, 2015) available in the docket.

serve the remaining 25 percent.[654] In states that have maintained traditional regulation, IOUs are generally vertically integrated (owning generating capacity as well as transmission and distribution infrastructure), and the wholesale sales of these EGUs are regulated by the state; in states that have deregulated their retail service, ownership of the EGU is separated from ownership of transmission, and wholesale sales of generation are regulated by FERC. Consumer-owned utilities comprise municipal utilities, public utility districts of various types owned by government agencies, nonprofit cooperative entities (co-ops), and a number of other entities such as Native American Tribes.

Operational control of the dispatch of power over the electricity grid is superimposed on this pattern of ownership. Prior to electricity restructuring, this dispatch was typically operated by major vertically-integrated utilities or by public power entities. Over the last 15 years, large portions of the power grid are now independently operated by ISOs or RTOs. These entities are regulated by FERC and dispatch power from multiple owners to meet the loads on the bulk power grid.

The combination of multiple ownership and types of operational control adds to the complexity of electricity dispatch, but all affected EGUs, regardless of ownership and

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[654] Regulatory Assistance Project, Electricity Regulation in the US: A Guide, Page 9, March 2011.

type of control, can use this building block to comply with the final rule. The principal difference among the differing entities lies in the types of methods that are available for the affected EGU owner to bring about the shift in generation that will make use of this building block for compliance. There are several alternatives to accomplish this result: the owner of the higher-emitting affected EGU may also own, or have affiliates that own, lower emitting generation and thus reduce its own generation and use its control over these other EGUs to increase their generation; an EGU may be able to reduce its generation and buy replacement power from the market that is lower emitting; or the EGU may be able to reduce its generation and procure generation from a separately-owned lower-emitting EGU. These alternatives will be available in states with either rate or mass-based state plans without any change in their general form. Under a rate-based state plan, an EGU owner may also be able to purchase ERCs and average the ERCs into its emission rate for purposes of demonstrating compliance with its standard of performance. Under standards of performance that incorporate emissions trading, an EGU owner may be able to purchase rate-based emission credits or mass-based emission allowances not needed by other EGUs and use those credits or allowances to help achieve its standard of performance.

The potential to shift generation identified for this building block is entirely consistent with the existing economic dispatch protocols described above. State environmental policies can shift generation in two ways. The first is operational restrictions, such as permit limits on the number of hours that an EGU can operate in order to limit emissions. The second is changes in the relative costs of generation among different types of EGUs related to pollution reduction measures. For example, a regulation that necessitates the use of a control technology that requires the application of a reagent in a certain kind of EGU will increase the variable cost of operating that plant, which in turn may reduce the amount of generation it is called upon to deliver to the grid through security-constrained economic dispatch procedures.

In an organized market, where the system operator dispatches units partly based upon costs, an electric power plant that experiences an increase in its variable costs will tend to operate less than it otherwise would have. For example, market-based pollution control programs require units to hold tradable allowances to authorize their emissions of a regulated pollutant. Such an allowance-holding requirement puts a price on the act of emitting the regulated pollutant, which increases the operating costs of units that emit that pollutant, and thus such units will be dispatched less than they otherwise would without such an allowance-holding requirement. The RGGI is an example of a state program that has this effect. In the present rule, although shifts in the mix of generation to address the costs of pollution control can lead to higher electricity generating costs overall, the EPA analysis shows these costs to be modest and well below their associated benefits.[655]

Many of the NGCC units are owned by the same companies or affiliates that also own steam units. In these cases, changes in EGU generation can be planned by the company or affiliate without the need to engage in separate market transactions with outside parties. Where the affected EGU owner is also the dispatch entity, as in most traditional market structures, the EGU owner will generally have operational control over the unit. Environmental conditions, such as compliance costs or limits on generation, can be factored in with fuel costs for purposes of determining when the unit is committed to be available, how the unit can be most efficiently cycled, and at what level the unit is dispatched.

An analysis of generation data from steam and NGCC units in 2012 shows that 77 percent of the steam generation occurred from an EGU that owned, or that had an affiliate that owned, NGCC generation. Eighty percent of the generation shift potential

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[655] See the Regulatory Impact Analysis.

identified in this building block (increasing NGCC generation up to a 75 percent capacity factor on a net basis to replace steam generation) could occur among these entities that own (either directly or through affiliates) both steam and NGCC generation.[656] These data show that most EGU generation relevant for this building block is produced by entities that own both steam and NGCC generation.

Another alternative available to an affected EGU owner that does not also own NGCC generation is for the higher-emitting affected EGU to reduce its generation and purchase replacement power from the market. In organized markets such as RTOs, it is available through standard practice, because the owner impacts how its EGUs are dispatched based upon how it bids into the RTO market. In this case, the owner can exercise control over the levels of generation across units by when it offers generation to the market operator (the RTO or ISO), and the prices it bids for this generation. As in traditional economic dispatch by a utility, environmental conditions, compliance costs, or limits on generation can be incorporated by the owner into the determination of the cost-effective generation pattern of its EGUs.

[656] SNL Energy. Data used with permission. Accessed May 2015.

In regions with organized electricity markets (including, but not limited to, RTOs or ISOs), the various types of EGU owners of higher-emitting sources can reduce their generation, and any resulting deficit in generation on the system can be supplied from other EGUs in the region; for example, a coal-fired unit can reduce generation that is then replaced through the operation of the market by generation from an NGCC unit, subject to dispatch by a regional operator to ensure the reliable delivery of the generation to loads within the region. To comply with this rule, higher-emitting steam units will need greater reductions relative to lower-emitting NGCC units which will, in turn, tend to raise steam unit costs compared to NGCC units. As a result, the bids that a steam unit provides a market operator will rise relative to NGCC units. This process of reducing generation from a higher-emitting unit will lead to substitution of lower-emitting generation.

EGU owners that do not participate in an organized electricity market may nevertheless purchase power from the wholesale power market. Purchases in the wholesale power market can be spot purchases, which are typically general purchases of system power supplied by the EGUs across a region, or contract purchases, which may have more provider-specific characteristics (such as specifying the type of unit that is providing the power). Purchases between EGUs through the wholesale power market will have similar emission-lowering properties as operation of the organized market discussed above, because dispatch in balancing areas outside RTOs and ISOs also follows a similar economic dispatch protocol that is informed by each unit's production costs and environmental limitations.

Under this alternative, the steam generators may, in effect, realize emission reductions from building block 2 simply by reducing their generation. Steam generators do not need to purchase replacement electricity as a prerequisite for realizing emission reductions from reducing their own generation because other generators already have an incentive to provide as much electricity as load-serving entities are willing to buy in order to satisfy electricity demand.[657] As noted above, higher-emitting generation sources will have to incorporate correspondingly higher costs of pollution reduction into their supply bids compared to lower-emitting generation sources, and as a result, load-serving entities will seek to buy a greater share of

[657] Some owners or operators of steam generators may have electricity supply obligations to which they may be applying power from those steam generators. However, such parties may fulfil those supply obligations using the wholesale power market in the exact same way described here that enables any other generator with economically attractive electricity to offer such supply. In other words, the ability of a steam generator to reduce its generation is not contingent on an associated purchase to replace that power, notwithstanding the possibility that the owner or operator of that steam unit may choose to make such a purchase to meet an electricity supply obligation.

electricity from the lower-emitting sources because their supply bids will be more economically attractive. Once the steam generators reduce their generation (and associated emissions), the other entities in the electricity system arrange for the replacement electricity. The outcome of this power market process will reduce both the mass and the rate of emissions across sources.

An owner of a source can also reduce the generation of an EGU by substituting generation from a lower-emitting NGCC directly. For an EGU owner without existing NGCC generation, this substitution can take the form of a bilateral contract purchase. In RTOs and ISOs, this alternative often takes the form of a contract for differences, where the replacement source could be an NGCC and the contract specifies a delivery location and the price of the power. In bilateral markets, the contract vehicle could be a Power Purchase Agreement from a replacement source. It is also possible that the owner of a steam unit could directly invest in an existing EGU by purchasing the asset or taking a partial ownership position, thus acquiring the generation from the unit through that means. The acquired generation and its associated emissions could be used for compliance by the higher-emitting EGU, in accordance with the plan under which it is operating. The amount of generation that could be shifted using the approaches described in this paragraph will depend on the type and terms of the commercial arrangements, as well as the potential need for regulated entities to obtain approvals for contracts or for changes in asset positions. The wide range of approaches permitted by this rule provides flexibility, both within a year and across multiple years, for EGUs to fashion these arrangements to fit their circumstances.

Where permitted under its state plan, an EGU would also be able to meet its reduction obligations using ERCs or allowances. The particular nature of this alternative will depend on how a state elects to develop its plan. If a state chooses a mass-based approach, the EGU would simply need to hold allowances to cover its emissions. To realize an emission reduction from building block 2 under this approach, a steam generator would only need either to reduce its emissions by reducing its generation, which would lead to that generator needing fewer allowances to cover its emissions under the program, or to purchase surplus allowances not needed by another EGU that had reduced its emissions. In a rate-based state, the state may choose to provide for compliance through the acquisition of tradable ERCs. To realize an emission reduction from building block 2 under this approach, a steam generator would be able to adjust its effective emission rate by purchasing ERCs that are produced by other sources whose emission rates are lower than the applicable rate standard. In this fashion, a steam generator does not need to purchase lower-emitting replacement power per se in order to demonstrate an emission reduction from this building block; instead, the steam generator may purchase any ERCs that were produced from lower-emitting sources (see section VIII for more detail on how state plans can use an ERC approach to facilitate a rate-based compliance demonstration of this type of emission reduction).[658]

The approaches shown here collectively demonstrate that all steam generators -- regardless of size, location, form of ownership, or type of market in which they operate -- can implement building block 2 through some or all of the mechanisms described.

2. Amount and timing of generation shift

The EPA has determined that for purposes of quantifying the CO_2 emission reductions achievable through building block 2, a reasonable amount of generation shift is the amount of generation shift that would result from existing NGCC units, on

[658] Stakeholders have recognized that ERCs and allowances are an effective tool for EGUs to implement the building blocks and achieve their standards of performance required under this rule. *See* "Clean Power Plan Implementation: Single-State Compliance Approaches with Interstate Elements," Georgetown Climate Center (May 2015), http://www.georgetownclimate.org/sites/www.georgetownclimate.org/files/GCC_ComplianceApproacheswithInterstateElements_May2015.pdf.

average, increasing their annual utilization rates to 75 percent of net summer capacity. However, the building block does not reflect achievement of this average capacity factor at the start of the interim period, but instead reflects a glide path of increases in NGCC utilization over the interim period. Below, we discuss the glide path, and in the following section we discuss the basis for finding the 75 percent utilization rate, achieved over the period of time consistent with the glide path, to be reasonable.

The EPA received significant public comments expressing concern regarding the proposal's incorporation of the full building block 2 shift in generation by the first year of the interim period. These commenters perceived this approach as requiring states to achieve such a significant portion of the required CO_2 emission reductions early in the interim period that states would lack flexibility in when and how they may achieve the required emission reductions. Other commenters expressed concern that the full extent of building block 2 would be difficult for some states to achieve by the first year of the interim period as a result of technical, engineering, and infrastructure limitations or other considerations; that such timing may crowd out other cost-effective options for emission reductions; and that such timing might have negative implications for reliability.

In the proposal, the EPA determined that emission reductions are feasible and achievable at fossil fuel-fired steam EGUs by shifting from more carbon-intensive EGUs to less carbon-intensive EGUs, as part of the BSER. More specifically, the EPA proposed that generation shifts from fossil fuel-fired steam units (which are primarily coal-fired) to NGCC units, up to a utilization of 70 percent on a nameplate capacity basis, could be achieved by 2020. In contrast, the EPA proposed that reductions in CO_2 emissions from fossil fuel-fired units associated with other measures, such as increased utilization of RE generating capacity and increased demand-side EE, would be achievable on a phased-in basis between 2020 and 2029, reflecting the time needed for deployment.[659] In light of the concerns noted above, in the October 2014 Notice of Data Availability the EPA solicited comment on potential rationales for phasing in the potential to shift generation under building block 2.[660]

As already noted, in the final rule the EPA has revised the interim period to start in 2022, which itself is a meaningful response regarding the concerns expressed by commenters about the timing of building block 2's generation shift potential. In addition, the EPA has evaluated the feasibility over time of

[659] 79 FR 34866.
[660] 79 FR 64543.

building block 2 within the framework of BSER, and is finalizing a change to building block 2 that gradually phases in the shift from existing fossil steam to existing NGCC over the interim period. This phase-in allows for additional time to complete potential infrastructure improvements (e.g., natural gas pipeline expansion or transmission improvements) that might be needed to support more use of existing natural gas-fired generation, and provides states with the increased ability to coordinate actions taken under building block 2 with actions taken under building block 3 (deployment of new renewable capacity).

The phase-in schedule applies a limit to the maximum building block 2 potential in each year of the interim period based on two parameters. The first parameter defines an amount of generation shift to existing NGCC capacity that is feasible by 2022, and the second parameter defines how quickly that amount could grow until the full amount of NGCC generation could be achieved as part of the BSER. Both of these parameters are determined by examining the extent to which gas-fired generation has increased over historical time periods. The first parameter is based on the single largest annual increase in power sector gas-fired generation since 1990, which occurred between 2011 and

2012 and is equal to 22 percent.[661] We believe that this amount is a conservative estimate of the ability of the sector to increase utilization of NGCC capacity by 2022, given that this increase has already occurred in a single year. The second parameter is based on the average annual growth in gas-fired generation in the power sector between 1990 and 2012, which is approximately 5 percent per year.

In the performance rate calculation methodology, these two parameters constrain the annual rate at which building block 2 shifts generation from fossil steam units to NGCC units. The interim performance rate is an average of annual rates calculated over the 2022-2029 period. The two parameters above limit the extent to which NGCC generation is able to increase and replace fossil steam generation in each year of the interim period. In the first year, NGCC generation is limited to a maximum of a 22 percent increase from 2012 levels in each region. In each subsequent year, regional NGCC generation is limited to a maximum of a 5 percent increase from the previous year. This phase-in continues in the performance rate-setting methodology until the full building block 2 level of shifting from fossil steam generation to NGCC generation is reached.

[661] US EIA Monthly Energy Review, Table 7.2b Electricity Net Generation: Electric Power Sector (2015), *available at* http://www.eia.gov/totalenergy/data/browser/xls.cfm?tbl=T07.02B&freq=m.

Under this approach, building block 2 is completely phased into the source category calculation of all regions by the end of the interim period.

Table 7. BSER Maximum NGCC Generation by Region and Year (TWh).

	NGCC Generation (TWh)										
Region	Maximum Potential at 75%	2012 (adjusted)	BSER Maximum								
			2022	2023	2024	2025	2026	2027	2028	2029	2030
Limit	--	--	22%	5%	5%	5%	5%	5%	5%	5%	5%
Eastern Interconnection	988	735	896	941	988	988	988	988	988	988	988
Western Interconnection	306	198	242	254	267	280	294	306	306	306	306
Texas Interconnection	204	137	167	176	185	194	203	204	204	204	204

This phase-in, in addition to the flexible nature of the goals, ensures that the overall framework of this final rule includes sufficient flexibility, particularly with respect to timing of and strategies for reducing emissions from the affected units, so that states can develop cost-effective strategies and allow for infrastructure improvements to occur should they prove necessary in some locations.

3. Basis for magnitude of generation shift

a. Technical feasibility of NGCC units to generate at 75% of their capacity. In order to estimate the potential magnitude of the opportunity to reduce power sector CO_2 emissions through shifting generation among existing EGUs, the EPA first examined information on the design capabilities and availability of NGCC units. Availability is defined as the number of hours that generators are available to generate electricity, and it is typically expressed as a percentage of the total number of hours in a year. Since the value of NGCC capacity is related to how much electricity the owner of that capacity can generate and sell, units are typically designed with very high availability ratings. Baseload units have annual average availabilities of approximately 91%-92%, and peaking units are generally available 96% to 98% of peak hours.[662] The EPA also examined information on the historical availability of NGCC units in practice. This examination showed that, although most NGCC units have historically been operated in intermediate-duty roles for economic reasons, they are technically capable of operating in baseload roles at much higher annual utilization rates. Average annual availability (that is, the percentage of annual hours

[662] Negotiating Availability Guarantees for Gas Turbine Plants, available at: http://www.power-eng.com/articles/print/volume-105/issue-3/features/negotiating-availability-guarantees-for-gas-turbine-plants.html.

when an EGU is not in a forced or maintenance outage) for NGCC units in the U.S. generally exceeds 85 percent, and can exceed 90 percent for some groups.[663]

We also researched historical data to determine the utilization rates that NGCC units have already demonstrated their capability to sustain. Over the last several years, the utilization patterns of fossil fuel-fired units have shifted relative to historical dispatch patterns, with NGCC units increasing generation and many coal-fired EGUs reducing generation. In fact, in April 2012, for the first time ever the total quantity of electricity generated nationwide from natural gas was approximately equal to the total quantity of electricity generated nationwide from coal.[664] These changes in generation patterns have been driven largely by changes over time in the relative prices of natural gas and coal. Although the relative fuel prices vary by location, as do the recent generation patterns, this trend holds across broad regions of the U.S. In the aggregate, the historical data provide ample evidence indicating that, on average, existing NGCC units can achieve and

[663] See, e.g., North American Electric Reliability Corp., 2008-2012 Generating Unit Statistical Brochure—All Units Reporting, http://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx; Higher Availability of Gas Turbine Combined Cycle, Power Engineering (Feb. 1, 2011), http://www.power-eng.com/articles/print/volume-115/issue-2/features/higher-availability-of-gas-turbine-combined-cycle.html.
[664] http://www.eia.gov/todayinenergy/detail.cfm?id=6990.

sustain utilization rates higher than their historical average utilization rates.

Utilization of EGUs is often considered using the metric of a capacity factor, which is the percentage of total production potential that an electric generating unit achieves in a given time period. A capacity factor of 75 percent thus represents a unit producing three-quarters of the electricity it could have produced in that time had it utilized its entire capacity. The EPA received multiple comments regarding the proposed use of nameplate capacity in calculating the potential utilization level of existing NGCCs under building block 2. These comments stated that net summer capacity is a more meaningful and reliable metric than nameplate capacity, because net capacity best reflects the electric output available to serve load. The EPA agrees with these comments. The quantification of building block 2 as well as performance rate and state goal calculations in the final rule are all based on net summer generating capacity. An annual utilization rate of 75 percent on a net summer basis is similar to the proposed rule's consideration of 70 percent utilization on a nameplate basis.[665]

[665] For a given amount of net generation, a net summer capacity factor appears higher compared to a corresponding nameplate capacity factor because net summer capacity reflects a lower amount of total generation potential achievable by the unit in practice.

The experience of relatively heavily-used NGCC units provides an additional indication of the degree of increase in average NGCC unit utilization that is technically feasible.

The EPA reexamined the historical NGCC plant utilization rate data reported to the EIA, and found that in 2012 roughly 15 percent of existing NGCC plants operated at annual utilization rates of 75 percent or higher on a net summer basis.[666] In effect, these plants were providing baseload power. In addition to the 15 percent of NGCC plants that operated approximately at a 75 percent utilization rate on an annual basis, some NGCC plants operated at even higher utilization rates for shorter, but still sustained, periods of time in response to high cyclical demand. For example, on a seasonal basis, a significant number of NGCC plants have achieved utilization rates greater than 90 percent on a net summer basis; during the summer of 2012 (June through August), about 30 percent of NGCC plants operated at utilization rates of 75 percent or more across the entire season. During the spring and fall periods when electricity demand levels are typically lower, these plants were sometimes

[666] Net summer capacity is defined as: "The maximum output, commonly expressed in megawatts (MW), that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of summer peak demand (period of June 1 through September 30.) This output reflects a reduction in capacity due to electricity use for station service or auxiliaries." (EIA, http://www.eia.gov/tools/glossary).

idled or operated at much lower capacity factors. Nonetheless, the data clearly demonstrate that a substantial number of existing NGCC plants have proven the ability to sustain 75 percent utilization rates for extended periods of time. We view this as strong evidence that increasing the annual average utilization rates of existing NGCC units to 75 percent on a net summer basis would be technically feasible.

The EPA believes that an annual average utilization rate of 75 percent on a net summer basis is a conservative assessment of what existing NGCC plants are capable of sustaining for extended periods of time. In 2012, roughly 10 percent of existing NGCC plants operated at annual utilization rates of 80 percent or higher on a net summer basis. While the EPA believes this level is also technically feasible on average for the existing NGCC fleet, the EPA is quantifying building block 2 assuming an NGCC utilization level of 75% on a net summer basis in order to offer sources additional compliance flexibility, given that the extent to which they realize a utilization level beyond 75 percent will reduce their need to rely on other emission reduction measures or building blocks.

b. <u>Historical generation shifts to NGCC generation</u>. In 2012, total electric generation from existing NGCC units was 966

TWh.[667] After the application of the building block 2 potential (increasing NGCC utilization up to a 75 percent capacity factor on a net summer basis, including generation from NGCC units that were under construction), the total generation from these existing sources is assumed to be 1,498 TWh.[668]

The EPA believes that producing this quantity of generation from this set of NGCC units is feasible. To put this level of generation into context, NGCC generation increased by approximately 439 TWh (an 83 percent increase) between 2005 and 2012. The EPA calculates that assumed NGCC generation in 2022 through the quantification of building block 2 potential is approximately 44 percent higher than 2014 levels. This reflects a smaller growth rate in potential NGCC generation between 2015 and 2022 than has been observed in practice from 2005 to 2012, a time period of the same duration.

c. Reliability. We also expect that an increase in NGCC generation of this amount would not impair power system reliability. Sources can achieve increases in utilization of existing NGCCs that displace generation from steam sources without impacting reliability because this shift in average annual utilization across existing EGUs does not inhibit the

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[667] Appendix 1, CO_2 Emission Performance Rate and Goal Computation Technical Support Document for CPP Final Rule.

[668] Appendix 1, CO_2 Emission Performance Rate and Goal Computation Technical Support Document for CPP Final Rule.

power sector's ability to maintain adequate dispatchable resources to continue to meet reserve margins and maintain reliability. Furthermore, sources are not required to achieve the exact or even the full extent of the building block 2 generation shift itself, which means that sources will have ample flexibility to maintain reliability-relevant operations while achieving emission reductions through a variety of measures.[669]

d. Natural gas infrastructure. The EPA also examined the technical capability of the natural gas supply and delivery system to provide increased quantities of natural gas and the capability of the electricity transmission system to accommodate shifting generation patterns. For several reasons, we conclude that these systems would be capable of supporting the degree of increased NGCC utilization potential in building block 2. First, the natural gas pipeline system is already supporting national average NGCC utilization rates of 60 percent or higher during peak hours, which are the hours when constraints on pipelines or electricity transmission networks are most likely to arise. NGCC unit utilization rates during the range of peak daytime hours from 10 a.m. to 9 p.m. are typically 15 to 20 percentage points

[669] See section VIII for further discussion of electric reliability planning.

above their average utilization rates (which have recently been in the range of 40 to 50 percent).[670] Fleet-wide combined-cycle average monthly utilization rates have reached 65 percent,[671] showing that the pipeline system can currently support these rates for an extended period. If the current pipeline and transmission systems allow these utilization rates to be achieved in peak hours and for extended periods, it is reasonable to expect that similar utilization rates should also be possible in other hours when constraints are typically less severe, and be reliably sustained for other months of the year. Furthermore, the NGCC utilization increase assumed in building block 2 could occur without a significant impact on peak demand for natural gas, including winter demand (when the power sector's demand for natural gas competes with other sectors' demands for natural gas), since increasing annual utilization of NGCCs could focus on non-peak periods when NGCC capacity factors are currently low.

[670] EIA, Average utilization of the nation's natural gas combined-cycle power plant fleet is rising, Today in Energy, July 9,2011, http://www.eia.gov/todayinenergy/detail.cfm?id=1730#; EIA, Today in Energy, Jan. 15, 2014, http://www.eia.gov/todayinenergy/detail.cfm?id=14611 (for recent data).

[671] EIA, Electric Power Monthly, February, 2014. Table 6.7.A.

The second consideration supporting a conclusion regarding the adequacy of the gas supply infrastructure is that pipeline and transmission planners have repeatedly demonstrated the ability to methodically relieve bottlenecks and expand capacity.[672] Natural gas pipeline capacity has regularly been added in response to increased gas demand and supply, such as the addition of large amounts of new NGCC capacity from 2001 to 2003, or the delivery to market of unconventional gas supplies since 2008. These pipeline capacity increases have added significant deliverability to the natural gas pipeline network to meet the potential demands from increased use of existing NGCC units. Over a longer time period, much more significant pipeline expansion is possible. In previous studies, when the pipeline system was expected to face very large demands for natural gas use by electric utilities, the pipeline industry projected that increases of up to 30 percent in total deliverability out of the pipeline system would be possible.[673] There have been notable pipeline capacity expansions over the

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[672] See, e.g., EIA, Natural Gas Pipeline Additions in 2011, Today in Energy; INGAA Foundation, Pipeline and Storage Infrastructure Requirements for a 30 Tcf Market (2004 update); INGAA Foundation, North American Midstream Infrastructure Through 2035—A Secure Energy Future Report (2011).
[673] Pipeline and Storage Infrastructure Requirements for a 30 Tcf Market, INGAA Foundation, 1999 (Updated July, 2004); U.S. gas groups confident of 30-tcf market, Oil and Gas Journal, 1999.

past five years, and substantial additional pipeline expansions are currently under construction.[674] Further, the phasing in of building block 2's potential in the determination of the BSER; the flexible nature of multi-year compliance with the ultimate emission reduction requirements of the rule; and the seven years between finalization of this rule and the first year of compliance provide time for infrastructure improvements to occur should they prove necessary in some locations. Combining these factors of currently observed average monthly NGCC utilization rates of up to 65 percent, the flexibility of the emission guidelines, the rates of historical growth, and the availability of time to address any existing pipeline infrastructure limitations, it is reasonable to conclude that the natural gas pipeline system can reliably deliver sufficient natural gas supplies to allow NGCC utilization to increase up to an average annual capacity factor of 75 percent on a net summer basis.

e. <u>Natural gas production</u>. We recognize that an increase in NGCC utilization rates at existing units corresponds with an associated increase in natural gas production, consistent with

[674] For example, between 2010 and April 2014, 118 pipeline projects with 44,107 MMcf/day of capacity (4,699 miles of pipe) were placed in service, and between April 2014 and 2016 an additional 47 pipeline projects with 20,505 MMcf/day of capacity (1,567 miles of pipe) are scheduled for completion. Energy Information Administration, http://www.eia.gov/naturalgas/data.cfm.

the current trends in the natural gas industry. The EPA expects the growth in NGCC generation assumed for building block 2 to be feasible and consistent with the production potential of domestic natural gas supplies. Increases in the natural gas resource base have led to fundamental changes in the outlook for natural gas. There is general agreement that recoverable natural gas resources will be substantially higher for the foreseeable future than previously anticipated, exerting downward pressure on natural gas prices. According to EIA, proven natural gas reserves have doubled between 2000 and 2012. Domestic dry gas production has increased by 25 percent over that same timeframe (from 19.2 TCF in 2000 to 24.0 TCF in 2012). EIA’s Annual Energy Outlook Reference Case for 2015 projects that production will further increase to 29.5 TCF by 2022 and 33 TCF by 2030, as a result of increased supplies and favorable market conditions. In the AEO 2015 high oil and gas resource case, production is projected to increase to 42.7 TCF in 2030. For comparison, building block 2 assumes NGCC generation growth of 235 TWh from 2012 to reach the level assumed for 2022, and that NGCC generation growth would result in increased gas consumption of less than 2 TCF for the electricity sector, which is less than EIA’s projected increase in natural gas production of 5.5 TCF from 2012 to 2022.

The EPA has also assessed the ability of the electricity and natural gas industries to achieve the potential quantified for building block 2 using the Integrated Planning Model (IPM). IPM is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector that the EPA has used for over two decades to evaluate the economic and emission impacts of prospective environmental policies. To inform its projections of least-cost capacity expansion and electricity dispatch, IPM incorporates representations of constraints related to fuel supply, bulk power transmission capacity, and unit availability. The model includes a detailed representation of the natural gas pipeline network and the capability to project economic expansion of that network based on pipeline load factors. At the EGU level, IPM includes detailed representations of key operational limitations such as turn-down constraints, which are designed to account for the cycling capabilities of EGUs to ensure that the model properly reflects the distinct operating characteristics of peaking, cycling, and base load units.

As described in more detail below, the EPA used IPM to assess the costs of increasing generation from existing NGCC capacity. IPM was able to meet average NGCC utilization rates of 75 percent on a net summer basis, while observing the market, technical, and regulatory constraints represented in the model.

This modeling also demonstrates the ability of domestic natural gas supplies to increase their production levels, and deliver that supply through the pipeline network, to support the level of NGCC generation quantified in building block 2. Such a result is consistent with the EPA's determination that increasing the average utilization rate of existing NGCC units to 75 percent would be technically feasible.

f. Transmission planning and construction. Achieving the generation shift quantified in building block 2 would not impose significant additional burden on the transmission planning process and does not necessitate major construction projects. Two considerations are important for this conclusion:

First, building block 2 applies only to increases in generation at *existing* NGCC facilities and does not contemplate any connection of new capacity to the bulk power grid. Second, regional grids are already supporting operation of the NGCC units for sustained periods of time at the capacity factors quantified in building block 2.[675] Although some upgrades to the grid (including potential, but modest, expansions of transmission capacity) may be necessary to support the extension of the time that these capacity factors are sustained over the course of the annual time period on which building block 2 is

[675] See Greenhouse Gas Mitigation Measures TSD for a discussion of regional NGCC capacity factors.

based, such upgrades are part of the normal planning process around the increased use of existing facilities. In fact, the electric transmission system is currently undergoing substantial expansion.[676] Consequently, EPA does not believe that achieving the generation shift potential in building block 2 would necessitate any significant additional requirements for transmission planning and construction beyond those already being addressed at routine intervals by the power sector. Furthermore, the phasing in of building block 2's potential in the determination of the BSER; the flexible nature of multi-year compliance with the ultimate emission reduction requirements of the rule; and the seven years between finalization of this rule and the first year of compliance all provide time for infrastructure improvements to occur should they prove necessary in some locations.

g. Regulatory flexibility. The final consideration supporting our view that natural gas and electricity system infrastructure would be capable of supporting increased NGCC unit utilization

[676] According to the Edison Electric Institute, member companies are planning over 170 projects through 2024, with costs totaling approximately $60.6 billion (this is only a portion of the total transmission investment anticipated). Approximately 75 percent of the reported projects (over 13,000 line miles) are high voltage (345 kV and higher). Construction of transmission lines of 345KV and above are generally major projects that are particularly effective at carrying power of large distances. http://www.eei.org/issuesandpolicy/transmission/Documents/Trans_Project_lowres_bookmarked.pdf.

rates at a maximum of 75% on a net summer basis is the substantial unit-level compliance flexibility of the emission guidelines. The final rule does not require any particular NGCC unit to achieve any particular utilization rate in any specific hour or year. Thus, even if isolated natural gas or electricity system constraints were to limit NGCC unit utilization rates in certain locations in certain hours, this would not prevent an increase in NGCC generation overall across a state or broader region and across all hours on the order assumed in the generation shift potential quantified for building block 2.

4. Cost

Having established the technical feasibility and quantification of the potential to replace incremental generation at higher-emitting EGUs with generation at NGCC facilities as a CO_2 emissions reduction strategy, we next turn to the question of cost. The cost of the power sector CO_2 emission reductions that can be achieved through shifting generation among existing fossil fuel-fired EGUs depends on the relative variable costs of electricity production at EGUs with different degrees of carbon intensity. These variable costs are driven by the EGUs' respective fuel costs and by the efficiencies with which they can convert fuel to electricity (i.e., their heat rates). Historically, natural gas has had a higher cost per unit of energy content (e.g., MMBtu) than coal in most locations, but for NGCC units this disadvantage in fuel cost per MMBtu relative to coal-fired EGUs is typically offset in significant part, and sometimes completely, by a technological heat rate advantage.

To consider the cost implications of building block 2, the EPA expanded upon the proposal's extensive analysis of the magnitude and cost of CO_2 emission reductions through generation shifting within defined areas (consistent with the application of building blocks for performance rate- and state goal-setting), without consideration of the availability of other emission reduction ultimately available to units for compliance.

To evaluate how EGU owners and grid operators could respond to a state plan's possible requirements, signals, or incentives to shift generation from more carbon-intensive to less carbon-intensive EGUs, the EPA analyzed a series of scenarios in which the fleet of NGCC units within each of the regions considered for quantifying BSER (i.e., the three interconnections) was directed to achieve a specified average annual utilization rate across that region on a net basis while maintaining a fixed level of aggregate generation in that region across all existing fossil fuel-fired sources. The EPA conducted such scenarios to address average utilization rates of 70 percent, 75 percent and 80 percent on a net basis, allowing for shifting of fossil generation between existing units within the regions described above. This scenario identifies a generation pattern that would meet electricity demand at the lowest total cost, subject to all other specified operating and bulk power transfer constraints for the scenario, including the specified average NGCC unit utilization rate.

The costs of the various scenarios were evaluated by comparing the total costs and emissions from each scenario to the costs and emissions from a base case scenario. For the scenario reflecting a 75 percent NGCC utilization rate on a net basis with regional fossil generation shifting, comparison to the base case indicates that the average cost of the CO_2 reductions achieved over the 2022-2030 period was $24 per short ton of CO_2. We view these estimated costs as reasonable and therefore as supporting the use of a 75 percent net utilization rate target for purposes of quantifying the emission reductions achievable at a reasonable cost through the application of building block 2 in the BSER.

We also conclude from these analyses that potential impacts to fuel prices and electricity prices from achieving the extent of fossil generation shifting quantified for this building block are reasonably within the bounds of power sector experience. For example, in the 75 percent NGCC unit utilization rate scenario where generation shifting is limited to regional boundaries, the delivered natural gas price was projected to increase by an average of 7 percent over the 2022-2030 period, which is well within the range of historical natural gas price variability.[677] Projected wholesale electricity price increases over the same period were less than 4 percent, which similarly is well within the range of historical electric price variability. These projected impacts on prices were captured in the emission reduction costs of these scenarios already described above, which are reasonable and support use of a 75 percent NGCC utilization rate target for purposes of quantifying the emission reductions achievable through application of the BSER.

However, we also note that the costs (and their incorporated price impacts) just described are higher than we would expect to actually occur in real-world compliance with the final rule's compliance requirements for the following reasons. First, this analysis does not capture the building block 2 phase-in, which assumes an average utilization rate over the interim period of less than 75 percent in all three interconnections. Second, the analysis overstates the extent to which building block 2 is ultimately reflected in the source category performance rates. While the performance rate computation procedure assumes a maximum NGCC utilization rate of 75 percent on a net summer basis, the Eastern Interconnection's

[677] According to EIA data, year-to-year changes in natural gas prices at Henry Hub averaged 29.9 percent over the period from 2000 to 2013. http://www.eia.gov/dnav/ng/hist/rngwhhdA.htm.

realization of this level of NGCC utilization yields higher source category performance rates for steam than what would have been calculated for units in the Western Interconnection and Texas Interconnection if they realized that maximum NGCC utilization rate in conjunction with the other building blocks. In other words, there is substantial building block 2 potential in the Western Interconnection and Texas Interconnection that is not actually captured in the source category performance rates that are ultimately assigned to steam through this rate- and goal-setting approach (where the performance rates are ultimately determined by the BSER region with the highest rate outcome in the calculation). Therefore, the building block 2 analysis overstates the cost of this component of BSER to the extent that it assumes achievement of this generation shift potential that is not reflected in the source category performance rates ultimately determined. Third, as a practical matter, sources will be able to achieve additional emission reductions through other measures that may prove to be less costly than generation shifting and could substitute for the reductions and costs considered here. These building block 2 analyses were focused on evaluating the potential impacts of fossil generation shifting in isolation, and as a result, they do not consider states' and sources' flexibility to choose among alternative CO_2 reduction strategies that could offer lower-cost reductions, instead of relying on fossil generation shifting to the extent analyzed here.

Based on the analyses summarized above, the EPA concludes that an average annual utilization rate for each region's NGCC units of up to 75 percent is a technically feasible, cost-effective, and adequately demonstrated building block for BSER.

For further information on the analysis discussed in this section, see Chapter 3 of the GHG Mitigation Measures TSD for the CPP Final Rule.

5. Major comments and responses

The EPA received numerous comments regarding building block 2. Many of these comments provided helpful information and insights and have resulted in improvements to the rule. This section summarizes some of these comments, and the remainder of the comments are responded to in the Response to Comment document, available in the docket.

The EPA received comment regarding the potential for an increase in upstream methane emissions from increased utilization of natural gas. Our analysis found that the net upstream methane emissions from natural gas systems and coal mines and CO_2 emissions from flaring of methane will likely decrease under the Clean Power Plan. Furthermore, the changes in upstream methane emissions are small relative to the changes in direct emissions from power plants. The technical details supporting this analysis can be found in the Regulatory Impact Analysis.

Commenters also expressed concern that neither a utility nor any state agency controls dispatch in most states. The EPA believes these comments fail to adequately appreciate that the utilities do control the dispatch of units that they own and/or operate, either by being the actual dispatch agent in many cases where there is no RTO or ISO that schedules the dispatch, or by the choice of units and bids they offer into an organized electricity market operated by an RTO or ISO. These entities currently control the dispatch of their units while respecting all existing requirements from environmental rules. This final rule does not change these current circumstances and makes clear that it is the EGU that is responsible for meeting the requirements in the state plan; the state is responsible for the development of that plan, but the state does not need to control the dispatch.

Other comments object to the use of a single capacity factor for all existing NGCCs to quantify building block 2 potential on the grounds that not all units may be able to achieve this utilization level, and that some units may be designed for cycling and so may need upgrades to sustain such utilization. The EPA disagrees with these comments. The 75 percent capacity factor establishes a regional potential for generation from existing NGCC capacity, and it does not establish any individual unit requirements.

Some comments argue that generation limits in permits for some existing NGCC units will limit the amount by which these units can increase their generation and thereby limit the feasibility of building block 2. The EPA disagrees with these comments. Although permit limits can constrain the ability of individual units to operate above certain levels, building block 2 was developed conservatively, with units operating on average at a level below the maximum levels at which some units have demonstrated the capability to operate. No individual unit is required to achieve the average generation levels used to quantify building block 2. Further, permit limits at individual units can be considered when state plans are developed. There are many flexibilities in the final rule, including the opportunity to establish standards of performance that incorporate emissions trading, that allow the development of plans that will not be constrained by existing permit limits at individual units.

The EPA also received comments asserting that increasing generation from new renewables would require increased use of natural gas capacity for back-up and ramping, and therefore it is not possible for NGCC units to run at BSER utilization rates and also be available to support the additional variable renewable generation resulting from building block 3. The EPA disagrees with this comment. The 75% net summer utilization rates defined by building block 2 is a conservative assessment and applied on an annual average basis. It is therefore possible for these existing units to both operate at higher annual utilization rates, and also to operate at higher rates during limited periods and still maintain a 75% net summer average annual utilization rate. While variable renewable generation does require additional load following and ramping resources and unit cycling, these requirements are generally a small part of the overall ramping costs of the system (see NREL, Relevant Studies for NERC's Analysis of EPA's Clean Power Plan 111(d) Compliance). Additionally, while existing NGCC units are an efficient source of ramping to support variable renewables, other units running in an intermediate mode can also provide load following and ramping.

E. Building Block 3 — New Zero-emitting Renewable Generating Capacity

The third element of the foundation for the EPA's BSER determination for reducing CO_2 emissions at affected fossil fuel-fired EGUs entails an analysis of the extent to which generation at the affected EGUs can be replaced by using an expanded amount of zero-emitting renewable electricity (RE) generating capacity to produce replacement generation.

In this section we address first the history of and then trends in RE development, as well as the importance of expanding the use of RE. Next we discuss the ability of affected EGUs to access generation from new RE generating capacity, followed by a discussion of renewable energy certificate (REC) markets. We then describe the quantification of the amount of generation from new RE generating capacity achievable through building block 3, including key comments, changes made from the proposal, the method by which RE target generation levels are quantified, and the magnitude and timing of increases in RE generation associated with this building block. Next, we discuss the feasibility of implementing the identified incremental amounts of RE generation. Finally, we address the costs associated with those increases in RE generation.

1. History of RE Development

RE generating technologies are a well-established part of the U.S. power sector. These technologies generate electricity from renewable resources, such as wind, sun and water. While RE has been used to generate electricity for over a century, the push to commercialize RE more broadly began in the 1970s.[678] Following a series of energy crises, new federal organizations

[678] Nearly all U.S. hydroelectric capacity was built before the mid-1970s. U.S. DOE. History of Hydropower. Accessed March 2015. Available at: http://energy.gov/eere/water/history-hydropower.

and initiatives were established to coordinate energy policy and promote energy self-sufficiency and security, including solar energy legislation, the Public Utility Regulatory Policies Act of 1978 (PURPA) and the 1980 Energy Security Act.[679]

PURPA was a key step in stimulating RE development. By requiring utilities to purchase generation from qualifying facilities (i.e., certain CHP and RE generators) at avoided costs, PURPA opened electricity markets to more RE generation and gave rise to non-utility generators that were willing to try new RE technologies.[680] In addition, since 1992, federal tax policy has provided important financial support via tax credits for the production of RE and investments in RE.

States have also taken a significant lead in requiring the development of RE resources. In particular, a number of states have adopted renewable portfolio standards (RPS), which are regulatory mandates to increase production of RE. As of 2013, 29 states and the District of Columbia had enforceable RPS or

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[679] U.S. DOE Office of Management, Timeline of Events: 1971-1980. Accessed March 2015. Available at: http://energy.gov/management/office-management/operational-management/history/doe-history-timeline/timeline-events-1.
[680] "Restructuring or Deregulation?" Smithsonian Museum of American History. Accessed March 2015. Available at: http://americanhistory.si.edu/powering/dereg/dereg1.htm.

similar laws.[681] These RPS requirements continue to drive robust near-term growth of non-hydropower RE.

2. Trends in RE Development

Today, RE is tightly integrated with the utility power sector in multiple ways: states have set RE targets for electrical load serving entities; utilities themselves are diversifying their portfolios by contracting with RE generators; and new RE generators are being developed to provide more electrical power grid support services beyond just energy (e.g., modern electronics allow wind turbines to provide voltage and reactive power control at all times).[682,683]

Use of RE continues to grow rapidly in the U.S. In 2013, electricity generated from RE technologies, including conventional hydropower, represented 13 percent of total U.S. electricity, up from 9 percent in 2005.[684] In 2013, U.S. non-

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681 Energy Information Administration, Annual Energy Outlook 2014 with Projections to 2040, at LR-5 (2014).
682 IPCC, Renewable Energy Sources and Climate Change Mitigation, 2012. Accessed March 2015. Available at: http://www.ipcc.ch/pdf/special-reports/srren/SRREN_Full_Report.pdf.
683 American Wind Energy Association. AWEA Comments on EPA's Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources and Supplemental Proposed Rule. p. 107.
684 Energy Information Administration, Annual Energy Outlook 2015 with Projections to 2040, at LR-5 (2014), P. ES-6 and Energy Information Administration, Monthly Energy Review, May 2015, Table 7.2b, Available at: http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf.

hydro RE capacity for the total electric power industry exceeded 80,000 megawatts, reflecting a fivefold increase in just 15 years.[685] In particular, there has been substantial growth in the wind and solar photovoltaic (PV) markets in the past decade. Since 2009, U.S. wind generation has tripled and solar generation has grown twentyfold.[686]

The global market for RE is projected to grow to $460 billion per year by 2030.[687] RE growth is further spurred by the significant amount of existing natural resources that can support RE production in the U.S.[688] In the Energy Information Administration's Annual Energy Outlook 2015, RE generation grows substantially from 2013 to 2040 in the reference case and all alternative cases.[689] In the reference case, RE generation

[685] Non-hydro RE capacity for the total electric power industry was more than 16,000 megawatts in 1998. Energy Information Administration, 1990-2013 Existing Nameplate and Net Summer Capacity by Energy Source Producer Type and State (EIA-860), Available at: http://www.eia.gov/electricity/data/state/.
[686] Energy Information Administration, Monthly Energy Review, May 2015, Table 7.2b. Available at: http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf.
[687] "Global Renewable Energy Market Outlook." Bloomberg New Energy Finance, November 16, 2011, Available at: http://bnef.com/WhitePapers/download/53.
[688] Lopez et al., NREL, ''U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis,'' (July 2012).
[689] Energy Information Administration, Annual Energy Outlook 2015 with Projections to 2040, at LR-5 (2014), P. 25.

increases by more than 70 percent from 2013 to 2040 and accounts for over one-third of new generation capacity.[690]

The recent and projected growth of RE is in part a reflection of its increasing economic competitiveness. Numerous studies have tracked capital cost reductions and performance improvements for RE, particularly for solar and wind. For instance, Lazard's analysis of wind and utility-scale solar PV levelized costs of energy (LCOE), on an unsubsidized basis, over the last five years found the average percentage decrease of high and low of LCOE ranges were 58 percent and 78 percent, respectively.[691] Analyses of wind's competitiveness found falling wind turbine LCOE while the wind industry developed projects at lower wind speed sites using new turbine designs (e.g., increased turbine hub heights and rotor diameters). Performance improvements have come from novel deployments of new turbines designed for lower quality wind sites that are deployed at higher quality wind sites, which have resulted in capacity

690 Energy Information Administration, Annual Energy Outlook 2015 with Projections to 2040, at LR-5 (2014), P. ES-6-7.

691 Lazard, *Levelized Cost of Energy Analysis-Version 8.0*, September 2014, p. 9, Available at: http://www.lazard.com/media/1777/levelized_cost_of_energy_-_version_80.pdf.

factor increases for these locations.[692,693] For utility-scale solar, cost and performance have also improved significantly. Analysis has shown that the installed price of solar photovoltaics (PV) systems, prior to any incentives, has declined substantially since 1998. Capacity-weighted average prices of solar PV in utility-scale deployments were 40 percent lower in 2013 than five years earlier.[694][695] Initially, price declines were partially driven by oversupply and manufacturers' thin margins, but, in 2014, prices have remained low due to reductions in manufacturing costs.[696] The capacity factors of new utility-scale installations have increased as systems are optimized to maximize energy production. For example, a growing number of utility-scale PV systems are increasing the direct current capacity of the solar array relative to the alternating current rating of the array's inverter to increase energy

[692] "2013 Wind Technologies Market Report," LBNL, August 2014. Available at: http://emp.lbl.gov/publications/2013-wind-technologies-market-report.

[693] "2013 Cost of Wind Energy Review," NREL, Feb 2015. Available at: http://www.nrel.gov/docs/fy15osti/63267.pdf.

[694] "Tracking the Sun VII" LBNL, Sept 2014. Available at: http://emp.lbl.gov/publications/tracking-sun-vii-historical-summary-installed-price-photovoltaics-united-states-1998-20.

[695] "Photovoltaic System Pricing Trends," NREL, 22 Sept 2014. Available at: http://www.nrel.gov/docs/fy14osti/62558.pdf.

[696] "Revolution Now – The Future Arrives for Four Clean Energy Technologies – 2014 Update," DOE, Oct 2014. Available at: http://energy.gov/sites/prod/files/2014/10/f18/revolution_now_updated_charts_and_text_october_2014_1.pdf.

production and improve project economics.[697] The cost and performance improvements for wind and solar are driven by increased scale of production, improved technologies, and advancements in system deployments.

3. Importance of Increasing Use of RE

Currently, the utility power sector accounts for 40 percent of total annual energy consumption in the U.S.[698] Introducing more zero-emitting RE generation over the long term could significantly reduce CO_2 emissions, as production of RE predominantly replaces fossil fuel-fired generation and thereby avoids the emissions from that replaced generation.

A number of studies and recent policy developments have acknowledged RE as an important means of achieving CO_2 reductions. California cited the reduction of CO_2 emissions from electrical generations as one of the reasons for increasing its RE target from 20 percent to 33 percent by 2020 (and potentially

[697] "Utility-Scale Solar 2013," LBNL, Sept 2014. Available at: http://emp.lbl.gov/publications/utility-scale-solar-2013-empirical-analysis-project-cost-performance-and-pricing-trends.
[698] U.S. Energy Information Administration Annual Energy Review, 2011. Accessed March 2015. Available at: http://www.eia.gov/totalenergy/data/monthly/pdf/flow/primary_energy.pdf.

50 percent by 2030).[699] A recent IPCC report also concluded that RE has large potential to mitigate CO_2 emissions.[700]

Increased use of RE provides numerous benefits in addition to lower CO_2 emissions. RE typically consumes less water than fossil fuel-fired EGUs. Wind power and solar PV systems do not require the use of any water to generate electricity; water is only needed for cleaning to ensure efficient operation. In contrast, utility boilers, in particular, require large quantities of water for steam generation and cooling.[701]

Increasing RE use will also continue to lower other air pollutants (e.g., fine particles, ground-level ozone, etc.), diversify energy supply, hedge against fossil fuel price increases and create economic development and jobs in manufacturing, installation, and other sectors of the economy.

4. Access to RE by Owners of Affected EGUs

The ability of affected EGUs to co-locate or obtain incremental RE to reduce CO_2 emissions is well-demonstrated,

[699] California S.B. 2 (1X), 2011. Accessed March 2015. Available at: http://www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.pdf.
[700] IPCC, Renewable Energy Sources and Climate Change Mitigation, 2012. Accessed March 2015. Available at: http://www.ipcc.ch/pdf/special-reports/srren/SRREN_Full_Report.pdf.
[701] EPA, Water Resource Use. Accessed on March 2015. Available at: http://www.epa.gov/cleanenergy/energy-and-you/affect/water-resource.html.

whether it is through direct ownership, bilateral contracts, or procurement of the environmental attributes associated with RE generation.[702] Consequently, the EPA believes that an increase in RE is a proven way to reduce CO_2 emissions at affected EGUs of all types at a reasonable cost.

Owners and operators of affected EGUs across the U.S. already have substantial opportunities to procure RE regardless of their organizational structure and/or business model. In many parts of the country, EGUs are owned and operated by vertically integrated utilities. These utilities can be investor-owned utilities that operate under traditional electricity regulation, municipal utilities (munis), or electric cooperatives (co-ops). These utilities have significant control over the types of generating capacity they develop or acquire, and over the electricity mix used to meet demand within their service territories.

Even when EGU owners participating in organized markets do not directly determine dispatch among energy sources, such EGU owners make decisions about what types of capacity they choose to develop and thus what generation mix they can ultimately supply into that market's dispatch choices. Because zero-emitting RE technologies have relatively low variable costs, an

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[702] Refer to the GHG Mitigation Measures TSD for additional information on RE ownership and co-location.

EGU owner's decision to install (or to finance the installation of) RE capacity will yield lower-cost electricity generation that, when available, a system dispatcher will prefer over higher-variable-cost generation from fossil fuel-fired capacity. Therefore, all owners of affected EGUs have a direct path for replacing higher-emitting generation with RE regardless of their organizational type and regardless of whether they operate in a cost-of-service framework or in a competitive, organized market.

Many affected EGUs have already directly invested in RE. Of the 404 entities that owned part of at least one affected EGU under this rule, 178 also owned RE (biomass, geothermal, solar, water or wind). These 178 owners owned 82 percent of affected EGU capacity. As a whole, these entities' share of RE capacity was equal to 25 percent of the total of their affected EGU capacity.[703]

Some of the largest owners of affected EGUs also owned RE (see Table 8). For example, NRG Energy, Inc. owns more than 3,000 megawatts of RE capacity, over 20 percent of which (nearly 800 megawatts) is solar, and almost 80 percent of which (over 2,500 megawatts) is wind. Duke Energy Corporation owns 175 megawatts of solar and over 1,500 megawatts of wind. NextEra

[703] SNL Energy. Data used with permission. Accessed on June 9, 2015.

Energy, Inc.'s share of RE capacity approaches 40 percent of their total affected EGU capacity.[704] Table 8 lists a sampling of affected EGUs that have large amounts of fossil fuel-fired capacity and RE capacity:

TABLE 8. Sample of Owners of Affected EGUs and RE Capacity.[705,706]

Ultimate Parent	***Affected EGU Capacity (MW)***	***Renewable Capacity (MW)***
NRG Energy, Inc.	48,787	3,149
Duke Energy Corporation	39,028	5,526
Southern Company	37,168	3,245
American Electric Power Company, Inc.	34,940	1,142
NextEra Energy, Inc.	29,471	11,626
Calpine Corporation	23,878	1,509
Tennessee Valley Authority	21,717	5,427
Berkshire Hathaway Inc.	18,899	6,650
FirstEnergy Corp.	16,175	1,371
Exelon Corporation	10,283	3,361
Nebraska Public Power District	2,003	90
Basin Electric Power Cooperative	1,526	275
American Municipal Power, Inc.	1,112	53
Sacramento Municipal Utility District	925	834
Golden Spread Electric Cooperative, Inc.	521	78

704 Ibid.

705 SNL Energy. Data used with permission. Accessed on June 9, 2015.

706 eGRID, EPA. 2012 Unit-Level Data Using the eGRID Methodology. June 7, 2015 version.

Large vertically integrated utilities generally have multiple options for investing in RE, including building their own RE capacity or procuring RE under a long-term power purchase agreement. Municipal utilities and rural cooperatives that own generating asset portfolios, particularly generation and transmission cooperatives and larger municipal utilities, have also used RE to reduce carbon emissions. Large generation and transmission cooperatives also purchase significant quantities of RE for their members. Federal power authorities own or contract for significant amounts of RE.[707,708]

The list of ten electric utilities with the largest amounts of wind power capacity on the system (owned or under contract) includes a variety of affected EGU organizational structures, including vertically integrated investor-owned utilities, municipal utilities, and federal power authorities. Xcel Energy and Berkshire Hathaway Energy rank first and second with 5,736 megawatts and 4,992 megawatts of wind capacity, respectively. Tennessee Valley Authority, a federal power authority, had 1,572 megawatts and CPS Energy, a public utility, had 1,059 megawatts

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[707] American Wind Energy Association. AWEA Comments on EPA's Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources and Supplemental Proposed Rule. pp. 88-91.
[708] Solar Energy Industries Association. Comments to the EPA and States on the Proposed Clean Power Plan Regulating Existing Power Plants Under Section 111(d) of the Clean Air Act. pp. 98-147.

of wind power capacity.[709] Basin Electric Power Cooperative had 716 megawatts and was the top ranked cooperative utility, but is not on the top ten utilities with wind power capacity list.

Many affected EGUs are already planning on deploying significant amounts of RE according to their integrated resource plans (IRPs). Electric utilities use IRPs to plan operations and investments over long time horizons. These plans typically cover 10 to 20 years and are mandated by public utility commissions (PUCs). A recent study of IRPs, included in the docket for this rulemaking, shows this trend.[710] For instance, Dominion plans for over 800 megawatts of wind and solar in their 2015 to 2029 planning period.[711] Duke Energy Carolinas' IRP has no plans for new coal, but describes plans for roughly 1,250 megawatts of additional RE by 2021, and approximately 2,150 megawatts by

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[709] American Wind Energy Association. U.S. Wind Industry Annual Market Report (2014 data). Accessed July 2015. Available at http://www.awea.org/AnnualMarketReport.aspx?ItemNumber=7422&RDtoken=64560&userID=. The ten largest electric utilities with wind power capacity on the system (owner or under contract) includes: Xcel Energy; Berkshire Hathaway Energy; Southern California Edison; American Electric Power; Pacific Gas & Electric; Tennessee Valley Authority; San Diego Gas & Electric; CPS Energy; Los Angeles Department of Water & Power; and Alliant Energy.

[710] See memo entitled "Review of Electric Utility Integrated Resource Plans" (May 7, 2015).

[711] Dominion North Carolina Power's and Dominion Virginia Power's Report of Its Integrated Resource Plan, August 2014, Available at: https://www.dom.com/library/domcom/pdfs/corporate/integrated-resource-planning/nc-irp-2014.pdf.

2029. A significant portion (1,670 megawatts) of the planned RE is solar.[712] Ameren is planning to retire one-third of the coal generating capacity, as well as installing an additional 400 megawatts of wind, 445 megawatts of solar, and 28 megawatts of hydroelectric generating capacity.[713]

Independent power producers (IPPs) also can and do own both RE and fossil generation. For example, NRG is a diversified IPP that operates substantial coal, natural gas, wind, solar, and nuclear capacity. NRG demonstrates the ability of IPPs to reduce utilization of fossil fuel-fired EGUs and replace that generation with RE. NRG announced a goal to cut CO_2 emissions from its fleet by 50 percent by 2030 (from a 2014 baseline).[714] NRG has already reduced CO_2 emissions from its fleet by 40 percent since 2005. This achievement demonstrates that when an IPP commits to shifting its generation portfolio, it can do so at reasonable cost and without reliability impacts. The NRG example shows that reduced utilization of fossil fuel-fired EGUs

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[712] Duke Energy Carolinas' 2014 Integrated Resource Plan, September 2014, Available at: http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=c3c5cbb5-51f2-423a-9dfc-a43ec559d307.

[713] Integrated Resource Plan Update, October 2014, Available at: https://www.ameren.com/missouri/environment/renewables/ameren-missouri-irp.

[714] NRG, "NRG Energy Sets Long-Term Sustainability Goals at Groundbreaking of "Ultra-Green" New Headquarters" (Nov. 20, 2014), *available at* http://investors.nrg.com/phoenix.zhtml?c=121544&p=irolnewsArticle&ID=1991552.

that is replaced by RE also owned by the EGU owner is adequately demonstrated.

EGU owners can also replace fossil fuel-fired generation with RE through bilateral contracts and REC purchases, as described below. Both the bilateral market for RE contracts and REC markets are well- developed. There are no legal or technical obstacles to a fossil fuel-fired EGU owner acting as the counterparty of a bilateral contract for purchase of energy from a RE facility. Any type of EGU owner (utility or otherwise) can purchase and retire RECs. The fact that RECs are purchased by a diverse set of market participants — including residential consumers, commercial businesses, and industrial facilities — demonstrates that such a purchase for all EGU owners is adequately demonstrated.

5. REC Markets

Affected EGU owners do not need to directly invest in, or own, renewable generating capacity in order to replace fossil fuel-fired generation with RE as an emission reduction measure. RECs are used to demonstrate compliance with state RE targets, such as state RPS, and also to substantiate claims stemming from RE use. RECs are tradable instruments that are associated with the generation of one megawatt-hour of RE and represent certain information or characteristics of the generation, called attributes.[715] RECs may be traded and transferred regardless of the actual energy flow.

The legal basis for RECs is established by state statutes and administrative rules. Nearly all states with a mandatory RPS have established RECs as a means of compliance. The Federal Energy Regulatory Commission (FERC) has observed that states created RECs to facilitate programs designed to promote increased use of RE, and that "attributes associated with the [RE] facilities are separate from, and may be sold separately from, the capacity and energy."[716]

In complying with states' RPS requirements, utilities have contracted for RECs from in-state and out-of-state resources in accordance with RPS requirements. Utilities may have sourced RECs from out-of-state to reduce the cost of compliance, to

[715] EPA Green Power Partnership, Renewable Energy Certificates July 2008). Available at http://www.epa.gov/greenpower/documents/gpp_basics-recs.pdf.
[716] FERC Docket No. EL03-133-000, Petition for Declaratory Order and Request for Expedited Consideration, American Ref-Fuel Company, Covanta Energy Group, Montenay Power Corporation, and Wheelabrator Technologies, Inc. June 16, 2003, *Order Granting Petition for Declaratory Ruling*, October 1, 2003. *American Ref-Fuel Co. et al.*, 105 FERC ¶ 61,004 (2003); and *Order Denying Rehearing*. April 15, 2004. 107 FERC ¶ 61,016 (2004). Available online at: http://www.ferc.gov/whats-new/comm-meet/041404/E-28.pdf (accessed 11/7/2014).

source RECs from specific generation types, or for other reasons.[717]

The development of REC markets to facilitate RPS compliance provides evidence that markets can develop to facilitate compliance with rate-based state plans. These markets will afford affected EGU owners an alternative to directly invest in, or own, renewable generating capacity in order to replace fossil fuel-fired generation with RE as an emission reduction measure.

6. Quantification of RE Generation Potential for BSER and Major Comments

The methodology for quantifying RE generation levels under building block 3 is a modified version of the alternative RE approach from proposal, with adjustments that reflect the data and information the EPA collected through stakeholder comments and the EPA's additional analysis and information collection. In evaluating the proposed and alternative RE approaches commenters observed that RPS, as the basis for quantifying RE generation levels under the proposed approach, are policy instruments that states may choose to implement for a variety of reasons not related to CO_2 emission reductions. Additionally, differences across RPS policies in eligible resources, crediting mechanisms,

[717] Heeter, J. Quantifying the Level of Cross-State Renewable Energy Transactions. NREL 2015. Available at http://www.nrel.gov/docs/fy15osti/63458.pdf.

deliverability requirements, alternative compliance payments, and other policy elements made the regional averaging of state-level RPS requirements challenging. Finally, commenters provided data demonstrating that RE resource potential can vary significantly within the regions identified under the proposed approach, producing state-level RE generation levels that may not be aligned with the opportunity to deploy incremental RE resources at reasonable cost. In contrast, commenters argued that a methodology similar to the alternative RE approach, which is based on economic potential, represents a more technically sound basis for quantifying building block 3 target generation levels that accounts for regional differences in RE resources and power market conditions, such as projected fuel prices, load growth and wholesale power prices. The EPA agrees with these comments.

Within the framework of the alternative RE approach, the EPA received significant comments on a number of issues, including the use of historical deployment rates, the interstate nature of RE and the power system, merits of total versus incremental RE generation as the metric by which building block 3 generation levels are quantified, types of RE technologies that contribute to those generation levels, cost and performance estimates associated with those RE technologies, magnitude of the reduced cost applied to new RE capacity as an incentive to deploy, and application of a nationally uniform benchmark development rate to modeled projections of economic deployment. Based on commenter data and information, as well as further analysis and information collection, the primary adjustments the EPA made to the alternative RE approach are:

- The basis for quantifying building block 3 generation has been modified to incorporate historical deployment patterns for RE technologies as well as the economic potential identified through modeling projections. The introduction of historical capacity additions to the final methodology further grounds building block 3 generation in demonstrated levels of RE deployment that have been successfully incorporated into the power system. This adjustment also serves to harmonize the approach across all three building blocks in which historical data is the primary basis for identifying emission reduction opportunities under the BSER.
- The RE technologies used to quantify building block 3 generation levels are onshore wind, utility-scale solar PV, concentrating solar power (CSP), geothermal and hydropower. Each of these technologies is a utility-scale, zero-emitting resource that was included under the alternative RE approach at proposal. Additionally, the EPA received

significant comments on the opportunities and challenges associated with distributed RE technologies. Distributed technologies, as a demand-side resource, present unique data and technical challenges (such as the role of evaluation, measurement and verification (EM&V) procedures in verifying their production, the diverse economic incentives of different parties involved in their deployment, and the variety of grid integration policies and conditions across potential deployment sites) that complicate identifying a technically feasible and cost-effective level of generation. Consequently, the EPA is, at this time, choosing not to include distributed technologies as part of the BSER (although, as explained in section VIII.K of this preamble, distributed RE technologies that meets eligibility criteria may be used for compliance). Finally, any RE technology that has not been deployed in the U.S., including demonstrated RE technologies for which there is clear evidence of technical feasibility and cost-effectiveness (e.g., offshore wind), contributes no generation to building block 3 under this historically-based methodology. These RE technologies are consequently reserved for compliance, which offers affected EGUs additional flexibility and will reduce their need to rely on other emission reduction measures or building blocks.

- Building block 3 generation levels are expressed in terms of incremental, rather than total, RE generation. As a metric, incremental generation is better aligned with quantifying an amount of expanded RE to replace generation at affected EGUs.[718] Specifically, the generation levels under building block 3 include generation from capacity that commenced operation subsequent to 2012 (the data year on which the BSER is evaluated). Commenters remarked that it is unnecessary to include generation from RE capacity that was already in operation by 2012 in building block 3 because the impact of that generation on fossil fuel-fired EGUs is already reflected in the observed 2012 emissions and generation data of those EGUs.
- Due to the interstate nature of RE and the power system, and consistent with the rationale provided in the October 2014 Notice of Data Availability (NODA), building block 3 generation levels are quantified for each of the three BSER regions – the Eastern Interconnection, Western Interconnection, and Texas Interconnection – rather than at

[718] Consistent with the November 2014 Notice of Data Availability, the final goal setting methodology assumes replacement of affected EGU generation by incremental building block 3 generation in calculating source-specific CO_2 emission performance rates. For additional information on the goal setting methodology refer to Section VI.

the state-level. This regionalized approach, as described in the NODA, takes into account the opportunity to develop regional RE resources and thus better aligns building block 3 generation levels with the rule's approach to allowing the use of qualifying out-of-state renewable generation for compliance.

- Commenters observed that the cost and performance estimates the EPA relied on at proposal from the Energy Information Administration's Annual Energy Outlook 2013 do not reflect the decline in cost and increase in performance that have been demonstrated by current projects, particularly in regards to wind and solar technologies. Commenters provided data from a variety of sources to support these claims, including Lawrence Berkeley National Laboratory, the Department of Energy (DOE) and Lazard. Each of these sources supported the contention that RE technologies, particularly wind and solar, have realized gains in cost and efficiency at a scale that has altered the competitive dynamic between RE and conventional resources. As a result, it has become increasingly necessary for any long-term outlook of the utility power sector to continually assess the development of RE technology cost and performance trends. In performing this task, the EPA revised its data for onshore wind and solar technologies to reflect the mid-case estimates from the National Renewable Energy Laboratory's (NREL's) 2015 Annual Technology Baseline. The EPA selected the NREL 2015 Annual Technology Baseline (ATB) estimates based on the quality of its data as well as NREL's demonstrated success in both reflecting and anticipating RE cost and performance trends. In addition to wind and solar technologies, the EPA evaluated hydropower deployment potential based on the latest cost and performance data from NREL's Renewable Energy Economic Potential study.[719]

- The benchmark development rate that constrained cost-effective RE deployment under the alternative RE approach in the proposal has been removed from the final methodology.[720] Commenters detailed several issues with applying the benchmark development rate, including that it does not factor in the total size of the RE resource in a given state and is inconsistent with a regional approach to quantifying target generation levels. EPA agrees with these

[719] For additional information on the updated RE cost and performance assumptions used to quantify building block 3 generation, refer to the GHG Mitigation Measures TSD.
[720] The technical potential limiter was a nationally uniform, technology-specific limit on cost-effective RE deployment based on the amount of 2012 generation in a state as a share of that state's total technical potential.

comments and the benchmark development rate has been eliminated.

In addition to the comments described above, the EPA received significant comments on a wide variety of topics related to building block 3. Many of these comments provided helpful information and insights, and have resulted in improvements to the final rule. These comments, as well as the EPA responses, are available in the Response to Comment document.

The final methodology for quantifying incremental RE target generation levels contains seven steps. Each step is described below.[721]

First, the EPA collected data for each RE technology (onshore wind, utility-scale solar PV, CSP, geothermal and hydropower) to determine the annual change in capacity over the most recent five-year period. From these data, the EPA calculated the five-year annual average change in capacity and the five-year maximum annual change in capacity for each technology.

Second, the EPA determined an appropriate capacity factor to apply to each RE technology that would be representative of

[721] For supporting data, documentation, and examples for each step of the quantification methodology, refer to the GHG Mitigation Measures TSD.

expected future performance from 2022 through 2030. For this purpose the EPA relied on NREL's ATB.

Third, the EPA calculated two generation levels for each RE technology. The first generation level is the product of each technology's five-year average capacity change and the assumed future capacity factor. The second generation level is the product of each technology's five-year maximum annual capacity deployment and the assumed future capacity factor. Table 9 below shows the data and assumptions used for these calculations.

TABLE 9. Historical Capacity Changes and Associated Generation Levels.

	Assumed Future Capacity Factor	***Five-Year Average Capacity Change (MW)***	***Generation Associated with Five Year-Average Capacity Change (MWh)***	***Maximum Annual Capacity Change (MW)***	***Generation Associated with Maximum Annual Capacity Change (MWh)***
Utility-Scale Solar PV[722]	*20.7%*	*1,927*	*3,494,268*	*3,934*	*7,133,601*
CSP	*34.3%*	*251*	*754,175*	*767*	*2,304,590*
Onshore Wind	*41.8%*	*6,200*	*22,702,416*	*13,131*	*48,081,520*
Geothermal	*85.0%*	*142*	*1,057,332*	*407*	*3,030,522*
Hydropower	*63.8%*	*141*	*788,032*	*294*	*1,643,131*
Total Generation	*N/A*	*N/A*	*28,796,222*	*N/A*	*62,193,363*

[722] Capacity values for utility-scale solar PV are expressed in terms of MW_{DC}. The assumed future capacity factor for this utility-scale solar PV includes a DC-to-AC conversion, enabling the generation totals to be combined across all RE technologies.

Fourth, the EPA quantified the RE generation from capacity commencing operation after 2012 that can be expected in 2021 (the year before this rule's first compliance period) without the imposition of this rule. Because building block 3 is focused on the ability of fossil fuel-fired EGUs to reduce their emissions by deploying incremental RE, it is reasonable to take into account the considerable amount of RE deployment that is already taking place and is projected to continue doing so before considering the additional deployment that would be motivated by this rule's mandate to reduce emissions from affected EGUs. The EPA considered its base case power sector modeling projections using IPM to quantify this component of future-year RE generation, which the EPA assumes to be 213,084,125 megawatt-hours in 2021.

Fifth, the EPA applied the generation associated with the five-year average capacity change to the first two years of the interim period. Combining the projected 2021 RE generation from capacity starting operation after 2012 with the generation increment associated with the five-year average change in capacity produces 241,880,347 megawatt-hours in 2022 and 270,676,570 megawatt-hours in 2023. The EPA believes it is appropriate to apply the generation associated with the five-year average capacity change for the first two years of the interim period to ensure adequate opportunity to plan for and implement any necessary RE integration strategies and investments in advance of the higher RE deployment levels assumed for later years.

Sixth, for all years subsequent to 2023 the EPA applied the generation associated with the maximum annual capacity change from the historical data analysis. In 2024, this produces a building block 3 generation level of 332,869,933 megawatt-hours (aggregated across all three BSER regions); by 2030, that generation level is 706,030,112 megawatt-hours.

Seventh, to further evaluate the technical feasibility and cost-effectiveness of the building block 3 generation levels (aggregated across all three BSER regions), as well as to produce interconnection-specific levels of building block 3 generation from the national totals described in steps 5 and 6, the EPA conducted analysis using IPM of a scenario directing the power sector to achieve those RE generation levels. IPM modeling projections assess opportunities for RE deployment in an integrated framework across power, fuel, and emission markets. The modeling framework incorporates a host of constraints on the deployment of RE resources, including resource constraints such as resource quality, land use exclusions, terrain variability, distance to existing transmission, and population density; system constraints such as interregional transmission limits, partial reserve margin credit for intermittent RE installations, minimum turndown constraints for fossil fuel-fired EGUs, and short-term capital cost adders to reflect the potential added cost due to competition for scarce labor and materials; and technology constraints such as construction lead times and hourly generation profiles for non-dispatchable resources by season.[723] Additionally, the EPA assumes in this analysis that deployment of variable, non-dispatchable RE resources is limited to 20 percent of net energy for load by technology type and 30 percent of net energy for load in total at each of IPM's 64 U.S. sub-regions.[724] The 30 percent constraint applied to variable, non-dispatchable RE resources reflects levels commonly modeled in grid integration studies at the level of the interconnection. These studies have demonstrated that impacts to the grid in reaching levels as high as 30 percent of net energy for load are relatively minor.[725] For example, the Western Wind and Solar Study Phase 2 found cycling costs ranged from $0.14 to $0.67 per

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[723] Refer to GHG Mitigation Measures TSD for more detail on modeling methodology.

[724] Regions that have already exceeded these limits are held at historical percent of net energy for load.

[725] Wind Technologies Market Report 2013. LBNL. Cochran, et al. 2014; Grid Integration and the Carrying Capacity of the U.S. Grid to Incorporate Variable Renewable Energy. NREL. Cochran, et al. 2015; The Western Wind and Solar Integration Study Phase 2. NREL. Lew, et al. 2013. Refer to GHG Mitigation Measures TSD for further analysis.

megawatt-hour of added wind and solar generation. These integration cost levels are not impactful in determining cost-effectiveness. As such, applying the 30 percent constraints at the IPM sub-region level is very conservative and provides a high degree of assurance that the RE capacity deployment pattern projected by the model would not incur significant grid integration costs.[726]

In addition to facilitating the EPA's assessment of the feasibility and cost of reaching the aggregate building block 3 generation levels across all three BSER regions, the IPM projections also provide the EPA with a basis for apportioning those generation levels to each interconnection. The EPA considered the projected regional location of the evaluated RE deployment in this analysis, which shows the majority of such deployment occurring in the Eastern Interconnection. The GHG Mitigation Measures TSD describes in greater detail the process by which the EPA calculated the apportionment of building block 3 generation levels to each of the BSER regions, taking these modeling projections into account. Table 10 describes the annual building block 3 generation levels for each interconnection from 2022 through 2030.

TABLE 10. Building Block 3 Generation Levels (MWh).

[726] Refer to the GHG Mitigation Measures TSD for additional information on constraints related to deployment of non-dispatchable RE.

Year	***Eastern Interconnection***	***Western Interconnection***	***Texas Interconnection***
2022	*166,253,134*	*56,663,541*	*18,963,672*
2023	*181,542,775*	*60,956,363*	*28,177,431*
2024	*218,243,050*	*75,244,721*	*39,382,162*
2025	*254,943,325*	*89,533,078*	*50,586,893*
2026	*291,643,600*	*103,821,436*	*61,791,623*
2027	*328,343,875*	*118,109,793*	*72,996,354*
2028	*365,044,150*	*132,398,151*	*84,201,085*
2029	*401,744,425*	*146,686,508*	*95,405,816*
2030	*438,444,700*	*160,974,866*	*106,610,547*

Through the quantification methodology detailed above, the EPA has identified amounts of incremental RE generation that are reasonable, rather than the maximum amounts that could be achieved while preserving the cost-effectiveness of the building block. For example, assuming gradual improvement in RE technology capacity factors consistent with historical trends, expanding the portfolio of RE technologies that contribute to the building block 3 generation level, and applying the five-year maximum capacity change values to all years of the interim period are adjustments that would produce higher building block 3 generation levels and maintain the primacy of historical data in quantifying RE generation potential. External analysis and studies of RE penetration levels strongly support the technical feasibility and cost-reasonableness of RE deployment well in excess of the levels established by building block 3, as detailed in section V.E.7. By identifying reasonable rather than maximum achievable amounts, we are increasing the assurance that that the identified amounts are achievable by the source category and providing greater flexibility to individual affected EGUs to choose among alternative measures for achieving compliance with the standards of performance established for them in their states' section 111(d) plans.

7. Feasibility of RE Deployment

The 2030 level of RE deployment and the rate of progress during the interim period in getting to that level are well supported by comments received, DOE and NREL analysis, and external studies evaluating the costs of and potential for RE penetration. The EPA has assessed the feasibility of RE in terms of deployment potential, system integration, reliability, backup capacity, transmission investments, and RE supply chains.

Historical RE deployment rates are a strong indication of the feasibility of the 2030 level of deployment and interim period pathway. The use of RE continues to grow rapidly in the U.S. In 2013, electricity generated from RE, including conventional hydropower, represented 13 percent of total U.S. electricity, up from 9 percent in 2005. In particular, there has been substantial growth in the wind and solar markets in the past decade. Since 2009, wind energy has tripled and solar has grown tenfold.

The expected future capacity installations in 2022-2030 needed to reach the 2030 level of incremental RE generation are consistent with historical deployment patterns. Forecasts by Cambridge Energy Research Associates (CERA) of 17 gigawatts in 2015 and historical deployment of 16 gigawatts in 2012 are significant. The average deployment of wind over the past five years was 6,200 megawatts per year; 2014 deployment of solar PV, both distributed and utility-scale, was 6,201 megawatts. This contribution from solar PV is consistent with the rapid reduction in costs that is currently being observed and is expected to continue.

Grid operators are reliably integrating large amounts of RE, including variable, non-dispatchable RE today. For example, Iowa and South Dakota produced more than 25 percent of their electricity from wind in 2013, with a total of nine states above 12 percent and 17 states at more than 5 percent. California served nearly 19 percent of total load in 2013 with RE resources, not including behind-the-meter distributed solar resources, and approximately 25 percent of total load with RE in 2014. On an instantaneous basis, California is regularly serving above 25 percent of load with RE resources, recently began seeing over 5,000 megawatt-hours of solar energy, and is on track for 33 percent of load with no serious reliability or grid integration issues. Germany exceeded 28 percent non-hydro RE as a percentage of total energy in first half of 2014. Other recent examples include: ERCOT met 40 percent of demand on March 31, 2014 with wind power; SPP met 33 percent of demand on April 6, 2013 with wind power; and, Xcel Energy Colorado met 60 percent of demand on May 2, 2013 with wind power. Operational and technical upgrades to the power system may be required to accommodate high levels of variable, non-dispatchable RE like wind and solar over longer time periods; however, the penetration levels cited above have been achieved without negative impacts to reliability due in large part to low-cost measures such as expanded operational flexibility and effective coordination with other regional markets.

RE can contribute to reliable system operation. The abundance and diversity of RE resources in the U.S. can support multiple combinations of RE in much higher penetrations. When California, the Midwest, PJM, New York, and New England experienced record winter demand and prices during the polar vortex, wind generation played a key role in maintaining system reliability.

Wind and solar PV are increasingly productive and capable of being accurately forecast, which improves grid reliability. Increasing capacity factors mean less variability and more generation. While the wind industry develops more projects at lower wind speed sites, wind turbine design changes are driving capacity factors higher among projects located in a given wind resource regime.[727] Average capacity factors have risen from the low 30 percent range to high 30 percent range and continue to improve. One key recent advancement is the increasing use of turbines designed for low to medium wind speed sites (with higher hub-heights and larger rotors, relative to nameplate capacity) at higher wind-speed sites with low turbulence.

New variable RE generators can provide more electrical power grid support services beyond just energy. Modern wind turbine power electronics allow turbines to provide voltage and reactive power control at all times. Wind plants meet a higher standard and far exceed the ability of conventional power plants to "ride-through" power system disturbances, which is essential for maintaining reliability when large conventional power plants break down. Xcel Energy sometimes uses its wind plants' exceedingly fast response to meet system need for frequency response and dispatchable resources. Utility-scale PV can incorporate control systems that enable solar PV to contribute to grid reliability and stability, such as voltage regulation, active power controls, ramp-rate controls, fault ride through, and frequency control. Solar generation is capable of providing

[727] LBNL, Wind Technologies Market Report 2013, August 2014, p. 43, Available at: http://emp.lbl.gov/sites/all/files/2013_Wind_Technologies_Market_Report_Final3.pdf.

many ancillary services that the grid needs but, like other generators, needs the proper market signals to trade energy generation for ancillary service provision.

The transmission network can connect distant high-quality RE to load centers and improve reliability by increasing system flexibility. Investments in transmission and distribution upgrades also enable improvements in system-wide environmental performance at lower cost.

The potential range of new transmission construction is within historical investment magnitudes. Under nearly all scenarios analyzed for the DOE’s Quadrennial Energy Review, circuit-miles of transmission added through 2030 are roughly equal to those needed under the base case, and while those base case transmission needs are significant, they do not appear to exceed historical annual build rates. DOE’s Wind Vision findings project 11.5 gigawatts of wind per year from 2021-2030. This deployment level would require 890 circuit miles per year of new transmission; 870 miles per year have been added on average between 1991 and 2013. 11.5 gigawatts per year is consistent with building block 3 deployment levels for wind capacity over the compliance period. DOE’s SunShot scenario, which increases utility-scale PV to 180 gigawatts by 2030, required spending of $60 billion on transmission through 2050. On an average annual basis, this expenditure is within the historical range of annual transmission investments made by IOUs in recent decades.

Incremental grid infrastructure needs can be minimized by repurposing existing transmission resources. Transmission formerly used to deliver fossil-fired power to distant loads can – and is – being used to deliver REwithout new infrastructure. First Solar’s Moapa project uses transmission built to deliver coal-fired power from Navajo to Los Angeles. NV Energy’s retirement of Reid-Gardner will free up additional transmission capacity. The Milford wind projects in Utah already utilize transmission that was built to deliver coal power to Los Angeles.

Storage can be helpful but is not essential for the feasibility of RE deployment because there are many sources of flexibility on the grid. DOE’s Wind Vision and many other studies have found an array of integration options (e.g., large balancing areas, geographically dispersed RE, weather forecasting used in system operations, sub-hourly energy markets, access to neighboring markets) for RE beyond storage. Storage is a system resource, as its value for renewables is a small share of its total value.

Increasing regional coordination between balancing areas will increase operational flexibility. The Energy Imbalance Market (EIM) recently implemented by the California ISO and

Pacificorp is a good example of the increased coordination that will be helpful in ensuring that resources across the West are being utilized in an efficient way.

Significant wind and solar supply chains have developed in the past decade to serve the fast-growing US RE market. For wind, domestic production capability would likely have to increase to accommodate projected builds under the CPP in the 2022-2030 time period; however, the global supply chain has expanded significantly to serve multiple markets and can augment production from the domestic supply chain, if necessary. At the start of 2014, the U.S. domestic supply chain could produce 10,000 blades (6.2 gigawatts) and 4300 towers (8 gigawatts) annually. It is not anticipated that expanded domestic manufacturing will be constrained by raw materials availability or manufacturing capability. For solar technologies, the global supply chain has a capacity that has significantly expanded over the past few years from 1.4 gigawatts per year in 2004 to 22.5 gigawatts per year in 2011. Current capacity exceeds these levels and is expected to grow. For PV systems, raw materials like tellurium and indium are at highest risk of supply shortage, but these materials are not used in the PV technologies currently being deployed at large-scale.

8. Cost of CO_2 Emission Reductions from RE Generation

The EPA believes that RE generation at the levels represented in building block 3 can be achieved at reasonable costs. In the EPA's modeling of the building block 3 generation level, the projected cost of achieving CO_2 reductions through this expansion of RE generation is $37 per ton on average from 2022 through 2030.[728] There are a number of reasons why the EPA believes that the cost of CO_2 emission reductions from RE generation will be lower than this analysis suggests. First, modeling constraints that restrict variable, non-dispatchable RE technologies to 30 percent of net energy for load at each of the 64 U.S. IPM regions is a conservative limit intended to eliminate significant grid integration costs at increased levels of RE penetration. In fact, many regions have already demonstrated levels of RE penetration that exceed the constraints, and in practice intermittency can be managed across larger regions than the 64. Consequently, the extent to which these regions could, in practice, achieve higher levels of RE deployment without facing substantial grid integration costs would lead to a lower-cost RE outcome than is estimated by this analysis. Second, there are multiple RE technologies not quantified under building block 3 that affected EGUs may use to demonstrate compliance (distributed generation technologies,

[728] Refer to the GHG Mitigation Measures TSD for further analysis and IPM run results.

offshore wind, etc.). Based on preliminary analysis from DOE and NREL, cost-effective opportunities for distributed generation alone could satisfy one-third to over one-half of the stringency associated with building block 3.[729] Third, as discussed in section V and VI of the preamble, the BSER reflects the degree of emission limitation achieved through the application of the building blocks in the least stringent region. By definition, in the other two regions the BSER is less stringent than the simple combination of the three building blocks, rendering a portion of the emission reduction potential quantified by the building blocks unnecessary to achieving the interim and final CO_2 emission performance rates. For example, the EPA has calculated that in excess of 160,000,000 megawatt-hours of building block 3 potential is not required to achieve the final CO_2 emission performance rates in 2030 – and would be accessible to affected EGUs for compliance.[730] Therefore, it is reasonable to expect that it would cost less to achieve the component of building block 3 potential that is reflected in the calculation of the final CO_2 emission performance rates, as compared to the results of this analysis which assumed achievement of the entire

[729] See Section VIII.K. for a description of qualifying RE technologies for compliance.

[730] For additional discussion on how this concept impacts building block 3 generation levels, refer to the GHG Mitigation Measures TSD and the CO_2 Emission Performance Rate and Goal Computation TSD for Final CPP.

quantified building block 3 potential. The EPA believes that these factors provide significant opportunities for achievement of the building block 3 generation levels at lower costs than estimated in this analysis.

VI. Subcategory-Specific CO_2 Emission Performance Rates

A. Overview

In this section, the EPA sets out subcategory-specific CO_2 emission performance rates to guide states in development of their state plans. The emission performance rates reflect the emission rates for two generating subcategories affected by the rule (fossil steam generation and gas-fired combustion turbines).[731] These final emission performance rates reflect the EPA's quantification of the BSER based on the three building blocks described in section V above. This procedure follows a similar logic to BSER quantification at proposal, but it keeps the emission performance rates separate for fossil steam and NGCC subcategories instead of immediately blending them together into a single value for all affected EGUs. Commenters noted that

[731] The only natural gas fired EGUs currently considered affected units under the 111(d) applicability criteria are NGCC units capable of supplying more than 25 MW of electrical output to the grid. The data and rates for these units represent all emissions and MWh output associated with both the combustion turbines as well as all associated heat recovery steam generating units. The remainder of the section will use the term "NGCC" to collectively refer to these natural gas fired EGUs.

the proposed rule established guidelines that were based on the aggregation of units, and their reduction potential, in a state rather than providing technology-specific guidelines. While many commenters appreciated the flexibility this state-focused structure provided, some noted two concerns with this approach: 1) it would potentially create different incentives for the same generating technology class depending on the state in which that generator was located, and 2) it deviated from the EPA's previous interpretation of the 111(d) regulatory guidelines by not providing technology-specific standards of performance. In response to these comments and our further consideration, the final rule establishes subcategory-specific emission performance rates that are identical across units within a subcategory regardless of where a unit is located within the contiguous U.S. These subcategory-specific emission performance rates are then translated into state-specific goals which, as in the proposal, reflect the particular energy mix present in each state. That translation is presented in section VII.

These performance rates reflect the average emission rate requirement for each subcategory. Similar to the proposal, they are presented as adjusted average emission rates that reflect other generation components of BSER (e.g., renewable) in addition to the fossil component. These performance rates must be achieved by 2030 and sustained thereafter. The interim performance rates apply over a 2022-2029 interim period and would be achieved on average through reasonable implementation of the best system of emission reduction (based on all three building blocks) described above. In other words, the interim performance rates are consistent with a reasonable deployment schedule of BSER technologies as they scale up to their full BSER potential by 2030. The performance rates are meant to reflect emission performance required across all affected EGUs when averaged together and inclusive of lower-emitting BSER components.

The performance rates are expressed in the form of adjusted[732] output-weighted-average CO_2 emission rates for affected EGUs. However, states are authorized to use a converted statewide rate-based or mass-based goal as discussed in the next section. The EPA has determined that the statewide rate-based and mass-based CO_2 goals are expressions of the emission performance rates equivalent to application of the emission performance rates to affected EGUs within a state.

[732] As described below, the emission performance rates include adjustments to incorporate the potential effects of emission reduction measures that address power sector CO_2 emissions primarily by reducing the amount of electricity produced at a state's affected EGUs (associated with, for example, increasing the amount of new low- or zero-carbon generation rather than by reducing their CO_2 emission rates per unit of energy output produced).

The EPA is finalizing the performance rates in a manner consistent with the proposal, with appropriate adjustments based on comments. Stakeholders had the opportunity to demonstrate during the comment period that application of one or more of the building blocks would not be expected to produce the level of emission reduction quantified by the EPA because implementation of the building block at the levels envisioned by the EPA was technically infeasible, or because the costs of doing so were significantly higher than projected by the EPA. The EPA has considered all of this input in setting final performance rates.

The remainder of this section addresses two sets of topics. First, we discuss several issues related to the form of the performance rates. Second, we describe the performance rates, computation procedure, and adjustments made between proposal and final based on stakeholder feedback in the comment period.

Some of the topics addressed in this section are addressed in greater detail in supplemental documents available in the docket for this rulemaking, including the CO_2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule and the Greenhouse Gas Mitigation Measures TSD. Specific topics addressed in the various TSDs are noted throughout the discussion below.

B. Emission Performance Rate Requirements

The EPA has developed a single performance rate requirement for existing fossil steam units in the contiguous U.S., and a single rate for existing gas turbines in the contiguous U.S., reflecting application of the BSER, based on all three building blocks described earlier, to pertinent data. The rates are intended to represent CO_2 emission rates achievable by 2030 after a 2022-2029 interim period on an output-weighted-average basis by all affected EGUs, with certain computation adjustments described below to reflect the potential to achieve mass emission reductions by avoiding fossil fuel-fired generation.

1. Final emission performance rate requirements

The emission performance rates are set forth in Table 11 below, followed by a description of the computation methodology.

Table 11. Emission Performance Rates (Adjusted Output-Weighted-Average Pounds of CO_2 Per Net MWh From All Affected Fossil Fuel-Fired EGUs).

Subcategory	Interim Rate	Final Rate
Fossil Fuel-Fired Electric Steam Generating Units	1,534	1,305
Stationary Combustion Turbines	832	771

The emission performance rates are expressed as adjusted output-weighted-average emission rates for each subcategory. As discussed later in this section, the emission rate computation includes an adjustment designed to reflect mass emission reductions associated with lower-emitting BSER components. The adjustment is made by estimating the annual net generation associated with an achievable amount of qualifying incremental lower-carbon and zero-carbon generation and substituting those MWhs for the baseline electricity generation and CO_2 emissions from the higher-emitting affected EGUs. Under the final rule approach, regionally identified building block 3 potential generation replaces fossil steam and NGCC generation on a pro-rata basis corresponding to the baseline mix of fossil generation in each region.

2. Interim Emission Performance Rates

Some commenters suggested that the interim period starting in 2020 provided too little time for implementation of measures required to demonstrate compliance during the interim period. As discussed in section V.A.3.g of this preamble, the EPA has determined that an interim period beginning in 2022 provides sufficient time for states to undertake necessary planning exercises and for the implementation of measures towards achieving the performance rates. The EPA determined the interim rates in a manner similar to proposal, with an adaptation to address the revised timing of the interim compliance period (beginning in 2022 rather than in 2020 as proposed). They reflect the averaging of estimated emission performance rates for each year in the interim period (i.e., 2022-2029).

The interim performance rates are less stringent than the final 2030 emission performance rates because the amount of emission reduction potential identified for the BSER increases over time, as explained in section V.

C. Form of the Emission Performance Rates

1. Rate-based guidelines

The interim and final emission performance rates for fossil steam and NGCC units are presented in the form of adjusted output-weighted-average CO_2 emission rates that the affected fossil fuel-fired units could achieve, through application of the measures comprising the BSER (or alternative control methods). Several aspects of this form of emission rate are worth noting at the outset: the use of emission rates expressed in terms of net rather than gross energy output; the use of output-weighted-average emission rates for all affected EGUs; the use of adjustments to accommodate incremental NGCC generation and RE measures that reduce CO_2 emissions by reducing the quantity of fossil fuel-fired generation and associated emissions; and the adjustability of the goals based on the severability of the underlying building blocks.

a. Rationale for rate-based guidelines. First, the EPA sets an emission rate requirement for each subcategory by identifying the technology-specific reductions available under the building blocks. We then give each state the choice to apply the emission performance rates directly to the affected EGUs within the state or provides the opportunity to use the statewide rate-based goal or the equivalent mass-based form translated from the emission performance rates for state plan purposes. The emission performance rates reflect the BSER, and the statewide rate-based goal and statewide mass-based goal are alternative metrics for realizing the emission performance rates at the aggregate affected fleet level for a state.

Stakeholders have expressed support for having the flexibility to choose from among the multiple options for crafting an implementation plan to realize the BSER. The EPA is providing emission performance rate-based guidelines that apply uniformly to technology subcategories nationwide, and the EPA is providing corresponding state emission rate goals and state mass goals to further enhance compliance flexibility for each state. This approach allows each state to adopt a plan that it considers optimal and is consistent with the state flexibility principle that is central to the EPA's development of this program.

b. Net vs. gross MWh. The second aspect noted above concerns the expression of the goals in terms of net energy output733 –

[733] As discussed below in Section VIII on state plans, we are similarly determining that states choosing a rate-based form of emission performance level for their plans should establish a

that is, energy output encompassing net MWh of generation measured at the point of delivery to the transmission grid rather than gross MWh of generation measured at the EGU's generator. The difference between net and gross generation is the electricity used at a plant to operate auxiliary equipment such as fans, pumps, motors, and pollution control devices. Because improvements in the efficiency of these devices represent opportunities to reduce carbon intensity at existing affected EGUs that would not be captured in measurements of emissions per gross MWh, goals are expressed in terms of net generation. As noted by commenters, EGUs have familiarity and in some places already have in place equipment necessary to collect and report hourly net generation.[734]

c. Output-weighted performance rates for all affected EGUs. This final rule provides an expression of the BSER as subcategory-specific emission performance rates rather than the state goals provided at proposal. Whereas the proposal also estimated the BSER impact on fossil steam and NGCC emissions and generation, it went one step further by averaging these two

requirement for affected EGUs to report hourly net energy output.

[734] Specifically, commenters noted that while net generation is not reported to the EPA under 40 CFR Part 75, affected EGUs are generally required to report gross and net generation on a monthly basis to EIA through form 923 submittal.

technology rates into a single rate for each state. Under this final rule, the EPA is identifying the fossil steam rate and the NGCC rate separately instead of only presenting them in a blended fashion at the state level.[735] These two emission performance rates are the expression of the BSER for the final rule for affected EGUs located within the contiguous U.S.

The modification from a blended emission rate in the proposed rule to a subcategory-specific emission performance rate for affected EGU categories in the final rule was made in response to comments that technology subcategory-specific emission rates were more analogous to prior 111(d) efforts and more consistent with the statute. The EPA received significant comments suggesting a technology subcategory-specific rate is consistent with past section 111(d) regulations. However, many commenters also supported the flexibility provided to states through a state goal metric provided at proposal. Therefore, the EPA does provide alternative statewide rate-based and mass-based goals in the next section.

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[735] However, as discussed in the next section, in order to provide maximum flexibility to states, the EPA averages these two emission rates together for each state using their adjusted 2012 baseline generation share to arrive at a single statewide emission performance goal. The state has the option to comply with this statewide goal through a compliance pathway of its choice. This compliance pathway may or may not involve requiring its affected units to meet the emission performance rates.

The EPA's main consideration has been to ensure that the expression of the BSER reflects opportunities to manage CO_2 emissions by shifting generation among different types of affected EGUs. Both the performance rates in this final rule and the state goals at proposal rely on the adjusted emission rate metric to reflect that potential shifting. Specifically, because CO_2 emission rates differ widely across the fleet of affected EGUs, and because transmission interconnections typically provide system operators with choices as to which EGU should be called upon to produce the next MWh of generation needed to meet demand, opportunities exist to manage utilization of high carbon-intensity EGUs based on the availability of less carbon-intensive generating capacity. For states and generators, this means that CO_2 emission reductions can be achieved by shifting generation from EGUs with higher CO_2 emission rates, such as coal-fired EGUs, to EGUs with lower CO_2 emission rates, such as NGCC units. Our analysis indicates that shifting generation among EGUs offers opportunities to achieve large amounts of CO_2 emission reductions at reasonable costs. The realization of these opportunities can be reflected in an emission rate established in the form of an output-weighted-average emission rate where the weighting reflects the varying levels of replacement generation technologies.

d. Severability of building blocks. Section V above discusses the severability of the three building blocks upon which the CO_2 emission performance rates are based. Because the building blocks can be implemented independently of one another and the emission performance rates reflect the sum of the emission reductions from all of the building blocks, if any of the building blocks is found to be an invalid basis for the “best system of emission reduction ... adequately demonstrated,” the rates would be adjusted to reflect the emissions reductions from the remaining building blocks. The sole exception, as described above, is the application of building block 1 in isolation, which would not be implemented independently. The performance rates and statewide goals that would result from any combination of the building blocks could be computed using the formulas and data included in the CO_2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule and its appendices using the methodology described below and elaborated on in that TSD.

D. Emission Performance Rate-Setting Equation and Computation Procedure

The methodology used to compute the performance rates is summarized on a step-by-step basis below in section 3. The methodology is described in more detail in the CO_2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule, which includes a numerical example illustrating the full procedure. The quantification of the building blocks used in the computation procedure is discussed in Section V above and in the Greenhouse Gas Mitigation Measures TSD.

1. Inventory of likely affected EGUs

In order to calculate the subcategory-specific emission performance rates reflecting the BSER, the EPA first needed to develop a baseline inventory of likely affected EGUs in order to estimate the impact of the BSER. The EPA developed an inventory of likely affected units that were operating in 2012 or that began construction prior to January 8, 2014 and that appeared to meet the final rule's applicability criteria.[736] This inventory does not constitute a final applicability determination, but best reflects the EPA's estimate of units subject to the 111(d) applicability criteria as laid out in Section IV. The EPA identified a list of likely affected units at proposal comprised of approximately 3,000 EGUs. The agency took comment on this list and has made a number of updates to the inventory in response to those comments and in regards to applicability criteria changes resulting from comments. However, the inventory

[736] The EPA's responsibility is to determine the BSER for all affected EGUs. Some of these under construction units may not enter operation until 2015 or later, but they are likely affected units and therefore appropriate to reflect in the baseline and corresponding subcategory-specific emission performance rates and state goals.

does not reflect a final applicability determination, and where a unit's status was unclear, the EPA generally treated the unit's status in a manner consistent with the proposal and publically available reported data.[737]

Since the final rule's applicability includes under construction units, the EPA also identified units that had not yet commenced operation by the 2012 baseline period, but that commenced construction before January 8, 2014. The EPA received significant comment on the proposal's sole use of the National Electric Energy Data System (NEEDS) to identify these under construction units. Commenters suggested that the EPA also utilize EIA and 2012 proposed unit-level files to help better identify under construction units. In some cases, NEEDS did not reflect units that had commenced construction. Therefore, the EPA updated its approach to identifying units that had commenced construction prior to January 8, 2014, but that had not commenced operation in 2012. In the final rule, the EPA uses EIA

[737] The EPA notes that in some cases, it may not yet be possible to determine the status of an EGU as affected or unaffected without additional data. There are potentially some units excluded or included in the baseline that will ultimately have a different status following an applicability determination. However, these cases are limited, and the effect of any collective changes to the affected fleet inventory will not yield a bias in the BSER computation at the regional level.

data, comments, as well as NEEDS data to identify these under construction units.[738,739,740]

These units that were operating by 2012 along with those that had not commenced operation by 2012 but had commenced construction by January 8, 2014, reflect the EPA baseline inventory of likely affected EGUs. The CO_2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule explains the prime mover, capacity, and fuel criteria used to identify the likely affected EGUs.[741]

The EPA received significant comment that units that came online during the baseline year (e.g., 2012) should be treated as under construction rather than operating units in 2012 for purposes of estimating baseline values, because their 2012 operation may be misrepresentative of anticipated future-year operation due to partial year operation in 2012. The EPA has made an adjustment to flag these units as having commenced

[738] The NEEDS database was also updated to reflect the latest data and commenter input on under construction units.
[739] For purposes of determining emission performance rates, the EPA classifies any unit that had begun construction prior to Jan. 8, 2014, but had not commenced operation by Dec. 31, 2011 as "under construction". Many of these "under construction" units have commenced operation at some point during 2012 or prior to signature of this final rule.
[740] "Commence" and "construction" are defined in 40 CFR 60.2.
[741] The baseline inventory relies on historical data and does not incorporate anticipated future retirements. Most commenters supported this treatment as they viewed those scheduled retirements (and corresponding emission reductions) as an alternative compliance flexibility.

operation during 2012 and treat them as under construction units, consistent with commenters' suggestion; for BSER computational purposes, generation and emissions for these units are estimated based on a representative first full year of operation for that technology class.

2. Data year

In the proposed rule, the EPA considered using a historical-year data set or a projected-year data set as a starting point for applying the technology assumptions identified under BSER. The EPA proposed using 2012 data as it was the most recent data year for which complete data were available when the EPA undertook analysis for the proposed rule and it reflected actual performance at the state level. The EPA took comment on alternative data sets. In particular, the EPA issued a NODA on October 30, 2014 (79 FR 64543) in which we provided 2010 and 2011 historic data for consideration.

The EPA received a significant number of comments supporting the use of historical data as the basis from which to quantify performance rates reflecting BSER. Some commenters supported the 2012 data year as the best reflection of the power fleet, and some suggested that the EPA use a different year or a historical average to control for data anomalies in 2012. Moreover, some commenters pointed out that using 2010, 2011, 2012 data, or an average of the three would not address their concerns about recent year anomalies in hydro generation due to high snow pack. Some commenters also suggested the EPA use a baseline including years prior to 2012, not to increase representativeness of the power sector, but as a means of recognizing early action.

In this final rule, the EPA is taking an approach to the baseline year where we still largely rely on reported 2012 data as the best and most recent available data representing the power sector from which to apply the BSER, but also including targeted baseline adjustments to address commenter concerns with 2012 data.[742] Below, we explain why – at the nationwide level - 2012 data are preferable, more objective, and more accurate than a prior year, or an average of years, for informing the baseline. Then, we explain the adjustments that we are making to the 2012 data along with our rationale for such adjustments, in response to comments we received.

Some commenters supported the EPA’s use of 2012 data to inform performance rates, and the EPA agrees that 2012 data with targeted adjustments, relative to other historical years, best reflects the power sector and best informs the performance rates that pertain to the BSER. The EPA believes that starting with

[742] The EPA recognizes that more recent emissions and generation data have become available since 2012, but 2012 data constituted the most recent year for which full data was available at the time the EPA began its analysis for proposal.

2012 data is more accurate and better informs the BSER than an earlier historical year or historical multi-year average for the following reasons:

1) Of the historical data fully available at the time the proposal analysis began, 2012 was the most recent and best reflects the power fleet. Approximately 43 GW of new capacity came online in 2010 and 2011. In other words, there was 43 GW of capacity online as of 2012 that had not been in service at some point during the 2010-2011 period. Likewise, approximately 17 GW of capacity that were operable in 2010 and/or 2011 were retired prior to 2012.[743] Using state-level, prior year data, either on its own, or as part of a multi-year baseline, is not as representative of the current power fleet as the 2012 data, which better reflects significant changes in power sector infrastructure.
2) A three-year baseline would not address some of the substantive concerns raised by commenters. Many commenters pointed out that using a three-year baseline would not address their critical concern about variation in the hydrological cycle due to snow pack (particularly in the Northwest), because the snow pack was

[743] EIA Form 860, 2012.

significantly above average in both 2011 and 2012. The EPA agrees with commenters that we can better address their baseline data concerns regarding an average hydro year by identifying those states with a significant share of hydro generation and variation in that hydro generation, and making targeted adjustments to those states' affected fossil generation levels in order to reflect a more typical snow-pack year. This procedure is described in more detail below and in the Technical Support Documents.

3) In addition to being, in the EPA's view, a less representative baseline of the existing power fleet, a multi-year baseline would also likely entail complexity when determining how to average together yearly fleet data while appropriately accounting for fleet changes occurring during those years. The 2012 baseline starting point maximizes the EPA's reliance on latest reported operating data and minimizes the need for fleet capacity adjustments. For instance, because of year-to-year fleet turnover, the averaging of multiple baseline years would require additional assumptions in regards to which generation to consider from a fleet that is changing in a given state or region (or even where units are switching fuel sources such as a coal-to-gas conversion).

4) Due to the region-based approach to quantify building blocks and the BSER as subcategory-specific emission performance rates, variations in unit-level data do not significantly impact the calculation of emission performance rates. For instance, if one fossil unit is operating less in a given year due to an outage, another fossil unit in the same region is generally operating more. Therefore, at the regional level, fossil generation and emissions do not vary to the same degree that unit-level data varies. Moreover, the variation at the regional level that does exist in 2012 relative to previous years is not necessarily unrepresentative variation, but illustrates trends in the power sector infrastructure that are desirable to capture for purposes of determining a representative year from which further improvements in CO_2 emissions performance can be made. Because the EPA is moving from a state approach at proposal to a regional approach for calculating the expression of the BSER in this final rule, unit-level operational variation from year to year becomes even less relevant to the calculation of regional emission performance rates.

5) Some commenters suggested the EPA use an earlier baseline year as a means of recognizing early action. They noted

that an earlier baseline would reflect a higher-emitting fleet and therefore when the same level of building block MWhs are applied, they would result in a higher (i.e., less stringent) state goal. The EPA disagrees with this view for several reasons. First, the objective of selecting a baseline to inform BSER is to have one that best reflects the power sector and consequently the best system of emission reductions of which the power fleet is capable. Using an earlier baseline that “inflates” the starting point would undermine this objective, not serve it. Second, the EPA disagrees with the premise of this comment – that the baseline would change and building block potentials would stay the same. For instance, building block 2 functions based on incremental generation potential (incremental generation = potential generation – baseline generation). This incremental value would increase if an earlier baseline period was used that had less existing NGCC generation.

6) Some commenters pointed out that the EPA relied on multi-year historical data in allowance allocation in previous rulemakings (e.g., CAIR and/or CSAPR allocations). However, that comparison is not relevant to the quantification of emission reduction potential under 111(d). In those previous instances, the EPA was

considering typical unit-level behavior for allowance allocation purposes – not for determining the emission reduction requirements of the program. Those allowance allocation determinations were independent of and subsequent to the determination of emission reduction requirements in those rulemakings.

7) The EPA received significant comment that 2012 was not a representative year for natural gas prices, and thus the EPA should use another year. The EPA disagrees with this comment, and does not view it as grounds for a change to the baseline period. While the EPA does recognize that Henry Hub natural gas prices were lower in 2012 relative to previous years, this does not invalidate the suitability of the data year selection. The EPA's objective in selecting a baseline is to identify potential reductions when BSER technologies are applied; year-to-year variation in market prices for natural gas does not frustrate this effort. For instance, a region may have generated only 5 MWh of NGCC generation in 2011 when gas prices were higher, and 10 MWh of NGCC generation in 2012 when gas prices dropped. However, this does not change the outcome of the quantification of the BSER, because the building block is based on the emission reduction *potential* of the fleet. That potential (e.g., a

fuller realization of the existing NGCC generation potential equivalent to 15 MWh) does not change regardless of the year used for baseline NGCC generation. Therefore, a different data year may change a baseline data point, but it would not change the total potential NGCC generation for quantifying the emission performance rates in these circumstances.

In summary, the EPA believes that continuing to rely on 2012 data while incorporating select data adjustments as detailed below is not only a reasonable choice and adequately supported, but a more reliable and preferable starting point for determining the BSER requirements.

3. Adjustments that the EPA made to the 2012 data

The EPA made corrections to unit-level 2012 data based on commenter feedback. In addition, we also made some adjustments to 2012 data, not to address a correction, but to address a concern about the representativeness of the data. Although the EPA determined that the 2012 data year better informed its BSER determination than a preceding year or a multi-year average, commenters did identify some limitations that we are addressing through targeted adjustments. These are discussed below:

1) Adjustments to state-level data to account for annual variation in the hydrologic cycle as it relates to fossil generation.

Hydropower plays a unique role in a handful of states in that 1) it is a significant portion of their generation portfolio, 2) it varies on an annual basis, and 3) 2012 was an outlier year for snow-pack (meaning hydropower was above and fossil generation was below its historical average).The EPA notes that these three conditions are not present in other weather-based RE technologies like solar or wind.[744] Therefore, no similar adjustment was needed to account for weather patterns with these technologies.

Unlike market conditions (e.g., changes in natural gas prices) that may produce different generation profiles year-to-year but that do not change the overall generating potential of the state’s power fleet, variation in the hydrologic cycle does fundamentally change the generating potential of the state’s power fleet in hydro-intensive states as they no longer have the same generating potential in an average year as they had in a “high hydro” year. The CO_2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule provides analysis and explains the adjustment that the EPA made to the state-level 2012 data

[744] While solar and wind generation may vary on an hourly or daily basis, their annual generation profiles are subject to notably less variation compared to hydropower. The EPA’s calculation of the BSER relies on annual generation data, not on hourly or daily generation data.

for Idaho, Maine, Montana, Oregon, South Dakota, and Washington to better reflect fossil generation levels when hydro generation performed at its average level as observed over a 1990-2012 timeframe. The EPA agrees with commenters that using a 2010-2012 baseline would not address the concern as 2011 was also an outlier year relative to historical snow-pack and hydro generation.

2) Extended unit outages due to maintenance.

Generally, because of the regional-level approach to calculate performance rates, the EPA does not believe that unit-level variations in operation influence the subcategory-specific performance rates reflecting BSER. For instance, as some units ramp down, and others ramp up to replace their load at the regional level, total fossil generation changes little due to these fossil-for-fossil substitutions. Unit-level variation does not inherently entail region-wide variation.

However, the EPA did receive comment that in limited cases, this could have a substantial impact on an individual state if it chooses to use a rate-based or mass-based statewide goal. Even though the EPA is calculating subcategory-specific performance rates that it believes are not affected by this type of unit-level variation, it still evaluated the possible impacts it may have when converting to state goals in the next section. The EPA examined units nationwide with 2012 outages to determine where an individual unit-level outage might yield a significant difference in state goal computation. When applying this test to all of the units informing the computation of the BSER, emission performance rates, and statewide goals, the EPA determined that the only unit with a 2012 outage that 1) decreased its output relative to preceding and subsequent years by 75 percent or more (signifying an outage), and 2) could potentially impact the state's goal as it constituted more than 10 percent of the state's generation was the Sherburne County Unit 3 in Minnesota. The EPA therefore adjusted this state's baseline coal steam generation upwards to reflect a more representative year for the state in which this 900 MW unit operates.

3) Many commenters also noted that because the EPA uses annual data, 2012 was not representative for units coming online part way through the year. The EPA relies on annual data, so if a unit is underrepresented in a certain part of the year because it is not yet online, then another unit is likely over-represented as it is operating more than it otherwise would when the second unit commences operation. Therefore, the resulting state-level and regional-level aggregate annual generation level used in determining the

BSER may be considered to be representative and there is not necessarily a need for any adjustment.

However, the EPA recognizes that the over-represented and under-represented units do not necessarily fall within the same state, and therefore this potential difference in the state location of the affected units could have an impact when estimating appropriate statewide goals. To address this comment, the EPA adjusted the 2012 generation data for fossil units coming online during 2012 to a more representative annual operating level for that type of unit reflecting its incremental impact on generation and emissions. This effectively resulted in increased baseline emissions and generation assumed for those units beyond their reported partial-year operations in 2012.

Conceptually, the assumption of full-year operation at units that came online partway through 2012 could pair with an assumed reduction in the operation of other units somewhere in the same region. However, the EPA made no corresponding deduction to represent this likely decreased utilization at other affected units because it was impossible to project the state location of such units with certainty and the assumed utilization level was meant to reflect the incremental impact on the baseline. As a result, this data adjustment increases the total generation and emissions for units reporting in the 2012 baseline beyond the 2012 reported levels.

Additionally, as done in proposal, the EPA continued to identify under construction units that did not begin operation in 2012, but had commenced construction prior to January 8, 2014 and would commence operation sometime after 2012. As described in the next section, the EPA estimated baseline generation and emissions for these units as they had no 2012 reported data.

In summary, this final rule continues to rely on the latest reported 2012 data as the foundation for quantifying the BSER. However, the EPA has made limited adjustments, in addition to corrections identified by commenters, to the 2012 data to address some of the relevant concerns raised by commenters. Therefore, the baseline is informed by 2012 data, but not limited to 2012 data.[745]

4. Equations

In this section we describe how we develop the equations used to determine the emission performance rates for fossil steam and NGCC units that express and implement BSER. More

[745] Updated unit-level data reflecting corrections identified by commenters to the underlying 2012 file are provided in Appendix 1 of the CO_2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule. The adjustments made to the aggregate data to address representativeness concerns are provided in Appendix 3.

detailed information regarding rate computation, including example calculations, can be found in the CO_2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule, which is available in the docket for this action. Here we first present the general principles we follow when developing equations to express the BSER; then, we summarize the steps taken to assemble baseline data to reflect 2012 baseline emissions and generation, and apply the building blocks that constitute the BSER to derive performance rates that will be used by states to implement BSER. Section VII then explains how these nationwide performance rates are reconstituted into a statewide goal metric similar to the proposal in order to allow a state (at its discretion) to use a statewide goal as a mechanism for demonstrating compliance at the aggregate state level in a state plan, as an alternative to applying the emission performance rates to its affected EGUs directly.

When developing equations to implement BSER, we adhere to a number of basic principles. First, we ensure that the equations are consistent with the BSER itself, and in particular, reflect the redistribution of generation among fossil steam, NGCC and renewables embodied in building blocks 2 and 3. In doing this, we account for the interactions between building blocks in a way that is consistent with the assessment of incremental building block generation potential and the compliance framework for

Emission Reduction Credits (ERCs). In particular, we must ensure that each increment of building block 3 emission reduction potential is applied to either fossil steam or NGCC units but not both. The equations we develop must also take account of the dual status of existing NGCC units, which are simultaneously affected units and provide generation that is an element of the BSER itself.

In addition, we are applying the BSER, as we have done in calculating other section 111(d) standards, to a defined population of existing affected sources, represented in this case by the generation of the source category in the 2012 adjusted baseline. This provides an empirical historical baseline against which we define the performance rates and their state goal equivalents. In doing so, we must account for any offsetting increases in emissions that result from applying the BSER control measures, as we have done in setting other standards. For example, when determining BSER for particulate matter control, a number of pollution control devices (such as sorbent injection technologies) themselves create particulate matter. If the particulate matter created by these control devices were not appropriately accounted for when developing the standard intended to address the primary emissions of particulate, this could create an unreasonably stringent PM standard. In the current context, this means recognizing that increasing NGCC capacity utilization in accordance with building block 2 both offsets higher emitting steam generation and increases emissions at the NGCC units themselves, which are also affected entities that must demonstrate compliance with the BSER. Thus, it is essential that we apply the building blocks in a way that avoids creating a level of stringency in the performance standards for affected EGUs that goes beyond what we have determined to be the BSER – while at the same time ensuring that equations apply the building blocks to generate performance standards that represent the full application of the BSER to the affected EGUs.

Under section 111, the EPA adopts emission performance standards that are based on the BSER. The emission performance rates reflect our recognition of the value of giving sources the flexibility to adopt equivalent emissions reduction strategies and measures that for them may be preferable (in a specific circumstance) to the technologies and measures that we define as the BSER. An important function of the emission performance rates representing the BSER is to provide the flexibility needed to allow alternative compliance options, including the development of new technologies or the deployment of effective technologies outside of the BSER technologies. In the guidelines we issued under section 111(d) for landfill gas, for example, we adopted the primary standard based on flaring of any captured landfill gas, but we also developed equations that led to an expression of the BSER that allowed for the alternative of capturing the gas and combusting it in an electrical generating unit.

Finally, in deriving the emission performance rates, there are a number of considerations we took into account. First, it is important that the baseline from which the rates are derived be transparent and based on observable, historical data. Second, the emission performance rates must reflect the emission reductions achievable through the best system of emission reduction. Because the BSER includes shifting of emissions from higher-emitting to lower-emitting sources, state compliance frameworks will likely involve a combination of physical measures at the plant (where either rate or generation may be reduced) and some form of credit for lower-emitting generation (or demand side measures) outside of the plant. In this context, the emission performance rates must provide appropriate incentives for affected entities to achieve the emission reductions encompassed in the BSER, including through state plans that provide crediting for lower-emitting generation. Third, and as set forth below, we must account for the EPA’s determination that pro rata implementation of building block 3 is the best reflection of the potential for RE to displace both fossil steam and NGCC, and the dual role of NGCC units as both affected sources and a BSER compliance technology.

This set of considerations was central to the development of the BSER equations that the EPA describes next. They were particularly important for steps five through seven below which address building blocks 2 and 3, building blocks that have both significant overlap with each other and which impact steam and NGCC units in an integrated way.

Step-by-Step Discussion of Equations

Step one (compilation of baseline data). On a unit-level basis, the EPA obtained total annual quantities of CO_2 emissions, net generation (MWh), and capacity (MW) from reported 2012 data for likely affected EGUs that had commenced operation prior to 2012.[746] The EPA made changes to the historical unit-level data

[746] EGUs whose capacity or fossil fuel combustion were insufficient to qualify them as likely affected EGUs were not included in the subcategory-specific rate and goal computations. Most simple cycle combustion turbines (CTs) were excluded on this basis at proposal, and all simple cycle CTs were excluded at final reflecting changes to the applicability language. IGCC's were designated as "other" generation at proposal, but they are grouped with coal units for purposes the final rule category-specific rates. Useful thermal output (UTO) was also translated to a MWh equivalent and included in state goals at proposal, resulting in more stringent rates for states with more cogeneration sources, but UTO is not included in this final rule emission performance rate or state goal calculations as a result of comments regarding potentially adverse impacts on cogeneration units and uncertainty of thermal load outputs. As described in the state plan section of the preamble, units may still quantify and convert UTO (i.e., taking credit for waste

based on comments received at proposal. For each state and region, the agency aggregated the 2012 operating data for all coal-fired steam EGUs as one group, all oil- and gas-fired steam EGUs as a second group, and all NGCC units as a third group. The EPA adjusted these state values upwards in a limited number of instances to reflect the hydropower and unit outage concerns raised in comments and described above. As discussed above, the EPA first only aggregated the reported data for units that commenced operation prior to 2012. For those likely affected units that commenced operation during 2012, the EPA treated that capacity consistent with its framework for under construction affected units, which were added next. This was done in response to comments recognizing the fact that the year during which a unit commences operation may not have been representative of its potential generation and emissions.

For the under construction units (i.e., those under construction prior to January 8, 2014 but which had not commenced operation by December 31, 2011), the EPA estimated their incremental impact on the baseline generation and emissions using their capacity. The EPA assumed a 55 percent capacity factor for under construction NGCC units and a 60

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heat capture) when demonstrating compliance. See the applicability criteria described in Section IV.D above.

percent capacity factor for under construction fossil steam units, which are consistent with the values and methodology the EPA proposed for under construction units.[747] These values are informed by the 2012 capacity factors for other units in these technology classes that recently commenced operation.[748] Using these capacity factors along with the capacity for the units, the EPA estimated an annual baseline generation value for these units. The agency then estimated annual baseline CO_2 emissions for these under construction units using the average emission rate of generating units of the same technology in the state where the under construction unit is located. Where no generators of the same technology existed in a given state, the

[747] The EPA notes that we did not identify any under construction coal units at proposal, but we are using a methodology in this final rule for newly categorized under construction coal units similar to our under construction assessment of NGCC at proposal.

[748] The EPA received comment on the assumed 55 percent capacity factor for under construction NGCC EGUs. Some comments suggested the value was too large of an estimation for incremental generation as some of that 55 percent utilization would have a replacement impact on 2012 operating generation. Others suggested it should be larger as a particular planned under construction unit was anticipated to have a higher utilization rate. The EPA reviewed operating patterns of EGUs that came online, and determined a 55 percent and 60 percent capacity factor assumption for under construction NGCC and coal EGUs respectively are a reasonable estimate for informing the incremental emissions and generation from under construction units. It recognizes that some of these units may indeed operate at a higher utilization level, but also recognizes that some of the generation may have a replacement effect instead of an incremental one.

EPA used the national baseline average for that technology. This is similar to the adjustment made at proposal for under construction units, with the main difference being units that commenced operation in 2012 are now also treated as under construction for baseline data purposes in the final rule.

The estimated emissions and generation for under construction units were added to the 2012 reported emissions and generation data for the affected units that had already commenced operation prior to 2012 to derive an adjusted historical baseline total for each state that was reflective of all likely affected 111(d) sources.[749]

Step two (aggregation to the regional level). The EPA took comment on applying building blocks at the regional level, and received significant comment supporting such an approach. Therefore, whereas the proposal aggregated the baseline data to the state level, the final rule further aggregated it to the regional level prior to building block application. The regions reflect the Eastern, Western, and Texas Interconnections. The shift to a regional framework was based on comments suggesting that the EPA would better capture the interstate impacts of the

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[749] The EPA received some comments suggesting that under construction units should not be included in the quantification of BSER and/or rate calculations, and other comments supporting their inclusion. The EPA determined that including it was consistent with our responsibility under the 111(d) statute to define a Best System of Emission Reduction for existing units.

building blocks and reflect the interconnected nature of the electric grid under a regional structure. The basis for the regions is defined and discussed in Section V.A.3.

Step three (identification of source category baseline emission rates). As discussed in the beginning of this section, the EPA took a technology-specific approach to quantifying guidelines. Therefore, whereas the proposal first averaged the fossil steam rate and NGCC rate together before applying the building blocks and defining state goals, the final rule applied the building blocks at the regional level to give a separate fossil steam rate and NGCC rate for each region. The starting point for calculating the subcategory-specific emission performance rates was the baseline regional emission rates for both fossil steam and NGCC in the year 2012 with the modifications discussed above.

Step four (application of building block 1). The baseline CO_2 emissions amount for the coal-fired steam EGU fleet in each region was reduced by 2.1, 2.3, and 4.3 percent in the Western, Texas, and Eastern Interconnections respectively, while the coal generation level was held constant, reflecting the EPA's assessment of the average opportunities in each region to reduce CO_2 emission rates across the existing fleet of coal-fired steam EGUs through heat rate improvements that are technically achievable at a reasonable cost. The EPA then averaged together the region's baseline oil- and natural gas-fired steam rate with its building block 1 adjusted coal steam rate to get a fossil steam rate post-building block 1.[750,751]

Step five (application of building block 3). At proposal, the EPA incorporated incremental RE MWhs (where incremental means the amount above the adjusted 2012 baseline) by adding them to the denominator of the emission rate goal. In response to comments on this approach, the EPA issued a NODA discussing an alternative methodology of incorporating building block 3 in a manner more analogous to building block 2 treatment, where the incremental MWhs identified for the building block replace baseline fossil MWhs on a one-to-one basis. The EPA is adopting this replacement methodology for building block 3 in the final rule consistent with comments noting that such a computational procedure better reflects the reduction potential of that building block.

Under this methodology, all of building block 2 incremental NGCC potential and part of building block 3 incremental RE potential were ultimately applied to replace higher-emitting

[750] Building block 1 analysis acknowledges some variation in heat rate improvement potential at different units. The implementation of this building block reflects a heat rate improvement on average across a region's coal fleet, not necessarily a heat rate improvement at every unit.
[751] Baseline OG steam emissions are added to adjusted coal emissions and divided by baseline OG steam generation and baseline coal generation.

fossil steam generation and emissions, while the remaining building block 3 potential was applied to replace NGCC generation and emissions. Commenters noted that under this approach building block 3 should be applied first, or the EPA would understate the potential of building block 2 by subtracting out some NGCC generation after the 75 percent utilization level of NGCC had been applied to replace fossil steam. The EPA agrees and calculated the building block 3 impacts first in developing the emission performance rates.

To implement this, first, building block 3 replacement potential was identified for each region to arrive at a total amount of incremental zero-emitting generation hours available to replace fossil generation in the region. Because renewable generation can replace both fossil steam and NGCC on the grid, the EPA determined that it was appropriate to apply these incremental zero-emitting generation hours to replace generation and associated emissions from each of the fossil steam and NGCC fleets in the region on a pro-rata basis in the following manner.[752] The EPA determined the percent of fossil steam

[752] The EPA took comment on a pro-rata or an intensity-based replacement approach. In this final rule, the EPA agrees with commenters that a pro-rata approach is a better reflection of the BSER. Incremental RE generation has, and is likely to continue, to replace both steam and gas turbine generation and the BSER captures this through a pro-rata distribution of identified building block 3 potential.

generation and the percent of NGCC generation of total affected fossil generation in each region's baseline. We then assigned those percentages of the incremental zero-emitting MWhs to each of those technology source categories.[753] The incremental zero-emitting generation assigned to each technology replaced the same amount of fossil generation from that technology's baseline value.

Step six (application of building block 2). If the remaining generation level for the NGCC fleet in a region, taking into account the previous step's replacement of NGCC generation, was less than 75 percent of the fleet's potential summertime generating capacity (the potential capacity factor the EPA determined to represent the BSER), then the NGCC generation in the region was assumed to increase to levels equal to the lesser of 1) its potential at a 75 percent capacity factor[754] or 2) a generation level above which there is no longer fossil steam generation remaining within the same region to replace. In other words, the regional NGCC capacity factor was

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[753] For example, if 100 MWh of incremental zero emitting generation is available in a given region and that region had 70 percent of its affected fossil generation coming from fossil steam units in the baseline and 30 percent from NGCC units – then 70 MWhs of the incremental zero-emitting generation are applied to baseline fossil steam generation and 30 MWhs are applied to baseline NGCC generation.

[754] In early years, will be less than 75 percent due to building block 2 gradual deployment.

only assumed to reach 75 percent if there was sufficient higher-emitting fossil steam generation that it could replace after step five. The increase in NGCC generation at this step compared to the post-building block 3 level was matched by an equal decrease in fossil steam generation reflecting the 1 for 1 MWh hour replacement. At this point, the generation for both steam and NGCC reflect the final distribution of generation between the subcategories after application of the building blocks. But the emission performance rates must account for CO_2 emissions and generation from incremental gas and renewable generation that comprise building blocks 2 and 3, to reflect and enable the emission reductions achievable under the best system of emission reduction, and ensure that the shared implementation of the BSER by steam and NGCC generation is reflected in the rates.

Step seven (accounting for and facilitating the emission reductions achievable through the implementation of the best system of emission reduction).

This step quantifies the aggregate emission changes associated with the emission rate improvement and generation replacement patterns described in steps four, five, and six to arrive at an adjusted fossil steam emission rate and an adjusted NGCC emission rate for each region that will, as discussed above, (1) enable the implementation of all three building blocks, (2) be based on observable, concrete baselines, and (3) reflect the BSER.

First, in developing the emission performance rates, the EPA had to answer the question of how to reflect the building blocks in the equations defining the rates in a manner that would enable the generation shifts that are essential components of the BSER. In the case of building block 3, the EPA accomplished this by incorporating the pro rata share of incremental (above baseline) zero emitting generation into the emission rates for each group of affected EGUs, thus ensuring that these EGUs would have to include a corresponding amount of zero-emitting generation in their compliance calculations, either through the acquisition of credits or through some other mechanism as determined by their state in its implementation plan.

For building block 2, a similar mechanism is needed. Accordingly, a portion of the NGCC generation and emissions used to replace fossil steam must be averaged into the steam rate, analogous to what was done with building block 3. The EPA considered two approaches to define the quantity of NGCC generation and emissions to be averaged into the steam rate: (1) incremental NGCC generation after the implementation of building block 3 and (2) incremental NGCC generation from baseline levels. For the reasons below, the EPA has determined that the second approach better reflects the considerations discussed above.

As discussed above, it is beneficial that the baseline from which emission performance rates are derived be transparent and based on observable historical data. The first approach, however, depends on the level of incremental NGCC generation relative to what is available after the implementation of building block 3. This level of NGCC generation (obtained after replacing baseline levels of generation with NGCC's pro rata share of incremental RE generation) only exists as an intermediate step in the BSER calculation. It is not based on an observable or concrete level of generation.

In Section VIII we discuss methods for creating ERCs for implementing shifting of generation from steam to NGCC, and this discussion illustrates the value of relying on an observable and concrete baseline. In that section we suggest that incentivizing and facilitating the purchase of ERCs as a compliance option for steam units could be implemented through the use of a factor that creates a fraction of an allowable credit for each hour that an NGCC operates. This factor is derived from the incremental generation of NGCC post-building block 2, relative to the baseline. While a different factor could be derived from the hypothetical intermediate level resulting from the pro rata application of zero emitting generation to NGCC in building block 3 (by transferring the full amount of NGCC emissions and generation replacing steam generation in building block 2), the EPA believes that grounding baselines in historical data (such as those used to derive the 2012 baseline) is both more transparent and easier to understand in a way that is more useful to states and utilities, in contrast to the practical challenges of relying on a calculated level that corresponds to an interim step within the emission performance rate calculation. As long as the crediting framework for creating ERCs is consistent with the amount of gas emissions and generation that is transferred to the coal rate, either the chosen option or the option of transferring the entire quantity of gas emissions and generation that occurred in step six to the coal rate would provide an incentive for the power market to implement the shift in generation from coal to gas.[755]

Also as discussed above, it is important that the compliance equations reflect the BSER pro rata allocation of RE to fossil steam and NGCC generation. The first approach to

[755] The EPA recognizes that real world market dynamics will necessarily differ from the BSER assumptions, and has designed the emission guidelines to provide flexibility beyond the emission reduction opportunities identified in the BSER. The essential criteria, however, are that the emission rates and crediting framework are consistent with the BSER and provide the incentives needed to facilitate the emission reduction measures reflected in the BSER and together produce an achievable compliance framework for sources.

define the quantity of NGCC generation and emission to be averaged into the steam rate would require the steam rate to take into account the total additional NGCC generation that results from the application of building block 3 before building block 2 has been applied. This approach would reflect in the compliance rate for steam units a greater share of the implementation of building block 3. Ensuring that emission performance rates for both steam and gas units reflect the emission reduction potential of building block 3 is integral to the building block 3 methodology and also recognizes that application of building block 3 on a pro-rata basis was intended to achieve emission reductions from both NGCC and fossil steam commensurate with their emissions reduction opportunities.

If the EPA were to use the increment of NGCC emissions and generation derived at the intermediary step after the application of building block 3, rather than the increment relative to the 2012 baseline, the effect would be to largely assign to fossil steam the building block 3 generation shift apportioned to NGCC. That, in turn, would have undermined the fact that building block 3 was determined to be a BSER measure applicable to the entire source category, comprising NGCC as well as fossil steam, and would have conflicted with the preceding steps we are taking to develop the equations. Instead, by using only the incremental NGCC generation relative to the baseline, the EPA has ensured that the logic behind the pro rata displacement of fossil generation by RE generation is reflected in the emission rates. Having established the appropriate way to measure the amount of incremental gas generation placed in the fossil steam rate, the EPA is able to calculate the subcategory-specific emission performance rates. For the numerator of the fossil steam rate, the EPA multiplied the remaining fossil steam generation (post-step six) by the fossil steam rate reflecting the heat rate improvement from building block 1 (step four). We then added in the emissions associated with the incremental NGCC generation from step six by multiplying the incremental NGCC generation as discussed above (difference between the baseline NGCC generation level and post-step six NGCC generation) by the baseline NGCC rate for that region.[756] This constitutes the numerator of the fossil steam emission rate.

For the fossil steam denominator, the EPA added the remaining fossil steam generation (post-step six), the incremental NGCC generation defined above, and the amount of zero emitting building block 3 MWhs apportioned to fossil steam generation in the region (step five). Dividing the fossil steam

[756] See CO_2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule for an illustration of this step. The EPA defined the "incremental NGCC generation" in this step in a manner consistent with its measurement and use described in section VIII of this preamble.

numerator described above by this fossil steam denominator resulted in a regional adjusted fossil steam rate reflecting the three building blocks.

For the NGCC performance rate, the EPA calculated a numerator in a similar manner. First, we took the remaining NGCC generation (post step six) and multiplied it by the regional baseline NGCC rate to calculate the total emissions in the numerator. For the denominator, the EPA added the remaining NGCC generation (post step six) to the amount of zero-emitting building block 3 generation assigned to that technology in step five. Dividing the emissions by this total generation value (inclusive of the RE generation apportioned to NGCC) provided a regional adjusted NGCC rate.[757]

Step eight (determining the nationwide subcategory-specific emission performance rate).

[757] See CO_2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule for an illustration of this step. We note that the entire NGCC generation level (inclusive of the amount assigned to the fossil steam rate) expected post building block application is included in the NGCC rate calculation. Including the entire NGCC generation in the NGCC rate recognizes the simultaneous compliance responsibility of affected NGCC units while the fossil steam rate recognizes its mitigation potential through incorporation of the incremental NGCC generation component. Failing to do so would result in a NGCC rate lower than that expected after full implementation of the building blocks and create a compliance inconsistency when reporting all generation.

Following step seven, we evaluated the resulting adjusted fossil steam rates and NGCC rates for each region and identified the highest (least stringent) emission rate among the three regions for each technology category. This becomes the nationwide emission performance rate for that technology class. This ensures that the same rates are applied to facilities in each region and that these rates are achievable by facilities in all three regions.

Finally, the EPA repeated steps four through eight for each year 2022-2030.[758] The resulting annual rates vary because the amount of building block 2 and 3 potential in each year varies. The rates for years 2022-2029 were averaged together to calculate an interim rate, and the 2030 value becomes the final emission performance rate for that year forward.

It bears emphasis that the procedure described above was used only to determine emission performance rates, and the particular data inputs used in the procedure are not intended to represent specific requirements that would apply to any individual EGU or to the collection of EGUs in any state. The

[758] At proposal, the EPA repeated this step over a 10 year period. The building blocks and corresponding BSER emission rates increased for ten consecutive years (2020-2029) in the EPA's rate calculation. In this final rule, the EPA has maintained the same 2030 compliance period for final rates but adjusted the start date to 2022 based on comments. Therefore, the deployment of building blocks is spread over a nine year period (2022-2030) instead of the proposed 10 year period.

specific requirements applicable to individual EGUs, to the EGUs in a given state collectively, or to other affected entities in the state, would be based on the emission standards established through that state's plan. The details of how states could demonstrate compliance with the emission performance rates or statewide goals through different state plan approaches that recognize emission reductions achieved through all the building blocks are discussed further in section VIII on state plans.

Finally, the procedures and assumptions in the equation to calculate emission performance rates are not intended to reflect a compliance scenario in a future year, but rather reflect a representative year in which the building blocks are applied. The power sector fleet will continue to turn over, and in some cases has already experienced turnover beyond the baseline period. However, while the system's fleet may change, the EPA believes this turnover will only further promote the feasibility of the emission performance rates. Fleet turnover has trended towards, and is expected to continue to trend towards, lower-emitting generation sources that will make reductions more readily available.

VII. State-Specific CO_2 Goals

A. Overview

In section VI of this preamble, the EPA provides the methodology for computing subcategory-specific CO_2 emission performance rates, based on the BSER. The subcategory-specific CO_2 emission performance rates are the quantitative expression of the BSER as determined by the EPA. In this section, we provide state rate-based goals and mass-based goals that can be used in the alternative, by states, as an equivalent quantitative expression of the BSER in establishing standards of performance for affected EGUs in state plans. In this section, the EPA also describes reasons for providing state-specific rate-based goals and mass-based goals equivalent to the emission performance rates, supported by the many requests from commenters for the provision of these alternative expressions of the BSER established by the EPA. We further ensure this equivalence, and therefore reflection of the BSER, by requiring that rate-based state goals and mass-based state goals fully implement the BSER, including by ensuring that affected EGUs operating under mass-based emission standards are not incented by dint of the mass-emissions constraint to shift generation to unaffected fossil fuel-fired sources to an extent that deviates from, or negates, the implementation of the BSER.

The EPA is reconstituting the emission performance rates discussed in section VI into statewide CO_2 emission performance goals for each state for the purpose of facilitating states' development of state plans encompassing maximum flexibilities in implementing the BSER. This state-specific goal is not a compliance requirement, but rather an alternative yet equivalent expression of the BSER that the state may choose to use to establish emission standards for its affected EGUs. The state goal is the equivalent of the technology-specific CO_2 emission performance rates and represents the equivalent of the state's applying the emission performance rates directly to its affected EGUs in the form of standards of performance. As discussed further in section VIII on state plans, the states are charged with setting emission standards for the affected EGUs in their respective jurisdictions such that the affected EGUs operating under those standards together satisfy the requirements of the final emission guidelines and statute by meeting the emission performance rates or equivalent statewide emission performance goals, and thereby meet emission standards that reflect the BSER.

In the June 2014 proposal, the EPA proposed a set of state-specific emission rate-based CO_2 goals (in lbs of CO_2 per MWh of electricity generated). In addition, the EPA proposed emission rate-based CO_2 goals for areas of Indian country and U.S. territories with affected EGUs in a supplemental proposal on November 4, 2014. To provide flexibility to states, territories, tribes and implementing authorities, the proposals authorized each implementing authority to translate the form of the goal to a mass-based form (i.e., goals expressed in terms of total tons of CO_2 per year from affected EGUs), as long as the translated goal was equivalent to the rate-based goal. Upon issuance of the proposed rule, the EPA continued the extensive outreach effort to stakeholders and members of the public that the EPA had engaged in for many months preceding the proposal. We also issued a notice of data availability (79 FR 67406, November 13, 2014) and technical support document (Docket ID: EPA-HQ-OAR-2013-0602-22187) to further clarify potential methods for the translation to a mass-based equivalent. The outreach provided additional opportunities for all jurisdictions with affected EGUs – both individually and in regional groups – as well as numerous industry groups and non-governmental organizations, to meet with the EPA and ask clarifying questions about, and give initial reactions to, the proposed components, requirements and timing of the rulemaking. As a result of the outreach and notice of data availability, the EPA received informed substantive comments for the EPA to consider for the final rule.

Numerous commenters encouraged and supported the EPA's efforts to allow states the maximum possible degree of flexibility in developing plans for their affected EGUs, either as a mass-based or rate-based CO_2 goal. States and other stakeholders supported the option to translate rate-based goals to mass-based goals for state plans and requested a simple and transparent method for determining mass-based statewide CO_2 goals that are equivalent to statewide rate-based CO_2 goals and thus reflective of the BSER. We received substantial comments on the potential methodologies for the translation of rate-based goals to mass-based goals. Several commenters requested that the EPA provide the translation to a statewide mass-based goals directly while others requested flexibility to translate to mass using a variety of methodologies and tools. In the context of these comments, the EPA has considered the appropriateness of rate-based and mass-based goals as an expression of BSER and their equivalence to the quantitative expression of BSER through the two CO_2 emission performance rates.

Based on the comments received, the EPA is providing a straightforward translation methodology from the CO_2 emission performance rates to yield statewide rate-based and mass-based CO_2 emission performance goals described in this section. The EPA is providing state mass-based goals in this final rule in place of having states determine the mass themselves. The mass-based goals are the result of a mathematical derivation that provides goals that are an equivalent expression of the BSER. Section VIII below discusses mechanisms for states to plan for and demonstrate achievement of the statewide CO_2 emission performance goals.

CAA section 111(d) requires states to submit a plan that establishes standards of performance for affected EGUs that implement the BSER. States meet the statutory requirements of CAA section 111(d) and the requirements of the final emission guidelines by submitting emission standards for affected EGUs that meet the performance rates, which reflect the application of the BSER as determined by the EPA. Therefore, as a first step for states that choose to submit plans that meet the rate-based or mass-based goals, the goals must be determined to have equivalence as an application of the BSER. For the rate-based and mass-based state goals provided here, this equivalence is evident in the mathematical derivation of the goals, as is described in sections VII.B and VII.C below.

Further (as described in section VIII.J), the state plan must demonstrate that it has measures in place to ensure that any alternative to the performance rates (i.e., rate-based or mass-based state goals that it uses to establish standards of performance) does not result in affected EGUs' failing to implement either the BSER measure themselves or alternative methods of compliance with emission standards that achieve equivalent reductions in emissions or carbon intensity. The EPA has identified one way in which affected EGUs could fail to meet, at a minimum, of the emission performance levels that would result from implementing the BSER, which state plans must do.

Specifically, the EPA has determined that the three building blocks are the BSER, including shifting generation from an affected EGU to a lower-emitting affected EGU or to a non-emitting EGU and that states are required to establish standards of performance that require affected EGUs to achieve, at a minimum, the emission performance levels that reflect the BSER (recognizing that affected sources may choose from a range of equivalent actions (e.g., undertaking the measures included in the building blocks, shifting generation to low-emitting or zero-emitting resources not included in the building blocks or achieving demand-side EE or transmission efficiency – either through operational undertakings, direct investment or emissions trading). Substantial shifting of generation from affected EGUs to new fossil fuel-fired EGUs, such as new NGCC units, represents a deviation from implementing the BSER or its compliance equivalent.

Since the two subcategory-specific emission performance rates represent the BSER, states that established standards of performance at or below those rates, by definition, would be implementing state plans that created no risk that affected EGUs would shift generation to new fossil-fired EGUs to an extent that would deviate from the BSER. Similarly, the EPA has determined that states using rate-based goals as the foundation for plans implementing the BSER are unlikely to foster generation shifts to new fossil fuel-fired sources to an extent that would deviate from the BSER. In contrast, however, EPA analysis has identified a concern that a mass-based state plan that failed to include appropriate measures to address leakage could result in failure to achieve emission performance levels consistent with the BSER.[759] Section VII.B. describes how the form of the rate-based state goals minimizes the risk of generation shifts to new fossil fuel-fired sources, or "leakage," by providing affected EGUs with a sufficient incentive to run, similar to the performance rates. Section VII.D. discusses how there is a potential for leakage under mass-based state goals because affected EGUs are incented to operate in a manner – in particular, by shifting generation to new NGCC units (as opposed to shifting generation as contemplated by the BSER or undertaking equivalent alternative compliance actions) –that would result in negating the equivalence with the emission performance rates and thus the BSER, and specifies that requirements are needed in mass-based implementation to assure those incentives are realigned.[760]

B. Reconstituting Statewide Rate-based CO_2 Emission Performance Goals from the Subcategory-Specific Emission Performance Rates

[759] See Chapter 3 of the Regulatory Impact Analysis for more information on this analysis, which is available in the docket.
[760] The specific mass-based plan requirements are explained in detail in section VIII.J.

In order to provide states flexibility for planning purposes, the EPA is providing a state-specific averaging of the subcategory-specific emission performance rates to determine a statewide goal. While the emission performance rates reflect the quantification of performance based on the BSER and embody the reductions estimated under building blocks 1, 2, and 3, the state goals reflect an equivalent approach through which states may choose to adopt and implement those subcategory-specific performance rates.

The EPA quantified the potential reductions of the BSER in the subcategory-specific emission performance rates established in section VI. These rates themselves reflect the reduction potential expected in emission rates under the BSER for each year from 2022 to 2030. To establish state goals, the EPA applied these rates to the baseline generation levels to estimate the affected fleet emission rate that would occur if all affected EGUs in the fleet met the subcategory-specific rates. This step respects the flexibility of sources to meet the rates in any manner that they see fit (e.g., on-site abatement technology, fuel switching, co-firing, credit purchase, etc.), and does not limit them to their building block assumptions. For example, the EPA derived the statewide rate-based CO_2 emission performance goals for 2030 by multiplying the fossil steam emission performance rate for 2030 by the baseline fossil steam generation in a state and multiplying the NGCC emission performance rate for 2030 by the baseline NGCC generation in a state. The resulting emissions for fossil steam and NGCC are then added together for each state. This emission total is divided by that state's baseline generation values from the likely affected EGUs in order to develop a state's rate-based CO_2 emission performance goal for 2030. This blended rate reflects the collective emission rate a state may expect to achieve when its baseline fleet of likely affected EGUs continues to operate at baseline levels while meeting its subcategory-specific emission performance rates reflecting the BSER. The EPA believes that using the adjusted 2012 baseline is the most appropriate way to combine the rates. First, as explained in Section VI, the EPA believes there are significant advantages to using real world data to set a baseline rather than using projected data. The adjusted 2012 data is the logical starting point because it is the data that all of the emission performance rates (discussed in Section VI) are based upon. Furthermore, it is clear that generation shifts as projected under the BSER are not the appropriate baseline. The emission performance rates already factor in the BSER assumptions about changes in generation (e.g., implementation of building block 2 significantly lowers the emission performance rate for fossil-steam units). If, on top of that, changes in generation were factored into the calculation of a combined rate, those changes in generation would be factored into the combined rate twice (once when calculating the individual emission performance rates and a second time, when incorporating those rates into a combined state rate).

This step is repeated for each year from 2022-2029 using the emission performance rates calculated for each of those years in the previous section. The EPA also repeats this step for the interim state goal using the interim subcategory rates. The EPA then averages together the annual amounts in increments of 3 years, 3 years, and 2 years for 2022-2024, 2025-2027, and 2028-2029 to estimate emission rate averages for those periods that can provide one illustrative pathway for states to consider in meeting their interim goals. These 3- and 2-year increment are not regulatory guidelines or equivalents for interim goals, but rather benchmarks for demonstrating plan performance as discussed in Section VIII.F illustrative of a potential gradual reduction compliance strategy that states may use to reach their interim and final stategoals.

As described in the steps above, the statewide goals represent an equivalent arithmetic combination of the subcategory-specific emission performance rates, weighted by the historical baseline generation levels upon which the BSER is premised. In particular, as discussed above, the method for deriving these goals assures equivalent flexibility by applying the CO_2 emission performance rates to the baseline levels, which respects the flexibility of affected EGUs to meet the rates in whatever way they wish. This corresponding treatment of affected EGUs based on the adjusted 2012 baseline ensures sufficient incentive to affected existing EGUs to generate and thus avoid leakage, similar to the CO_2 emission performance rates (this is further discussed in section VII.D below). Consequently, the statewide goals are equivalent to the CO_2 emission performance rates and are thus an equivalent expression of the BSER. The rate-based statewide goals are provided below in Table 12.

C. Quantifying Mass-based CO_2 Emission Performance Goals from the Statewide Rate-based CO_2 Emission Performance Goals

The EPA is also establishing mass-based statewide CO_2 emission performance goals for each state, which are provided below in Table 12. For state plans choosing to meet a mass-based goal, such a goal must be equivalent to the CO_2 emission performance rates in their application of the BSER, as required by the statute and the final emission guidelines. In the following discussion we describe the mathematical calculations that provide an equivalent expression of the BSER. In evaluating the equivalence of the form of mass goals, the EPA must also recognize the impact that the form of the standard has on the relative incentives that the implementation of these goals provides to affected and unaffected EGUs. This section specifies how we have established a quantitative basis for mass goals that is equivalent to CO_2 emission performance rates. The next section (section VII.D) specifies how we require state plans to ensure equivalence to the CO_2 emission performance rates through certain requirements that realign the potential difference in incentives provided to affected and unaffected EGUs to generate under a mass-based implementation compared to a rate-based implementation that could result in leakage.

The starting place for quantifying mass-based statewide CO_2 emission performance goals is the emission amounts directly represented in the numerator of the statewide rate-based CO_2 emission performance goals. Each state-specific emission amount is the product of the fossil steam emission performance rate and historical fossil steam generation, added to the product of the NGCC emission performance rate and historical NGCC generation. The resulting emission amounts for each state represent the emissions associated with rate-based compliance at historical generation levels.

However, under a rate-based state plan, all affected EGUs have the opportunity to increase utilization, provided that sufficient emission reduction measures are available to maintain the necessary ratio of emissions to generation as quantified by the subcategory-specific emission performance rates. Due to the nature of the emission performance rate methodology, which selects the highest of the three interconnection-based values for each source category as the CO_2 emission performance rate, there are cost-effective lower-emitting generation opportunities quantified under the building blocks that are not necessary for affected EGUs in the Western and Texas interconnections to demonstrate compliance at historical generation levels. The EPA recognizes that these lower-emitting generation opportunities are available to affected EGUs at a national level as a means to increase their own output (and, as a result, their own emissions) while maintaining the relevant emission performance rate. To afford affected EGUs subject to a mass-based goal similar compliance flexibility as EGUs subject to a rate-based goal, the EPA has quantified the emissions associated with the potential realization of these lower-emitting generation opportunities and incorporated those additional tons into each state's mass-based goal.[761] Because the derivation of these mass-based goals respects the arithmetic of the subcategory-specific emission performance rates and the flexibility of affected EGUs to achieve those rates while utilizing up to the full potential quantified in the building blocks, the derivation of these mass-

[761] For more detail on this methodology, please refer to the CO_2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule, which is available in the docket.

based state goals offers an equivalent expression of BSER in mass form.

The mass goals for existing sources are presented in Table 13. Although their derivation is equivalent to the subcategory-specific emission performance rates, in order to maintain this equivalence in the establishment of emission standards in state plans mass goals must be implemented in combination with requirements that align the incentives provided to affected and unaffected EGUs, specifically in order to prevent leakage.

D. Addressing Potential Leakage in Determining the Equivalence of State-Specific CO_2 Emission Performance Goals

As described in section VI, the subcategory-specific emission performance rates reflect the BSER as determined by the EPA. This final rule allows states to establish emission standards that meet either rate-based or mass-based state goals. As stated above, rate-based state goals were published in the proposed rule, and commenters not only supported having the flexibility to use rate-based goals or mass-based goals as part of state plans, but also requested that the EPA include mass-based goals in this final rule. But to ensure the equivalence of mass-based state goals, we must consider how the form of the goal affects its implementation and how the incentives it provides to affected EGUs on the interstate grid affect whether or not the BSER is fully implemented.

Because of the integrated nature of the utility power sector, the form of the emission performance requirements for existing sources may ultimately impact the relative incentives to generate and emit at affected EGUs as opposed to shifting generation to new sources, with potential implications for whether a given set of standards of performance is, at a minimum, consistent with the BSER, in the context of overall emissions from the sector. In this context, we, again, define as “leakage” the potential of an alternative form of implementation of the BSER (e.g., the rate-based and mass-based state goals) to create a larger incentive for affected EGUs to shift generation to new fossil fuel-fired EGUs relative to what would occur when the implementation of the BSER took the form of standards of performance incorporating the subcategory-specific emission performance rates representing the BSER. In the proposal, the EPA recognized that the statutory construction regarding the BSER is to reduce emissions, which can be achieved through shifts of generation. Movement of generation between and among sources is needed to produce overall reductions, particularly movement from higher-emitting affected EGUs to lower-emitting affected EGUs, and from all affected EGUs to zero-emitting RE. In all of these cases, the fossil sources involved in these generation shifts are subject to obligations under this final rule.[762]

However, leakage, where shifts in generation to unaffected fossil fuel-fired sources result in increased emissions, relative to what would have happened had generation shifts consistent with the BSER occurred, is contrary to this construction. Therefore, if the form of the standard does not address leakage or incents the kinds of generation shifts that we identify as leakage, the states must otherwise address leakage in order to ensure that the standards of performance applied to the affected EGUs are, in the aggregate, at least equivalent with the emission performance rates, and therefore appropriately reflect the BSER as required by the statute. Commenters noted that shifting generation and emissions from existing sources to new sources undermined the intent of this rule and the overall emission reduction goals, and that requiring states to address leakage is consistent with the the

[762] The final rule includes state plan conditions to prevent perverse incentives that could otherwise result in greater overall emissions when generation shifts across affected EGUs. For example, states that wish to engage in rate-based trading through an emission standards plan type must adopt plans designed to achieve either a common rate-based state goal or the subcategory-specific emission performance rates (see section VIII.L). Such a state plan condition avoids encouraging generation to shift from a state with a relatively lower state goal to a state with a relatively higher state goal solely as a response to the form of CPP implementation.

obligation that states establish standards of performance that, in the aggregate, at a minimum, reflect the BSER for affected EGUs operating in the interconnected electricity sector.

This section specifically addresses the need for state plans designed to achieve either rate- or mass-based state goals to ensure that their plans succeed in implementing standards of performance that reflect the BSER by minimizing the difference in incentives provided to affected EGUs and new sources to generate in order to maintain equivalent emission performance with the CO_2 emission performance rates.

Rate-based goals do not in our view implicate leakage to an extent that would negate or limit the implementation of the BSER because under a rate-based state goal, similar to the subcategory-specific emission performance rates, existing lower-emitting affected EGUs, primarily NGCC units, are incentivized to increase their utilization in order to improve the average emission rates of affected EGUs overall. New units that are not subject to the rate-based state goal, and that are not an allowable measure for adjusting an EGU's CO_2 emission rate, will not have this incentive to increase utilization, and as a result, the imposition of a rate-based goal on affected EGUs is unlikely to encourage increased generation and emissions from unaffected new EGUs. The form of the rate-based state goals provides an equivalent or greater incentive to affected existing

EGUs as they are provided in the CO_2 emission performance rates, and similarly avoid the potential for leakage. Under both approaches, existing NGCC units can generate ERCs. These ERCs provide an economic incentive to utilize existing NGCC units rather than new NGCC units. Further, ERCs from incremental RE incentivize new renewable generation over new NGCC generation. Both of these features, which exist in the context of implementation with a state rate-based goal or CO_2 emission performance rates, provide significant incentives to ensure that, consistent with the BSER, shifting of generation does not occur between existing fossil fuel-fired units and new NGCC units.

Mass-based goals for existing sources, however, incur a leakage risk to the extent that they incent generation shifts from affected EGUs to unaffected fossil fuel-fired sources in a way that negates the reliance on the BSER. In contrast to various forms of rate-based implementation, mass-based implementation in a state plan can unintentionally incentivize increased generation from unaffected new EGUs as a substitute action for reducing emissions at units subject to the existing source mass goal in ways that would negate the implementation of the BSER and would result in increased emissions. This occurs because, unlike in a rate-based system where rate-based averaging lowers the cost of generation from existing NGCC units relative to generation from new NGCC units, in a mass-based system the allowance price increases the cost of generation from existing NGCC units relative to generation from new NGCC units. The extent to which electricity providers opt to rely on this increase in unaffected new source utilization as a substitute for improving the emissions performance across existing sources would be fundamentally inconsistent with relying on the BSER to reduce emissions as the basis of the subcategory-specific emission performance rates.

As a result, notwithstanding the fact that mass goals for existing sources are quantified in a way that is an equivalent expression of the BSER, the form of mass goals is only equivalent if leakage is satisfactorily addressed in the state plan's establishment of emission standards and implementation measures. The EPA is therefore requiring that states adopting a mass-based state plan include requirements that address leakage, or otherwise provide additional justification that leakage would not occur under the state's implementation of mass-based emission standards. This requirement enables states to establish standards of performance that meet a mass-based goal equivalent to the performance rates and therefore reflect the BSER, as required by section 111(d). The required demonstration and options for state plans to minimize leakage are discussed in detail in section VIII.J of this preamble.

Further supporting the need for this requirement, the EPA has evaluated the mass goals in concert with some of the options to minimize leakage described in that section. As mentioned above, the EPA analysis identified a concern regarding leakage in a mass-based approach, namely that the mass-based implementation without measures to address leakage produced higher generation from new NGCC units and lower emission performance when compared to a rate-based implementation. Further analysis where implementation of the mass-based goals was coupled with measures to address leakage produce utility power sector emissions performance that is similar to emissions performance under the rate goals.[763]

E. State Plan Adjustments of State Goals

The EPA notes that it is the emission performance rates in section VI that constitute the application of the BSER to the affected EGUs and serve as the chief regulatory requirement of this rulemaking. The statewide CO_2 rate-based and mass-based emission performance goals provided here are metrics that states may choose to adopt when demonstrating compliance at the state level, and states may consider these goals when determining how to set unit-level compliance requirements. The EPA believes that the regional nature of determining the emission performance

[763] See Chapter 3 of the Regulatory Impact Analysis for more information on this analysis, which is available in the docket.

rates encompasses a large population size and makes it robust against unit-level variation and unit-level inventory discrepancies. The EPA does acknowledge that state-level rate-based goals or mass-based goals may be sensitive to applicability changes within a state's affected population. In the proposal, the EPA used a baseline that aggregated data for what it believed to be affected units and asked states, companies and other stakeholders to provide corrections in their comments. We received input from many commenters and have corrected information as appropriate. Therefore, we believe the baseline to be accurate. However, if subsequent applicability review or formal applicability determinations change the status of units in regards to being affected or unaffected by this rulemaking, states can, via state plan submittal or revision, adjust their statewide rate or mass goal to reflect this change of status.

This adjustment flexibility provision is based on comments received at proposal. For example, some stakeholders noted that the affected status of particular units was unclear. The EPA recognizes that all the necessary data to determine the affected status of some units may not be available at this time. As stated above, the EPA does not believe unit-level variation or inclusion/exclusion disparities between baseline inventory and affected units will impact the regionally determined emission performance rates discussed in the previous section. However, variations in baseline data or inventory may have an impact on the *state-level* rate-based or mass-based goals provided in this section. Therefore, the EPA is allowing the flexibility for states to demonstrate the need for this type of adjustment under the justifications above and utilize an adjusted value for compliance purposes when submitting or revising its state plan. The EPA will evaluate the appropriateness of such an adjusted value based on the state's demonstration and evaluate the approvability of a plan or plan revision accordingly.

Rate-based statewide CO_2 emission performance goals are listed below in Table 12. Mass-based statewide CO_2 emission performance goals are found in Table 13.

Table 12. Statewide[764] Rate-Based CO_2 Emission Performance Goals (Adjusted Output-Weighted-Average Pounds of CO_2 Per Net MWh From All Affected Fossil Fuel-Fired EGUs)

State Name	Interim Goal - Step 1	Interim Goal - Step 2	Interim Goal - Step 3	Interim Goal	Final Goal
Alabama	1,244	1,133	1,060	1,157	1,018
Arizona*	1,263	1,149	1,074	1,173	1,031
Arkansas	1,411	1,276	1,185	1,304	1,130
California	961	890	848	907	828
Colorado	1,476	1,332	1,233	1,362	1,174
Connecticut	899	836	801	852	786
Delaware	1,093	1,003	946	1,023	916
Florida	1,097	1,006	949	1,026	919

[764] The EPA has not developed statewide rate-based or mass-based CO_2 emission performance goals for Vermont and the District of Columbia because current information indicates those jurisdictions have no affected EGUs.

Georgia	1,290	1,173	1,094	1,198	1,049
Idaho	877	817	784	832	771
Illinois	1,582	1,423	1,313	1,456	1,245
Indiana	1,578	1,419	1,309	1,451	1,242
Iowa	1,638	1,472	1,355	1,505	1,283
Kansas	1,654	1,485	1,366	1,519	1,293
Kentucky	1,643	1,476	1,358	1,509	1,286
Lands of the Fort Mojave Tribe	877	817	784	832	771
Lands of the Navajo Nation	1,671	1,500	1,380	1,534	1,305
Lands of the Uintah and Ouray Reservation	1,671	1,500	1,380	1,534	1,305
Louisiana	1,398	1,265	1,175	1,293	1,121
Maine	888	827	793	842	779
Maryland	1,644	1,476	1,359	1,510	1,287
Massachusetts	956	885	844	902	824
Michigan	1,468	1,325	1,228	1,355	1,169
Minnesota	1,535	1,383	1,277	1,414	1,213
Mississippi	1,136	1,040	978	1,061	945
Missouri	1,621	1,457	1,342	1,490	1,272
Montana	1,671	1,500	1,380	1,534	1,305
Nebraska	1,658	1,488	1,369	1,522	1,296
Nevada	1,001	924	877	942	855
New Hampshire	1,006	929	881	947	858
New Jersey	937	869	829	885	812
New Mexico*	1,435	1,297	1,203	1,325	1,146
New York	1,095	1,005	948	1,025	918
North Carolina	1,419	1,283	1,191	1,311	1,136
North Dakota	1,671	1,500	1,380	1,534	1,305
Ohio	1,501	1,353	1,252	1,383	1,190
Oklahoma	1,319	1,197	1,116	1,223	1,068
Oregon	1,026	945	896	964	871
Pennsylvania	1,359	1,232	1,146	1,258	1,095
Rhode Island	877	817	784	832	771
South Carolina	1,449	1,309	1,213	1,338	1,156
South Dakota	1,465	1,323	1,225	1,352	1,167
Tennessee	1,531	1,380	1,275	1,411	1,211
Texas	1,279	1,163	1,086	1,188	1,042
Utah*	1,483	1,339	1,239	1,368	1,179
Virginia	1,120	1,026	966	1,047	934

Washington	1,192	1,088	1,021	1,111	983
West Virginia	1,671	1,500	1,380	1,534	1,305
Wisconsin	1,479	1,335	1,236	1,364	1,176
Wyoming	1,662	1,492	1,373	1,526	1,299

* Excludes EGUs located in Indian country within the state.

Table 13. Statewide Mass-Based CO_2 Emission Performance Goals (Adjusted Output-Weighted-Average Tons of CO_2 from All Affected Fossil Fuel-Fired EGUs)

State	Interim Goal - Step 1	Interim Goal - Step 2	Interim Goal - Step 3	Interim Goal	Final Goal
Alabama	66,164,470	60,918,973	58,215,989	62,210,288	56,880,474
Arizona*	35,189,232	32,371,942	30,906,226	33,061,997	30,170,750
Arkansas	36,032,671	32,953,521	31,253,744	33,683,258	30,322,632
California	53,500,107	50,080,840	48,736,877	51,027,075	48,410,120
Colorado	35,785,322	32,654,483	30,891,824	33,387,883	29,900,397
Connecticut	7,555,787	7,108,466	6,955,080	7,237,865	6,941,523
Delaware	5,348,363	4,963,102	4,784,280	5,062,869	4,711,825
Florida	119,380,477	110,754,683	106,736,177	112,984,729	105,094,704
Georgia	54,257,931	49,855,082	47,534,817	50,926,084	46,346,846
Idaho	1,615,518	1,522,826	1,493,052	1,550,142	1,492,856
Illinois	80,396,108	73,124,936	68,921,937	74,800,876	66,477,157
Indiana	92,010,787	83,700,336	78,901,574	85,617,065	76,113,835
Iowa	30,408,352	27,615,429	25,981,975	28,254,411	25,018,136
Kansas	26,763,719	24,295,773	22,848,095	24,859,333	21,990,826
Kentucky	76,757,356	69,698,851	65,566,898	71,312,802	63,126,121
Lands of the Fort Mojave Tribe	636,876	600,334	588,596	611,103	588,519
Lands of the Navajo Nation	26,449,393	23,999,556	22,557,749	24,557,793	21,700,587
Lands of the Ute Tribe of the Uintah and Ouray Reservation	2,758,744	2,503,220	2,352,835	2,561,445	2,263,431
Louisiana	42,035,202	38,461,163	36,496,707	39,310,314	35,427,023
Maine	2,251,173	2,119,865	2,076,179	2,158,184	2,073,942
Maryland	17,447,354	15,842,485	14,902,826	16,209,396	14,347,628
Massachusetts	13,360,735	12,511,985	12,181,628	12,747,677	12,104,747
Michigan	56,854,256	51,893,556	49,106,884	53,057,150	47,544,064
Minnesota	27,303,150	24,868,570	23,476,788	25,433,592	22,678,368
Mississippi	28,940,675	26,790,683	25,756,215	27,338,313	25,304,337
Missouri	67,312,915	61,158,279	57,570,942	62,569,433	55,462,884

Montana	13,776,601	12,500,563	11,749,574	12,791,330	11,303,107
Nebraska	22,246,365	20,192,820	18,987,285	20,661,516	18,272,739
Nevada	15,076,534	14,072,636	13,652,612	14,344,092	13,523,584
New Hampshire	4,461,569	4,162,981	4,037,142	4,243,492	3,997,579
New Jersey	18,241,502	17,107,548	16,681,949	17,426,381	16,599,745
New Mexico*	14,789,981	13,514,670	12,805,266	13,815,561	12,412,602
New York	35,493,488	32,932,763	31,741,940	33,595,329	31,257,429
North Carolina	60,975,831	55,749,239	52,856,495	56,986,025	51,266,234
North Dakota	25,453,173	23,095,610	21,708,108	23,632,821	20,883,232
Ohio	88,512,313	80,704,944	76,280,168	82,526,513	73,769,806
Oklahoma	47,577,611	43,665,021	41,577,379	44,610,332	40,488,199
Oregon	9,097,720	8,477,658	8,209,589	8,643,164	8,118,654
Pennsylvania	106,082,757	97,204,723	92,392,088	99,330,827	89,822,308
Rhode Island	3,811,632	3,592,937	3,522,686	3,657,385	3,522,225
South Carolina	31,025,518	28,336,836	26,834,962	28,969,623	25,998,968
South Dakota	4,231,184	3,862,401	3,655,422	3,948,950	3,539,481
Tennessee	34,118,301	31,079,178	29,343,221	31,784,860	28,348,396
Texas	221,613,296	203,728,060	194,351,330	208,090,841	189,588,842
Utah*	28,479,805	25,981,970	24,572,858	26,566,380	23,778,193
Virginia	31,290,209	28,990,999	27,898,475	29,580,072	27,433,111
Washington	12,395,697	11,441,137	10,963,576	11,679,707	10,739,172
West Virginia	62,557,024	56,762,771	53,352,666	58,083,089	51,325,342
Wisconsin	33,505,657	30,571,326	28,917,949	31,258,356	27,986,988
Wyoming	38,528,498	34,967,826	32,875,725	35,780,052	31,634,412

* Excludes EGUs located in Indian country within the state.

F. Geographically Isolated States and Territories with Affected EGUs

Alaska, Hawaii, Guam, and Puerto Rico constitute a small set of states and U.S. territories representing about one percent of total U.S. EGU GHG emissions. Based on the current record, the EPA does not possess all of the information or the analytic tools needed to quantify the application of the BSER for these states and territories, particularly data regarding RE costs and performance characteristics needed for building block

3 of the BSER. The NREL data for RE that the EPA is relying upon for building block 3 does not cover the non-contiguous states and territories.

The EPA acknowledges that NREL has collaborated with the state of Hawaii to provide technical expertise in support of the state's aggressive goals for clean energy, including analyses of the grid integration and transmission of solar and wind resources.[765] The EPA also recognizes that there are studies and data for some renewable resources in some of the other non-contiguous jurisdictions. However, taken as a whole, the data we currently possess do not allow us to quantify the emissions reductions available from building block 3 using the same methodology used for the contiguous states encompassed by the three interconnections. Lastly, the IPM model used to support the EPA's analysis is geographically limited to the contiguous U.S. As a result of these factors, the EPA currently lacks the necessary analytic resources to set emission performance goals for these areas.

Because of the lack of suitable data and analytic tools needed to develop area-appropriate building block targets as defined in section V, the EPA is not setting CO_2 emission performance goals for Alaska, Hawaii, Guam, or Puerto Rico in

[765] Hawaii Solar Integration Study, NREL Technical Report NREL/TP-5500-57215, June 2013.

this final rule at this time. The EPA believes it is within its authority to address performance goals only for the contiguous U.S. states in this final rule. Under section 111(d), the EPA is not required, at the time that the EPA promulgates section 111(b) requirements for new sources, to promulgate emission guidelines for all of the sources that, if they were new sources, would be subject to the section 111(b) requirements if there is a reasonable basis for deferring certain groups of sources. As discussed, in this rule, the EPA has a reasonable basis for deferring setting goals for these four jurisdictions. In addition, the Courts have recognized the authority of agencies to develop regulatory programs in step-by-step fashion. As the U.S. Supreme Court noted in Massachusetts v. EPA, 549 U.S. 497, 524 (2007): "Agencies, like legislatures, do not generally resolve massive problems in one fell regulatory swoop;" and instead they may permissibly implement such regulatory programs over time, "refining their preferred approach as circumstances change and as they develop a more nuanced understanding of how best to proceed."[766]

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[766] *See, e.g., Grand Canyon Air Tour Coalition v. F.A.A.*, 154 F.3d 455, 471 (D.C. Cir. 1998) (ordinarily, agencies have wide latitude to attack a regulatory problem in phases and that a phased attack often has substantial benefits); *National Association of Broadcasters v. FCC,* 740 F.2d 1190, 121-11 (D.C. Cir. 1984) ("We have therefore recognized the reasonableness of [an agency's] decision to engage in incremental rulemaking and to defer resolution of issues raised in a rulemaking....").

The EPA recognizes, however, that EGUs in Alaska, Hawaii, Puerto Rico, and Guam emit CO_2 and that there are opportunities to reduce the carbon intensity of generation in those areas over time. We recognize further that there are efforts underway to increase the use of RE in these jurisdictions. In particular, we recognize that Hawaii has tremendous opportunities for RE and has adopted very ambitious goals: 40 percent clean energy by 2030 and 100 percent by 2045. Since 2008, Alaska has apportioned in excess of $1.34 billion pursuing its aspirational goal of 50 percent of the state's total yearly electric load from renewable and alternative energy sources by 2025. Puerto Rico's goal is to achieve 20 percent RE sales by 2035, and the territory is working hard to meet the requirements of the Mercury and Air Toxics Standards, which will reduce emissions from its power plants substantially. Guam's RPS is to achieve 25 percent REsales by 2035.

The agency intends to continue to consider these issues and determine what the appropriate BSER is for these areas. As part of that effort, the agency will investigate sources of information and types of analysis appropriate to devise the appropriate levels for building block 3 and BSER performance levels. Because we recognize that these areas face some of the most urgent climate change challenges, severe public health problems from air pollution and some of the highest electricity rates in the U.S., the EPA is committed to obtaining the right information to quantify the emission reductions that are achievable in these four areas and putting goals in place soon.

VIII. State Plans

A. Overview

After the EPA establishes the emission guidelines that set forth the BSER, each state with one or more affected EGUs[767] shall then develop, adopt and submit a state plan under CAA section 111(d) that establishes standards of performance for the affected EGUs in its jurisdiction in order to implement the BSER. Starting from the foundation of CAA section 111(d) and the EPA's implementing regulations (40 CFR part 60 subpart B), the EPA's proposal laid out a number of options, variations and flexibilities that were intended to provide states and affected EGUs the ability to design state plans that accorded with states' specific situations and policies (now and in the future), and to ensure reliability and affordability of electricity across the system and for all ratepayers. The

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[767] As stated previously, states with one or more affected EGUs will be required to develop and implement plans that set emission standards for affected EGUs. The CAA section 111(d) emission guidelines that the EPA is promulgating in this action apply to only the 48 contiguous states and any Indian tribe that has been approved by the EPA pursuant to 40 CFR 49.9 as eligible to develop and implement a CAA section 111(d) plan. Because Vermont and the District of Columbia do not have affected EGUs, they will not be required to submit a state plan.

proposal has prompted numerous discussions between and among stakeholders, especially states and groups of states, including state environmental and energy regulators and policy officials. The EPA has received many comments from a wide range of stakeholders seeking a final rule that afforded freedom and flexibility to consider a wide range of standards of performance to implement the BSER, but also providing significant feedback on the elements and options in the proposal and constructive suggestions for alternative approaches. The EPA has carefully considered all of this input, and is finalizing emission guidelines that continue to provide a variety of options for states to fashion their plans in ways legally supportable by the CAA, while also making certain adjustments to address key comments.

The next few paragraphs present an overview of the main features of the final emission guidelines, highlighting key changes from proposal. In the rest of this section, we describe in detail the various elements of the final emission guidelines' requirements for state plans.

The proposal contained rate-based goals for each state, reflecting a blended reduction target for that state's fossil fired EGUs, and provided that states could either meet that rate-based goal or convert it to a mass-based equivalent goal. Reflecting the final BSER described in section V and in response to many comments desirous that the EPA establish mass-based goals in the final rule, these final guidelines include three approaches that states may adopt for purposes of implementing the BSER, any one of which a state may use in its plan. These are: 1) establishing standards of performance that apply the subcategory specific CO_2 emission performance rates to their affected EGUs, 2) adopting a combination of standards and/or other measures that achieve state-specific rate-based goals that represent the weighted aggregate of the CO_2 emission performance rates applied to the affected EGUs in each state, and 3) adopting a program to meet mass-based CO_2 emission goals that represent the equivalent of the rate-based goal for each state. These alternatives, as well as the other options we are finalizing, ensure that both states and affected EGUs enjoy the maximum flexibility and latitude in meeting the requirements of the emission guidelines and that the BSER is fully implemented by each state.

In the proposal, we provided two designs for state plans: one where all the reduction obligations are placed directly on the affected EGUs and one, which we called the "portfolio approach," that could include measures to be implemented, in whole or in part, by parties other than the affected EGUs. In the final guidelines, we retain that basic choice, but with some modifications to respond to comments we received, especially on the portfolio approach. In their plans, states will be able to choose either to impose federally enforceable emission standards that fully meet the emission guidelines directly on affected EGUs (the “emission standards” approach) or to use a “state measures" approach, which would be composed, at least in part, of measures implemented by the state that are not included as federally enforceable components of the plan but result in the affected EGUs meeting the requirements of the emission guidelines. A state measures type plan must include a backstop of federally enforceable standards on affected EGUs that fully meet the emission guidelines and that would be triggered if the state measures fail to result in the affected EGUs achieving on schedule the required emission reductions.

States that choose an emission standards plan may establish as standards of performance for their affected EGUs the subcategory specific CO_2 emission performance rates, which express the BSER.[768] This would satisfy the requirement described in section VIII.D.2.a.3 that a state demonstrate its plan would achieve the CO_2 emission performance rates; in this case, no further demonstration would be necessary. Alternatively, a state may establish emission standards for affected EGUs at different levels from the uniform subcategory-specific emission

[768] Rate-based and mass-based emission standards may incorporate the use of emission trading.

performance rates, provided that when implemented, the emission standards achieve the CO_2 emission performance rates or state rate- or mass-based CO_2 emission goal set forth by the EPA for the state. States that adopt differential standards of performance among their affected EGUs must demonstrate that, in the aggregate, the differential standards of performance will result in their affected EGUs meeting the CO_2 emission performance rates, the state's rate-based CO_2 emission goal or its mass-based CO_2 emission goal.

In the proposal, we proposed that states could use the portfolio approach to meet either a rate- or mass-based goal. In these final emission guidelines, the state measures approach is available only for a state choosing a mass-based CO_2 emission goal, to provide certainty that the state measures are achieving the required emission reductions. Similar to emission standards plans with differential standards of performance, states that adopt state measures plans must demonstrate that the state measures, alone or in conjunction with any federally enforceable emission standards on affected EGUs also included in the state plan, will result in the affected EGUs in the state meeting the state's mass-based CO_2 emission goal. A "state measures" type plan must also include a backstop provision – triggered if, during the interim period, the state plan fails to achieve the emission reduction trajectory identified in the plan or if, during the final phase, the state plan fails to meet the final state mass-based CO_2 emission goal – that would impose federally enforceable emission standards on the affected EGUs adequate to meet the emission guidelines when fully implemented.

The final guidelines reflect the changes to the timing of the reductions within the interim period, which is laid out in section V as part of the determination of the BSER. States may adopt in their plans emission reduction trajectories different from the illustrative three-step trajectory included in these guidelines for purposes of creating a "glide path" between 2022 and 2029, provided that the interim and final CO_2 emission performance rates or state CO_2 emission goals are met.

We recognize that while we are establishing 2022 as the date by which the period for mandatory reductions must start as part of our BSER determination, utilities and other parties are moving forward with projects that reduce emissions of CO_2 from affected EGUs. We received numerous comments urging us to allow credit for these early actions. The final guidelines encourage those early reductions, by making clear that states may, in their plans, allow EGUs to use allowances or ERCs generated through the CEIP. The final guidelines also require that states include in their final plans a schedule of the actions they will be taking to ensure that the period for mandatory reductions will begin as required starting in 2022, and submit a progress report on those actions.

For all types of plans, the final guidelines make clear that states may adopt programs that allow trading among affected EGUs. The final guidelines retain the flexibility for states to do individual plans, or to join with other states in a multi-state plan. In addition, and in response to comments from many states and other stakeholders, the guidelines provide that states may design their programs so that they are "ready for interstate trading," that is, that they contain features necessary and suitable for their affected EGUs to engage in trading with affected EGUs in other "trading ready" states without the need for formal arrangements between individual states.

We have been mindful of the concerns raised by stakeholders about reliability. The final BSER, especially the changes in the timing of the interim period, substantially address these concerns. The flexibilities provided for the design of state plans, including the ability to use trading programs, further enhance system reliability. We have included, as an additional assurance, a reliability safety valve for use where the built-in flexibilities are not sufficient to address an immediate, unexpected reliability situation.

The EPA believes that all the flexibilities provided in the final rule are not only appropriate, but will enhance the success of the program. CO_2 is a global pollutant, and where and when the reductions occur is not as significant to the environmental outcome as compared to many other conventional pollutants. The flexibilities provided in the final guidelines will better reflect the unique interconnectedness of the electricity system, and will allow states and EGUs to reduce CO_2 emissions while maintaining reliability and affordability for all consumers.

In developing the plan, the state rulemaking process must meet the minimum public participation requirements of the implementing regulations as applicable to these guidelines, including a public hearing and meaningful engagement with all members of the public, including vulnerable communities. In the community and environmental justice considerations section, section IX of this preamble, the EPA addresses the actions that the agency is taking to help ensure that vulnerable communities are not disproportionately impacted by this rule. These actions include conducting a proximity analysis, setting expectations for states to engage meaningfully with vulnerable communities and requiring that they describe their plans for doing so as they develop their state plans, providing communities with access to additional resources, providing communities with information on federal programs and resources available to them, recommending that states take a multi-pollutant planning approach that examines the potential impacts of co-pollutants on overburdened communities, and conducting an assessment to determine if any localized air quality impacts need to be further addressed. Additionally, the EPA outlines the continued engagement that it will be conducting with states and communities throughout the state plan development process.

As discussed in more detail in section VIII.E, commenters, particularly states, provided compelling information establishing that for some, and perhaps many, states it will take longer than the agency initially anticipated to develop and submit their required plans. In response to those comments, we are finalizing a plan submittal process that provides additional time for states that need it to submit a final plan submittal to the EPA after September 6, 2016. Within the time period specified in the emission guidelines (from as early as September 6, 2016, to as late as September 6, 2018, depending on whether the state receives an extension), the state must submit its final state plan to the EPA. The EPA then must determine whether to approve or disapprove the plan. If a state does not submit a plan, or if the EPA disapproves a state's plan, then the EPA has the express authority under CAA section 111(d) to establish a federal plan for the state.[769] During and following implementation of its approved state plan, each state must demonstrate to the EPA that its affected EGUs are meeting the interim and final performance requirements included in this final rule through monitoring and reporting requirements.

This section is organized as follows. First, we discuss the timeline for state plan performance and provisions to encourage early action. Second, we describe the types of plans that states can submit. Third, we summarize the components of an approvable state plan submittal. Fourth, we address the process and timing for submittal of state plans and plan revisions. Fifth, we address plan implementation and achievement of CO_2 emission performance rates or state CO_2 emission goals for affected EGUs, and the consequences if they are not met. Sixth, we discuss general considerations for states in developing and implementing plans, including consideration of a facility's "remaining useful life" and "other factors" and electric reliability. Seventh, we note certain resources that are available to facilitate state plan development and implementation. Finally, we discuss additional considerations for inclusion of CO_2 emission reduction

[769] A federal plan may be withdrawn if the state submits, and the EPA approves, a state plan that meets the requirements of this final rule and section 111(d) of the CAA. More details regarding the federal plan are addressed in the EPA's proposed federal plan rulemaking.

measures in state plans, including: accounting for emission reduction measures in state plans; requirements for mass-based and rate-based emission trading approaches; EM&V requirements for RE and demand-side EE resources and other measures used to adjust a CO_2 rate; and treatment of interstate effects.

B. Timeline for State Plan Performance and Provisions to Encourage Early Action

This section describes state plan requirements related to the timing of achieving the emission reductions required in the guidelines and the state plan performance periods. This section also describes the CEIP the EPA is establishing to encourage early investment in certain types of RE projects, as well as in demand-side EE projects implemented in low income communities.

1. Timeline for state plan performance

The final guidelines establish three types of performance periods: 1) a final deadline by which and after which affected EGUs must be in compliance with the final reduction requirements, 2) an interim period, and 3) within that interim period, three multi-year interim step periods. As discussed below and in section V, these performance periods are consistent with our determination of the BSER and are also responsive to the key comments we received on this aspect of the state plans.

A performance period is a period for which the final plan submittal must demonstrate that the required CO_2 emission performance rates or state CO_2 emission goal will be met. The final guidelines establish 2030 as the deadline for compliance by affected EGUs with the final CO_2 emission performance rates or CO_2 rate or mass emission goal; 2030 is the beginning of the final performance period. The interim performance period is 2022 to 2029, and there are three interim step periods - 2022-2024, 2025-2027, and 2028-2029 — where increasingly stringent emission performance rates or state emission goals must be met. The state may submit a plan that incorporates alternative interim step emission performance rates or state emission goals to those provided by EPA, as long as on average or cumulatively, as appropriate, they result in the equivalent of the interim emission performance rates or state emission goals in the emission guidelines. These timelines are based on careful consideration of the substantial comments we received on both the timing of the interim period and the trajectory of compliance by affected EGUs over the interim period and our determination of the BSER, discussed in section V above. The modifications we have made to the timelines included in the proposal respond to these comments and to concerns about, among other things, reliability, feasibility, and cost.

As previously discussed, the EPA has determined that the BSER includes implementation of reduction measures over the period of 2022 through 2029, with final compliance by affected

EGUs in 2030. Therefore, the final rule requires that interim CO_2 emission performance rates or state CO_2 emission goals be met for the interim period of 2022-2029. Many commenters expressed a desire that the EPA designate steps during the interim period to create an interim goal that offered states and utilities greater flexibility and choice in determining their own emission reduction trajectories over the course of the interim period. Since our intent at proposal was to provide such flexibility and choice, and since it remains our intent to do so in this final rule, we are addressing these comments by including in the 2022-2029 interim period three interim step periods (2022-2024, 2025-2027, 2028-2029), which correspond roughly to the phasing in of the BSER. We note, however, that the final rule also allows states the flexibility to define an alternate trajectory of emission performance between 2022 and 2029, provided that 1) the state plan specifies its own interim step CO_2 emission performance rates or state CO_2 emission goals, 2) meeting the alternative interim step CO_2 emission performance rates or state CO_2 emission goals will result in the interim emission performance rates or state CO_2 emission goal being met on an 8-year average or cumulative basis, and, 3) the final CO_2 emission performance rates or state CO_2 emission goal is achieved. To be approvable, a state plan submittal must demonstrate that the emission performance of affected EGUs will meet the interim step

CO_2 emission performance rates or interim step state CO_2 emission goals over the 2022-2024, 2025-2027, and 2028-2029 periods and the final CO_2 emission performance rates or state CO_2 emission goal no later than 2030.[770]

This relatively long period – first for planning, then for implementation and achievement of the interim and final CO_2 emission performance rates or state CO_2 emission goals – provides states and utilities with substantial flexibility regarding methods and timing of achieving emission reductions from affected EGUs. The EPA believes that timing flexibility in implementing measures provides significant benefits that allow states to develop plans that will help achieve a number of goals, including, but not limited to: reducing cost, addressing reliability concerns, addressing concerns about stranded assets, and facilitating the integration of meeting the emission guidelines and compliance by affected EGUs with other air quality and pollution control obligations on the part of both states and affected EGUs. Moreover, we note that over the course of time between submittal of final plans and 2030, circumstances

[770] States are free to establish different interim step performance rates or interim step state goals than those the EPA has specified in this final rule. If states choose to determine their own interim step performance rates or state goals, the state must demonstrate that the plan will still meet the interim performance rates or state goal for 2022-2029 finalized in this action.

may change such that states may need or wish to modify their plans. The relatively lengthy performance periods provided in the final rule should help keep those situations to a minimum but will also accommodate them if necessary.[771] The EPA envisions that the agency, states and affected EGUs will have an ongoing relationship in the course of implementing this program. Since the record also indicates a high degree of interest on the part of states and stakeholders in pursuing banking and trading programs, the timing and level of stringency of the interim CO_2 performance rates or state CO_2 emission goals we are finalizing should provide states and affected EGUs with ample capacity to accommodate such changes without necessitating changes in state plans in many instances.

The timelines established in the final rule respond to the issues raised in numerous comments regarding the concept of the interim period, including comments supporting the flexibility afforded states in developing their plans and the timing necessary to meet the 2030 emission requirements. Some commenters supported beginning the interim goal plan period at 2020. Others stated that the investments necessary to meet the proposed interim emission performance goals beginning in 2020 are unachievable in that timeframe or would place too great a

[771] Modifications to state plans are addressed more specifically in section VIII.E.7 below.

burden on affected EGUs, states, and ratepayers. Some suggested that the 2020 interim goal step should be eliminated in favor of later start dates, including 2022, 2025, or other years. Some commenters urged the EPA to establish phased interim steps creating a steady downward trajectory that allowed several years for each step, compatible with the "chunkiness" of utility planning processes. Yet other commenters provided input suggesting that states be allowed to establish their own set of emission performance steps during the interim plan performance period and thereby control their own emission reduction trajectory or "glide path" for achievement of the interim goal and the 2030 goal, or that the EPA not establish any interim standards at all. Commenters also noted that for some states, there was not a significant difference between the interim and final goal, and, therefore, no glide path for those states. As discussed in previous sections, based on this input and our final determination of the BSER, the EPA has adjusted the interim period to include 2022-2029, is establishing three interim performance periods creating a reasonable trajectory from 2022 to 2030, and is also retaining the flexibility for states to establish their own emission reduction trajectory during the interim period.

As noted, the EPA has determined that the period for mandated reductions should begin in 2022, instead of 2020 as we proposed, because of the substantial amount of comment and data we received indicating that states and utilities reasonably needed that additional time to take the steps necessary to start achieving reductions. In order to assure the EPA and the public that states are making progress in implementing the plan between the time of the state plan submittal and the beginning of the interim period, and as discussed in further detail in section VIII.D, the final rule requires that the state plan submittal include a timeline with all the programmatic milestone steps the state will take between the time of the state plan submittal and 2022 to ensure the plan is effective as of 2022.

2. Provisions to encourage early action

Many commenters supported providing incentives for states and utilities to deploy CO_2-reducing investments, such as RE and demand-side EE measures, as early as possible. In the proposal, the EPA requested comment on an approach that would recognize emission reductions that existing programs provide prior to the initial plan performance period starting from a specified date. We also requested comment on options for that specified date and on conditions that should apply to counting those pre-compliance emission reductions toward a state goal. The EPA received many comments requesting that the agency recognize early actions for the emission reductions they provide prior to the performance period, that the EPA allow those pre-compliance impacts to be counted toward meeting requirements under the rule, and that certain conditions should be applied to recognition of early reductions so as to ensure the emission reductions required in the rule. We also received comments from stakeholders regarding the disproportionate burdens that some communities already bear, and stating that all communities should have equal access to the benefits of clean and affordable energy. The EPA recognizes the validity and importance of these perspectives, and as a result has determined to provide a program – called the Clean Energy Incentive Program (CEIP) – in which states may choose to participate. This section describes this program.

The CEIP is designed to incentivize investment in certain RE and demand-side EE projects that commence construction in the case of RE, or commence operation in the case of EE, following the submission of a final state plan to the EPA, or after September 6, 2018, for states that choose not to submit a final state plan by that date, and that generate MWh (RE) or reduce end-use energy demand (EE) during 2020 and/or 2021. State participation in the program is optional; the EPA is establishing this program as an additional flexibility to facilitate achievement of the CO_2 emission reductions required by this final rule, regardless of the type of state plan a state chooses to implement.

Under the CEIP, a state may set aside allowances from the

CO_2 emission budget it establishes for the interim plan performance period or may generate early action ERCs (ERCs are discussed in more detail in section VIII.K.2), and allocate these allowances or ERCs to eligible projects for the MWh those projects generate or the end-use energy savings they achieve in 2020 and/or 2021. A state implementing a mass-based plan approach, as described in section VIII.C, may issue early action allowances; a state implementing a rate-based plan approach, also described in section VIII.C, may issue early action ERCs. For each early action allowance or ERC a state allocates to such projects, the EPA will provide the state with an appropriate number of matching allowances or ERCs, as outlined below, for the state to allocate to the project. The EPA will match state-issued early action ERCs and allowances up to an amount that represents the equivalent of 300 million short tons of CO_2 emissions. The EPA intends that a portion of this pool will be reserved for eligible wind and solar projects, and a portion will be reserved for low-income EE projects. In the proposed federal plan, the EPA is taking comment on the size of each reserve, and is proposing provisions to provide that any unallocated amounts would be redistributed among participating states.

The EPA has determined that the size of this 300 million short ton CO_2-equivalent matching pool is an appropriate reflection of the CO_2 emission reductions that could be achieved by the additional early investment in RE and demand-side EE the agency expects will be incentivized by the CEIP. For example, in 2012, 13 GW of utility scale wind were deployed,[772] and, in 2014, 3.4 GW of utility-scale solar[773] plus 2-3 GW of distributed solar were deployed,[774] according to industry estimates. Assuming 19 GW per year of RE from 2017-2020 based on these historic maximums yields an installed base of 76 GW of RE potentially eligible for CEIP incentives in 2020 and/or 2021. Assuming an average capacity factor of 30 percent, this would translate into approximately 200 TWh/year of generation, which would be eligible for approximately 300 million short tons of matching allowances over the 2-year period, if the RE MWh were converted to allowances based on the 2012 carbon intensity of 0.8 short tons per MWh. This would leave the remaining half of the pool of matching federal allowances available for EE projects implemented in low-income communities, and additional growth in RE deployment beyond these historic maximums as potentially

[772] U.S. Energy Information Administration Electric Power Annual 2013. http://www.eia.gov/electricity/annual. Table 4.6: Capacity additions, retirements and changes by energy source. March 2015.
[773] U.S. Energy Information Administration Electric Power Monthly. http://www.eia.gov/electricity/monthly. Table 6.3: New Utility Scale Generating Units by Operating Company, Plant, Month, and Year.
[774] GTM Research/Solar Energy Industries Association: U.S. Solar Market Insight Q1 2015.

enabled by reductions in cost and improvements in performance.

For a state to be eligible for a matching award of allowances or ERCs from the EPA, it must demonstrate that it will award allowances or ERCs only to eligible projects. These are projects that:

- Are located in or benefit a state that has submitted a final state plan that includes requirements establishing its participation in the CEIP;
- Are implemented following the submission of a final state plan to the EPA, or after September 6, 2018, for a state that chooses not to submit a complete state plan by that date;
- For RE: Generate metered MWh from any type of wind or solar resources;
- For EE: Result in quantified and verified electricity savings (MWh) through demand-side EE implemented in low-income communities; and
- Generate or save MWh in 2020 and/or 2021.

The following provisions outline how a state may award early action ERCs or allowances to eligible projects, and how the EPA will provide matching ERCs or allowances to states.

- For RE projects that generate metered MWh from any type of wind or solar resources: for every two MWh generated, the project will receive one early action ERC (or the equivalent number of allowances) from the state, and the EPA will provide one matching ERC (or the equivalent number of allowances) to the state to award to the project.

- For EE projects implemented in low-income communities: for every two MWh in end-use demand savings achieved, the project will receive two early action ERCs (or the equivalent number of allowances) from the state, and the EPA will provide two matching ERCs (or the equivalent number of allowances) to the state to award to the project.

Early action allowances or ERCs awarded by the state, and matching allowances or ERCs awarded by the EPA pursuant to the CEIP, may be used for compliance by an affected EGU with its emission standards and are fully transferrable prior to such use.

The EPA discusses the CEIP in the proposed federal plan rule, and will address design and implementation details of the CEIP, including the appropriate factor for determining equivalence between allowances and MWh and the definition of a low-income community for project eligibility purposes, in a subsequent action. Before doing so, the EPA will engage states and stakeholders to gather additional information concerning implementation topics, and to solicit information about the concerns, interests and priorities of states, stakeholders and the public.

In order for a state that chooses to participate in the CEIP to be eligible for a future award of allowances or ERCs from the EPA, a state must include in its initial submittal a non-binding statement of intent to participate in the program. In the case of a state submitting a final plan by September 6, 2016, the state plan would either include requirements establishing the necessary infrastructure to implement such a program and authorizing its affected EGUs to use early action allowances or ERCs as appropriate, or would include a non-binding statement of intent as part of its supporting documentation and revise its plan to include those requirements at a later date.

Following approval of a final state plan that includes requirements for implementing the CEIP, the agency will create an account of matching allowances or ERCs for the state that reflects the pro rata share – based on the amount of the reductions from 2012 levels the affected EGUs in the state are required to achieve relative to those in the other participating states – of the 300 million short ton CO_2 emissions-equivalent matching pool that the state is eligible to receive. Thus, states whose EGUs have greater reduction obligations will be eligible to secure a larger proportion of the federal matching pool upon demonstration of quantified and verified MWh of RE generation or demand side-EE savings from eligible projects realized in 2020 and/or 2021.

Any matching allowances or ERCs that remain undistributed after September 6, 2018,[775] will be distributed to those states with approved state plans that include requirements for CEIP participation. These ERCs and allowances will be distributed according to the pro rata method outlined above. Unused matching allowances or ERCs that remain in the accounts of states participating in the CEIP on January 1, 2023, will be retired by the EPA.

For purposes of establishing a state plan program eligible for an award of matching allowances or ERCs from the EPA, such a program must include a mechanism for awarding early action emission allowances or ERCs for eligible actions that reduce or avoid CO_2 emissions in 2020 and/or 2021, and that is implemented in a way such that the early action allowances or ERCs allocated by the state would maintain the stringency of the state's goal for emission performance from affected EGUs in the performance periods established in this rule. Specifically, the state must demonstrate in its plan that it has a mechanism in place that enables issuance of ERCs or allowances from the state to parties effectuating reductions in 2020 and/or 2021 in a manner that

[775] This may occur because not all states may elect to include requirements for CEIP participation in their state plans.

would have no impact on the aggregate emission performance of affected EGUs required to meet rate-based or mass-based CO_2 emission standards during the compliance periods.[776] This demonstration is not required to account for matching ERCs or allowances that may be issued to the state by the EPA. Participation in this program is entirely voluntary, and nothing in these provisions would have the effect of requiring any particular affected EGU to achieve reductions prior to 2022, or requiring states to offer incentives for emission reductions achieved prior to 2022.[777] These and other details will be developed in the subsequent action.

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[776] For example, under a mass-based implementation, the state plan could include a set-aside of early action allowances from an emissions budget that itself reflects the state goals. Allocation of those early action allowances to parties effectuating reductions in 2020 and 2021 would have no impact on the total emissions budget, which sets the total allowable emissions in the compliance periods. Alternatively, under a rate-based implementation, the state plan could require that early action ERCs issued to parties effectuating reductions in 2020 and 2021 would be “borrowed” from a pool of ERCs created by the state during the interim plan performance period. States could limit the size of the “borrowed” pool of ERCs to be equivalent to the size of the federal matching pool, or could take into consideration the potential for each state’s federal matching pool to expand after a redistribution of unused credits. For every early action ERC awarded for actions in 2020 and 2021, the state would retire one ERC from the pool of ERCs created as a result of reductions achieved from 2022 onward.

[777] In addition to the CEIP, states may also offer credit for early investments in RE and demand-side EE according to the provisions of section VIII.K.1 of this final rule: a state may award ERCs to qualified providers that implement projects from 2013 onward that realize quantified and verified MWh results in 2022 and subsequent years.

The EPA is providing the CEIP as an option for states implementing plans – and is including a similar program for the federal plan proposal being issued concurrently – for several reasons. Chief among them is that offered by commenters to the effect that the overall cost of achievement of the emission performance rates or state goals could be reduced by an approach that granted some form of beneficial recognition to emissions reduction investments that both occur and yield reductions prior to the first date on which the program of the interim plan performance period. Other commenters pointed out that to the extent that states and utilities would benefit from the availability of low-cost RE and other zero-emitting generation options during the interim and final plan performance periods, the EPA should include in the final emission guidelines provisions that accelerate deployment of RE resources, since in so doing the final emission guidelines would speed achievement of expected reductions in the cost of those technologies commensurate with their accelerated deployment. In addition, the incentives and market signal generated by the CEIP can help sustain the momentum toward greater RE investment in the period between now and 2022 so as to offset any dampening effects that might be created by setting the start date 2 years later than at proposal.

The specific criteria the EPA is establishing for eligible

RE projects reflect a variety of considerations. First, the EPA seeks to preserve the incentive for project developers to execute on planned investments in all types of solar and wind technologies. Commenters raised concerns that the fast pace of reductions underlying the emission targets in the proposed rule could potentially shift investment from RE to natural gas, thus dampening the incentive to develop wind and solar projects, in particular. Second, the EPA, consistent with the CAA's directive to incentivize technology and to accelerate the decline in the costs of technology, seeks to drive the widespread development and deployment of wind and solar, as these broad categories of renewable technology are essential to longer term climate strategies. Finally, in contrast to other CO_2-reducing technologies – including other zero-emitting or RE technologies – solar and wind projects often require lead times of shorter duration, which would allow them to generate MWh beginning in 2020.

The specific criterion the EPA is establishing for eligible EE projects – namely that these projects be implemented in low-income communities - is also consistent with the technology-forcing and development purposes of section 111. The EPA believes it is appropriate to offer an additional incentive to remove current barriers to implementing demand-side EE programs in low-income communities. While the EPA acknowledges that a number of states have demand-side EE programs focused on these communities,[778] the agency also recognizes that there have been historic economic, logistical, and information barriers to implementing programs in these communities. As a result, the costs of implementing demand-side EE programs in these communities are typically higher than in other communities and stand as barrier to harvesting potentially cost effective reductions and advancing these technologies. The EPA intends for the CEIP to help incentivize increased deployment of projects that will deliver demand-side EE benefits to these communities, which will in turn lower the costs of these approaches. These lower costs will help new technologies and delivery mechanisms penetrate in the future, thus improving the cost of implementation of the emission guidelines overall, consistent with Congress' goals in the New Source Performance Standard provisions of the CAA. Further, reducing barriers to demand-side EE in low-income communities will help ensure that the benefits of the final rule are shared broadly across society and that potential adverse impacts on low-income ratepayers are avoided. It complements other steps the federal government is taking to bring clean energy technologies to these communities, as we

[778] Several of these programs are discussed in section IX of this preamble, including, for example, Maryland's EmPOWER Low Income Energy Efficiency Program (LIEEP) and New York's EmPower New York program.

discuss in section IX of this preamble.

More broadly, the CEIP responds to the urgency of meeting the challenge of climate change in two key ways. First, of course, it fosters reductions before 2022. Second, in targeting investments in wind, solar and low-income EE, it focuses on the kinds of measures and technologies that are the essential foundation of longer-term climate strategies, strategies that inevitably depend on the further development and widespread deployment of highly adaptable zero-emitting technologies.

We are not requiring that projects demonstrate to states that they are "additional" or surplus relative to a business-as-usual or state goal-related baseline in order to be eligible. At the same time, we believe that including an incentive to develop projects that benefit low-income communities will increase the likelihood of investments being made that would not have been made otherwise.

In order to be awarded matching ERCs or allowances by the EPA for projects that meet the eligibility criteria, a final state plan must have requirements establishing the appropriate infrastructure to issue early action ERCs or allowances to eligible project providers by 2020. The state must require that the state or its agent will, in accordance with state plan requirements approved as meeting the ERC issuance and EM&V requirements included in section VIII.K: (1) evaluate project proposals from eligible RE and demand-side EE project providers, including the EM&V plans that must accompany such proposals; (2) evaluate monitoring and verification reports submitted by eligible providers following project implementation, which contain the quantified and verified MWh of RE generation or energy savings achieved by the project in 2020 and/or 2021; (3) issue ERCs or allowances to eligible providers for these MWh results; (4) ensure that no MWh of renewable generation or energy savings receives early action or matching ERCs or allowances more than once.[779]

The CEIP will provide a number of benefits. First, the program will provide incentives designed to reduce energy bills early in the implementation of the guidelines through earlier and broader application of energy saving technologies, and help ensure that these benefits are fully shared by low-income communities. Second, the EPA believes that stimulating or supporting early investment in RE generation technologies could accelerate the rate at which the costs of these technologies

[779] For a state plan incorporating the use of ERCs or allowances to be approvable by the EPA, such a plan must use an EPA-approved or EPA-administered tracking system for ERCs or allowances. The EPA received a number of comments from states and stakeholders about the value of the EPA's support in developing and/or administering tracking systems to support state administration of rate-based emission trading programs. The EPA is exploring options for providing such support and is conducting an initial scoping assessment of tracking system support needs and functionality.

fall over the course of the interim performance period. Third, the CEIP will provide affected EGUs and states with additional emission reduction resources to help them achieve their state plan obligations. Finally, the program will improve the liquidity, in the early years of the program, of the ERC and allowance markets we expect to emerge for compliance with the requirements of these guidelines.[780]

The EPA is establishing this program as an option for states that wish to drive investments in RE and low-income EE that will result in actual, early reductions in CO_2 emissions from affected EGUs. States are also authorized to set their own glide path, or interim step performance rates or goals, so long as the interim and final performance rates or goals are met, and could do so in a way that takes into account the availability of the CEIP to assist affected EGUs in meeting the applicable glide path and performance rates or goals. While the EPA is not requiring states to take advantage of this program, its availability simply enhances these already-existing implementation and compliance flexibilities while at the same

[780] The CEIP is expected to provide states and affected EGUs additional flexibility in meeting the guidelines, and bears similarity in both design and purpose to the Compliance Supplement Pool, which the agency established as a part of the NO_x SIP Call. *See* 63 FR 57356, 57428-30 (Oct. 27, 1998). Certain aspects of the Compliance Supplement Pool were challenged in litigation and upheld by the D.C. Circuit Court of Appeals. *See Michigan v. EPA*, 213 F.3d 663, 694 (D.C. Cir. 2000).

time delivering meaningful benefits, particularly for low-income communities. The EPA looks forward to an upcoming public dialogue about the implementation details of the CEIP.

C. State Plan Approaches

1. Overview

Under the final emission guidelines, states may adopt and submit either of two different types of state plans. The first would apply all requirements for meeting the emission guidelines to affected EGUs in the form of federally enforceable emission standards.[781] We refer to this as an "emission standards" state

[781] 40 CFR 60.21(f) defines "emission standard" as "a legally enforceable regulation setting forth an allowable rate of emissions into the atmosphere, establishing an allowance system, or prescribing equipment specifications for control of air pollution emissions." This definition is promulgated and effective, and we note that it authorizes the use of allowance systems as a form of emission standard. To resolve any doubt that allowance systems are an acceptable form of emission standard in the final rule, we are including regulatory text in the final subpart UUUU regulations authorizing the use of allowance systems as a form of emission standard under section 111(d). Section 60.21(f) was originally amended in 2005 to include recognition of allowance systems as a form of emission standard in the Clean Air Mercury Rule (CAMR) (70 FR 28606, 28649; May 18, 2005). CAMR was vacated in its entirety in *New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008). However, the reason for vacatur was wholly unrelated to the question of whether an allowance system could be a form of emission standard. In response to the *New Jersey* decision, the agency removed CAMR provisions from the Code of Federal Regulations. The agency chose to retain the language of 60.21(f) and 60.24(b)(1) generally recognizing allowance systems. This language is broader than CAMR and unrelated to the reasons for its vacatur. The EPA re-promulgated these provisions in February of 2012 (77 FR 9304, 9447; Feb. 16, 2012). Even if this were not

plan type. The second, which we refer to as a "state measures" plan type, would allow the state mass CO_2 emission goals to be achieved by affected EGUs in part, or entirely, through state measures[782] that apply to affected EGUs, other entities, or some combination thereof. The state measures plan type also includes a mandatory contingent backstop of federally enforceable emission standards for affected EGUs that would apply in the event the plan does not achieve its anticipated level of emission performance as specified in the state plan during the period that the state is relying on state measures. The inclusion of a backstop of federally enforceable emission standards in a state measures plan type is legally necessary for a state plan to meet the terms of 111(d), which specifically require a state to submit standards of performance.

These two types of state plans and their respective approaches, either of which could be implemented on a single-

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the case, the agency would not concede that simply because "allowance systems" were not provided for in the framework regulations of subpart B, they could not be relied upon in specific emission guidelines, such as these for CO_2. The implementing regulations generally serve a gap-filling role where there are not more specific provisions laid out in the relevant emission guidelines. In order to resolve any question whether allowance systems are authorized under the final rule, we are including regulatory text in subpart UUUU to make this authorization explicit.

[782] "State measures" refer to measures that the state adopts and implements as a matter of state law. Such measures are enforceable only per state law, and are not included in and codified as part of the federally enforceable state plan.

state or multi-state basis, allow states to meet the statutory requirements of CAA section 111(d) while accommodating the wide range of regulatory requirements and other programs that states have deployed or will deploy in the electricity sector that reduce CO_2 emissions from affected EGUs. Further, as described in detail below, both types of plans are responsive to comments we received from states and other stakeholders. In addition to providing states the option of developing an emission standards or state measures type plan, the final rule makes clear that states that choose an emission standards plan can adopt either a rate-based or mass-based CO_2 emission goal.

Under these two basic plan types, the final emission guidelines provide states with a number of potential plan pathways for meeting the emission guidelines. A plan pathway represents a specific plan design approach used to meet the emission guidelines. These plan pathways are discussed in section VIII.C.2 through C.5 below, and further elaborated in sections VIII.J (for mass-based emission standards) and VIII.K (for rate-based emission standards).

The final emission guidelines provide four streamlined plan pathways. These streamlined plan pathways represent straightforward plan approaches for meeting the emission guidelines, and avoid the need to meet additional plan requirements and include additional elements in a plan submittal. The streamlined plan pathways include the following:

- Establishing federally enforceable, mass-based CO_2 emission standards for affected EGUs, complemented by state-enforceable mass-based CO_2 emission standards for new fossil fuel-fired EGUs.[783] This approach could involve an emission budget trading program that includes affected EGUs as well as new fossil fuel-fired EGUs. This approach facilitates interstate emission trading, through either a single-state "ready-for-interstate-trading" plan approach or through a multi-state plan. Under a "ready-for-interstate-trading" plan, interstate emission trading may occur without the need for a multi-state plan.[784]
- Establishing federally enforceable, mass-based CO_2 emission standards for affected EGUs.[785] This approach facilitates interstate emission trading, through either a single-state

[783] New source CO_2 emission complements are discussed in section VIII.J.2.b, which also provides EPA-derived new source CO_2 emission complements for states.
[784] Mass-based trading-ready plans are addressed in section VIII.J.3. Multi-state plans, where a group of states are meeting a joint CO_2 goal for affected EGUs, are addressed in section VIII.C.5.
[785] This plan approach would meet a state mass-based CO_2 goal for affected EGUs, or a joint multi-state mass-based CO_2 goal for affected EGUs. These plan approaches are discussed in sections VIII.J.2 and VIII.C.5, respectively.

"ready-for-interstate-trading" plan approach or through a multi-state plan. In a separate concurrent action, the EPA is proposing a model rule for states that could be used in a plan implementing this approach.[786]

- Establishing federally enforceable, subcategory-specific rate-based CO_2 emission standards for affected EGUs, consistent with the CO_2 emission performance rates in the emission guidelines. This approach provides for interstate emission trading, through either a single-state "ready-for-interstate-trading" plan approach or through a multi-state plan.[787] In a separate concurrent action, the EPA is proposing a model rule for states that could be used in a plan implementing this approach.
- Establishing federally enforceable rate-based CO_2 emission standards at a single level that applies for all affected EGUs, consistent with the state rate-based CO_2 goal for affected EGUs in the emission guidelines.[788] This approach provides for interstate emission trading, through a multi-

[786] Submission of a state plan based on the EPA's finalized model rule for a mass-based emission trading program could be considered presumptively approvable. The EPA would evaluate the approvability of such submission through an independent notice and comment rulemaking.
[787] Rate-based trading-ready plans are addressed in section VIII.K.4.
[788] This plan approach is addressed in section VIII.C.2.a.

state plan that meets a single weighted average multi-state rate-based CO_2 goal.[789]

The final emission guidelines also provide for a range of additional custom plan approaches that a state may pursue, if it chooses, to address specific circumstances or policy objectives in a state. The custom plan pathways, while viable options for meeting the emission guidelines, come with additional plan requirements and plan submittal elements. These additional plan requirements and plan submittal elements are necessary to ensure that the emission guidelines are met and that the necessary level of CO_2 emission performance is achieved by affected EGUs.

Based on this overall approach, the final emission guidelines provide for a range of state options – both easily implementable approaches that can be used to meet the emission guidelines, and more customizable approaches that can be used, if a state chooses, to address special circumstances or state policy objectives.

2. “Emission standards” state plan type

The emission standards type of state plan imposes requirements solely on affected EGUs in the form of federally enforceable emission standards. This type of state plan, as described below, may consist of rate-based emission standards

[789] This multi-state plan approach is addressed in section VIII.C.5.

for affected EGUs or mass-based emission standards for affected EGUs.

The state plan submittal for an emission standards type plan must demonstrate that these federally enforceable emission standards for affected EGUs will achieve the CO_2 emission performance rates or the applicable state rate-based or mass-based CO_2 emission goal for affected EGUs.

Both rate-based and mass-based emission standards included in a state plan must be quantifiable, verifiable, enforceable, non-duplicative and permanent. These requirements are described in more detail at section VIII.D.2.

Rate-based and mass-based emission standards may incorporate the use of emission trading, as described below. The EPA anticipates the use of emission trading in state plans, given the advantages of this approach and comments suggesting a high degree of interest on the part of states, utilities, and independent power producers in the inclusion of emission trading in state plans.[790]

The EPA notes it is proposing model rules for both mass-based and rate-based emission trading programs. States could adopt and submit the finalized model rules for either emission trading program to meet the requirements of CAA section 111(d)

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[790] The legal basis for authorizing trading in emission standards is discussed in section VIII.C.6.

and these emission guidelines. The EPA will evaluate the approvability of such submission, as with any state plan submission, through independent notice-and-comment rulemaking. The EPA notes that state plan submittals that adopt the finalized model rule may be administratively and technically more straightforward for the EPA in evaluating approvability, as the EPA will have determined that the model rule meets the applicable requirements of the emission guidelines through the process of finalization of such rule.

a. Rate-based approach. The first type of "emission standards" plan approach a state may choose is one that uses rate-based emission standards. Under this plan approach, the plan would include federally enforceable emission standards for affected EGUs, in the form of lb CO_2/MWh emission standards.

A rate-based "emission standards" plan may be designed to either meet the CO_2 emission performance rates for affected EGUs or achieve the state's rate-based CO_2 emission goal for affected EGUs. A plan could be designed such that compliance by affected EGUs would assure achievement of either the CO_2 emission performance rates for affected EGUs or the state rate-based CO_2 emission goal. To meet the CO_2 emission performance rates for affected EGUs, a plan would establish separate rate-based emission standards for affected fossil fuel-fired electric utility steam generating units and stationary combustion turbines (in lb CO_2/MWh) that are equal to or lower than the CO_2 emission performance rates in the emission guidelines. To meet a state rate-based CO_2 goal, a plan would establish a uniform rate-based emission standard (in lb CO_2/MWh) that applies to all affected EGUs in the state. This uniform emission rate would be equal to or lower than the applicable state rate-based CO_2 goal specified in the final emission guidelines.

Under these two approaches, compliance by affected EGUs with the rate-based emission standards in a plan would ensure that affected EGUs meet the CO_2 emission performance rates in the emission guidelines or the state rate-based CO_2 goal for affected EGUs. No further demonstration would be necessary by the state to demonstrate that its plan would achieve the CO_2 emission performance rates or the state's rate-based CO_2 goal.

Alternatively, if a state chooses, it could apply rate-based emission standards to individual affected EGUs, or to categories of affected EGUs, at a lb CO_2/MWh rate that differs from the CO_2 emission performance rates or the state's rate-based CO_2 goal. In this case, compliance by affected EGUs with their emission standards would not necessarily ensure that the collective, weighted average CO_2 emission rate for these affected EGUs meets the CO_2 emission performance rates or the state's rate-based CO_2 goal.[791]

Under this type of approach, therefore, the state would be required to include a demonstration,[792] in the state plan submittal, that its plan would achieve the CO_2 emission performance rates or applicable state rate-based CO_2 goal. This demonstration would include a projection of the collective, weighted average CO_2 emission rate the fleet of affected EGUs would achieve as a result of compliance with the emission standards in the plan. Once the plan is implemented, if the CO_2 emission performance rates or applicable state rate-based CO_2 goal are not achieved, corrective measures would need to be implemented, as described in section VIII.F.3.

Under a rate-based approach, a state may include in its plan a number of provisions to facilitate affected EGU compliance with the emission standards. First, a state may encourage (or require) EGUs to undertake actions to reduce CO_2

[791] The weighted average CO_2 emission rate that will be achieved by the fleet of affected EGUs in a state that applies different rate-based emission standards to individual affected EGUs or groups of affected EGUs will depend upon the mix of electric generation from affected EGUs subject to different emission standards. For example, if a state applies higher emission standards for affected steam generating units and lower emission standards for affected NGCC units, the greater the projected amount of electric generation from steam generating units, the higher the projected weighted average emission rate that will be achieved for all affected EGUs.

[792] A demonstration of how a plan will achieve a state's rate-based or mass-based CO_2 emission goal is one of the required plan components, as described in section VIII.D.2.

emissions at the affected EGU level, such as heat rate improvements or fuel switching. These measures are discussed in section VIII.I. Second, a state may implement a market-based emission trading program, which enables EGUs to generate and procure ERCs, a tradable compliance unit representing one MWh of electric generation (or reduced electricity use) with zero associated CO_2 emissions. Considerations and requirements for rate-based trading programs are discussed in section VIII.K.

ERCs would be issued by the administering state regulatory body. The state may issue ERCs to affected EGUs that emit below a specified CO_2 emission rate, as well as for measures that provide substitute generation for affected EGUs or avoid the need for generation from affected EGUs. These ERCs may then be used to adjust the reported CO_2 emission rate of an affected EGU when demonstrating compliance with a rate-based emission standard. For each submitted ERC, one MWh is added to the denominator of the reported CO_2 emission rate, resulting in a lower adjusted CO_2 emission rate.

Eligible measures that may generate ERCs, as well as the accounting method for adjusting a CO_2 emission rate, are discussed in section VIII.K.1. Requirements for rate-based emission trading approaches are discussed in section VIII.K.2. Quantification and verification requirements for measures eligible to generate ERCs are discussed in section VIII.K.3.

(1) Rate-based emission standards based on operational or other standards. As discussed in further detail in section VIII.D.2.d.3, regarding the legal considerations and statutory language of CAA section 111(h), the EPA is finalizing that design, equipment, work practice, and operational standards cannot be considered to be "standards of performance" for this final rule. However, a state may elect to use emission standards for affected EGUs that result in a reduced CO_2 lb/MWh emission rate for affected EGUs because of operational or other standards. The state would include in its state plan an emission standard that is the rate standard that results from the applicable operational or other standard. For example, a state might choose to recognize that an individual affected EGU has plans to retire, and those plans could be codified in the state plan by adopting an emission standard of 0 CO_2 lb/MWh as of a certain date. The state would thus include in the state plan an emission standard of 0 CO_2 lb/MWh for that affected EGU that applies after a specified date.

An approvable plan could apply such emission standards to a subset of affected EGUs or all affected EGUs. As with any rate-based plan, the state would need to demonstrate that the plan would achieve the required level of emission performance for affected EGUs, in CO_2 lb/MWh. A plan could also apply such emission standards to a subset of affected EGUs in the state while applying other rate-based emission standards to the remainder of affected EGUs in the state. For example, a plan might include an emission standard of 0 CO_2 lb/MWh reflecting a retirement mandate for one or more affected EGUs in a state and apply a rate-based emission standard equal to the CO_2 emission performance rates or a state's rate-based CO_2 emission goal to the remainder of affected EGUs.

As with all emission standards, emission standards based on design, equipment, work practice, and operational standards must be quantifiable, verifiable, enforceable, non-duplicative and permanent. These requirements are described in more detail at section VIII.D.2.

(2) Additional considerations for rate-based approach. Additional considerations and requirements for rate-based emission standards state plans are addressed in section VIII.K. This includes the basic accounting method for adjusting the reported CO_2 emission rate of an affected EGU, as well as requirements for the use of measures to adjust a CO_2 emission rate, both of which are discussed in sections VIII.K.1 through 3. Such requirements include eligibility, accounting, and quantification and verification requirements (EM&V) for the use of CO_2 emission reduction measures that provide substitute generation for affected EGUs or avoid the need for generation from affected EGUs in rate-based state plans. Section VIII.K.4

addresses multi-state coordination among rate-based emission trading programs.

b. Mass-based approach. The second "emission standards" approach a state may elect to use is mass-based emission standards applied to affected EGUs. Under this approach, the plan would include federally enforceable emission standards for mass CO_2 emissions from affected EGUs. The plan would be designed to achieve the mass-based CO_2 goal for a state's affected EGUs (see section VII) or a level of CO_2 emissions equal to or less than the mass-based CO_2 goal plus the new source complement CO_2 emissions (see section VIII.J.2.b, Table 14).[793]

Under a mass-based approach, a state could require that individual affected EGUs meet a specified mass emission standard. Alternatively, a state could choose to implement a market-based emission budget trading program. The EPA envisions that the latter option is most likely to be exercised by states seeking to implement a mass-based emission standard approach, as it would maximize compliance flexibility for affected EGUs and enable the state to meet its mass goal in the most economically

[793] For example, a state plan designed to meet a state mass-based CO_2 goal for affected EGUs plus a new source complement could include a mass-based emission budget trading program that applies to both affected EGUs, as well as new fossil fuel-fired EGUs. The program requirements for affected EGUs would be federally enforceable, while the program requirements for other fossil fuel-fired EGUs would be state-enforceable. This approach is described further in section VIII.J.2.

efficient manner possible.

(1) Mass-based emission standard applied to individual affected EGUs.

One pathway a state could take to achieve its mass-based CO_2 goal would be to apply mass-based emission standards to individual affected EGUs, in the form of a limit on total allowable CO_2 emissions. These emission standards would be designed such that total allowable CO_2 emissions from all affected EGUs in a state are equal to or less than the state's mass-based CO_2 goal, or a state's mass-based CO_2 goal plus the new source complement CO_2 emissions specified in section VIII.J.2.b, Table 14. The individual affected EGUs would be required to emit at or below their mass-based standard to demonstrate compliance. Under this approach, individual affected EGUs would be required to undertake source-specific measures to assure their CO_2 emissions do not exceed their assigned emission standard. Affected EGU compliance with the emission standards prescribed under this type of mass-based approach would ensure that the affected EGUs in a state achieve the state's mass-based CO_2 goal, or mass-based CO_2 goal plus new source complement.

(2) Mass-based emission standard with a market-based emission budget trading program.

A second pathway a state could take to achieve its mass-based CO_2 goal would be to implement a market-based emission budget trading program. This type of program provides maximum compliance flexibility to affected EGUs, and as a result, may be attractive to states that choose to implement a mass-based approach in their state plan.

An emission budget trading program establishes a combined emission standard for a group of emission sources in the form of an emission budget. Emission allowances are issued in an amount up to the established emission budget.[794] Allowances may be distributed to affected emission sources (as well as to other parties) through a number of different methods, including direct allocation to affected sources or auction. These allowances can be traded among affected sources and other parties. The emission standard applied to individual emission sources is a requirement to surrender emission allowances equal to reported emissions, with each allowance representing one ton of CO_2.

The EPA views an emission budget trading program as a highly efficient, market-based approach for reducing CO_2 emissions from affected EGUs. Such programs include a limit on mass CO_2 emissions while providing both short-term and long-term price signals that encourage the owners or operators of affected EGUs, as well as other entities, to determine the most efficient

[794] An emission allowance represents a limited authorization to emit, typically denominated in one short ton or metric ton of emissions.

means of achieving the mass emission standard. Notably, such an approach incentivizes actions taken at affected EGUs to reduce CO_2 emissions, as well as the use of strategies such as RE and demand-side EE as complementary measures that reduce CO_2 emissions. However, unlike under a rate-based approach, for this latter set of measures there is no need to address and describe these state measures in a state plan submission or quantify and verify the RE and EE MWh of generation and savings. As a result, a mass-based emission budget trading program incentivizes and recognizes a wide range of emission reduction actions while being relatively simple for a state to implement and administer. Furthermore, the EPA notes that such an approach still allows for a state to address electricity load growth, as load growth can be met through low- and zero-emitting generating resources, as well as avoided through demand-side EE and demand-side management (DSM) measures.

Additional considerations and requirements for mass-based emission standards state plans are addressed in section VIII.J. This includes use of emission budget trading programs in a state plan, including provisions required for such programs (section VIII.J.2.a) and the design of such programs in the context of a state plan. Section VIII.J addresses program design approaches that ensure achievement of a state mass-based CO_2 emission goal (section VIII.J.2.c), as well as how states can use emission budget trading programs with broader source coverage and other flexibility features in a state plan, such as the programs currently implemented by California and the RGGI participating states (section VIII.J.2.d). Section VIII.J.2.e addresses other considerations for the design of emission budget trading programs that states may want to consider, such as allowance allocation approaches. Section VIII.J.3 addresses multi-state coordination among emission budget trading programs used in states that retain their individual state mass-based CO_2 goals.

(3) Mass-based emission standards based on operational or other standards.

As discussed in section VIII.C.2.a.(1) above, a state may elect to use mass-based emission standards for affected EGUs that result in a reduced total tonnage of CO_2 emissions from affected EGUs because of operational or other standards. The state would include in its state plan an emission standard that is the mass standard that results from the applicable operational or other standard. For example, a state might choose to recognize that an individual affected EGU has plans to retire, and those plans could be codified in the state plan by adopting an emission standard of 0 total tons of CO_2, as of a certain date. The state would thus include in the state plan an emission standard of 0 total tons of CO_2 for that affected EGU that applies after a specified date. Under a mass-based approach, the state could also include an emission standard (e.g., a mass limit) that reflects the result of a limit on an affected EGU's total operating hours over a specified period. Such an emission standard would be based on an affected EGU's potential to emit given a specified number of operating hours.

An approvable plan could apply such emission standards to a subset of affected EGUs or all affected EGUs. As with any mass-based plan, the state would need to demonstrate that the plan would achieve the required level of emission performance for affected EGUs, in total tons of CO_2. A plan could also apply such emission standards to a subset of affected EGUs in the state while applying other emission standards to the remainder of affected EGUs in the state. For example, a plan might include an emission standard of 0 tons of CO_2 for one or more affected EGUs, reflecting a retirement mandate for one or more affected EGUs in a state, and include the remainder of affected EGUs in an emission budget trading program.

3. "State measures" state plan type

The second type of state plan is what we refer to as a "state measures" plan. As previously discussed, the EPA believes states will be able to submit state plans under the emission standards plan type, and its respective approaches, and achieve the CO_2 emission performance rates or state rate-based or mass-based CO_2 goals by imposing federally enforceable requirements on affected EGUs. Upon further consideration of the requirements of CAA section 111(d), in consideration of the comments we received on the proposed portfolio approach and the state commitments approach, and in order to provide flexibility and choice to states that may wish to adopt a plan that does not place all the obligations on affected EGUs, the EPA is finalizing the state measures plan type in addition to the emission standards plan type. The EPA believes the state measures plan type will provide states with additional latitude in accommodating existing or planned programs that involve measures implemented by the state, or by entities other than affected EGUs, that result in avoided generation and CO_2 emission reductions at affected EGUs. This includes market-based emission budget trading programs that apply, in part, to affected EGUs, such as the programs implemented by California and the RGGI participating states in the Northeast and Mid-Atlantic, as well as RE and demand-side EE requirements and programs, such as renewable portfolio standards (RPS), EERS, and utility- and state-administered incentive programs for the deployment of RE and demand-side EE technologies and practices. The EPA believes this second state plan type will afford states with appropriate flexibility while meeting the statutory requirements of CAA section 111(d).

Measures implemented under the state measures plan type could include RE and demand-side EE requirements and deployment programs. This type of plan could align with existing state resource planning in the electricity sector, including RE and demand-side EE investments by state-regulated electric utilities. The state measures plan type also can accommodate emission budget trading programs that address a broader set of emission sources than just affected EGUs subject to CAA section 111(d), such as the programs currently implemented by California and the RGGI participating states. The EPA also notes that the state measures plan type could accommodate imposition by a state of a fee for CO_2 emissions from affected EGUs, an approach suggested by a number of commenters.

This plan type would allow the state to implement a suite of state measures that are adopted, implemented, and enforceable only under state law, and rely upon such measures[795] in achieving the required level of CO_2 emission performance from affected EGUs. The state measures under this plan type could be measures involving entities other than affected EGUs, or a combination of such measures with emission standards for affected EGUs, so long as the state demonstrates that such measures will result in achievement of a state's mass-based CO_2 goal (or mass-based CO_2 goal plus new source complement), as discussed below. The EPA

[795] "State measures" refer to measures that the state adopts and implements as a matter of state law. Such measures are enforceable only per applicable state law, and are not included in the federally enforceable state plan.

notes that under this plan type, a state could also choose to include any emission standards for affected EGUs, which are required to be included in the plan as federally enforceable measures, to be implemented alongside or in conjunction with state measures the state would implement and enforce.

For a state measures plan to be approvable, it must include a demonstration of how the measures, whether state measures alone or state measures in conjunction with any federally enforceable emission standards for affected EGUs, will achieve the state mass-based CO_2 emission goal for affected EGUs (or mass-based CO_2 goal plus new source complement). However, because the state measures would not be federally enforceable emission standards, the plan must also include a backstop of federally enforceable emission standards for all affected EGUs, in order for the state measures plan type to satisfy the requirement of CAA section 111(d) that a state establish standards of performance for affected EGUs. This backstop would impose federally enforceable emission standards on the state's affected EGUs in the case that the state measures fail to achieve the state mass-based CO_2 goal. The backstop, discussed further below, would assure that the state CO_2 emission goal or CO_2 emission performance rates are fully achieved by affected EGUs in the form of federally enforceable emission standards.

a. Requirements for state measures under a state measures type plan. Under the state measures plan type, state measures must be satisfactorily described in the supporting material for a state plan submittal. The supporting material would need to demonstrate that the state measures meet the same integrity elements that would apply to federally enforceable emission standards. Specifically, the state plan submittal must demonstrate that the state measures are quantifiable, verifiable, enforceable, non-duplicative and permanent. These requirements are described in more detail at section VIII.D.2. Under the state measures plan, if a state chooses to impose emission standards on affected EGUs, such emission standards must be included in the federally enforceable plan as they would be under an emission standards plan.

The EPA would assess the overall approvability of a state measures plan based, in part, on the state's satisfactory demonstration that the state measures, in conjunction with any federally enforceable emission standards on the affected EGUs that might be included in the plan, would result in the state plan's achievement of the mass-based CO_2 goal for the state's affected EGUs (or mass-based CO_2 goal plus new source complement). This includes a demonstration of adequate legal authority and funding to implement the state plan and any associated measures. The EPA's determination that such a plan is satisfactory would be based in part on whether the state measures are adequately described in the supporting documentation and the plan submittal demonstrates that the state measures are quantifiable, verifiable, enforceable, non-duplicative and permanent as described above. This is necessary for the EPA to ensure that the results achieved through the plan are quantifiable and verifiable, and to assess whether the state measures are anticipated to achieve the state mass-based CO_2 goal for affected EGUs (or mass-based CO_2 goal plus new source complement).

The EPA's evaluation of the approvability of a state measures plan would also include an assessment of whether the backstop consisting of federally enforceable emission standards for the state's affected EGUs would ensure that the required emission performance level is fully achieved by affected EGUs, in the case that the state measures fail to achieve the state mass-based CO_2 goal (or mass-based CO_2 goal plus new source complement), or the state does not meet programmatic milestones during the interim period. The trigger for the backstop must also satisfactorily provide for the implementation of the backstop emission standards.

b. Considerations for the backstop included in a state measures type plan. As further discussed in section VIII.C.6.c, the EPA believes a backstop, composed of federally enforceable emission standards for the affected EGUs that are sufficient to achieve the state CO_2 emission goal or the CO_2 emission performance rates in the event that state measures do not result in the required CO_2 emission performance, is necessary for the state measures plan type to meet the requirements of CAA section 111(d). The state plan must specify the backstop that would apply federally enforceable emission standards to the affected EGUs if the state measures plan does not achieve the anticipated level of CO_2 emission performance by affected EGUs, or a state does not meet programmatic milestones during the interim period. The state plan must include promulgated regulations (or other requirements) that fully specify these emission standard requirements, which must be quantifiable, verifiable, enforceable, non-duplicative and permanent. These requirements are described in more detail at section VIII.D.2.

These federally enforceable emission standards must be designed such that compliance by affected EGUs with the emission standards would achieve the state's mass-based interim and final goals for affected EGUs. The backstop emission standards must specify CO_2 emission performance levels (in mass) that would apply for the interim plan performance period (including specifying levels for each of the interim step 1 through step 3 periods) and the final two-year plan performance periods.[796] If a state chose, these backstop emission standards could be based on a model rule or federal plan promulgated by the EPA.

The state measures plan must specify the trigger and conditions under which the backstop federally enforceable emission standards would apply that is consistent with the requirements in the emission guidelines. The trigger and attendant conditions for deployment of the backstop would address the CAA section 111(d) requirement that states submit a program that provides for the implementation of standards of performance. The state measures plan must specify the level of emission performance that will be achieved by affected EGUs as a result of implementation of the state measures plan during the interim and final plan performance periods. This includes the level of emission performance during the interim plan periods 2022-2024, 2025-2027 and 2028-2029, as well as the performance level that would be achieved during every subsequent 2-year final plan performance period (2030-2031, and subsequent 2-year periods). If actual CO_2 emission performance by affected EGUs fails to meet the level of emission performance specified in the

[796] This includes the level of emission performance during the interim plan periods 2022-2024, 2025-2027 and 2028-2029, as well as the performance level that would be achieved during every subsequent 2-year final plan performance period (2030-2031, and subsequent 2-year periods).

plan over the 8-year interim performance period (2022-2029) or for any 2-year final goal performance period, the state measures plan must require that the backstop federally enforceable emission standards would take effect and be applied to affected EGUs. Similarly, the plan must require that the backstop standards take effect if actual emission performance is deficient by 10 percent or more relative to the performance levels that the state has chosen to specify in the plan for the interim step 1 period (2022-2024) or the interim step 2 period (2025-2027). The backstop standards are also triggered if, at the time of the state's annual reports to the EPA during the interim period, the state has not met the programmatic milestones for the reporting period. The state measures plan must provide that, in the event the backstop is triggered, such emission standards would be effective within 18 months of the deadline for the state's submission of its periodic report to the EPA on state plan implementation and performance, as described in section VIII.D.2.c.[797,798]

[797] States may choose to establish an effective date for backstop emission standards that is sooner than 18 months.
[798] In the event a state does not implement the backstop as required if actual emission performance triggers the backstop, the EPA will take appropriate action. The EPA notes that as part of the proposed federal plan rulemaking, it is proposing a regulatory mechanism to call plans in the instances of substantial inadequacy to meet applicable requirements or failure to implement an approved plan.

The backstop emission standards must make up for the shortfall in CO_2 emission performance. The shortfall must be made up as expeditiously as practicable. The state may address the requirement to make up for the shortfall in CO_2 emission performance by submitting, as part of the final plan, backstop emission standards that assure affected EGUs would achieve the state's interim and final CO_2 emission goals or the CO_2 emission performance rates for affected EGUs, and then later submit appropriate revisions to the backstop emission standards adjusting for the shortfall through the state plan revision process. The state may alternately effectuate this by submitting, along with the backstop emission standards, provisions to adjust the emission standards to account for any prior emission performance shortfall, such that no modification of the emission standards is necessary in order to address the emission performance shortfall.

For example, assume a state measures plan identified a mass-based CO_2 standard for affected EGUs of 100 million tons during the interim step 1 performance period (2022-2024), 90 million tons during the interim step 2 performance period (2025-2027), and 80 million tons during the interim step 3 performance period (2028-2029). Over the entire interim plan performance period (2022-2029), the interim mass-based CO_2 goal is cumulative emissions of 270 million tons. Assume that CO_2 emissions from affected EGUs in the interim step 1 period were actually 115 million tons, triggering implementation of the backstop. In this instance, the mass-based standard for affected EGUs implemented as part of the backstop during subsequent plan performance periods would need to ensure that cumulative CO_2 emissions during the 2022-2029 interim period do not exceed 270 million tons. This could be achieved, for example, by implementing a mass standard of 75 million tons during the interim step 2 performance period (rather than the 90 million tons originally specified in the plan), or some other combination during the remaining interim step 2 and 3 performance periods.[799] The emission standards included as the backstop in the plan must specify calculations for how such adjustments will be made.

4. Summary of comments on state plan approaches

The EPA received a wide range of comments on the basic plan approaches in the proposal. Numerous commenters supported providing states with the option of implementing a rate-based or mass-based approach. Some commenters expressed concern that a rate-based approach would not reduce overall emissions, and could actually lead to increased emissions. The EPA does not

[799] In this example, states could elect to implement different combinations of mass-based standards during the remaining interim step 2 and 3 plan performance periods, provided that cumulative CO_2 emissions during the full interim plan performance period (2022-2029) do not exceed 270 million tons.

agree with this latter comment, because both approaches would result in adequate and appropriate constraints on CO_2 emissions. As documented in the RIA, a rate-based approach would result in a substantial reduction in CO_2 emissions relative to emissions under a business-as-usual case.

Numerous commenters supported allowing states to implement a rate-based emission standard approach applied to affected EGUs. There was also broad support in comments for allowing states to pursue a mass-based approach in the form of mass emission standards on affected EGUs. The EPA is finalizing both of these approaches.

The EPA received a mix of comments for and against the proposed portfolio approach, in which state requirements and other measures that apply to non-EGU entities would be part of a state's federally enforceable state plan. Multiple commenters supported the portfolio approach because it would align with existing state and utility planning processes in the electric power sector, and would maximize state discretion and flexibility in developing plans. Commenters mentioned the range of state requirements and utility programs overseen by states that could be used under a portfolio approach and result in achieving the CO_2 emission goal for affected EGUs, including state RPS, EERS and utility-administered EE programs. Commenters noted that the portfolio approach would provide states maximum flexibility to take local circumstances, economics and state policy into account when developing their plans.

By contrast, multiple commenters opposed the portfolio approach. Some commenters questioned how a portfolio approach would work, and whether the EPA had provided sufficient detail explaining how such a plan approach could be implemented by a state. In particular, multiple commenters questioned how different state programs, such as utility-administered EE programs, could be made federally enforceable in practice under CAA section 111(d).[800] Multiple commenters expressed concern about making state requirements and utility programs for RE and demand-side EE enforceable under the CAA. Some of these commenters supported the state commitments plan approach that the EPA took comment on in the proposal, which was a variant of the portfolio approach. Under the state commitment variant, measures that applied to entities other than affected EGUs would not be federally enforceable under the CAA, but state commitments to implement those measures would be federally enforceable elements of a state plan under the CAA.

After considering these comments, the EPA is not finalizing the portfolio approach or the state commitment variant. However, the EPA is finalizing the state measures plan type, as described

[800] Legal considerations with the proposed portfolio approach are explored in section VIII.C.6.d.

above, which would accommodate state choices and allow states to rely upon a variety of measures, as was envisioned under the portfolio approach, in a way that meets the statutory requirements of CAA section 111(d).

5. Multi-state plans and multi-state coordination

The EPA views the ability of a state to implement an individual plan or a multi-state plan as a significant flexibility that allows a state to tailor implementation of its plan to state policy objectives and circumstances. The EPA sees particular value in multi-state plans and multi-state coordination, which allow states to implement a plan in a coordinated fashion with other states. Such approaches can lead to more efficient implementation, lower compliance costs for affected EGUs and lower impacts on electricity ratepayers. Coordinated approaches also will help states identify and address any potential electric reliability impacts when developing plans.

The EPA received broad support in comments for allowing states to implement multi-state plan approaches, and has made multiple changes in the final rule to address many suggestions outlining different approaches states may want to take. These changes are intended to provide streamlined approaches for multi-state coordination while maintaining transparency and assuring that the CO_2 emission performance rates or state CO_2

emission goals are achieved.

The EPA is finalizing two approaches that allow states to coordinate implementation in order to meet the emission guidelines.[801]

First, states may meet the requirements of the emission guidelines and CAA section 111(d) by submitting multi-state plans that address the affected EGUs in a group of states. The EPA is finalizing the proposed approach by which multiple states aggregate their rate or mass CO_2 goals and submit a multi-state plan that will achieve a joint CO_2 emission goal for the fleet of affected EGUs located within those states (or a joint mass-based CO_2 goal plus a joint new source CO_2 emission complement).[802]

Second, the EPA is also finalizing another approach, in response to comments received on the proposed rule. This approach enables states to retain their individual state goals for affected EGUs and submit individual plans, but to coordinate plan implementation with other states through the interstate

[801] The EPA notes that in addition to these approved approaches, other types of multi-state approaches may be acceptable in an approvable plan, provided the obligations of each state under the multi-state plan are clear and the submitted plan(s) meets applicable emission guideline requirements.

[802] The concept of a new source CO_2 emission complement is addressed in section VIII.J.2.b. Table 14 provides individual state new source CO_2 emission complements. For a multi-state plan, a joint new source CO_2 emission complement would be the sum of the individual new source CO_2 emission complements in Table 14 for the states participating in the multi-state plan.

transfer of ERCs or emission allowances.[803] This approach facilitates interstate emission trading without requiring states to submit joint plans.[804] The EPA considers these to be individual state plans, not multi-state plans.

States have the option to implement this second approach in different ways, as discussed in section VIII.C.5.c. These different implementation options allow states to tailor their implementation of linked emission trading programs, based on state policy preferences, as well as economic and other considerations. These different options provide varying levels of state control over emission trading system partners and require varying levels of coordination in the course of state plan development.

In response to comments, the EPA is also further clarifying how multi-state plans with a joint goal for affected EGUs may be implemented. The EPA is clarifying that states may participate in more than one multi-state plan, if necessary, for example, to address affected EGUs in states that are served by more than one ISO or RTO. The EPA is further clarifying that a subset of affected EGUs in a state may participate in a multi-state plan.

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[803] This approach also applies where a state plan is designed to meet a state mass-based CO_2 goal plus a state's new source CO_2 emission complement.

[804] States may submit individual plans with such linkages, or if they choose, provide a joint submittal. Forms of joint submittals are described at section VIII.E.

These clarifications are discussed in section VIII.C.5.d.

a. Summary of comments on multi-state plans. Multiple commenters supported the EPA's proposed approach that would allow states to implement a multi-state plan to meet a joint CO_2 emission goal. However, a number of states commented that states should also be allowed to coordinate without aggregating multiple individual state goals into a single joint goal. Many states questioned the incentives that a state would have to aggregate its goal with other states that have different goals, and also noted the administrative complexities presented by states seeking to formally coordinate state plans with one another.

The EPA notes that there are multiple incentives for states to collaborate by implementing a multi-state plan to meet an aggregated joint goal, regardless of the specific level of their individual goals, because states share grid regions and impacts from plan implementation will be regional in nature. Further, multiple analyses, including those by ISOs and RTOs, indicate that regional approaches could achieve state goals at lesser cost than individual state plan approaches. However, the EPA also recognizes the value in allowing for collaboration where states retain individual goals. These approaches could provide some of the benefits of a joint goal while reducing the negotiations among states necessary to develop a multi-state plan with a joint goal. As a result, the EPA has finalized the additional approaches described in section VIII.C.5 to provide for coordination while maintaining individual goals. These approaches would allow for interstate transfer of ERCs or emission allowances while retaining individual state goals.

Many commenters suggested that states should be encouraged to join or form regional market-based programs. Many commenters touted the economic efficiency benefits of such approaches, and noted that such programs have features that support electric reliability.

The EPA agrees with these comments, and notes that it encouraged such approaches in the proposal. While the EPA is not requiring states to join and/or form regional market-based programs, we note that such programs can be helpful for many reasons, including features that support reliability. Market-based programs allow greater flexibility for affected EGUs both in the short-term and long-term. Under a market-based program, affected EGUs have the ability to obtain sufficient allowances or credits to cover their emissions in order to comply with their emission standards. Additionally, we continue to encourage states to cooperate regionally. Regional cooperation in planning and reliability assessments is an important tool to meeting system needs in the most cost-effective, efficient, and reliable way.

b. Multi-state coordination through a joint emission goal. Multiple states may submit a multi-state plan that achieves an aggregated joint CO_2 emission goal for the affected EGUs in the participating states (or a joint mass-based CO_2 goal plus a joint new source CO_2 emission complement).[805] The joint emission goal approach is acceptable for both types of state plans, the "emission standards" plan type and the "state measures" plan type. However, the EPA is requiring that a joint goal may apply only to states implementing the same type of plan, either an "emission standards" plan or a "state measures" plan.[806]

[805] As a conceptual and legal matter, the relationship between states coordinating to meet a joint CO_2 emission goal under this rule is similar to the relationship between states coordinating SIP submissions to attain the NAAQS in an interstate nonattainment area. In both cases, the states coordinate their actions in a way that, cumulatively, the measures applicable in each state will lead to achievement of a common interstate goal (with the EPA evaluating the sufficiency and success of the plans on a holistic, interstate basis). Despite the shared goal, in both cases, the mere fact of coordination has no effect on each state's sovereign legal authority. For example, the legally applicable rules in a given state are adopted by that state individually, not by a joint entity or other interstate mechanism. Similarly, the fact that the states coordinate their rules does not grant them the authority to directly enforce each other's rules, or to take direct legal action against a state that is failing to implement its own rules. Although some states may jointly submit their coordinated rules to the EPA as a matter of administrative convenience, the state rules within such a plan are nothing more than reciprocal laws of the sort that states routinely enact in voluntary coordination with each other.

[806] This is necessary because if the joint goal is not achieved during a plan performance period, different remedies would apply under an emission standards plan and a state measures plan.

Under this approach, a rate-based multi-state plan would include a weighted average rate-based emission goal, derived by calculating a weighted average CO_2 emission rate based on the individual rate-based goals for each of the participating states and 2012 generation from affected EGUs. A mass-based multi-state plan would include an aggregated mass-based CO_2 emission goal for the participating states, in cumulative tons of CO_2, derived by summing the individual mass-based CO_2 emission goals of the participating states.[807]

Such plans could include emission standards in the form of a multi-state rate-based or mass-based emission trading program.[808] Alternatively, states could submit a multi-state plan

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Under an emission standards plan, corrective measures would be triggered. Under a state measures plan, the federally enforceable backstop emission standards would be triggered. See section VIII.F.3.

[807] Where a multi-state plan is designed to meet a joint mass-based CO_2 goal plus a joint new source CO_2 emission complement, the joint new source CO_2 emission complement would be the sum of the individual new source CO_2 emission complements in section VIII.J.2.b, Table 14, for the states participating in the multi-state plan.

[808] A potential example of this approach is the method by which the states participating in RGGI have implemented individual CO_2 Budget Trading Program regulations in a linked manner using a shared emission and allowance tracking system. Each state's regulations implementing RGGI stand alone on a legal basis, but provide for the use of CO_2 allowances issued in other participating states for compliance under the state regulations. These states are not listed by name in state regulations, which instead refer to participating states that have established a corresponding CO_2 Budget Trading Program regulation. More information is available at http://www.rggi.org.

using a state measures approach.[809] Both approaches could provide for implementation of a multi-state emission trading program.

c. Multi-state coordination among states retaining individual state goals. States that do not wish to pursue a joint CO_2 emission goal with other states may pursue a second pathway to multi-state collaboration. States may submit individual plans that will meet the CO_2 emission performance rates or a state mass CO_2 goal for affected EGUs (or mass-based CO_2 goal plus the new source CO_2 emission complement), but include implementation in coordination with other state plans by providing for the interstate transfer of ERCs or CO_2 allowances, depending on whether the state is implementing a rate-based or mass-based emission trading program. This form of coordinated implementation may occur under both an "emission standards" type of plan and a "state measures" type of plan, where states are implementing emission trading programs.[810] For rate-based plans, this type of coordinated approach is limited to state plans with rate-based emission standards that are equal to the CO_2 emission performance rates in the emission guidelines.

[809] Under this approach, a state measure could include, if a state chose, a multi-state emission trading program that is enforceable at the state level.

[810] ERCs may only be transferred among states implementing rate-based emission limits. Likewise, emission allowances may only be transferred among states implementing mass-based emission limits.

Under this approach, a state plan could indicate that ERCs or CO_2 allowances issued by other states with an EPA-approved state plan could be used by affected EGUs for compliance with the state's rate-based or mass-based emission standard, respectively. Such plans must indicate how ERCs or emission allowances will be tracked from issuance through use by affected EGUs for compliance,[811] through either a joint tracking system, interoperable tracking systems, or an EPA-administered tracking system.[812]

The EPA would assess the approvability of each state's plan individually — the use of ERCs or emission allowances issued in another state would not impact the approvability of the components of the individual state plan.[813] However, the EPA would also assess linkages with other state plans, to ensure

[811] Referred to in different programs as "surrender," "retirement," or "cancellation."

[812] The EPA received a number of comments from states and stakeholders about the value of the EPA's support in developing and/or administering tracking systems to support state administration of rate-based emission trading programs. The EPA is exploring options for providing such support and is conducting an initial scoping assessment of tracking system support needs and functionality.

[813] Note that for mass-based plans, the approvability requirements for a state plan would differ, depending on the structure of the emission budget trading program included in the state plan. For example, approvability requirements and basic accounting with regard to whether a plan achieves a state's mass CO_2 goal would differ for emission budget trading programs that cover only affected EGUs subject to CAA section 111(d) vs. programs that apply to a broader set of emission sources. These considerations are addressed in section VIII.J.

that the joint tracking system or interoperable tracking systems used to implement rate-based or mass-based emission trading programs across states are properly designed with necessary components, systems, and procedures to maintain the integrity of the linked emission trading programs.

Coordinated state plan implementation among states that retain individual state mass-based CO_2 goals (or that implement individual state plans with rate-based emission standards consistent with the CO_2 emission performance rates in the emission guidelines) is discussed in more detail in sections VIII.J and K. Section VIII.J discusses coordinated implementation among states implementing individual mass-based emission budget trading programs and section VIII.K discusses coordinated implementation among states implementing individual rate-based emission trading programs.

d. Multi-state plans that address a subset of EGUs in a state. The EPA is clarifying in the final emission guidelines that a state may participate in more than one multi-state plan. Under this approach, the state would identify in its submittal the subset of affected EGUs in the state that are subject to the multi-state plan or plans. This could involve a subset of affected EGUs that are subject to a multi-state plan, with the remainder of affected EGUs subject to a state's individual plan. Alternatively, different affected EGUs in a state may be subject to different multi-state plans. In all cases, the state would need to identify in each specific plan which affected EGUs are subject to such plan, with each affected EGU subject to only one multi-state plan or subject only to the state's individual plan (if relevant).

These scenarios may occur where a state chooses to cover affected EGUs in different ISOs or RTOs in different multi-state plans. This will provide states with flexibility to participate in multi-state plans that address the affected EGUs in a respective grid region, in the case where state borders cross grid regions.

These scenarios may also occur where a state is served by multiple vertically integrated electric utilities with service territories that cross state lines. This will provide states with flexibility to participate in multi-state plans that address the affected EGUs owned and operated by a utility with a multi-state service territory.

6. Legal bases and considerations for state plan types and approaches

a. Legal basis for emission standards approach. The emission standards approach is consistent with the requirements of CAA section 111(d). If a state simply adopts the CO_2 emission performance rates, then the corresponding rate-based emission standards in the state plan establish standards of performance for affected EGUs as required under section 111(d)(1)(A). Similarly, if a state chooses to achieve the rate-based CO_2 emission goal through rate-based emission standards applicable only to affected EGUs, or to achieve the mass-based CO_2 emission goal through mass-based emission standards applicable only to affected EGUs (or, alternatively, to achieve the mass CO_2 goal and a new source CO_2 emission complement through federally enforceable mass-based emission standards in conjunction with state enforceable emission standards on new sources), then the set of rate-based emission standards or the set of mass-based emission standards in the state plan establishes standards of performance for affected EGUs as required under section 111(d)(1)(A). The EPA has the authority to approve emission standards for affected EGUs as part of a state plan under all three cases (as long as such emission standards meet the requirements of CAA section 111(d) and the final emission guidelines), thereby making such emission standards federally enforceable upon approval by the EPA. In all three cases, the emission standards must be quantifiable, verifiable, enforceable, non-duplicative and permanent; this ensures that the plan provides for implementation and enforcement of the standards of performance (i.e. the emission standards) as required by section 111(d)(1)(B). Finally, as described in section VIII.B.7.b below, standards of performance may include emission trading. Thus, the credit and allowance trading that is allowed under the emission standards approach is consistent with the statutory requirement that the plan establish standards of performance.

We note that the standard the statute provides for the EPA's review of a state plan is whether it is "satisfactory." We interpret a "satisfactory" plan as one that meets all applicable requirements of the CAA, including applicable requirements of these guidelines. Some commenters suggested that "satisfactory" should be taken to mean something less (such as mostly or substantially meeting requirements) but the structure of 111(d) shows otherwise. When a state plan is unsatisfactory, section 111(d)(2) gives the EPA the "same" authority to promulgate a federal plan as the EPA has under section 110(c). Under section 110(c), the EPA has authority to promulgate a federal implementation plan if a SIP does not comply with all CAA requirements (see sections 110(k)(3) and 110(l)).

For example, if an emission standards type plan includes an emission standard that is unenforceable due to defective rule language, then the plan is not satisfactory because it does not comply with the guideline requirement that emission standards must be enforceable. On the other hand, if a state plan complies with all applicable requirements of the CAA (including these guidelines), then the EPA must approve it as satisfactory. This is true even if the emission standards in the state plan are more stringent than the minimum requirements of these guidelines, or the state plan achieves more emission reductions than required by these guidelines. This follows from section 116 of the CAA as interpreted by the U.S. Supreme Court in *Union Elec. Co. v. EPA*, 427 U.S. 246, 263-64 (1976).

b. Legal basis for emissions trading in state plans. There are three legal considerations with respect to emissions trading in state plans. First, we explain how the definition of "standard of performance" in section 111(a)(1) allows section 111(d) plans to include standards of performance that authorize emissions trading. Second, we explain how the EPA interprets the phrase "provides for implementation and enforcement of [the] standards of performance" in the context of a rate-based ERC trading program. Third, we give a similar explanation of the EPA's interpretation of the same phrase in the context of a mass-based allowance trading program.

(1). In the proposal, the EPA proposed that CAA section 111(d) plans may include standards of performance that authorize emissions averaging and trading. 79 FR 34830, 34927/1 (June 18, 2014). We are finalizing that states may include the use of emission trading in approvable state plans.

For purposes of this legal discussion, in the case of an emission limitation expressed as an emission rate, trading takes the form of buying or selling ERCs that an affected EGU may generate if its actual emission rate is lower than its allowed emission rate or that an eligible resource may generate. In the case of an emission limitation expressed as a mass-based limit, trading takes the form of buying or selling allowances.

To reiterate for convenience, the definition of "standard of performance" under CAA section 111(a)(1) is:

> The term 'standard of performance' means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

Both an emission rate that may be met through tradable ERCs, and a mass limit requirement that emissions not exceed the number of tradable allowances surrendered by an affected source, qualify as a "standard for emissions." The term "standard" is not defined, but its everyday meaning is a rule or requirement,[814] which, under the only (or at least a permissible) reading of the provision, would include an emission rate that may be met through tradable ERCs and a requirement to retire tradable allowances.

Treating a tradable emission rate or mass limit requirement as a "standard of performance" is consistent with past EPA practice. In the Clean Air Mercury Rule, promulgated in 2005, the EPA established tradable mass limits as the emission guidelines for certain air pollutants from fossil fuel-fired EGUs, and explained that a tradable mass limit qualifies as a "standard for emissions."[815] In addition, in the 1995 Municipal Solid Waste (MSW) Combustor rule the EPA authorized emission trading by sources.[816]

It should be noted that CAA section 302(l) includes another definition of "standard of performance," which is "a requirement of continuous emission reduction, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction." As described above, section 111(d) contains its own, more specific definition of "standard

[814] E.g., "Something that is set up and established by authority as a rule for the measure of quantity, weight, value, or quality." Webster's Third New International Dictionary 2223 (1967); see also The American College Dictionary (C.L. Barnhart, ed. 1970) ("an authoritative model or measure").
[815] 70 FR 28606, 28616-17 (May 18, 2005).
[816] 60 FR 65387, 6540/2 (Dec. 19, 1995).

of performance," which a tradable emission rate or mass limit satisfies. Whether or not section 302(l) applies in light of section 111(d)'s more specific definition, a tradable emission rate or mass limit also meets section 302(l)'s requirements. A tradable emission rate applies continuously in that the source is under a continuous obligation to meet its emission rate, and that is so regardless of the averaging time, e.g., a rate that must be met on an annual basis. Similarly, a mass limit requirement implemented through the use of allowances applies continuously in that the source is continuously under an obligation to assure that at the appropriate time, its emissions will not exceed the allowances it will surrender. In this respect, a tradable emission rate or mass limit requirement is similar to a non-tradable emission rate that must be met over a specified period, such as one year. In all of these cases, a source is continuously subject to its requirement although it may be able to emit at different levels at different points in time. It should also be noted that a tradable emission rate or mass limit requirement is appropriate for CO_2 emissions, the air pollutant covered by this rule, because the environmental effects of CO_2 emissions are not dependent on the location of the emissions.

(2). In our final rule, we are prescribing certain specific requirements for trading systems for ERCs in a rate-based approach. These specific requirements are in addition to the generic requirements for any state plan (see section VIII.D.2.d below for the legal basis for the generic components for state plans) and are intended to ensure the integrity of the ERC trading system. The integrity of the trading system is key to ensuring that a state plan provides for implementation and enforcement of the standards of performance, as required by section 111(d)(1)(B). Requirements relating to ERCs in a rate-based trading system, and allowances in a mass-based system, must also be submitted as federally enforceable components of the state plan, as such requirements provide for the implementation and enforcement of a tradable emission rate or mass limit for an affected EGU.

However, as described in section VIII.C.6.d, the EPA has legal concerns regarding whether federally enforceable requirements under a CAA section 111(d) state plan can be imposed on entities other than affected EGUs. It is important to note that the use of ERCs and inclusion of state plan requirements regarding a rate-based trading system, and the use of allowances and inclusion of state plan requirements regarding a mass-based trading system, does not run afoul of these legal concerns, as neither the requirements of section 111(d) nor of the federally enforceable state plan in either case extend to non-EGU generators or third-party verifiers of such compliance units.

(3). In our final rule, we are prescribing certain specific requirements for trading systems for allowances in a mass-based approach. These specific requirements are in addition to the generic requirements for any state plan (see section VIII.D.2.d below for the legal basis for the generic requirements for state plans) and are intended to ensure the integrity of the allowance trading system. The integrity of the trading system is key to ensuring that a state plan provides for implementation and enforcement of the standards of performance.

Our interpretation of the phrase "provides for implementation and enforcement of [the] standards of performance" in the context of the integrity of a trading system for allowances under a mass-based approach is further explained in the Legal Memorandum.

c. <u>Legal basis for state measures plan type</u>. The EPA believes the state measures plan type is consistent with CAA section 111(d). Section 111(d)(1) requires a state to submit a plan that "(A) establishes standards of performance for any existing source for [certain] air pollutant[s] ... and (B) provides for the implementation and enforcement of such standards of performance." Section 111(d)(2)(A) indicates that the EPA must approve the state plan if it is "satisfactory."

For states that choose to adopt and submit a state measures plan, such state must submit a state plan that includes standards of performance for CO_2 emissions from affected EGUs in the form of a federally enforceable backstop in order to meet the requirements of section 111(d). Section 111(d) unambiguously requires a state to submit a plan that establishes standards of performance for certain sources, but does not mandate when such standards of performance must be in effect or implemented in order to meet applicable compliance deadlines. Instead, Congress has delegated to the EPA the determination of the appropriate effective date of standards of performance submitted under state plans to meet the requirements of section 111(d). In other words, where the statute is silent, the EPA has authority to provide a reasonable interpretation. The EPA's interpretation is that for states that submit state plans establishing standards of performance under section 111(d), the effective date of such standards of performance may be later in time, perhaps indefinitely, for a number of reasons and under certain conditions. A key condition is that the state plan provides for the achievement of the required reduction by means other than the standards of performance on the timetable required by the BSER, with provision for federally enforceable standards of performance to be implemented if those other means fall short. The EPA believes it is reasonable to defer the effective date for standards of performance for affected EGUs as long as affected EGU CO_2 emissions are projected to achieve, and do achieve, the requisite state goal.

Additionally, under the state measures plan type, if a state chooses to impose emission standards for the affected EGUs in conjunction with state measures that apply to other entities for any period prior to the triggering of the backstop, this final rule requires such emission standards to be submitted as federally enforceable measures included in the state plan. The EPA believes this is appropriate to help ensure the performance of a state measures plan will meet the requirements of this final rule. Section 111(d) clearly authorizes states to impose, and the EPA to approve, federally enforceable emission standards for affected EGUs. Though federally enforceable emission standards for affected EGUs in a state measures plan themselves would not necessarily achieve the requisite state goals, the EPA is authorized to approve state plans when they satisfactorily meet applicable requirements. The EPA can evaluate whether a state measures plan is satisfactory by determining whether any federally enforceable emission standards for affected EGUs in conjunction with state measures on other entities will result in the achievement of the requisite emissions performance level. As previously explained in this final rule, the performance rates and the state goals are the arithmetic expression of BSER as applied across affected EGUs in a state as a source category. In a state measures plan, the evaluation of whether a state measures plan is satisfactory goes to evaluating both the state measures and any federally enforceable emission standards on the affected EGUs to determine whether the plan as a whole will result in the affected EGUs achieving the applicable goals that reflect BSER.

Section 111(d)(1)(B) also requires a state to submit a program that provides for the implementation and enforcement of the applicable standards of performance. Under the state measures approach, this requirement regarding implementation is satisfied in part by the submission of an approvable trigger mechanism for the backstop and appropriate monitoring, reporting and recordkeeping requirements. The trigger mechanism provides for the "implementation" of the backstop, i.e., the standards of performance, by putting the backstop into effect once the associated trigger is deployed. In other words, when the CO_2 performance level under a state plan exceeds the trigger as described in section VIII.C.4.b, the emission standards that were submitted as the federally enforceable backstop and any attendant requirements must be implemented and in effect. The statutory requirement under CAA section 111(d)(2) regarding enforcement is also satisfied under the state measures plan type by the state submitting standards of performance sufficient to meet the requisite emission performance rates or state goal, in the form of the backstop, for inclusion as part of the federally enforceable state plan.

Additionally, by requiring states that choose to impose emission standards on affected EGUs under the state measures approach to submit such emission standards for inclusion in the federally enforceable plan, this requirement further provides for implementation and enforcement as required by the statute. Regulating the affected EGUs through federally enforceable emission standards themselves in conjunction with any state measures the state chooses to rely upon further assures the likelihood of the affected EGUs achieving the state goals as required under this rule and section 111(d).

The state measures plan is a variation of the proposed portfolio approach in that both plan types allow the state to rely upon measures that impose requirements on sources other than affected EGUs in meeting the requisite state CO_2 emission goal. The state measures plan type is also a variation of the proposed state commitment approach in that the measures involving entities other than affected EGUs are not included as part of the federally enforceable 111(d) state plan, but the state may rely upon such measures that have the effect of reducing CO_2 emissions from affected EGUs as a matter of state law. The EPA took comment on the proposed portfolio approach and state commitment approach, and on the utilization of measures on entities other than affected EGUs in meeting the requirements of the emission guidelines and CAA section 111(d). With respect to the proposed state commitment approach, the EPA received comments recommending that the EPA require a federally enforceable backstop with emission standards sufficient to achieve the requisite CO_2 emission performance. The backstop component the EPA is finalizing as part of the state measures plan type is consistent with the EPA's statements in the proposal regarding states' obligations under section 111(d) to establish emission standards for affected EGUs, as the backstop contains federally enforceable emission standards for affected EGUs that will achieve the requisite CO_2 emission performance, and is consistent with comments received regarding the proposed state commitment approach.

The state measures plan type the EPA is finalizing is also a logical outgrowth of the comments received on the proposed portfolio approach. As further explained below, legal questions remain as to whether state plans under section 111(d) can include federally enforceable measures that impose requirements on sources other than affected EGUs. However, a number of commenters and stakeholders expressed robust support for the ability to rely on measures and programs that do not impose requirements on affected EGUs themselves through plan types such as the proposed portfolio and state commitment approaches. The

EPA is reasonably interpreting 111(d) as authorizing the state measures plan type, and believes this plan type is also responsive to, and accommodating of, states and stakeholders who have expressed the importance of being able to rely upon various measures that have the effect of reducing CO_2 emissions from affected EGUs. The EPA is finalizing the state measures plan type upon careful consideration of statutory requirements and comments received based on the proposed portfolio approach and state commitment approach.

The EPA additionally notes that the state measures plan type is not precluded by the recent Ninth Circuit Court of Appeals' decision in *Committee for a Better Arvin et al. v. US EPA et al.*, Nos. 11-73924 and 12-71332 (May 20, 2015). The court held that the EPA violated the CAA by approving a California SIP which relied on emission reductions from state-only mobile source standards ("waiver measures") without including those standards in the SIP. The court first looked at the plain language of section 110(a)(2)(A) of the CAA, which states that SIPs "shall include" the emission limitations and other control measures on which a state relies to comply with the CAA. The court then stated that the EPA's action was also inconsistent with the structure of the CAA. The EPA has the primary responsibility to protect the nation's air quality, but in the court's view, the EPA itself would be unable to enforce the state-only standards. In addition, the court stated that the EPA's action was inconsistent with citizens' right to enforce SIP provisions under section 304.

There are a number of reasons why this decision does not preclude the state measures plan type. The Ninth Circuit's textual analysis does not apply here, as the language of section 110(a)(2)(A) does not control for 111(d) state plans. Section 111(d)(1) requires state plans to "establish standards of performance" and to "provide for implementation and enforcement" of the standards of performance, but, unlike section 110(a)(2)(A), section 111(d) does not specifically say that every emission reduction measure must be "included" in the state plan and be made federally enforceable. Even if section 111(d) did impose such requirements, the state measures approach satisfies them because the trigger is included in the plan as a federally enforceable implementation measure, and the backstop included in the plan also contains standards of performance that reflect the BSER and are federally enforceable once they are triggered.

The Ninth Circuit's structural analysis also does not apply. The availability of the trigger and backstop gives the EPA and citizens a federally enforceable route to ensure that all necessary emission reductions take place in order to achieve the standards of performance. This is markedly different than the state-only standards, where according to the Ninth Circuit, the EPA and citizens had no route to ensure that all necessary emission reductions took place in order to attain the NAAQS. In addition, case law suggests that federal enforceability for every requirement may not be necessary when there are sufficient federally enforceable requirements to satisfy the statute, see *National Mining Ass'n v. United States EPA*, 59 F.3d 1351 (D.C. Cir. 1995); in this case federal enforceability for the state-only measures is not necessary to meet the statutory requirements of section 111(d)(1) as the federally enforceable trigger and backstop are sufficient.

d. Legal considerations with proposed portfolio approach. The EPA is not finalizing the portfolio approach that was included in the proposed rulemaking, 79 FR 34830, 34902 (June 18, 2014). In the proposal, the EPA noted that the portfolio approach raised legal questions. 79 FR 34830, 34902-03. A number of commenters stated that the portfolio approach is unlawful because it exceeds the limitations that section 111(d)(1) places on state plans. Upon further review, we agree with these comments.

Section 111(d)(1) provides that state plans shall "establish[] "standards of performance for any existing source" and "provide[] for the implementation and enforcement of . . . standards of performance" under CAA section 111(d)(1). Although in the proposal we identified possible interpretations of section 111(d)(1) that could justify the proposed portfolio approach, after reviewing the comments, we are not adopting those interpretations. Because section 111(d)(1) specifically requires state plans to include only (A) standards for emissions imposed on affected sources and (B) measures that implement and enforce such standards,[817] we interpret it as allowing federal enforceability only of requirements or measures that are in those two specifically required provisions. We therefore do not interpret the term "implementation of ... such standards of performance" to authorize the EPA to approve state plans with obligations enforceable against the broad array of non-emitting entities that would have been implicated by the portfolio approach. Thus, the EPA is not finalizing the portfolio approach, and in the event that states submit such measures to the EPA for inclusion in the state plan, the EPA would not approve them into the state plan and therefore would not make them federally enforceable.

We note that section 111(d) limits on federal enforceability of requirements against non-affected sources do not imply that the BSER cannot be based on actions by non-affected sources. As discussed in section V, the BSER may be

[817] Such measures include, for example, in this rule, requirements for ERCs.

based on the ability of owners/operators of affected sources to engage in commercial relationships with a wide range of other entities, from the vendors, installers, and operators of air pollution control equipment to, in this rulemaking, owners/operators of RE.

The EPA notes it is also not finalizing the proposed state commitment approach or state crediting approach. The EPA believes the finalized state measures plan type provides states with the same flexibilities as would have been allowed under these two proposed approaches, and does so in a way that is legally supportable by the CAA. Therefore, the EPA does not believe it necessary to finalize the state commitment approach or state crediting approach.

e. Legal basis for multi-state plans. While nothing in section 111(d)(1) explicitly authorizes either states to adopt and submit multi-state plans, or the EPA to approve them as satisfactory, nothing in section 111(d)(1) explicitly prohibits it, either. In addition, nothing in section 111(d)(2)(A)'s standard of "satisfactory" prohibits the EPA from considering multi-state plans as satisfactory. There is thus a gap that the EPA may reasonably fill.

In light of the purpose of these emission guidelines, to reduce emissions of a pollutant that globally mixes in the stratosphere, and the mechanisms to reduce those emissions, which may have beneficial effects across state lines, it is reasonable to allow for multi-state plans. Thus, our gap-filling interpretation of section 111(d) in this context is reasonable.

D. State Plan Components and Approvability Criteria

1. Approvability criteria

In the "Criteria for Approving State Plans" section of the preamble to the June 2014 proposal (section VIII.C), the EPA proposed the following as necessary components of an approvable state plan:

1. The plan must contain enforceable measures that reduce EGU CO_2 emissions;

2. The projected CO_2 emission performance by affected EGUs must be equivalent to or better than the required CO_2 emission performance level in the state plan;

3. The EGU CO_2 emission performance must be quantifiable and verifiable;

4. The plan must include a process for state reporting of plan implementation, CO_2 emission performance outcomes, and implementation of corrective measures, if necessary.

After reviewing the comments we received concerning the approvability criteria, the EPA has decided against maintaining the four proposed approvability criteria separately from the list of components required for an approvable plan, which may be confusing and potentially redundant. The EPA has determined that a satisfactory state plan that meets the required plan components discussed below will inevitably meet the proposed approvability criteria. The EPA, therefore, has incorporated the proposed approvability criteria into the section titled "Components of a state plan submittal" (section VIII.D.2 below). There is no functional change in the approvability criteria or the components of a state plan addressed in the proposal; they are simply combined and this change does not have a substantive effect on state plan development or approval.

Under the proposed "Enforceable Measures" criterion (section VIII.C.1 of the proposal preamble), the EPA specifically requested comment on the appropriateness of applying existing EPA guidance on enforceability to state plans under CAA section 111(d), considering the types of entities that might be included in a state plan.[818]

The EPA also requested comment on whether the agency should provide guidance on enforceability considerations related to requirements in a state plan for entities other than affected

[818] The existing guidance documents referenced were: (1) September 23, 1987 memorandum and accompanying implementing guidance, "Review of State Implementation Plans and Revisions for Enforceability and Legal Sufficiency," (2) August 5, 2004 "Guidance on SIP Credits for Emission Reductions from Electric-Sector Energy Efficiency and Renewable Energy Measures," and (3) July 2012 "Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, Appendix F."

EGUs, and if so, what types of entities. Comments received strongly suggested that the EPA provide guidance on enforceability considerations for non-EGU affected entities, particularly for RE and EE. Comments also requested additional guidance specific to this rulemaking, including examples of enforceable measures for specific activities, such as solar thermal technologies, waste heat recovery, net-metering energy savings and state RPS.

These enforcement considerations arose primarily under the proposed portfolio approach for state plans, which would have allowed state plans to include federally enforceable measures that apply to entities that are not affected EGUs. In this action, the EPA is finalizing the state measures approach instead of the portfolio approach, under which a state can rely upon measures that are not federally enforceable as long as the plan also includes a backstop of federally enforceable emission standards that apply to affected EGUs. As explained in depth in section VIII.C, if the state is adopting the state measures approach, the state plan submittal will need to specify, in the supporting materials, the state-enforceable measures that the state is relying upon, in conjunction with any federally enforceable emission standards for affected EGUs, to meet the emission guidelines. As part of the state measures approach, the EPA is finalizing a requirement for a federally enforceable backstop, which requires the affected EGUs to meet emission standards that fully achieve the CO_2 emission performance rates or the state's CO_2 emission goal if the state measures do not meet the intended emission performance levels. Because the EPA is not finalizing the portfolio approach, which would have allowed states to include federally enforceable measures in a state plan that apply to entities that are not affected EGUs, the agency is not providing additional guidance on federal enforceability of measures that might apply to such entities. As proposed, we are requiring that state plans include a demonstration that plan measures are enforceable, which for emission standards plan types is discussed in section VIII.D.2.b.3 below and for state measures plan types is discussed in section VIII.D.2.c.6 below.

Commenters also requested that the EPA allow states to rely on provisions with flexible compliance mechanisms in state plans and clarify how to address flexible compliance mechanisms when demonstrating achievement of a state CO_2 emission goal. Additionally, a commenter requested that the enforceability mechanisms that the EPA requires in state plans should support existing programs, as well as new programs in other states, by minimizing program changes required purely to conform with federal requirements, while still providing enough additional program review and accounting to ensure that CO_2 emission reductions are achieved. These and related comments contributed to the EPA's decision to finalize the option for states to submit a state measures plan, which would be comprised, at least in part, of measures implemented by the state that are not included as federally enforceable components of the plan, with a backstop of federally enforceable emission standards for affected EGUs that fully meet the emission guidelines and that would be triggered if the plan failed to achieve the CO_2 emission performance levels specified in the plan on schedule. For more information on the state measures plan approach, see section VIII.C.3 of this preamble above.

2. Components of a state plan submittal

In this action, the EPA is finalizing that a state plan submittal must include the components described below. As a result of constructive comments received from many commenters and additional considerations, the EPA is finalizing state plan components that are responsive to that input and are appropriate for the types of state plans allowed in the final emission guidelines. A state plan submittal must also be consistent with additional specific requirements elsewhere in this final rule and with the EPA implementing regulations at 40 CFR 60.23-60.29, except as otherwise specified by this final rule. These requirements apply to both individual state plan submittals and multi-state plan submittals. When a state plan submittal is approved by the EPA, the EPA will codify the approved CAA section 111(d) state plan in 40 CFR part 62. Section VIII.D.3 discusses the components of a state plan submittal that would be codified as the state CAA section 111(d) plan when the state plan submittal is approved by the EPA.

The EPA is finalizing that states can choose to meet the emission guidelines through one of two types of state plans: an emission standards plan type or a state measures plan type. A state pursuing the emission standards plan type may opt to submit a plan that meets the CO_2 emission performance rates for affected EGUs or meets the state rate-based or mass-based CO_2 emission goal for affected EGUs. A state implementing a state measures approach plan type must submit a plan that meets the state mass-based CO_2 goal for affected EGUs. The content of the state plan submittal will vary depending on which plan type the state decides to adopt. States that choose to participate in multi-state plans must adequately address plan components that apply to all participating states in the multi-state plan.

The rest of this section covers components that are required for all types of plans, as well as components specific to each specific type of plans. Section VIII.D.2.a addresses the components required for all plan submittals. Section VIII.D.2.b addresses the additional components required for submittals under the emission standards plan type. Section VIII.D.2.c addresses additional components required for submittals under the state measures plan type.

a. <u>Components required for all state plan submittals</u>. The EPA is finalizing requirements that a final plan submittal must contain the following components, in addition to those in either section VIII.D.2.b (for the emission standards plan type) or VIII.D.2.c (for the state measures plan type) of this section.

(1) <u>Description of the plan approach and geographic scope</u>.

The description of the plan type must indicate whether the state will meet the emission guidelines on an individual state basis or jointly through a multi-state plan, and whether the state is adopting an emission standards plan type or a state measures plan type. For multi-state plans this component must identify all participating states and geographic boundaries applicable to each component in the plan submittal. If a state intends to implement its individual plan in coordination with other states by allowing for the interstate transfer of ERCs or emission allowances, such links must also be identified.[819]

(2) <u>Applicability of state plans to affected EGUs</u>.

The state plan submittal must list the individual affected EGUs that meet the applicability criteria of 40 CFR 60.5845 and

[819] If applicable, this plan component must also identify if the plan is being submitted as a "ready-for-interstate-trading" plan, as discussed in section VIII.J.3 and VIII.K.4.

provide an inventory of CO_2 emissions from those affected EGUs for the most recent calendar year prior to plan submission for which data are available.

(3) Demonstration that a state plan will achieve the CO_2 emission performance rates or state CO_2 emission goal.

A state plan submittal must demonstrate that the federally enforceable emission standards for affected EGUs and/or state measures are sufficient to meet either the CO_2 emission performance rates or the state's CO_2 emission goal for affected EGUs in the emission guidelines for the interim and final plan performance periods. This includes during the interim period of 2022-2029, including the interim step 1 period (2022-2024); interim step 2 period (2025-2027); and interim step 3 period (2028-2029) period, as well as during the final period of 2030-2031 and subsequent 2-year periods.[820] A demonstration of CO_2 emission performance is required through 2031. For the post-2031 period, the demonstration requirement may be satisfied by showing that emission standards or state measures on which the

[820] State plans may meet the CO_2 emission performance rates in the emission guidelines during the interim plan performance step periods, or assign different interim step CO_2 emission performance rates, provided the CO_2 emission performance rates in the emission guidelines are achieved during the full interim period. Likewise, a state plan may meet the interim step state CO_2 emission goals in the emission guidelines or establish different interim step CO_2 emission levels, provided the state interim CO_2 goal is achieved during the full interim period.

demonstration through 2031 is based are permanent and will remain in place. As discussed in more detail in section VIII.J, states adopting a plan based upon a mass-based state CO_2 emission goal must demonstrate that they have addressed the risk of potential emission leakage in their mass-based state plan.

The type of demonstration of CO_2 emission performance and documentation required for such a demonstration in a state plan submittal will vary depending on how the CO_2 emission standards for affected EGUs and/or state measures in a state plan are applied across the fleet of affected EGUs in a state, as discussed below.[821]

(a) State plan type designs that require a projection of CO_2 emission performance. Whether a projection of affected EGU CO_2 emission performance must be included in a state plan submittal depends on the design of the state plan. The following plan designs do not require a projection of CO_2 emission performance by affected EGUs under the state plan because they ensure that the CO_2 emission performance rates or state rate-based or mass-

[821] For simplicity, the EPA refers here to state measures under a state measures plan as being included "in the state plan" although such state-enforceable measures are not codified as part of the federally enforceable approved state plan. However, the approval of a state measures plan is dependent on a demonstration in the state plan submittal that those state-enforceable measures meet the requirements in the emission guidelines and that those state measures, alone or in combination with federally enforceable emission standards for affected EGUs, will meet the mass-based CO_2 goal.

based CO_2 goals are achieved when affected EGUs comply with the emission standards:

- State plan establishes separate rate-based CO_2 emission standards for affected fossil fuel-fired electric utility steam generating units and stationary combustion turbines (in lb CO_2/MWh) that are equal to or lower than the CO_2 emission performance rates in the emission guidelines during the interim and final plan performance periods.
- State plan establishes a single rate-based CO_2 emission standard for all affected EGUs that is equal to or lower than the state's rate-based CO_2 goal in the emission guidelines during the interim and final plan performance periods.
- State plan establishes mass-based CO_2 emission standards for affected EGUs that cumulatively do not exceed a state's mass-based CO_2 goal in the emission guidelines during the interim and final plan performance periods.
- State plan establishes mass-based CO_2 emission standards for affected EGUs that, together with state enforceable limits on mass emissions from new EGUs, cumulatively do not exceed the state's EPA-specified mass CO_2 emission

budget[822] in the emission guidelines during the interim and final plan performance periods.

All other state plan designs must include a projection of CO_2 emission performance by affected EGUs under the state plan. For example, if a state chooses to apply rate-based CO_2 emission standards to individual affected EGUs, or to subcategories of affected EGUs (such as fossil fuel-fired electric utility steam generating units and stationary combustion turbines), at a lb CO_2/MWh rate that differs from the CO_2 emission performance rates or the state's rate-based CO_2 goal in the emission guidelines, then a projection is required. Also, if a state chooses to implement a mass-based program including both affected EGUs and new EGUs, but with total allowable emissions in excess of the presumptively approvable EPA-specified mass CO_2 emission budget for that state, the state must provide a projection of CO_2 emission performance. Likewise, if a state chooses a state measures state plan approach, a projection of CO_2 emission performance is required.

(b) Methods and tools. A satisfactory demonstration of the future CO_2 emission performance of affected EGUs must use technically sound methods that are reliable and replicable. A

[822] A state's EPA-specified mass CO_2 emission budget is the state's mass-based CO_2 goal for affected EGUs plus the EPA-specified new source CO_2 emission complement. See section VIII.J.2.b.

state plan submittal must explain how the projection method and/or tool works and why the method and/or tool chosen is appropriate considering the type of emission standards and/or state measures included (or relied upon, in the case of state measures) in a state plan. The results of the demonstration must be reproducible using the documented assumptions described in the state plan submittal. The method and projection of EGU generation and CO_2 emissions can differ from the EPA's forecast in the RIA. The EPA received comments on whether it would require specific modeling tools and input assumptions. Commenters raised concerns that the EPA may require states to use proprietary models, and that states do not have the financial resources to use such models. The EPA is not requiring a specific type of method or model, as long as the one chosen uses technically sound methods and tools that establish a clear relationship between electricity grid interactions and the range of factors that impact future EGU economic behavior, generation, and CO_2 emissions. The EPA will assess whether a method or tool is technically sound based on its capability to represent changes in the electric system commensurate to the set of emission standards and state measures in a state plan while accounting for the key parameters specified in section VIII.D.2.a.(3)(c) below. Including a base case CO_2 emission projection in the state plan submittal (i.e., one that does not include any federally enforceable CO_2 emission standards included in a plan or state-enforceable measures referenced in a plan submittal), will help facilitate the EPA's assessment of the CO_2 emission performance projection. Methods and tools could range from applying future growth rates to historical generation and emissions data, using statistical analysis, or electric sector energy modeling.

(c) Required documentation of projections. When required to provide a CO_2 emission performance projection, the state must also provide comprehensive documentation of analytic parameters for the EPA to assess the reasonableness of the projection. The analytic parameters, when considered as a whole, should reflect a logically consistent future outlook of the electric system. Refer to the Incorporating RE and Demand-side EE Impacts into State Plan Demonstrations TSD of the final rule for further details on quantifying impacts of eligible RE and demand-side EE measures.

The CO_2 emission performance projection documentation must include:

- Geographic representation, which must be appropriate for capturing impacts and/or changes in the electric system
- Time period of analysis, which must extend through 2031
- Electricity demand forecast (MWh load and MW peak demand)

at the state and regional level. If the demand forecast is not from NERC, an ISO or RTO, EIA, or other publicly available source, then the projection must include justification and documentation of underlying assumptions that inform the development of the demand forecast, such as annual economic and demand growth rate, population growth rate.

- Planning reserve margins
- Planned new electric generating capacity
- Analytic treatment of the potential for building unplanned new electric generating capacity
- Wholesale electricity prices
- Fuel prices, when applicable;
- Fuel CO_2 content
- Unit-level fixed operations and maintenance costs, when applicable;
- Unit-level variable operations and maintenance costs, when applicable;
- Unit-level capacity
- Unit-level heat rate
- If applicable, EGU-specific actions in the state plan designed to meet the required CO_2 emission performance, including their timeline for implementation

- If applicable, state-enforceable measures, with electricity savings and renewable electricity generation (MWhs) expected for individual and collective measures, as applicable. Quantification of MWhs expected from EE and RE measures will involve assumptions that states must document, as described in the Incorporating RE and Demand-side EE Impacts into State Plan Demonstrations TSD.
- Annual electricity generation (MWh) by fuel type and CO_2 emission levels, for each affected EGU
- ERC or emission allowance prices, when applicable

The state must also provide a clear demonstration that the state measures and/or federally enforceable emission standards informing the projected achievement of the emission performance requirements will be permanent and remain in place.

The EPA encourages participation in regional modeling efforts which are designed to allow sharing of data and help promote consistent approaches across state boundaries. A state that submits a single-state plan must consider interstate transfer of electricity across state boundaries, taking into account other states' plan types reflecting the best available information at the time of the CO_2 emission performance projection. Projections of CO_2 emission performance for multi-state plans and single-state plans that include multi-state coordination must either use a single (regional) electricity demand forecast or must document the use of electricity demand forecasts from different information sources and demonstrate how any inconsistencies between the individual electricity demand forecasts have been reconciled.

(d) Additional projection requirements under a rate-based emission standards plan. For an emission standards plan that applies rate-based CO_2 emission standards to individual affected EGUs, or to subcategories of affected EGUs, at a lb CO_2/MWh rate that differs from the CO_2 emission performance rates or the state’s rate-based CO_2 goal in the emission guidelines, a projection of affected EGU CO_2 emission performance is required. The state must demonstrate that the weighted average CO_2 emission rate of affected EGUs, when weighted by generation (in MWh) from affected EGUs subject to the different rate-based emission standards, will be equal to or less than the CO_2 emission performance rates or the state's rate-based CO_2 emission goal during the interim and final plan performance periods.

The projection will involve an analysis of the change in generation of affected EGUs given the compliance costs and incentives under the application of different emission rate standards across affected EGUs in a state. It must accurately represent the emission standards in the plan, including the use of market-based aspects of the emission standards (if applicable), such as use of ERCs or emission allowances as compliance instruments.

In addition to the elements described in the previous section (c), the projection under this plan design must include:

- The assignment of federally enforceable emission standards for each affected EGU;
- A projection showing how generation is expected to shift between affected EGUs and across affected EGUs and non-affected EGUs over time;
- Underlying assumptions regarding the availability and anticipated use of the MWh of electricity generation or electricity savings from eligible measures that can be issued ERCs;
- The specific calculation (or assumption) of how eligible MWh of electricity generation or savings that can be issued ERCs are being used in the projection to adjust the reported CO_2 emission rate of affected EGUs, consistent with the accounting methods for adjusting the CO_2 emission rate of an affected EGU specified in section VIII.K.1 of the emission guidelines, if applicable;
- ERC prices, if applicable;
- If a state plan provides for the ability of RE resources

located in states with mass-based plans to be issued ERCs for use in adjusting the reported CO_2 emission rates of affected EGUs, consideration in the projection that such resources must meet geographic eligibility requirements, based on power purchase agreements or related documentation, consistent with the requirements at section VIII.K.1 and section VIII.L; and

- Any other applicable assumptions used in the projection.

(e) Additional projections requirements for a state measures plan. For a state measures plan, a projection of affected EGU CO_2 emission performance must demonstrate that the state measures, whether alone or in conjunction with any federally enforceable CO_2 emission standards for affected EGUs, will achieve the state's mass-based CO_2 goals in the emission guidelines for the interim and final periods. The projection must accurately represent individual state-enforceable measures (or bundled measures) and timing for implementation of these state measures.

A state must demonstrate that its state-enforceable measures, along with any federally enforceable CO_2 emission standards for affected EGUs included in a state plan, will achieve the state mass-based CO_2 goal. In addition to the elements described in section VIII.D.2.a.(3).(c), the state must clearly document, at a minimum:

- the assignment of federally enforceable emission standards for each affected EGUs, if applicable; and

- the individual state measures, including their projected impacts over time.

Because different types of state measures could have varying degrees of impact on reducing or avoiding CO_2 emissions from affected EGUs, and different state measures may interact with one another in terms of CO_2 emission reduction impacts, the method and tools a state uses to project CO_2 emissions impacts must have the capability to project how the combined set of state-enforceable measures are likely to impact CO_2 emissions at affected EGUs. If a state chooses to use an emission budget trading program as a mass-based state measure, for example, the state must choose an analytic method or tool that can account for and properly represent any program flexibilities that impact CO_2 emissions from affected EGUs, such as use of out-of-sector GHG offsets and cost-containment provisions. The state would show that the emissions budget trading program included in the state measures plan, as well as any other state measures, ensure that the sum of emissions at all affected EGUs will be lower than or equal to the state's CO_2 emission goal in the time periods specified in these guidelines. All flexibilities must be clearly documented in the demonstration.

(4) Monitoring, reporting and recordkeeping requirements for affected EGUs.

The state plan submittal must specify how each emission standard is quantifiable and verifiable by describing the CO_2 emission monitoring, reporting and recordkeeping requirements for affected EGUs. The applicable monitoring, recordkeeping and reporting requirements for affected EGUs are outlined in section VIII.F.

In the June 2014 proposal, the EPA proposed that states must include in their state plans a record retention requirement for affected EGUs to maintain records for at least 10 years following the date of each occurrence, measurement, maintenance, corrective action, report or record. Commenters requested clarification of the record retention requirements for states as compared to for affected EGUs and also requested that the EPA clarify onsite versus offsite record maintenance requirements for affected EGUs. The EPA is finalizing that states must include in their plans a record retention requirement for affected EGUs of not less than 5 years following the date of each compliance period, compliance true-up period, occurrence, measurement, maintenance, corrective action, report, or record, whichever is latest. Affected EGUs must maintain each record onsite for at least 2 years after the date of the occurrence of each record and may maintain records offsite and electronically for the remaining years. Each record must be in a form suitable and readily available for expeditious review. The EPA finds that these final recordkeeping requirements are appropriate and consistent with the requirements for other CAA section 111(d) emission guidelines.

(5) State reporting and recordkeeping requirements.

A state plan submittal must contain the process, content and schedule for state reporting to the EPA on plan implementation and progress toward meeting the CO_2 emission performance rates or state CO_2 emission goal.

The EPA requested comments on whether full reports containing all of the report elements should only be required every 2 years and on the appropriate frequency of reporting of the different proposed elements, considering both the goals of minimizing unnecessary burdens on states and ensuring program transparency and effectiveness. Commenters recognized that different reporting frequencies may be appropriate for different types of state plans. The EPA agrees with the commenters and is finalizing state reporting requirements based on the type of plan the state chooses to adopt and implement. These state reporting requirements and reporting periods are discussed in section VIII.D.2.b (for emission standards plan types) and VIII.D.2.c (for state measures plan types). The EPA finalizes that each state report is due to the EPA no later than the July 1 following the end of each reporting period. The EPA recognizes the multiple comments received recommending extending the state report due date from July 1 to a later date or to allow the states the flexibility to propose an alternative report submittal date. The EPA is not pursuing these recommendations due to the implications of the state reports’ due date and the trigger and schedule for implementation of corrective measures (for the emission standards approach) or the backstop federally enforceable emission standards (for the state measures approach). The EPA believes the July 1 deadline for states to submit reports to the EPA on plan implementation is feasible given that the information required to be included in the reports will be available per the reporting requirements for affected EGUs in state plans.

In addition to the state reporting requirements discussed in section VIII.D.2.b (for emission standards approach) and VIII.D.2.c (for state measures approach) and as discussed below, states must include in the supporting material of a final state plan submittal a timeline with all the programmatic milestone steps the state will take between the time of the final state plan submittal and 2022 to ensure the plan is effective as of 2022. The EPA is also finalizing a requirement that states must submit a report to the EPA in 2021 that demonstrates that the state has met the programmatic milestone steps that the state indicated it would take from the submittal of the final plan through the end of 2020, and that the state is on track to implement the approved state plan as of January 1, 2022. A final state plan submission must include a requirement for the state to submit this report to the EPA no later than July 1, 2021. This report will help the EPA further assist and facilitate plan implementation with states as part of an ongoing joint effort to ensure the necessary reductions are achieved.

The EPA is finalizing the requirement that submissions related to this program be submitted electronically. Specifically, this includes negative declarations, state plan submittals (including any supporting materials that are part of a state plan submittal), any plan revisions, and all reports required by the state plan. The EPA is developing an electronic system to support this requirement that can be accessed at the EPA’s Central Data Exchange (CDX) (http://www.epa.gov/cdx/). See section VIII.E.8 for additional information on electronic submittal requirements.

In the June 2014 proposal, the EPA proposed that states must keep records, for a minimum of 20 years, of all plan components, plan requirements, plan supporting documentation and status of meeting the plan requirements, including records of all data submitted by each affected EGU used to determine compliance with its emission standards. The EPA received multiple comments recommending that the EPA reduce recordkeeping requirements due to the burden in expenditure of resources and manpower to maintain records for at least 20 years. Commenters recommended that recordkeeping requirements be reduced to 5 years consistent with emission guidelines for other existing sources.

After considering the comments received, this final rule requires that a state must keep records of all plan components, plan requirements, supporting documentation, and the status of meeting the plan requirements defined in the plan for the interim plan period from 2022-2029 (including interim steps 1, 2 and 3). After 2029, states must keep records of all information relied upon in support of any continued demonstration that the final CO_2 emission performance rates or goals are being achieved. The EPA agrees with comments that a 20-year record retention requirement could be unduly burdensome, and has reduced the length of the record retention requirement for the final rule. During the interim period, states must keep records for 10 years from the date the record is used to determine compliance with an emission standard, plan requirement, CO_2 emission performance rate or CO_2 emission goal. During the final period, states must keep records for 5 years from the date the date the record is used to determine compliance with an emission standard, plan requirement, CO_2 emission performance rate or CO_2 emissions goal. All records must be in a form suitable and readily available for expeditious review. States must also keep records of all data submitted by each affected EGU that was used to determine compliance with each affected EGU's emission standard, and such data must meet the requirements of the emission guidelines, except for any information that is submitted to the EPA electronically pursuant to requirements in 40 CFR part 75. If the state is adopting and implementing the state measures approach, the state must also maintain records of all data regarding implementation of each state measure and all data used to demonstrate achievement of the CO_2 emission goal and such data must meet the requirements of the emission guidelines. The EPA finds that these final recordkeeping requirements balance the need to maintain records while reducing the strain on state resources.

(6) Public participation and certification of hearing on state plan.

A robust and meaningful public participation process during state plan development is critical. For the final plan submittal, states must meaningfully engage with members of the public, including vulnerable communities, during the plan development process. This section describes how the EPA will evaluate a state plan for compliance with the minimum required elements for public participation provided in the existing implementing regulations as well as recommendations for other steps the state can take to assure robust and inclusive public participation.

The existing implementing regulations regarding public participation requirements are in 40 CFR 60.23(c)-(f). Per the implementing regulations, states must conduct a public hearing on a final state plan before such plan is adopted and submitted. State plan development can be enhanced by tapping the expertise and program experience of several state government agencies. The EPA encourages states to include utility regulators (e.g. the PUCs) and state energy offices as appropriate early on and throughout in the development of the state plan.[823] The EPA notes that utility regulators and state energy offices have the opportunity during the public participation processes required for state plans to provide input as well. The EPA also encourages states to conduct outreach meetings (that could include public hearings or meetings) with vulnerable communities on its initial submittal before the plan is submitted. In its final plan submittal, a state must provide certification that the state made the plan submittal available to the public and gave reasonable notice and opportunity for public comment on the state plan submittal. The state must demonstrate that the public hearing on the state plan was held only after reasonable notice,

[823] While we specifically encourage state environmental agencies and utility regulators to consult here, we note that, under CAA programs, state agencies have a history of consultation with one another as appropriate.

which will be considered to include, at least 30 days prior to the date of such hearing, notice given to the public by prominent advertisement announcing the date(s), time(s) and place(s) of such hearing(s). For each hearing held, a state plan submittal must include in the supporting documentation the list of witnesses and their organizational affiliations, if any, appearing at the hearing, and a brief written summary of each presentation or written submission pursuant to the requirements of the implementing regulations at 40 CFR 60.23. Additionally, the EPA recommends that states work with local municipalities, community-based organizations and the press to advertise their state public hearing(s). The EPA also encourages states to provide background information about their proposed final state plan or their initial submittal in the appropriate languages in advance of their public hearing and at their public hearing. Additionally, the EPA recommends that states provide translators and other resources at their public hearings, to ensure that all members of the public can provide oral feedback.

As previously discussed in this rule, recent studies also find that certain communities, including low-income communities and some communities of color (more specifically, populations defined jointly by ethnic/racial characteristics and geographic location) are disproportionately affected by certain climate change related impacts.[824] Also as discussed in this rule, effects from this rule can be anticipated to affect vulnerable communities in various ways. Because certain communities have a potential likelihood to be impacted by state plans, the EPA believes that the existing public participation requirements under 40 CFR 60.23 are effectuated for the purposes of this final rule by states engaging in meaningful, active ways with such communities.

In addition, certain communities whose economies are significantly dependent on coal, or whose economies may be affected by ongoing changes in the utility power and related sectors, may be particularly concerned about the final rule. The EPA encourages states to make an effort to provide background information about their proposed initial submittal and final state plans to these communities in advance of their public hearing. In particular, the EPA encourages states to engage with workers and their representatives in the utility and related sectors, including the EE sector.

The EPA notes that meaningful public involvement goes beyond the holding of a public hearing. The EPA envisions meaningful engagement to include outreach to vulnerable communities,

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[824] USGCRP 2014: Melillo, Jerry M., Terese (T.C.) Richmond, and Gary W. Yohe, Eds., 2014: *Climate Change Impacts in the United States: The Third National Climate Assessment.* U.S. Global Change Research Program, 841 pp.

sharing information and soliciting input on state plan development and on any accompanying assessments, such as those described in section IX. The agency uses the terms "vulnerable" and "overburdened" in referring to low-income communities, communities of color, and indigenous populations that are most affected by, and least resilient to, the impacts of climate change, and are central to our community and environmental justice considerations. In section VIII.E, the EPA provides states with examples of resources on how they can engage with vulnerable communities in a meaningful way. With respect specifically to ensuring meaningful community involvement in their public hearing(s), however, the EPA recommends that states have both a website and toll-free number that all stakeholders, including overburdened communities, labor unions, and others can access to get more information regarding the upcoming hearing(s) and to get their questions related to upcoming hearings answered. Furthermore, the EPA recommends that states work with their local government partners to help them in reaching out to all stakeholders, including vulnerable communities, about the upcoming public hearing(s).

(7) Supporting documentation.

The state plan submittal must provide supporting material and technical documentation related to applicable components of the plan submittal.

(a) Legal authority.

In its submittal, a state must adequately demonstrate that it has the legal authority (regulations/legislation) and funding to implement and enforce each component of the state plan submittal, including federally enforceable emission standards for affected EGUs and state measures. A state can make such a demonstration by providing supporting material related to the state's legal authority used to implement and enforce each component of the plan, such as copies of statutes, regulations, PUC orders, and any other applicable legal instruments. For states participating in a multi-state plan, the submittal(s) must also include as supporting documentation each state's necessary legal authority to implement the portion of the plan that applies within the particular state, such as copies of state regulations and statutes, including a showing that the states have the necessary authority to enter into a multi-state agreement.

(b) Technical documentation.

As applicable, the state submittal must include materials necessary to support the EPA's evaluation of the submittal including analytical materials used in the calculation of interim goal steps (if applicable), analytical materials used in the multi-state goal calculation (if multi-state plan), analytical materials used in projecting CO_2 emission performance that will be achieved through the plan, relevant implementation materials and any additional technical requirements and guidance the state proposes to use to implement elements of the plan.

(c) Programmatic milestones and timeline.

As part of the state plan supporting documentation, the state must include in its submittal a timeline with all the programmatic milestone steps the state will take between the time of the state plan submittal and 2022 to ensure the plan is effective as of January 1, 2022. The programmatic milestones and timeline should be appropriate to the overall state plan approach included in the state plan submittal.

(d) Reliability.

As discussed in more detail in section VIII.G.2, each state must demonstrate as part of its state plan submission that it has considered reliability issues while developing its plan.

b. Additional components required for the emission standards plan type. The EPA is finalizing requirements that a final plan submittal using the emission standards plan type must contain the following components, in addition to the components discussed in the preceding section VIII.D.2.a.

(1) Identification of interim period emission performance rates or state goal (for 2022-2029), interim step performance rates or interim state goals (2022-2024; 2025-2027; 2028-2029) and final emission performance rates or state goal (2030 and

beyond).

The state plan submittal must indicate whether the plan is designed to meet the CO_2 emission performance rates or the state CO_2 emission goal. As noted in the emission guidelines, the EPA is finalizing CO_2 emission performance rates for fossil fuel-fired steam generating units and for stationary combustion turbines. The EPA has translated the source category-specific CO_2 emission performance rates into equivalent state-level rate-based and mass-based CO_2 goals in order to maximize the range of choices that states will have in developing their plans. The state may choose to develop a state plan that meets the CO_2 performance rates for the two subcategories of affected EGUs or develop a plan that adopts either the rate-based or the mass-based state CO_2 emission goal provided in the emission guidelines.

Each state plan must identify the emission performance rates or rate-based or mass-based CO_2 emission goal that must be achieved through the plan (expressed in numeric values, including the units of measurement, such as pounds of CO_2 per net MWh of useful energy output or tons of CO_2). The plan submittal must identify the CO_2 interim period performance rates or state goal (for 2022-2029), interim step performance rates or state goals (interim step performance rates or state goal 1 for 2022-2024; interim step performance rates or state goal 2 for 2025-

2027; interim step performance rates or state goal 3 for 2028-2029) and final CO_2 emission performance rates or state goal of 2030 and beyond.

The EPA has finalized an interim performance rates or state goal for the interim period of 2022-2029 and a final performance rates or state goal to be met by 2030. For the interim period, the EPA has also finalized three interim step performance rates or state goals: interim step 1 performance rates or state goal for 2022-2024, interim step 2 performance rates or state goal for 2025-2027 and interim step 3 performance rates or state goal for 2028-2029.[825] States are free to establish different interim step performance rates or interim step state goals than those the EPA has specified in this final rule. If states choose to determine their own interim step performance rates or state goals, the state must demonstrate that the plan will still meet the interim performance rates or state goal for 2022-2029 finalized in the emission guidelines and the plan submittal must include in its supporting documentation a description of the analytic process, tools, methods, and assumptions used to make this demonstration.

For states participating in a multi-state plan with a joint

[825] In this action, the EPA is providing interim state goals in the form of a CO_2 emission rate (emission rate-based goal) and in the form of tonnage CO_2 emissions (mass-based goal).

goal (for interim and final periods), the individual state goals in the emission guidelines would be replaced with an equivalent multi-state goal for each period (interim and final). For a rate-based multi-state plan this would be a weighted average rate-based emission goal, derived by the participating states, by calculating a weighted average CO_2 emission rate based on the individual rate-based goals for each of the participating states and 2012 generation from affected EGUs. For a mass-based multi-state plan, the joint goal would be a sum of the individual mass-based goals of the participating states, in tons of CO_2. The plan submittal must include in its supporting documentation a description of the analytic process, tools, methods, and assumptions used to calculate the joint multi-state goal.

(2) Identification of federally enforceable emission standards for affected EGUs.

The state plan submittal for an emission standards plan type must include federally enforceable emission standards that apply to affected EGUs. The emission standards must meet the requirement of component (3) of this section, "Demonstrations that each emission standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable." The plan must identify the affected EGUs to which these standards apply. The compliance periods for each emission standard for affected EGUs, on a calendar year basis, must be as follows for the interim period:

January 1, 2022 – December 31, 2024; January 1, 2025 – December 31, 2027; and January 1, 2028 – December 31, 2029. Starting on January 1, 2030, the compliance period for each emission standard is every 2 calendar years. States can choose to set shorter compliance periods for the emission standards than the compliance periods the EPA is finalizing in this rulemaking, but cannot set longer periods. As discussed in more detail in section VIII.F, the EPA recognizes that the compliance periods provided for in this rulemaking are longer than those historically and typically specified in CAA rulemakings. The EPA determined that the longer compliance periods provided for in this rulemaking are acceptable in the context of this specific rulemaking because of the unique characteristics of this rulemaking, including that CO_2 is long-lived in the atmosphere, and this rulemaking is focused on performance standards related to those long-term impacts.

For state plans in which affected EGUs may rely upon the use of ERCs for meeting a rate-based federally enforceable emission standard, the emission standards in the state plan must include requirements addressing the issuance, tracking and use for compliance of ERCs consistent with the requirements in the emission guidelines. These requirements are discussed in sections VIII.K.1-2. The state plan must also demonstrate that the appropriate ERC tracking infrastructure that meets the requirements of the emission guidelines will be in place to administer the state plan requirements regarding ERCs and document the functionality of the tracking system. State plan requirements must include provisions to ensure that ERCs are properly tracked from issuance to submission for compliance. The state plan must also demonstrate that the MWh for which ERCs are issued are properly quantified and verified, through plan requirements for EM&V and verification that meet the requirements in the emission guidelines. EM&V requirements are discussed in section VIII.K.3. Rate-based emission standards must also include monitoring, reporting, and recordkeeping requirements for CO_2 emissions and useful energy output for affected EGUs; and related compliance demonstration requirements and mechanisms. These requirements are discussed in more detail in sections VIII.F and VIII.K.

For state plans using a mass-based emission trading program approach, the state plan must include implementation requirements that specify the emission budget and related compliance requirements and mechanisms. These requirements must include: CO_2 emission monitoring, reporting, and recordkeeping requirements for affected EGUs; provisions for state allocation of allowances; provisions for tracking of allowances, from issuance through submission for compliance; and the process for affected EGUs to demonstrate compliance (allowance "true-up" with reported CO_2 emissions).

(3) Demonstration that each emission standard is quantifiable, non-duplicative, permanent, verifiable and enforceable.

The plan submittal must demonstrate that each emission standard is quantifiable, non-duplicative, permanent, verifiable and enforceable with respect to an affected EGU, as outlined below.

An emission standard is quantifiable if it can be reliably measured, using technically sound methods, in a manner that can be replicated.[826]

An emission standard is non-duplicative with respect to an affected EGU if it is not already incorporated in another state plan, except in instances where incorporated as part of a multi-state plan. An example of a duplicative emission standard would occur, for example, where a quantified and verified MWh from a wind turbine could be applied in more than one state's CAA

[826] A CO_2 continuous emissions monitoring system (CEMS) is the most technically reliable method of emission measurement for EGUs. A CEMS provides a measurement method that is performance based rather than equipment specific and is verified based on NIST traceable standards. A CEMS provides a continuous measurement stream that can account for variability in the fuels and the combustion process. Reference methods have been developed to ensure that all CEMS meet the same performance criteria, which helps to ensure a level playing field and consistent, accurate data.

section 111(d) plan to adjust the reported CO_2 emission rate of an affected EGU (e.g., through issuance and use of an ERC), except in the case of a multi-state plan where CO_2 emission performance is demonstrated jointly for all affected EGUs subject to the multi-state plan or where states are implementing coordinated individual plans that allow for the interstate transfer of ERCs.[827] This does not mean that measures used to comply with an emission standard cannot also be used for other purposes. For example, a MWh of electric generation from a wind turbine could be used by an electric distribution utility to comply with state RPS requirements and also be used by an affected EGU comply with emission standard requirements under a state plan. Another example is when actions taken pursuant to CAA section 111(d) requirements can satisfy other CAA program requirements (e.g., Regional Haze requirements, MATS).

An emission standard is permanent if the emission standard must be met for each applicable compliance period.

[827] For example, an ERC that is issued by a state under its rate-based emission standards may be used only once by an affected EGU to adjust its reported CO_2 emission rate when demonstrating compliance with the emission standards. However, an ERC issued in one state could be used by an affected EGU to demonstrate compliance with its emission standard in another state, where states are collaborating in the implementation of their individual emission trading programs through interstate transfer of ERCs, or participating in a multi-state plan with a rate-based emission trading program. These coordinated multi-state approaches are addressed in sections VIII.C.5, VIII.J.3, and VIII.K.4.

An emission standard is verifiable if adequate monitoring, recordkeeping and reporting requirements are in place to enable the state and the Administrator to independently evaluate, measure, and verify compliance with it.

An emission standard is enforceable if: (1) it represents a technically accurate limitation or requirement and the time period for the limitation or requirement is specified; (2) compliance requirements are clearly defined; (3) the entities responsible for compliance and liable for violations can be identified; and (4) each compliance activity or measure is enforceable as a practical matter in accordance with EPA guidance on practical enforceability,[828] and the Administrator, the state, and third parties, maintain the ability to enforce against affected EGUs for violations and secure appropriate corrective actions, in the case of the Administrator pursuant to CAA sections 113(a)-(h), in the case of a state, pursuant to its state plan, state law or CAA section 304, as applicable, and in the case of third parties, pursuant to CAA section 304.

[828] The EPA guidance on enforceability includes: (1) September 23, 1987, memorandum and accompanying implementing guidance, "Review of State Implementation Plans and Revisions for Enforceability and Legal Sufficiency," (2) August 5, 2004, "Guidance on SIP Credits for Emission Reductions from Electric-Sector Energy Efficiency and Renewable Energy Measures," and (3) July 2012 "Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, Appendix F."

In developing its CAA section 111(d) plan, to ensure that the plan submittal is enforceable and in conformance with the CAA, a state should follow the EPA's prior guidance on enforceability.[829] These guidance documents serve as the foundation for the types of monitoring, reporting, and emission standards that the EPA has found can be, as a practical matter, enforced.

In the proposed regulatory text describing the enforcing measures that states must include in state plans, the EPA inadvertently excluded a required demonstration that states and other third parties can enforce against affected EGUs for violations of an emission standard included in a state plan via civil action pursuant to CAA section 304. Commenters noted the EPA's intent to require this demonstration based on statements in both the proposal preamble text and "State Plan Considerations" TSD[830] and based on the requirements of CAA section 304. We are finalizing a requirement for a demonstration that states and other third parties can enforce against affected EGUs for violations of an emission standard included in a state plan via civil action as part of the required plan component

[829] See prior footnote.
[830] State Plan Considerations technical support document for the Clean Power Plan Proposed Rule: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-state-plan-considerations.

demonstrating enforceability. We are finalizing this requirement as a logical outgrowth of proposal preamble text, the proposal preamble citation to existing enforceability guidance documents that discuss this requirement, comments received, and the clear statutory foundation.

(4) State reporting requirements.

After consideration of the comments received regarding state reporting requirements, the EPA is finalizing for state plans using the emission standards approach that a state report is due to the EPA no later than the July 1 following the end of each reporting period. Within the interim period (2022-2029) the EPA is finalizing the following interim reporting periods: interim step 1 covers the three calendar years 2022-2024, interim step 2 covers the three calendar years 2025-2027, and interim step 3 covers the two calendar years 2028-2029. A biennial state report is required starting in 2030 and beyond covering the two calendar years of each reporting period. This final reporting schedule reduces the reporting frequency for states implementing the emission standards approach and is responsive to comments received that different reporting frequencies may be appropriate for different type of state plans. The EPA believes that because of the federally enforceable emission standards that apply to affected EGUs and their corresponding monitoring, reporting and recordkeeping requirements under the emission standards plan type, a lesser frequency of reporting by the state is warranted.

The state must include in each report to the EPA the status of implementation of emission standards for affected EGUs under the state plan, including current aggregate and individual CO_2 emission performance by affected EGUs during the reporting period. The state report must include compliance demonstrations for affected EGUs and identify whether affected EGUs are on schedule to meet the applicable CO_2 emission performance rate or emission goal during the performance periods and compliance periods, as specified in the state plan. For rate-based emission trading programs, the report must also include for EPA review the state's review of the administration of their state rate-based emission trading program, as discussed in section VIII.K.2.g.

As discussed in more detail in section VIII.F, the state must include an interim performance check in the report submitted after each of the first two interim step periods. The interim performance check will compare the CO_2 emission performance level identified in the state plan for the applicable interim step period with the actual CO_2 emission performance achieved by affected EGUs during the period. In the report due to the EPA on July 1, 2030, the state must include a comparison of the actual CO_2 emission performance achieved by affected EGUs for the interim period (2022-2029) with the interim CO_2 emission performance rates or state rate-based or mass-based CO_2 interim goal, as applicable. The report due on July 1, 2030, must also include the actual CO_2 emission performance achieved by affected EGUs during the interim step 3 period (2028-2029). Starting in 2032, the biennial state report must include a final performance check to demonstrate that the affected EGUs continue to meet the final CO_2 emission performance rates or state rate-based or mass-based CO_2 goal.

For state plans that use the emission standards approach and are subject to the corrective measures provisions in the emission guidelines, if actual CO_2 emission performance (i.e., the emissions or emission rate) of affected EGUs exceeds the specified level of CO_2 emission performance in the state plan by 10 percent or more during the interim step 1 or step 2 reporting periods, the state report must include a notification to the EPA that corrective measures have been triggered. The same notification is required if actual CO_2 emission performance fails to meet the specified level of emission performance in the state plan for the 8-year interim performance period or any final plan reporting period. Corrective measures are discussed in detail in section VIII.F.

c. Additional components required for the state measures approach. The EPA is finalizing requirements that a final plan submittal using the state measures approach must contain the following components, in addition to the components discussed in section VIII.D.2.a. We note again that states choosing the state measures plan type must use a mass-based state goal.

(1) Identification of interim state mass goal (for 2022-2029), interim step state mass goals (2022-2024; 2025-2027; 2028-2029) and final state mass goal (2030 and beyond).

The state plan submittal must identify the mass-based CO_2 emission goal that must be achieved through the plan (expressed in tons of CO_2). The plan submittal must identify the state CO_2 interim period goal (for 2022-2029), interim step goals (interim step goal 1 for 2022-2024; interim step goal 2 for 2025-2027; interim step goal 3 for 2028-2029) and final CO_2 emission goal of 2030 and beyond.

For each state, the EPA has finalized an interim goal for the interim period of 2022-2029 and a final goal to be met by 2030. For the interim period, the EPA has also finalized three interim step goals: interim step 1 goal for 2022-2024, interim step 2 goal for 2025-2027 and interim step 3 goal for 2028-2029.[831] States are free to establish different interim step goals than those the EPA has specified in this final rule. If

[831] In this action, the EPA is providing interim state goals in the form of a CO_2 emission rate (emission rate-based goal) and in the form of tonnage CO_2 emissions (mass-based goal).

states choose to determine their own interim step goals, the state must demonstrate that it will still meet the interim goal for 2022-2029 finalized in this action and the plan submittal must include in its supporting documentation a description of the analytic process, tools, methods, and assumptions used to make this demonstration.

For states participating in a multi-state plan with a joint goal (for interim and final periods), the individual state goals in the emission guidelines would be replaced with an equivalent multi-state goal for each period (interim and final). The joint goal would be a sum of the individual mass-based goals of the participating states, in tons of CO_2. The plan submittal must include in its supporting documentation a description of the analytic process, tools, methods, and assumptions used to calculate the joint multi-state goal.

(2) Identification of federally enforceable emission standards for affected EGUs (if applicable).

If applicable, the state plan submittal must include any federally enforceable CO_2 emission standards that apply to affected EGUs, and demonstrate that those emission standards meet the requirements that apply in the context of an emission standards approach, discussed in the preceding section VIII.D.2.b. Specifically, the state plan submittal must demonstrate that each federally enforceable emission standard is quantifiable, non-duplicative, permanent verifiable, and enforceable. If a state measures plan type includes CO_2 emission standards that apply to affected EGUs, these emission standards must be federally enforceable.

(3) Identification of backstop of federally enforceable emission standards.

A state measures plan must include a backstop of federally enforceable emission standards for affected EGUs that fully achieve the interim and final CO_2 emission performance rates or the state's interim and final CO_2 emission goal if the state plan fails to achieve the intended level of CO_2 emission performance. The backstop emission standards could be based on the finalized model rule that the EPA is proposing in a separate action. For the federally enforceable backstop, the state plan submittal must identify the federally enforceable emission standards for affected EGUs, demonstrate that those emission standards meet the requirements that apply in the context of an emission standards approach, discussed in the preceding section, identify a schedule and trigger for implementation of the backstop that is consistent with the requirements in the emission guidelines as discussed in section VIII.C.3.b and identify all necessary state administrative and technical procedures for implementing the backstop (e.g. how and when the state would notify affected EGUs that the backstop has been triggered). Aspects of the backstop are discussed in detail in section VIII.C.3.b.

(4) Identification of state measures.

A state adopting a state measures plan type must provide as a part of the supporting documentation of its plan submittal, a description of all the state enforceable measures the state will rely upon to achieve the requisite state mass-based goal, the applicable state laws or regulations related to such measures, and identification of parties or entities implementing or complying with such state measures. The state must also include in its supporting documentation the schedule and milestones for the implementation of the state measures, showing that the measures are expected to achieve the mass-based CO_2 emission goal for the interim period (including the interim step periods) and meet the final goal by 2030. A state measures plan submittal that relies upon state measures that include RE and demand-side EE programs and projects must also demonstrate in its supporting documentation that the minimum EM&V requirements in the emission guidelines apply to those programs and projects as a matter of state law.

(5) State reporting requirements.

After consideration of the comments received regarding state reporting requirements, the EPA is requiring in this final rule for states using the state measures approach that an annual state report is due to the EPA no later than July 1 following the end of each calendar year during the interim period. This annual state report must include the status of implementation of federally enforceable emission standards (if applicable) and state measures, and must include a report of the periodic programmatic milestones to show progress in program implementation. The programmatic milestones with specific dates for achievement should be appropriate to the state measures included in the state plan submittal. The EPA believes that annual state reporting is appropriate for state measures approach due to the flexibility inherent to the approach described in section VIII.C.3 including the potential use by the state of a wider variety of state measures, responsible parties, etc. This reporting frequency will also increase the degree of certainty on plan performance for states pursuing the state measures approach.

As discussed in section VIII.F, for states using the state measures approach, the EPA is finalizing that at the end of the first two interim step periods, the state must also include in their annual report to the EPA the corresponding emission performance checks. The interim performance checks will compare the CO_2 emission performance level identified in the state plan for the applicable interim step period versus the actual CO_2 emission performance achieved by the aggregate of affected EGUs. In the report submitted to the EPA on July 1, 2030, the state must also report the actual CO_2 performance check for the interim period (2022-2029) with the interim mass-based CO_2 goal, as well as the actual CO_2 emission performance achieved by affected EGUs during the interim step 3 period (2028-2029).

Beginning with the final period, the state must submit biennial reports no later than July 1 after the end of each reporting period that includes an actual performance check to demonstrate that the state continues to meet the final state CO_2 goal.

If, at the time of the state report to the EPA, the state has not met the programmatic milestones for the reporting period, or the performance check shows that the actual CO_2 emission performance of affected EGUs warrants implementation of backstop requirements,[832] the state must include in the state report a notification to the EPA that the backstop has been triggered and describe the steps taken by the state to inform the affected EGUs that the backstop has been triggered. In the

[832] As explained in section VIII.C.3.b, state plans subject to the backstop requirement must require the backstop to take effect if actual CO_2 emission performance by affected EGUs fails to meet the level of emission performance specified in the plan over the 8-year interim performance period (2022-2029), or for any 2-year final goal performance period. The plan also must require the backstop to take effect if actual emission performance is deficient by 10 percent or more relative to the performance levels that the state has chosen to specify in its plan for the interim step 1 period (2022-2024) or the interim step 2 period (2025-2027).

event of such an exceedance under the state measures approach, the backstop federally enforceable emission standards for the EGUs must be effective within 18 months of the deadline for the state reporting to the EPA on plan implementation and progress toward the meeting the state CO_2 emission goal. For example, if a state report due on July 1, 2025, shows that actual CO_2 emission performance of affected EGUs is deficient by 10 percent or more relative to the specified level of emission performance for 2022-2024 in the state plan, the backstop federally enforceable emission standards for affected EGUs must be effective as of January 1, 2027.

(6) Supporting documentation.

(a) Demonstration that each state measure is quantifiable, non-duplicative, permanent, verifiable and enforceable.

A state using the state measures approach, in support of its plan, must also include in the supporting documentation of the state plan submittal the state measures[833] that are not federally enforceable emission standards, and describe how each state measure is quantifiable, non-duplicative, permanent, verifiable, and enforceable with respect to an affected entity.

[833] "State measures" refer to measures that the state adopts and implements as a matter of state law. Such measures are enforceable only per applicable state law, and are not included in the federally enforceable state plan.

A state measure is quantifiable if it can be reliably measured, using technically sound methods, in a manner that can be replicated.

A state measure is non-duplicative with respect to an affected entity if it is not already incorporated as a state measure or an emission standard in another state plan or state plan supporting material, except in instances where incorporated in another state as part of a multi-state plan. This does not mean that measures in a state measure cannot also be used for other purposes. For example actions taken pursuant to CAA section 111(d) requirements can satisfy other CAA program requirements (e.g., Regional Haze requirements, MATS) and state requirements (e.g., RPS).

A state measure is permanent if the state measure must be met for each applicable compliance period.

A state measure is verifiable if adequate monitoring, recordkeeping and reporting requirements are in place to enable the state to independently evaluate, measure and verify compliance with it.

A state measure is enforceable[834] if: (1) it represents a technically accurate limitation or requirement and the time period for the limitation or requirement is specified; (2)

[834] Under the state measures approach, state measures are enforceable only per applicable state law.

compliance requirements are clearly defined; (3) the affected entities responsible for compliance and liable for violations can be identified; and (4) each compliance activity or measure is practically enforceable in accordance with EPA guidance on practical enforceability,[835] and the state maintains the ability to enforce against affected EGUs for violations and secure appropriate corrective actions pursuant to its plan or state law.

The EPA will disapprove a state plan if the documentation is not sufficient for the EPA to be able to determine whether the state measures are expected to yield CO_2 emission reductions sufficient to result in the necessary CO_2 emission performance from affected EGUs for the state CO_2 emission goal to be achieved.

d. Legal basis for the components.

(1) General legal basis.

[835] The EPA's prior guidance on enforceability serves as the foundation for the types of measures that the EPA has found can be, as a practical matter, enforced. The EPA's guidance on enforceability includes: (1) September 23, 1987, memorandum and accompanying implementing guidance, "Review of State Implementation Plans and Revisions for Enforceability and Legal Sufficiency," (2) August 5, 2004, "Guidance on SIP Credits for Emission Reductions from Electric-Sector Energy Efficiency and Renewable Energy Measures," and (3) July 2012 "Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans," Appendix F.

Under section 111(d), state plans must "provide for the implementation and enforcement of [the] standards of performance." Similar language occurs elsewhere in the CAA. First, for SIPs, section 110(a)(1) requires SIPs to "provide for implementation, maintenance, and enforcement" of the NAAQS. However, section 110(a)(2), unlike 111(d), details a number of specific requirements for SIPs that, in part, speak exactly to how a SIP should "provide for implementation, maintenance, and enforcement" of the NAAQS. We note that section 111(d) provides explicitly only that the "procedures," and not the substantive requirements, for section 111(d) state plans should be "similar" to those in section 110, and thus a substantive requirement in section 110(a)(2) is not an independent source of authority for the EPA to require the same for section 111(d) plans. However, when there is a gap for the EPA to fill in interpreting how a section 111(d) plan should "provide for implementation and enforcement of the] standards of performance," and Congress explicitly addressed a similar gap in section 110, then it may be reasonable for the EPA to fill the gap in section 111(d) using an analogous mechanism to that in section 110(a)(2), to the extent that the section 110(a)(2) requirement makes sense and is reasonable in the context of section 111(d). On the other hand, that Congress did not explicitly provide such details as are found in section 110(a)(2) indicates that Congress intended to give the EPA considerable leeway in interpreting the ambiguous phrase "provides for implementation and enforcement of [the] standards of performance."

For example, section 110(a)(2)(E)(i) explicitly requires states to provide necessary assurances that they have adequate personnel, funding and authority to carry out the SIP. Section 111(d), on the other hand, does not explicitly contain this requirement. Thus, there is a gap to fill with respect to this issue when the EPA interprets section 111(d)'s requirement that plans "provide for implementation and enforcement" of the standards of performance, and it is reasonable for the EPA to fill the gap by requiring adequate funding and authority, both because adequate funding and authority are fundamental prerequisites to adequate implementation and enforcement of any program, and because Congress has explicitly recognized this fundamental nature in the section 110 context.[836]

We note two other places where the CAA requires a state program to satisfy similar language regarding implementation and enforcement. First, section 112(l)(1) allows states to adopt and

[836] On the other hand, there are specific requirements in 110(a)(2) that are fundamental for SIPs, but would not make sense in the 111(d) context. For example, the specific requirement for an ambient air quality monitoring network in 110(a)(2)(B) is irrelevant in the 111(d) context. For a detailed discussion of the specific legal basis for each component, please see the Legal Memorandum for this final rule.

submit a program for "implementation and enforcement" of section 112 standards. Section 112(l)(5) further provides that the program must (among other things) have adequate authority to enforce against sources, and adequate authority and resources to implement the program. Second, section 111(c) provides that, if a state develops and submits "adequate procedures" for "implementing and enforcing" section 111(b) standards of performance for new sources in that state, the Administrator shall delegate to the state the Administrator's authority to "implement and enforce" those standards. The EPA has interpreted these ambiguous provisions in the EPA's "Good Practices Manual for Delegation of NSPS and NESHAPS" and recommended (in the context of guidance) that state programs have a number of components, such as source monitoring, recordkeeping, and reporting, in order to adequately implement and enforce section 111(b) or 112 standards. This again indicates it is reasonable for the EPA to fill a gap in section 111(d)'s language and similarly require source monitoring, recordkeeping, and reporting, as these are fundamental to implementing and enforcing standards of performance that achieve the state performance rates or goals.

Some commenters argued that states have primary authority over the content of state plans and that the EPA lacks authority to disapprove a state plan as unsatisfactory simply because it lacks one or more of these components. We disagree. The EPA has the authority to interpret the statutory language of section 111(d) and to make rules that effectuate that interpretation. With respect to the components of an approvable plan, we are interpreting the statutory phrase "provide for implementation and enforcement" and making rules that set out the minimum elements that are necessary for a state plan to be "satisfactory" in meeting this statutory requirement. This does not in any way intrude on the state's ability to decide what mix of measures should be used to achieve the necessary emission reductions. Nor does it intrude in any way on the state's ability to decide how to satisfy a component. For example, for legal authority, we are not dictating which state agencies or officials must specifically have the necessary legal authority; that is entirely up to the state so long as the fundamental requirement to have adequate legal authority to implement and enforce the plan is met.

In addition, the EPA has already determined in the 1975 implementing regulations that certain components, such as monitoring, recordkeeping, and reporting, are necessary for implementation and enforcement of section 111(d) standards of performance. 40 FR 53340, 53348/1 (Nov. 17, 1975). Thus, EPA's position here is hardly novel. The EPA notes in discussing the implementing regulations, nothing in this final rule reopens provisions or issues that were previously decided in the original promulgation of the regulations unless otherwise explicitly reopened for this rule.

(2) Legal considerations with changes to affected EGUs.

In the proposed rulemaking, the EPA proposed the interpretation that if an existing source is subject to a section 111(d) state plan, and then undertakes a modification or reconstruction, the source remains subject to the state plan, while also becoming subject to the modification or reconstruction requirements. 79 FR 34830, 34903-4. The EPA is not finalizing a position on this issue in this final rule, and is re-proposing and taking comment on this issue through the federal plan rulemaking being proposed concurrently with this action. The EPA's deferral of action on this issue does not impact states' and affected EGUs' pending obligations under this final rule relating to plan submission deadlines, as this issue concerns potential obligations or impacts after an existing source is subject to the requirements of a state plan. The EPA will propose and finalize its position on this issue through the federal plan rulemaking, which will be well in advance of the plan performance period beginning in 2022, at which point state plan obligations on existing sources are effectuated.

(3) Legal considerations regarding design, equipment, work practice or operational standards.

In the proposal, the EPA asked for comment on three approaches to inclusion of design, equipment, work practice and operational standards in section 111(d) plans. 79 FR 34830, 34926/3 (June 18, 2014). Under the first approach, states would be precluded from including these standards in section 111(d) plans unless the design, equipment, work practice or operational standard could be understood as a "standard of performance" or could be understood to "provide for implementation and enforcement" of standards of performance. We also asked, for the first approach, whether it was even possible, given the statutory language of 111(h), to consider a design, equipment, work practice or operational standard as a "standard of performance." Under the second approach, states could include design, equipment, work practice or operational standards in the event that it could be shown a "standard of performance" was not feasible, as set out in section 111(h). Under the third approach, a state could include design, equipment, work practice and operational standards in a 111(d) plan without any constraints. We also asked whether, if there was legal uncertainty as to the status of these standards, the EPA should authorize states to include them in their 111(d) plans with the understanding that if the EPA's authorization were invalidated by a court, states would have to revise their plans accordingly.

The EPA is finalizing the first approach. Specifically, a state’s standards of performance (in other words, either the federally enforceable backstop under the state measures approach or the emission standards under the emission standards approach) cannot consist of (in whole or part) design, equipment, work practice or operational standards. A state may include such standards in a 111(d) plan in order to implement the standards of performance. For example, a state taking a mass-based approach may include in its 111(d) plan a limit on hours of operation on a particular affected EGU, but that operational standard itself cannot substitute for a mass-based emission standard on the affected EGU.[837]

This follows from the statute. First, section 111(h)(1) authorizes the Administrator, when it is not feasible for certain reasons (specified in 111(h)(2)) to prescribe or enforce a standard of performance, to instead promulgate a design, equipment, work practice or operational standard. If a standard of performance could include design, equipment, work practice or operational standards, such authority would be unnecessary. Second, 111(h)(5) states that design, equipment, work practice or operational standards “described in” 111(h) shall be treated as standards of performance for the purposes of the CAA. This

[837] In particular, a state may include in its 111(d) state plan an emission standard that is reflective of the CO_2 performance resulting from operational standards the state imposes on an affected EGU.

creates a strong inference that standards of performance otherwise should not include design, equipment, work practice, or operational standards. Finally, the general definition of "standard of performance" in section 302(l) is similar to the definition of "emission limitation" (or "emission standard") in section 302(k), with the exception that the definition of "emission limitation" explicitly includes design, equipment, work practice and operational standards, but the definition of "standard of performance" omits them. Thus, as with our discussion of the term "standard of performance" above in VIII.C.6.b, even if the general definition of "standard of performance" in 302(l) applies to 111(d), the omission of design, equipment, work practice, and operational standards in 302(l) confirms our interpretation that they cannot be a 111 "standard of performance" (except under the limited circumstances in 111(h)). We conclude that it is reasonable, and perhaps compelled, to interpret the term "standards of performance" in 111(d) to not include design, equipment, work practice and operational standards.

However, section 111(d) requires plans to "provide for implementation and enforcement of [the] standards of performance." This language does not explicitly prohibit a plan from including design, equipment, work practice and operational standards, and allows for them to be included so long as they are understood to provide for implementation of the standards of performance. If they are included, the 111(d) plan must still be "satisfactory" in other respects, in particular in establishing standards of performance that are not in whole or in part design, equipment, work practice, and operational standards.

(4) <u>Legal basis for engagement with communities</u>.

As previously discussed, section 111(d)(1) requires the EPA to promulgate procedures "similar" to those in section 110 under which states adopt and submit 111(d) plans. Section 110(a)(1) requires states to adopt and submit implementation plans "after reasonable notice and public hearings." The implementing regulations under 40 CFR 60.27 reflect similar public participation requirements with respect to section 111(d) state plans. The EPA is sensitive to the legal importance of adequate public participation in the state plan process, including public participation by affected communities. As previously discussed in this rule, recent studies also find that certain communities, including low-income communities and some communities of color, are disproportionately affected by certain climate change-related impacts. Because certain communities have a potential likelihood to be impacted by state plans for this rule, the EPA believes that the existing public participation requirements under 40 CFR 60.23 are effectuated for the purposes of this final rule by states engaging in meaningful, active ways with such communities. By requiring states to demonstrate how they have meaningfully engaged with vulnerable communities potentially impacted by state plans as part of the state plan development process, states meeting this requirement will satisfy the applicable statutory and regulatory requirements regarding public participation.

3. Components of the federally approved state plan

In this action the EPA finalizes that, to be fully approved, a state plan submittal must meet the criteria and include the required components described above. The EPA will propose and take final action on each state plan submittal in the *Federal Register* and provide an opportunity for notice and comment. When a state plan submittal is approved by the EPA, the EPA will codify the approved 111(d) state plan in 40 CFR part 62. The following components of the state plan submittal will become the federally enforceable state 111(d) plan:

- Federally enforceable emission standards for affected EGUs
- Federally enforceable backstop of emission standards for affected EGUs
- Implementing and enforcing measures for federally enforceable emission standards including EGU monitoring, recordkeeping and reporting requirements
- State recordkeeping and reporting requirements

E. State Plan Submittal and Approval Process and Timing

1. Overview

In this action the EPA is finalizing that state plan submittals are due on September 6, 2016, with the option of an extension to submit final state plans by September 6, 2018, which is 3 years after finalization of this rule. The compelling nature of the climate change challenge, and the need to begin promptly what will be a lengthy effort to implement the requirements of these guidelines, warrant this schedule. The EPA also believes, for reasons further described in the next section, why this schedule is achievable for states to submit final plans. We discuss the timing of state plans in more detail in this section below.

Discussed in the following sections are state plan submittal and timing, required components for initial submittals and the 2017 update, multi-state plan submissions, process for EPA review of state plans, failure to submit a plan, state plan modifications (including modifications to interim and final CO_2 emission goals), plan templates and electronic submittal, and legal bases regarding state plan process.

2. State plan submittal and timing

The implementing regulations (40 CFR 60.23) require that state plans be submitted to the EPA within 9 months of promulgation of the emission guidelines, unless the EPA specifies otherwise.[838] For these 111(d) guidelines, the EPA is finalizing that each state must by September 6, 2016, either submit a final plan submittal or seek an extension to submit a final plan by September 6, 2018. In the case of a state electing to participate in the CEIP, this 2016 submittal must include a non-binding statement of intent to participate in the program. To seek an extension of the September 6, 2016 deadline until no later than September 6, 2018, a state must submit an initial submittal by September 6, 2016, that addresses three required components sufficiently to demonstrate that a state is able to undertake steps and processes necessary to timely submit a final plan by the extended date of September 6, 2018. If an extension is requested and granted, states must also submit a 2017 update by September 6, 2017, that documents the state's continued progress towards meeting the September 6, 2018 final plan submittal deadline.

In the proposal, EPA proposed a 13 month final state plan submittal deadline, with a 1 year possible extension for states submitting individual state plans and a 2 year possible extension for states submitting multi-state plans as part of a multi-state region. The EPA received substantive comment on the achievability of these proposed deadlines for state plan

[838] 40 CFR 60.23(a)(1).

submittals. Multiple commenters expressed concern that due to timing of legislative cycles (some of which are every 2 years), regulatory processes, and other necessary tasks, states would find it extremely difficult to submit plans in 1 or 2 years, whether or not they were planning to submit as part of a multi-state region. The EPA agrees based on this input that a schedule shorter than 3 years will be challenging for many — though not all - states. In light of the comments received and in order to provide maximum flexibility to states while still taking timely action to reduce CO_2 emissions, in this final rule the EPA is allowing for a 2 year extension until September 6, 2018, for both individual and multi-state plans, to provide a total of 3 years for states to submit a final plan if an extension is received. Based on comments received, information the EPA has regarding steps states have already begun taking towards plan development, and extensive experience with similar state plan submission deadlines under CAA section 110 SIPs, the EPA believes states will be able to submit final plans within 3 years by September 6, 2018, in the event states are not required to submit a final plan by September 6, 2016. We address the substantive requirements of initial submittals and the 2017 update in the next section. States that receive 2-year extensions may submit the final plan earlier than September 6, 2018, if they so choose.

The EPA highlights one purpose of the initial submittal is to encourage and potentially facilitate states to do necessary planning and engagement with stakeholders so states are able to submit an approvable final state plan by the extended deadline of September 6, 2018. Some states have well-developed existing programs and the attendant legal authority underpinning such programs to more easily meet the September 6, 2016 deadline by submitting a final plan which largely contains or relies upon such existing programs.[839] Based on comments and stakeholder feedback, however, the EPA anticipates that many states intending to develop and submit a final plan will seek the optional extension given the time it may take to undergo necessary legislative, stakeholder, and planning processes. The EPA acknowledges that the initial submittal of September 6, 2016, is not essential to the ability for states to submit final plans by September 6, 2018, so that even without this 2016 deadline, the EPA could require states to meet the 2018 deadline. Even so, this earlier date in the 3 year planning process serves as a useful “check-in” that provides several significant advantages. First, this earlier date provides all states an opportunity to understand what approaches other states

[839] Based on comments received, we understand that the Northeast and Mid-Atlantic states that participate in RGGI may be in this position.

are considering. Because there are significant benefits to regional cooperation, the EPA believes that a formal process to collect and then provide this information will help all states develop better plans. Second, because the guidelines provide significant flexibility, the ability for the EPA to provide early input to states who may be pursuing more innovative approaches will help ensure that all state plans are ultimately approvable. The EPA therefore believes the initial submittal is an appropriate means by which to offer the optional extension, and for reasons further described in section VIII.E.3, that the requirements of the initial submittal are achievable by September 6, 2016, so states will be able to develop and submit a plan that meets the requirements of the final emission guidelines and section 111(d) of the CAA by the extended date.

Additionally, some states may not submit a state plan as required by the final emission guidelines and section 111(d) of the CAA. For states that do not submit a state plan, the CAA gives the EPA express authority to implement a federal plan for sources in that state upon determination by the EPA that a state has failed to submit a state plan by the required date. For states that do not intend to submit a state plan to meet the obligations of this final rule, by promulgating a federal plan for affected EGUs in states that do not submit a plan by September 6, 2016, such affected EGUs would have an additional 2 years to plan for and determine compliance strategies than had promulgation of a federal plan been predicated on states failing to submit a plan by September 6, 2018. The EPA also notes that this final rule affords states and affected EGUs with many implementation flexibilities and approaches for state plans that the EPA itself may not have the authority to implement through a federal plan. Therefore, affected EGUs subject to a federal plan promulgated for a state that refuses to submit a state plan may benefit from an additional 2 years to plan for compliance with a federal plan with potentially fewer flexibilities.

If no affected EGU is located within a state, the state must submit a letter to the EPA certifying that no such facilities exist by September 6, 2016.[840] The EPA will publish a notice in the *Federal Register* to notify the public of receipt of such letters. If an affected EGU is later found to be located in that state, the state must submit a final plan addressing such affected EGU or the EPA will determine the state has failed to submit a plan as required by the emission guidelines and CAA section 111(d), and begin the process of implementing a federal plan for that affected EGU.

In the case of a tribe that has one or more affected EGUs located in its area of Indian country, if the tribe either does

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[840] 40 CFR 60.23(b).

not submit a CAA section 111(d) plan or does not receive EPA approval of a submitted plan, the EPA has the responsibility to establish a CAA section 111(d) plan for that area if it determines that such a plan is necessary or appropriate to protect air quality.[841] See the proposed federal plan rulemaking for further information.

The EPA notes that the current implementing regulations at 40 CFR part 60 do not specify who has the authority to make a formal submission of the state plan to the EPA for review. In order to clarify who on behalf of a state is authorized to submit an initial submittal, 2017 update, final state plan (or negative declaration, if applicable), and any revisions to an approved plan, the EPA has included a requirement in this final rule mirroring that of the requirement in 40 CFR part 51 App. V.2.1.(a) with respect to SIPs that identifies the Governor of a state as the authorized official for submitting the state plan to the EPA. If the Governor wishes to designate another responsible official the authority to submit a state plan, the EPA must be notified via letter from the Governor prior to the 2016 deadline for plan submittal so that they have the ability to submit the initial submittal or final plan in the State Plan Electronic Collection System (SPeCS). If the Governor has

[841] See 40 CFR 49.1 to 49.11.

previously delegated authority to make CAA submittals on the Governor’s behalf, a state may submit documentation of the delegation in lieu of a letter from the Governor. The letter or documentation must identify the designee to whom authority is being designated and must include the name and contact information for the designee and also identify the state plan preparers who will need access to SPeCS discussed in section VIII.E.8. A state may also submit the names of the state plan preparers via a separate letter prior to the designation letter from the Governor in order to expedite the state plan administrative process. Required contact information for the designee and preparers includes the person’s title, organization and email address. The EPA recommends this information be submitted early in the state planning process to allow sufficient time for completion of SPeCS registration so that those authorized to use the system are provided access.

3. Components of an initial submittal and 2017 update

As noted, states may request a 2-year extension to submit a final plan through making an initial submittal by September 6, 2016. For the extension to be granted, the EPA is finalizing that the initial submittal must address three required components sufficiently to demonstrate that a state is able to undertake steps and processes necessary to timely submit a final plan by the extended date of September 6, 2018:[842]

- An identification of final plan approach or approaches under consideration, including a description of progress made to date.
- An appropriate explanation for why the state requires additional time to submit a final plan by September 6, 2018.
- Demonstration or description of opportunity for public comment on the initial submittal and meaningful engagement with stakeholders,[843] including vulnerable communities, during the time in preparation of the initial submittal and plans for engagement during development of the final plan.

During the public comment period, multiple commenters stated that the proposed timeframe for states to submit an initial submittal was not achievable, citing, among other things, the number of decisions needed to be made by a state or states, and that the EPA needed to clarify the requirements for an initial submittal. Multiple commenters also expressed concern

[842] As stated previously, in the case of a state electing to participate in the CEIP, this 2016 submittal must include a non-binding statement of intent to participate in the program.
[843] Such stakeholders may include labor unions and workers that have an interest in the state plan, and communities whose economies are dependent on coal.

that the requirements for an initial submittal required final decisions to be made by states, and that the initial submittal deadline was not enough time for states to make these decisions.

It is important to note that the EPA is not requiring the adoption of any enforceable measures or final decisions in order for the state to address any of the initial submittal components by September 6, 2016. The EPA believes the absence of requiring enforceable measures to be included with the initial submittal greatly supports the ability of states intending to develop a final state plan to submit an initial submittal by September 6, 2016. States are required to submit enforceable measures supported by technically complex documentation, such as modeling, and adopted through state public participation and regulatory or legislative processes as part of SIPs under other parts of the CAA within timeframes comparable to the time the EPA is providing for initial submittals.[844]

In order to further address the commenters’ concerns regarding possible ambiguity of the requirements for an initial submittal so that an extension is granted, the EPA is providing

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[844] For example, 13 states were required to submit SIP revisions sufficient to regulate GHGs under the Prevention of Significant Deterioration (PSD) permitting requirements of the CAA within either 3 weeks or 12 months in response to the EPA’s SIP call. *See* “Action To Ensure Authority To Issue Permits Under the Prevention of Significant Deterioration Program to Sources of Greenhouse Gas Emissions: Finding of Substantial Inadequacy and SIP Call”, 75 FR 77698, (December 13, 2010).

clarity regarding the required components for an initial submittal. Regarding the component that states address an appropriate explanation for an extension, the EPA proposed that appropriate explanations for seeking an extension beyond 2016 for submitting a final plan include: a state's required schedule for legislative approval and administrative rulemaking, the need for multi-state coordination in the development of an individual state plan, or the process and coordination necessary to develop a multi-state plan. In this final rule, the EPA is finalizing these as appropriate explanations for seeking an extension beyond 2016, but makes clear — as explained further below — that other appropriate explanations will be acceptable as well. It is important to note that the initial submittal does not require legislation and/or regulations to be passed prior in order for the state to be granted an extension, but the initial submittal should describe any concrete steps the state has already taken on legislation and/or administrative rulemaking and detail what the remaining steps are in those processes before a final plan can be submitted. The EPA also sought comment on other circumstances for which an extension of time would be appropriate, and also whether some explanations for extensions should not be permitted. Commenters stated that states should be able to seek extensions whenever an extension can be reasonably justified, and that the EPA should take at face value states' good faith efforts by accepting any state assertion that more time is needed to develop a plan unless there is clear evidence to the contrary. The EPA believes there may be appropriate explanations states may submit in addition to the ones described in this final rule sufficient to demonstrate that a state is able to undertake steps and processes necessary to timely submit a final plan by the extended date of September 6, 2018. Given the opportunity for states to submit appropriate explanations other than the ones detailed here, the EPA believes addressing this component requiring an appropriate explanation for an extension is easily achievable by September 6, 2016.

In order to additionally clarify the required components of the initial submittal, the following are types of explanations of information states may provide as part of the initial submittal to sufficiently address each of the three required components for getting an extension:

- Details on whether a state is considering a single or multi-state plan, a plan that meets the CO_2 emission performance rates or state CO_2 rate or mass emission goal, and/or an emission standards or state measures plan type.
- A description of how the state intends to address development of the required components of the final state

plan, including describing what actions have already been taken, what steps remain, and the schedule for completing those steps.

- A commitment to maintain any existing measures the state intends to rely upon for its final plan in order to achieve the necessary reductions once the performance period begins.
- Describing public participation opportunities such as stakeholder and community meetings, or public hearings, throughout the 3 year plan development process. This could also include leverage of public participation approaches that states already use to identify and engage potentially affected communities.

The EPA emphasizes the required initial submittal components are intended to provide a reasonable pathway for states to demonstrate whether they will be able to submit an approvable plan by the extended date of September 6, 2018. The EPA also anticipates that through the requirement to address these components, the initial submittal will also facilitate state planning and stakeholder engagement, particularly as one component requires the public and stakeholders to have an opportunity to comment on the initial submittal. As previously described, these components do not require final decisions to be made by states, and this is further illustrated by the clarifications on how states may meet each of the three required components. Accordingly, the EPA believes none of these components is onerous for states to address in an initial submittal by the September 6, 2016 deadline. To further underscore this point, the EPA is further explaining the clarifying examples listed above of how states may address the three required components, and highlighting the achievability of these examples for states to address through the initial submittal by September 6, 2016.

For identification of the final plan approach or approaches the state is considering, and description of progress made to date, states could identify whether the state is considering the option of the CO_2 emission performance rates, a rate-based CO_2 goal, or a mass-based CO_2 goal, and whether the state is intending to pursue a single-state or multi-state plan. Stakeholders commented that states will not be far enough along in the rule development process to have made these decisions. Commenters also stated that many state legislatures would need to pass legislation giving state environmental agencies legal authority and direction before they could begin to make decisions such as rate or mass-based approach or single or multi-state plan submittal. In order to address the commenters' concerns, the EPA wishes to clarify that state approaches identified in the initial submittal do not need to be final and/or formalized through a state legislature, and that states may opt to identify pursuit of more than one approach at the same time, or to indicate the status of the deliberation of this issue within the state.

The EPA received substantive comment regarding the potential adverse consequences for states pursuing a multi-state approach and receiving an extension until 2018, where, for various reasons, a state or states then decide(s) to pursue the single state approach. Commenters viewed this as being potentially problematic since, as proposed, a single state could only receive an extension until 2017, and if a multi-state plan effort does not work out the deadline for seeking the extension until 2017 would have passed. The EPA notes finalizing a 2 year extension that is available for any state, whether they are pursuing an individual state plan or a multi-state plan resolves the commenters' concern about conflicting extension deadlines if states involved in a multi-state effort decide not to pursue the multi-state approach. Importantly, such identification in an initial submittal does not obligate the state to then actually adopt that approach in their final plan as the EPA acknowledges that based on state processes and public input through plan development during the extended submission period, a state may end up adopting a state plan approach more suitable to the needs of that state and its affected EGUs than previously identified in the initial submittal.

States can also describe progress made to date by identifying steps already taken to address development of the final state plan, as the EPA recognizes that states in general have already taken a number of steps to prepare for state plan development to meet the obligations of this rule. For example, since proposal, states have: begun exploring tradeoffs among various state plan approaches such as individual versus multistate coordination, increased utilization of demand-side EE and RE programs, and implementing rate-based versus mass-based programs; increased their understanding of existing state programs and policies that reduce carbon emissions; built relationships and communications between key state institutions such as environmental agencies, PUCs, governors' offices, and energy regulators; hosted public stakeholder meetings to educate and solicit input from the public; and begun discussing state processes for developing potential state plans. States may meet the first required component by describing steps such as these already undertaken.

The EPA underscores that states may easily address the first component of the initial submittal by describing such steps, and also address the second required component by identifying next steps (which may be a natural extension of these already implemented activities), and laying out a schedule for development of a final plan. States that have taken these steps would especially be able to address the component regarding an appropriate explanation for an extension as the EPA recognizes the substantial work such states have begun to put towards development of state plans, and the continuation of this work justifies additional time to complete necessary steps to result in an approvable state plan. The EPA emphasizes that for states who intend to submit a final plan and need an extension, the components of the initial submittal are not intended to require burdensome final action by states by September 6, 2016, but to identify a viable path to completing a final plan by September 6, 2018.

An initial submittal that contains a commitment to maintain any existing measures the state intends to rely upon for its final plan in order to get the necessary reductions once the performance period begins (e.g. RE standards and demand-side EE programs the state intends to rely upon through a state measures plan type), at least until the final plan is approved, also addresses the requirement that states provide an appropriate explanation for an extension. Given the state's request for additional time prior to putting in place enforceable measures to reduce CO_2, it would be reasonable and appropriate, and in keeping with the goals of 111(d) to ensure that any existing CO_2

reduction measures that the state intends to rely upon remain in place while the state is developing a final plan. Such commitment would demonstrate that the state is taking substantive steps towards successful development of a final plan within 3 years.

Regarding the required public participation component of the initial submittal, the EPA believes this requirement is both achievable for states to submit an initial submittal by the September 6, 2016 deadline, and provides a benefit in facilitating state plan development so that states are more likely to be able to submit a final plan within 3 years if the extension is granted. The EPA can use a comment opportunity on the initial submittal to advise the state whether aspects of the draft initial submittal and overall plan development are appropriate for purposes of meeting the requirements of the final rule so that the state will be able to procure the extension through an acceptable initial submittal and submit a final plan by the extended deadline. The EPA notes the comment period on the initial submittal is only one opportunity the EPA has to assist a state in the state plan development process. The EPA has historically worked with states throughout the state plan development process to help ensure that the state plan is approvable once submitted to the EPA, and expects this level of engagement with states to continue throughout the plan development process. This requirement will also facilitate early identification of concerns stakeholders and the public may have with aspects of a final plan the state is considering. As states have longtime and extensive experience with responding to public comments in numerous contexts, including in the context of other CAA programs such as section 110 SIP development and in permit issuance under NSR and Title V, the EPA anticipates states will be able to timely address the initial submittal public participation.

As previously discussed, because certain communities have a potential likelihood to be impacted by state plans, the EPA believes that the existing public participation requirements under 40 CFR 60.23 are effectuated for the purposes of this final rule by states engaging in meaningful, active ways with such communities. Therefore, the public participation component of the initial submittal includes meaningful engagement with vulnerable communities, throughout the state plan development process and including through the initial submittal. In order to demonstrate to the EPA that states are actively engaging with communities, states could provide in their initial submittal a summary of steps they have already taken to engage the public and how they intend to continue meaningful engagement, including with vulnerable communities, during the additional time (if an extension is granted) for development of the final plan. In addition to approaches that states already use to identify and engage potentially affected communities, the EPA encourages states to use the proximity analysis conducted for this rulemaking (which is described in section IX.A) as a tool to help them identify overburdened communities that could be potentially impacted by their plans. Other tools, such as EJ screen, can also be helpful. The EPA in its continued outreach with states during the implementation phase will also provide resources to assist them in engaging with communities. The EPA believes that through the provision of these resources states will also more easily be able to address this required component of the initial submittal regarding public engagement, including with vulnerable communities, by September 6, 2016.

In addition to the resources the EPA intends to provide to states, there are existing resources states can take advantage of to address this component as well. On the steps that states could take to engage vulnerable communities in a meaningful way, the Agency recommends that states consult the EPA's May 2015 *Guidance on Considering Environmental Justice During the Development of Regulatory Actions*. In this document, the EPA defines meaningful involvement as ensuring that "potentially affected community members have an appropriate opportunity to participate in decisions about a proposed activity (i.e., rulemaking) that may affect their environment and/or health; the population’s contribution can influence the EPA’s [regulatory authority’s] rulemaking decisions; the concerns of all participants involved will be considered in the decision-making process; and the EPA [decision-makers] will seek out and facilitate the involvement of those potentially affected by the EPA’s [or other regulatory authority’s] rulemaking process.”[845] Additionally, this guidance document also encourages those writing rules to consider the positive impacts that a rulemaking will have on communities).[846] Another resource that the EPA recommends that states consult when devising their state plans is the document “Considering Environmental Justice in Permitting” available on the agency’s website.[847] Both of the resources discussed above can add to what states may already have in place to effectively engage vulnerable communities in the rulemaking process.

The EPA recommends that as part of their meaningful engagement with vulnerable communities, states work with communities to ensure that they have a clear understanding of the benefits and any potential adverse impacts that a state plan

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[845] Guidance on Considering Environmental Justice During the Development of Regulatory Actions. http://epa.gov/environmentaljustice/resources/policy/considering-ej-in-rulemaking-guide-final.pdf. May 2015.
[846] Ibid.
[847] Considering Environmental Justice in Permitting. http://www.epa.gov/environmentaljustice/plan-ej/permitting.html#actions.

might have on their overburdened communities and that there is a clear process for states to respond to input from communities.

If a state seeks an extension by submitting an appropriate initial submittal addressing the three required components as described above by September 6, 2016, the EPA will grant the extension. If the state does not submit an initial submittal by September 6, 2016, that contains the three required components, the EPA will notify the state by letter, within 90 days, that the agency cannot grant the extension request based the state's initial submittal. The EPA will notify a state by letter only if the initial submittal does not address the three required components. An extension for submitting a final plan will be deemed granted if the EPA does not deny the extension request based on the initial submittal. The EPA has determined this approach is authorized by, and consistent with, 40 CFR 60.27(a) of the implementing regulations.

For states that request and receive a 2-year extension, the state must submit an update halfway through that extension, by September 6, 2017. In the proposal the EPA included a requirement regarding a 2017 check in. Because the EPA is finalizing that states are able to get a 2-year extension regardless of whether they are submitting an individual or multi state final plan, the EPA believes it appropriate to ensure through the 2017 update that the state is making continuous progress on its initial submittal and that it is on track to meet the final plan submittal deadline of September 6, 2018. The EPA will also be able to use the information provided through the 2017 update to further assist states in plan development.

The final rule requires that states address in the 2017 update the following components:

- A summary of the status with respect to required components of the final plan, including a list of which components are not yet complete.
- A commitment to a plan approach (e.g., single or multi-state, rate or mass emission performance level), including draft or proposed legislation and/or regulations.
- An updated comprehensive roadmap with a schedule and milestones for completing the plan, including progress to date in developing a final plan and steps taken in furtherance of actions needed to finalize a final plan.

In order to assess whether a state is on track to submit a final plan by the 2018 extension deadline, the EPA is requiring that the 2017 update must contain a progress update on components from the initial submittal and a list of which final plan components are still not complete. This progress update must demonstrate that state is meeting any steps and schedule it outlined in its initial submittal.

The EPA is also requiring that the 2017 update include a commitment to the type of plan approach the state will take in the final plan submittal. During the public comment period, many commenters stated that legislative action would be required to enact this final rule at the state level, and that the proposal did not provide enough time for legislative action or other regulatory actions needed for a state to be granted an extension. In order to respond to these comments, the EPA is clarifying that proposed or passed legislation or regulations are not required in the initial submittal due by September 6, 2016. While a state may indicate consideration of multiple state plan approaches in the initial submittal, the EPA is requiring that the state commit to one approach in the 2017 update. This commitment must include draft or proposed legislation or regulations that must become final at the state level prior to submitting a final plan submittal to the EPA. While commenters expressed concern with not being able to have legislation enacted in time to receive an extension until 2018, the EPA has determined that 2 years is a reasonable timeframe for a state to decide on the type of approach it will take in the final plan submittal and to draft legislation or regulations for this approach in order to timely meet the extended September 6, 2018 deadline.

4. Multi-state plan submittals

For states wishing to participate in a multi-state plan, the EPA is finalizing three forms of submittal that states may choose for the submittal of a multi-state plan.

First, the EPA is finalizing its proposed approach where one multi-state plan submittal is made on behalf of all participating states. The joint submittal must be signed by authorized officials for each of the states participating in the multi-state plan and would have the same legal effect as an individual submittal for each participating state. The joint submittal must adequately address plan components that apply jointly for all participating states and for each individual state in the multi-state plan, including necessary state legal authority to implement the plan, such as state regulations and statutes. Because the multi-state plan functions as a single plan, each of the required plan components (e.g., plan emission goals, program implementation milestones, emission performance checks, and reporting) would be designed and implemented by the participating states on a multi-state basis.

The EPA received comments from states requesting flexibility for multi-state plan submittals. In response to these comments, the EPA is also finalizing two additional options on which it solicited comment. First, states participating in a multi-state plan can provide a single submittal — signed by authorized officials from each participating state — that addresses common plan elements. This option requires individual participating states to provide supplemental individual submittals that provide state-specific elements of the multi-state plan. The common multi-state submittal must address all relevant common plan elements and each individual participating state submittal must address all required plan components (including common plan elements, even if only through cross reference to the common plan submittal). Under this approach, the combined common submittal and each of the individual participating state submittals would constitute the multi-state plan submitted for EPA review. The joint common submittal must be signed by authorized officials for each of the states participating in the multi-state plan and would have the same legal effect as an individual submittal for each participating state.

Second, the EPA is finalizing an approach where all states participating in a multi-state plan separately make individual submittals that address all elements of the multi-state plan. These submittals would need to be materially consistent for all common plan elements that apply to all participating states, and would also address individual state-specific aspects of the multi-state plan. Each individual state plan submittal would need to address all required plan components. The EPA encourages states participating in this type of multi-state plan to use as much common material as possible to ease review of the state plans.

These approaches will provide states with flexibility in addressing contingencies where one or more states submit plan components that are not approvable. In such instances, these options simplify the EPA's approval of remaining common or individual portions of a multi-state plan and help address contingencies during plan development where a state fails to finalize its participation in a multi-state plan, with minimal disruption to the submittals of the remaining participating states. These additional submittal approaches also facilitate multi-state plans where the participating states are coordinating the implementation of their plans but are not taking on a joint multi-state emission goal for affected EGUs. For example, states may seek to engage in a multi-state approach that links rate-based or mass-based emission trading programs through appropriate authorizations (e.g. reciprocity agreements, or state regulations) that allow affected EGUs to use emission allowances or RE/EE credits issued in one state for compliance with an emission standard in another state.

In order to avoid a multi-state plan becoming unapprovable due to one state submitting an unapprovable portion of a multi-state plan, withdrawing from the multi-state plan, or failing to implement the multi-state plan, states may include express severability clauses if their multi-state plan is able to stand without further revision if one of the situations described above occurs. The severability clause must specify how the remainder of the multi-state plan or individual state plan would continue to function with the withdrawal of a state or states, and may also include pre-specified revisions. The EPA will evaluate the appropriateness of such a clause as part of its review of the multi-state plan submittal.

5. Process for EPA review of state plans

Our proposal laid out the basic steps for the EPA's review and action on submitted state plans and, at some length, discussed the required components of state plans, as further described in the preceding sections. We received a number of thoughtful and helpful comments on these issues. We are finalizing the basic requirements in this rule and are proposing, in the companion proposed federal plan under section 111(d), some additional procedural elements we believe will be helpful to states, stakeholders and the EPA moving forward.

Following the September 6, 2016 deadline for state plan submittals, the EPA will review plan submittals. For a state that submits an initial submittal by September 6, 2016, and requests an extension of the deadline for the submission of a final state plan submittal, the EPA will determine if the initial submittal meets the minimum requirements for an initial submittal. If the state does not submit an initial submittal by September 6, 2016, that contains the three required components, the EPA will notify the state by letter, within 90 days, that the agency cannot grant the extension request based the state's initial submittal. If the initial submittal meets the minimum requirements specified in the emission guidelines, the state's request for a deadline extension to submit a final plan submittal will be deemed granted, and the final plan submittal must be submitted to the EPA by no later than September 6, 2018.

After receipt of a final plan submittal, the EPA will review the plan submittal and, within 12 months, approve or disapprove the plan through a notice-and-comment rulemaking process publicized in the *Federal Register*, similar to that used for acting upon SIP submittals under section 110 of the CAA. The implementing regulations currently provide for the EPA to act on a final plan within 4 months after the deadline for submission, which is consistent with versions of section 110 prior to the 1990 Amendments to the CAA. 40 CFR 60.27(b). To be consistent with the current version of section 110, the EPA intends to adopt a timeline of 12 months to review final plan submittals upon receipt of complete submittals, as is generally consistent with the timing requirements of section 110 with respect to complete SIP submittals. Such a timeline would also provide the

EPA with adequate time for review and rulemaking procedures, and ensuring an opportunity for public notice and opportunity for comment. We note, however, that we proposed this timeline for review and action on state plans in our proposal, but our proposal was specific to the timeline for state plans submitted pursuant to this rule rather than for state plans submitted under 111(d) generally.[848] We are finalizing as part of this rule that state plans submitted to meet the requirements of this rule will be reviewed and acted upon by the EPA within 12 months of submission. Because such timeline would be appropriate to be made to 111(d) state plans more generally, we are also proposing the appropriate revisions to the implementing regulations as part of the federal plan proposal for section 111(d).

In addition, while the proposal and this final rule lay out in considerable detail the required components of a state plan, the EPA believes that it would also be helpful to include in the rule a completeness determination process, similar to that used for SIP submittals under section 110, which will allow the EPA to determine whether a final plan submittal contains the components necessary to enable the EPA to determine through notice and comment rulemaking whether such submittal complies

[848] The EPA proposed 12 months after the date required for submission of a plan or plan revision to approve or disapprove such plan or revision or each portion thereof.

with the requirements of section 111(d). This is a procedural requirement under CAA section 110(k)(1) for SIPs, and the EPA believes this requirement is appropriate to establish under section 111(d)'s direction to the EPA to prescribe through regulations a procedure similar to that provided by section 110. However, because the EPA did not propose such regulations as part of the proposal for this action, the EPA is proposing such regulations as part of the federal plan proposal for section 111(d). The EPA notes that this preamble (in section VIII.D) and final rule lay out required components of state plans and all the requirements for a state plan submittal, and therefore states have the necessary information at this time to develop state plans. The upcoming completeness criteria will not add to or change these required components, but only add a procedural step that allows the EPA to identify whether there are absent or insufficient components in the plan submittal that would render the EPA unable to act on such submittal because it is incomplete. As we further explain in the federal plan proposal, a determination by the EPA that a plan submittal is incomplete has the effect of a state having a still-pending statutory obligation to submit a plan that meets the requirements of section 111(d).

The EPA is planning to propose an amendment to the section 111(d) implementing regulations that will add the partial approval/disapproval and conditional approval mechanisms in section 110(k)(3) and (4) to the procedure for acting on section 111(d) plans. The input the agency received in response to the proposal for these guidelines indicated that the flexibility provided by these mechanisms could be useful getting state plans in place. The EPA agrees, and is proposing to amend the implementing regulations as part of the rulemaking for the federal 111(d) plan. The EPA is not taking final action on these changes in this action.

The later timing for our action on partial approval/disapproval and conditional procedures does not create any issue with finalizing this rule. These procedural adjustments will only come into play after states have submitted their plans and the EPA is required to act on them, and we intend to finalize these procedural changes prior to September 6, 2016, when the first plan submittals would occur. Until then, the EPA believes that every plan is submitted with the intent to be fully approvable and there is no need for states to rely on the possibility of these procedures when developing their plans. Conditional approval and partial approval/disapproval should be used to deal with approvability issues that arise despite the best efforts of states and the EPA to work together to make sure a submittal in the first instance is fully approvable. The EPA plans to finalize any changes in the implementing regulations before the EPA is required to act on state submittals, so that the EPA and states will have appropriate flexibility in the plan approval process.

6. Failure to submit a plan

If a state does not submit a final plan submittal by the applicable deadline, or submits a final plan the EPA determines to be incomplete, the EPA will notify the state by letter of its failure to submit. The EPA will publish a *Federal Register* notice informing the public of its finding of failure to submit. Upon a finding of failure to submit for a state, a statutory clock will run requiring the EPA to promulgate a federal plan for such state no later than 1 year after the EPA makes the finding unless the state submits, and the EPA approves, a state plan during this time. Refer to the federal plan proposal for more details on how and when a federal plan would be triggered.

7. State plan modifications

a. Modifications to an approved state plan. During the course of implementation of an approved state plan, a state may wish to update or alter one or more of the enforceable measures in the state plan, or replace certain existing enforceable measures with new measures. The EPA received broad support for allowing states to submit modifications to approved state plans, and we agree that this is an important aspect of this program. In this rulemaking, therefore, the EPA is finalizing that a state may revise its state plan, and states in a multi-state plan may revise their joint plan. Consistent with the timing for final plan submittals originally submitted by states, the EPA will act on state plan revisions within 12 months of a complete submittal. The EPA expects that the long plan performance timeframes in this final rule and flexibility provided to states in developing state plans will lessen the need for modifications to approved state plans.

A state may enter or exit a multi-state plan through a plan modification, with certain limitations. Multiple commenters stated that the EPA should clarify the plan modification process in such instances.

Where a state with a single-state approved plan seeks to join a multi-state plan, the state may submit a modification of its plan indicating that it is joining the multi-state plan and including the necessary plan components under the multi-state plan. The current participants of the multi-state plan will also need to submit a plan modification, to acknowledge the new state participant and to recalculate the multi-state rate-based or mass-based CO_2 goal. Functionally, both the modification of the single-state plan of the new participant and the multi-state plan of the current plan participants could be addressed through the same plan modification submittal or addressed under a plan modification submittal comparable to the alternate formats for multi-state plan submittals addressed in section VIII.E.4.

The entry or exit of a state to/from a multi-state plan involves the recalculation of the multi-state rate-based or mass-based CO_2 goal for affected EGUs in the participating states. The recalculated multi-state rate-based or mass-based CO_2 goal must take into account and ensure achievement of the individual state rate-based or mass-based CO_2 goal for any state that is joining the multi-state plan. If implementation of the individual state plan has triggered corrective measures or backstop emission standards prior to the plan modification, as described in Section VIII.F.3, the modification must take into account the need to make up for any shortfall in CO_2 emission performance in the individual state plan prior to joining the multi-state plan. Where one or more states are leaving a multi-state plan through a plan modification, the process is similar and the same considerations must be taken into account in connection with the states that are leaving the multi-state plan.

As a result of these requirements and considerations, the EPA is finalizing certain requirements for multi-state plan modifications. A multi-state plan modification may be submitted to the EPA at any time. However, an approved multi-state plan modification may only take effect at the beginning of a new interim or final plan performance period. These requirements are necessary to ensure that state rate-based or mass-based CO_2 goals in the emission guidelines are achieved. In addition, such requirements for the timing of the effective date of multi-state plan modifications are necessary for coordination of the implementation of multi-state plans, especially where such plans include a multi-state emission trading approach. This approach is also consistent with the approach the EPA is proposing for the implementation of federal plan, where relevant for a state(s).

The EPA solicited comment on whether, for new projections of emission performance included in a submitted plan modification, the projection methods, tools, and assumptions used should match those used for the projection in the original demonstration of plan performance, or should be updated to reflect the latest data and assumptions, such as assumptions for current and future economic conditions and technology cost and performance. Comments received on this topic were generally supportive of allowing the use of updated data in state plan modifications, citing that states should have the ability to determine whether the original data and assumptions or updated data and assumptions are appropriate. The EPA is finalizing that new projections of emission performance, the projection methods, tools, and assumptions do not have to match those used for the projection in the original demonstration of plan performance;

they can be updated to reflect the latest data and assumptions, such as assumptions for current and future economic conditions and technology cost and performance.

As discussed in more detail in section VIII.G.2, the final rule has several measures to ensure that it does not interfere with the industry's ability to maintain reliability. One such measure is that if a state cannot address a reliability issue in accordance with an approved state plan, the state can submit a request to the EPA to modify the state plan. See section VIII.G.2 for a more detailed discussion of this issue.

The EPA is not finalizing any circumstances under which a state may or may not revise its state plan, with the exception that a state may not revise its state plan in a way that results in the affected EGU or EGUs not meeting the requisite CO_2 emission performance levels.

b. Modifications to interim and final CO_2 emission goals. As discussed in section VII, the final rule specifies that the state interim and final CO_2 emission goals for affected EGUs in a state may be adjusted to address changes within a state's fleet of affected EGUs. If these changes occur before a state submits its initial submittal or final plan, the state should indicate in its submittal the circumstance that necessitates the goal adjustment and the revised interim or final CO_2 emission goal. If the circumstances occur after a state has an approved plan, a state must submit a modification to its approved plan. The plan revision submittal must indicate the circumstance that necessitates the goal adjustment, the revised interim and/or final CO_2 emission goal, and the adjustments to the enforceable measures in the plan.

8. Plan templates and electronic submittal

The EPA is finalizing the requirement that submissions related to this program be submitted electronically. Specifically, that includes negative declarations, state plan submittals (including any supporting materials that are part of a state plan submittal), any plan revisions, and all reports required by the state plan. The rule provides that files that are submitted to the EPA in an electronic format may be maintained by states in an electronic format. The submission of the information by the authorized official must be in a non-editable format. In addition to the non-editable version, the EPA is also requiring that all plan components designated as federally enforceable must be submitted in an editable version as well, as discussed below.

a. <u>Submittal of an editable version of federally enforceable plan components</u>. To ensure that the EPA has the ability to identify, evaluate, merge, update and track federally enforceable plan components in a timely and comprehensive manner, the EPA is requiring states to submit an editable copy of the specific plan components in their submittals that are designated as federally enforceable, either effective upon the EPA plan approval or as a state plan backstop measure. The editable version is in addition to the non-editable version. Examples of editable file formats include Microsoft Word, Apple Pages and WordPerfect.

b. <u>Revisions to an approved plan</u>. States shall provide the EPA with both a non-editable and editable copy of any submitted revision to existing approved federally enforceable plan components, including state plan backstop measures. The editable copy of any such submitted plan revision must indicate the changes made, if any, to the existing approved federally enforceable plan components, using a mechanism such as redline/strikethrough. This approach to identifying the changes made to the existing federally enforceable plan components is consistent with the criteria for determining the completeness of SIP submissions set forth in Section 2.1(d) of Appendix V to 40 CFR part 51.

c. <u>Electronic submittal</u>. It is the EPA's experience that electronic submittal of information has increased the ease and efficiency of data submittal and data accessibility. The EPA is developing the SPeCS, a web accessible electronic system to support this requirement that will be accessed at the EPA's Central Data Exchange (CDX) (http://www.epa.gov/cdx/). The EPA will pre-register authorized officials and plan preparers in CDX. See section VIII.E.2 for additional information on the pre-registration process for authorized officials and plan preparers. Detailed instructions for accessing CDX and SPeCS will be outlined in the "111(d) SPeCS User Guide: How to submit state 111(d) plan material to EPA" which will be available on the EPA's Clean Power Plan Toolbox for States. The EPA will provide SPeCS training for states prior to the state plan submittal due date.

Once in CDX, SPeCS can be selected from the Active Program Service List. The preparer (e.g., state representative compiling a state plan submittal) assembles the submission package. The preparer can upload files and complete electronic forms. However, the preparer may not formally submit and sign packages. Only registered authorized officials may submit and sign for the state with the exception of draft submittals. The EPA's intent is to allow submittal of draft plans or parts of plans for early EPA review prior to formal submission by the authorized official and will allow preparers, as well as authorized officials, to submit draft documents. The authorized official will be able to assemble submission packages and will be able to modify submission packages that a preparer has assembled. The key difference between the preparer and the authorized official is that the authorized official can submit and sign a package for formal EPA review using an electronic signature. In the case of a multi-state plan, each participating state's authorized official must provide an electronic signature.

The process has been designed to be compliant with the Cross-Media Electronic Reporting Rule (CROMERR), under 40 CFR part 3, which provides the legal framework for electronic reporting under all of the EPA's environmental regulations. The framework includes criteria for assuring that the electronic signature is legally associated with an electronic document for the purpose of expressing the same meaning and intention as would a handwritten signature if affixed to an equivalent paper document. In other words, the electronic signature is as equally enforceable as a paper signature. For more information on CROMERR, see the Web site: http://www.epa.gov/cromerr/. States who claim that a state plan submittal or supporting documentation includes confidential business information (CBI) must submit that information on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: State and Local Programs Group, MD C539-01, 4930 Old Page Rd., Durham, NC 27703.

The EPA received a number of comments on the electronic submittal of state plans. Some commenters preferred the option to submit electronically rather than the requirement to do so.

In the final rule, for the reasons discussed below, the EPA is requiring electronic submittal of state plans and not allowing alternate options for plan submittal (e.g. paper submittal).

Requiring electronic submittal is in keeping with current trends in data availability and will result in less burden on the regulated community. Electronic submittal will facilitate two-way business communication between states and the EPA, will guide states through the submittal process to ensure submission of all required plan components, and will enable states to submit proposed plans to the EPA electronically for early EPA comments. Electronic submittal will also facilitate, expedite and promote national consistency in the EPA's review of state plans and promote transparency by providing stakeholder-specific access to updated information on state plan status and posting of plan requirements for viewing by the public, government regulators and regulated entities. The EPA recently implemented an electronic submittal process for SIPs under CAA section 110 and continues to explore opportunities to increase the ease and efficiency with which states and the regulated community can meet regulatory data submittal requirements. In summary, the EPA believes electronic submittal will be enormously beneficial in terms of improving coordination and cooperation between the EPA and its state partners in developing approvable state plans. We note, however, that there may be some circumstances where having paper copies of the plan is needed to facilitate public engagement, and encourage states to take those considerations into account.

d. Plan templates. In the proposal, the EPA requested comment on the creation of templates for initial submittals and final state plan submittals. Multiple commenters requested the EPA provide state plan templates. One commenter requested templates for different plan designs (e.g. a mass-based trading framework, a rate-based trading framework, multi-state compliance and a utility-based portfolio approach) and for specific plan components (e.g. how to incorporate a state RE standard and an EE program into a state plan, how to assess the emission reductions delivered by RE and EE). The EPA has determined that the broad range of approaches states may take in preparing individual or multi-state plans makes the development of specific templates challenging and likely not useful to states. However, concurrent with this final rule, the EPA is proposing model rules for both rate- and mass-based programs in conjunction with the proposed federal plan. These effectively can serve as a template for states when preparing their state plan submittals. The EPA will continue extensive outreach to states and work closely with them on the need for additional tools and guidance to facilitate the development of approvable state plans.

9. Legal basis regarding state plan process

Section 111(d)(1) requires the EPA to promulgate procedures "similar" to those in section 110 under which states adopt and submit 111(d) plans. The EPA has interpreted this provision previously in the implementing regulations found in 40 CFR part 60 subpart B. As discussed above, the EPA intends that planned revisions to the part 60 implementing regulations will clarify (among other things) whether certain procedures are appropriate for the EPA's action on 111(d) state plans, and if so, precisely how those procedures should apply. The EPA is proposing these revisions to the 111(d) implementing regulations in the notice of proposed rulemaking for the federal plan being issued concurrently with this final rule. In this section we discuss the legal basis for procedures that the EPA is finalizing in this action: initial submittals, extensions, and plan revisions.

First, by using the ambiguous word "similar," Congress delegated authority to the EPA to determine precisely what procedures would govern 111(d) plans. "Similar" does not have an identical meaning as the word "same." One definition of "similar" is "having likeness or resemblance, especially in a general way." The American College Dictionary 1127 (C.L. Barnhart, ed. 1970). On the other hand, "same" is defined as "alike in kind, degree, quality; that is, identical" or "unchanged in character." *Id.* at 1073.

Had Congress intended that the procedures for section 111(d) plans be indistinguishable from those in section 110, Congress knew how to say so. *See, e.g.*, 36 U.S.C. § 2352(b)(2)(B) ("same procedures"). And had Congress intended that the procedures for section 111(d) plans be as close as possible to those in section 110, Congress knew how to say that. *See, e.g.*, 38 U.S.C. § 4325(c) (agency "shall ensure, *to the maximum extent practicable, that the procedures are similar* to" certain other procedures). Therefore, Congress must have intended to give the EPA leeway to create procedures for section 111(d) state plans that somewhat vary from those in section 110, so long as the section 111(d) procedures are reasonably tied to the purpose and text of section 111(d). In other words, "similar" creates a gap in the statute that the EPA may reasonably fill.

a. <u>Initial submittals and extensions</u>. Initial submittals in this instance are a reasonable gap-filling procedural step. As explained in our proposal, certain aspects of section 111(d) plan development for these particular guidelines warrant our creation of this procedural step, even though section 110 does not provide for initial submittals. As explained above, though, we are not bound under section 111(d)(1) to follow exactly the same procedures.

With respect to the timing of initial submittals, final submittals, and extensions, we note that section 111 does not prescribe any particular deadlines, instead leaving it to EPA's discretion to establish "similar" procedures to section 110. The implementing regulations for section 111(d) plans require state plans to be submitted within 9 months of finalization of emission guidelines. Section 110(a)(1) provides that states should adopt and submit SIPs that provide for implementation, maintenance, and enforcement of the NAAQS within 3 years, or such shorter period as the Administrator may prescribe.[849] As further explained in Section VIII.E., the EPA is providing states with up to 3 years to submit a final plan under this rule, contingent upon the grant of an extension through an initial submittal due by September 6, 2016. Section 110(a)(1) does not provide any particular factors for the Administrator to consider in prescribing a shorter period. Thus, the EPA's prescription of a shorter period for either an initial submittal or a final plan submittal is consistent with the discretion granted in section 110(a)(1). We further discuss why the September 6, 2016 initial submittal deadline is reasonable in Section VIII.E., and such deadline is achievable by states seeking to submit a final plan within 3 years. We also note that

[849] Under this grant of authority to prescribe shorter deadlines, the EPA has in a number of occasions required SIPs to be submitted in 1 year.

section 110(b) provides for extensions of 2 years for plans to implement secondary NAAQS, that other provisions in part D provide for extensions of due dates of attainment plans in certain circumstances, and that the section 111(d) implementing regulations provide for extensions generally. We conclude, in view of the above discussion of "similar," that the approach of initial submittals and extensions of due dates as proposed are reasonable procedures that, while not identical to the procedures in section 110, are still similar.

Some commenters argued that the 1-year period for initial submittals and, even assuming an extension, the additional 1- to 2-year period for final submittals were unreasonably short, particularly in light of the possibility that some state legislatures might need to act to provide adequate legal authority for these particular plans. We are not finalizing the 1-year extension for single state submittals, and we have addressed concerns about legal authority for the initial submittals by allowing states to identify remaining legislative action in those submittals.

With respect to the overall period of up to 3 years for submittals, we continue to find it reasonable and consistent with other deadlines in the CAA. First, section 110(a)(1) requires states to submit a plan for implementation, maintenance, and enforcement of new NAAQS within 3 years of promulgation of that NAAQS. This is true even if the EPA promulgates a NAAQS for a previously non-criteria pollutant. In that case, it is possible and even likely that at least some state agencies will lack statutory authority to regulate the new pollutant. Nonetheless, Congress dictated that states should submit section 110(a)(1) plans within 3 years.

Furthermore, we note that under subpart 1 of Part D of Title 1, attainment plans are generally due no later than 3 years after designation of a nonattainment area, and under other subparts of Part D, plans are due even more quickly. For example, under subpart 4, attainment plans for particulate matter are generally due 18 months after designation, and under subpart 5, the same deadline applies for attainment plans for sulfur oxides, nitrogen dioxide and lead. Developing attainment plans may or may not require states to seek additional legislative authority, but certainly in terms of complexity they are similar to section 111(d) plans for this guideline. In general, attainment plans must contain (among other things) a comprehensive inventory of sources of the relevant pollutant and its precursors (which in populated areas can be very numerous), control measures for those sources (including individualized control measures for the larger sources), and modeled demonstrations of attainment (which in some instances requires photochemical grid modeling). Thus, it is reasonable to have the same timeline for these section 111(d) plans as Congress generally provided for attainment plans in section 172(b).

b. State plan modifications. Section 110(l) provides for states to revise their SIPs, as does 40 CFR 60.28 for section 111(d) plans. Section 110(l) also sets out a standard for revisions: it prohibits the EPA from approving a SIP revision that would interfere with any applicable requirement concerning attainment or reasonable further progress, or any other applicable requirement of the CAA. Under the existing section 111(d) implementing regulations, the Administrator will disapprove section 111(d) plan revisions as unsatisfactory when they do not meet the requirements of subpart B to part 60. See 40 CFR 60.27(c)(3). However, the implementing regulations do not set forth a substantive standard like that in section 110(l).

Section 111(d)(1) does not mention revisions (except indirectly through the reference to section 110) and, therefore, does not explicitly provide any substantive requirements for them. There is, therefore, a gap in the statute that the EPA may reasonably fill, since many stakeholders commented on the desirability of states being able to modify their plans, and the EPA agrees. It is reasonable, at a minimum, that the state plan as revised should continue to provide for implementation and enforcement of the standards of performance, and to achieve the CO_2 emission performance rates or state CO_2 emission performance goal. This is analogous to the substantive requirements of section 110(l), which as explained above for section 110(a)(2), we may consider in determining how to reasonably fill statutory gaps for section 111(d) plans.

In our proposal, we stated that certain revisions to state plans under these emission guidelines, those that revised enforceable measures for affected EGUs, should satisfy some additional conditions. First, the state should demonstrate that the plan continues to achieve the CO_2 emission performance rates or state CO_2 emission performance goal. We proposed that this demonstration might be simple for minor revisions, but for major revisions a more complete demonstration may be required. We are finalizing this proposal. As legal basis for this position, we note that a demonstration is necessary to show that a state plan provides for implementation of standards of performance that achieve the CO_2 emission performance rates or state CO_2 emission performance goal, and as explained above we can reasonably require the same of revisions.

It is also reasonable to tailor the requirements of the demonstration to the magnitude of the revision. The EPA has taken a similar approach to tailoring the requirements for a technical demonstration that, under section 110(l), a SIP revision does not interfere with any applicable requirement concerning attainment of the NAAQS. If a SIP revision does not relax the stringency of any SIP measure, then the demonstration is simple. If the SIP revision does relax the stringency of SIP measures, then a qualitative or quantitative analysis may be necessary to show non-interference, depending on the nature of the revision, the current air quality in the area, and other factors.

Finally, we proposed that revisions "should not result in reducing the required emission performance for affected EGUs specified in the original approved plan. In other words, no 'backsliding' on overall plan emission performance through a plan modification would be allowed." 79 FR 34917/1. We received adverse comments that this standard did not have a basis in section 111(d). According to commenters, since the standard for EPA approval of a section 111(d) plan is whether the plan is satisfactory in establishing and providing for implementation and enforcement of standards of performance that achieve the emission performance rates or goal, the same standard should apply to revisions. In other words, the standard for revisions should be whether the plan as revised is satisfactory. We believe that our proposal was unclear as to this point, and we agree that the same standard for revisions should be the same as for submittals. We have finalized this position.

F. State Plan Performance Demonstrations

This section describes state plan requirements related to compliance periods, monitoring and reporting for affected EGUs; plan performance demonstrations; consequences if the CO_2 emission performance rates or state CO_2 emission goals are not met; and out-year requirements.

1. Compliance periods, monitoring and reporting requirements for affected EGUs

For plans that include emission standards on affected EGUs, the EGU emission standards for the interim period must have schedules of compliance for each interim step 1, 2 and 3 for the calendar years 2022-2024, 2025-2027 and 2028-2029, respectively. For the final period, EGUs must have emission standards that have schedules of compliance for each 2 calendar years starting in 2030 (i.e., 2030-2031, 2032-2033, 2034-2035, etc.). If a backstop is triggered for a state measures plan, the schedule of compliance for the federally enforceable emission standards must begin no later than 18 months after the backstop is triggered and end at the end of the same compliance period. For example, if a backstop is triggered on July 1, 2025, the compliance period for the backstop emission standards must begin no later than January 1, 2027, and end on December 31, 2027. The next compliance period for the backstop emission standards would be January 1, 2028-December 31, 2029.

In the June 2014 proposal, the EPA proposed that the appropriate averaging time for any rate-based emission standard for affected EGUs be no longer than 12 months within a plan performance period and no longer than 3 years for a mass-based standard. The EPA solicited comments on longer and shorter averaging times for emission standards included in state plans. The EPA received comments stating that the proposed 12-month averaging was too short and that there was no reason why the compliance period under a rate-based plan should be different from a mass-based plan. Comments stated that a multi-year averaging period is appropriate for rate-based and mass-based plans to account for variations that can occur in a single year, allowing operators the flexibility they need to manage unforeseen events. The commenters also recommended that the final rule use discrete 3-year periods for compliance reconciliation instead of the rolling-average approach proposed.

The EPA has considered all comments received on this matter and is finalizing the compliance periods specified above, which respond to the comments by applying to both rate- and mass-based programs, providing compliance periods longer than 1 year, and establishing block compliance periods rather than a rolling average approach. We agree with comments that longer averaging periods allow for operational and seasonal variability to even out. The EPA finalizes that states can choose to set shorter compliance periods for their emission standards but none that are longer than the compliance periods the EPA is finalizing in this rulemaking. If a state chooses to set shorter compliance periods, we urge them to make efforts to be cognizant of other deadlines facing EGUs to assure that there will not be conflicts. The EPA recognizes that the compliance periods provided for in this rulemaking are longer than those historically and typically specified in CAA rulemakings. "The time over which [the compliance standards] extend should be as short term as possible and should generally not exceed one month." See e.g., June 13, 1989 "Guidance on Limiting Potential to Emit in New Source Permitting" and January 25, 1995 "Guidance on Enforceability Requirements for Limiting Potential to Emit through SIP and §112 Rules and General Permits." However, the EPA has determined that the longer compliance periods provided for in this rulemaking are acceptable in the context of this specific rulemaking because of the unique characteristics of this rulemaking, including that CO_2 is long-lived in the atmosphere, and this rulemaking is focused on performance standards related to those long-term impacts. The distinction between these unique characteristics and the EPA's general practice regarding compliance periods is bolstered by the EPA guidance on appropriate averaging periods for emission limitations in NAAQS implementation. For example, the EPA guidance has stated that in implementation of the ozone standards, which have a short averaging period, the averaging period for VOC emission limitations should be correspondingly short. See 51 FR 43857. A longer averaging period for VOC emission limitations (VOCs are one of the key precursors to ozone formation) can allow spikes in emissions that adversely impact ambient air and violate the short term ozone standards. This is precisely the opposite of the unique characteristics cited above: the long-lived persistence of CO_2 in the stratosphere and the intent of these guidelines to address the long-term impacts.

State plans must contain requirements for tracking and reporting actual plan performance during implementation, which includes reporting of CO_2 emissions from affected EGUs. Affected EGUs must comply with emissions monitoring and reporting requirements that are largely incorporated from 40 CFR part 75 monitoring and reporting requirements. The majority of affected EGUs are already familiar with the reporting requirements of part 75, and because of this, the EPA has chosen to streamline the applicable reporting requirements for affected EGUs under the state plans in the final rule. States must require all affected EGUs to monitor and report hourly CO_2 emissions and net energy output (including total net MWh output that is comprised of generation, and where applicable, useful thermal output converted to net MWhs) on a quarterly basis in accordance with 40 CFR part 75. Note that this requirement applies for all types of state plans, regardless of whether the state chooses the option of the CO_2 emission performance rates, a state rate-based CO_2 emission goal, or a state mass-based CO_2 emission goal.

In the June 2014 proposal, the EPA proposed that state plans must include monitoring, reporting and recordkeeping requirements for useful energy output from affected EGUs. Multiple commenters questioned whether gross rather than net electrical production should be reported by affected EGUs and recommended that the EPA should utilize gross rather than net generation. Many commenters recommended electricity be reported in the form used in the 111(b) rules for consistency between reporting requirements and simplification of calculation of emission limitations between new and old sources. Commenters also stated that to the extent the EPA seeks to provide guidance to states regarding its preferred monitoring and reporting procedures, the EPA should encourage states to avoid imposing additional monitoring and reporting burdens by taking advantage of the monitoring requirements that already exist to the greatest extent possible. For example, the commenters noted that the 40 CFR part 75 monitoring procedures used to comply with other programs, such as the Title IV Acid Rain Program, provide much of the data that would be needed to demonstrate compliance under the rule. Comments stated that the June 2014 proposal appeared to mandate a monitoring approach that would eliminate key flexibilities provided in the part 75 regulations, thus requiring utilities to maintain separate document collection and reporting procedures and potentially eliminating important alternative monitoring options intended to ensure representative, cost-effective monitoring approaches are available. The commenters asked the EPA to revise its proposal to make clear that the procedures established under part 75 will suffice or explain the need for any exceptions. Commenters indicated that the rule should require all affected EGUs to monitor CO_2 emissions and net hourly electric output under 40 CFR part 75, and report the data using the EPA's Emission Collection and Monitoring Plan System (ECMPS) assuring a more uniform monitoring and reporting process for all EGUs. The EPA believes that the final monitoring and reporting requirements (via ECMPS) address the issue of duplicative requirements and alleviate concern about lost flexibility raised by commenters.

2. Plan performance demonstrations

The state plan must include emission performance checks, and for state measures plans, periodic program implementation milestones. The state plan must provide for tracking of emission performance, and for measures to be implemented if the emission performance of affected EGUs in the state does not meet the applicable CO_2 emission performance rates or state CO_2 emission goal during a performance period.

As discussed above in section VII, the agency is finalizing CO_2 emission performance rates or state-specific CO_2 emission goals that represent emission levels to be achieved by 2030 and emission levels to be achieved over the 2022-2029 interim period, and over three interim steps of 2022-2024, 2025-2027 and 2028-2029. A state may choose to define different interim step emission levels for achieving its required 2022-2029 average performance rate. The EPA recognizes the importance of ensuring that, during the 8-year interim period (2022-2029) for the interim performance rates or interim state goal, a state is making steady progress toward achieving the required level of emission performance. For both emission standards plans and state measures plans, the final rule requires periodic checks on overall emission performance leading to corrective measures or implementation of the backstop, if necessary, as described in section VIII.F.3 below. States must demonstrate that the interim steps were achieved at the end of the first two interim step periods.

In 2032 and every 2 years thereafter, states must demonstrate that affected EGUs achieved the final performance rates or state goal on average or cumulatively, as appropriate, during each 2-year reporting period (i.e., 2030-31, 2032-33, 2034-2035 etc.). The multi-year performance periods for measuring actual plan performance against the performance rates or state goals allow states some flexibility that accounts for seasonal operation of affected EGUs, and inclusion of RE and demand-side EE efforts.

For a rate-based plan, emission performance is an average CO_2 emission rate for affected EGUs representing cumulative CO_2 emissions for affected EGUs over the course of each reporting period divided by cumulative MWh energy output[850] from affected EGUs over the reporting period, with rate adjustments for qualifying measures, such as RE and demand-side EE measures. For a mass-based plan, emission performance is total tons of CO_2 emitted by affected EGUs over the reporting period.

For emission standards plans, as discussed in section VIII.D, the state must submit a report to the EPA containing the emissions performance comparison for each reporting period no later than the July 1 following the end of each reporting period (i.e., by July 1, 2025; July 1, 2028; July 1, 2030; July 1, 2032; and so on). As discussed in section VIII.D, the emission comparison required in the July 1, 2030 report must compare the actual emissions from affected EGUs over the interim period (2022-2029) with the interim CO_2 emission performance rates or state CO_2 emission goal. The report is not required to include a

[850] For EGUs that produce both electric energy output and other useful energy output, there would also be a credit for non-electric output, expressed in MWh.

comparison for the interim step 3 period, but must include the actual emissions from affected EGUs during the interim step 3 period.

The EPA notes that for certain types of emission standards plans, with mass-based emission standards in the form of an emission budget trading program, achievement of a state's mass-based CO_2 goal (including interim step goals and final goal) will be assessed by the EPA based on compliance by affected EGUs with their emission standards under the program, rather than CO_2 emissions during a specific interim step period or final period. This approach is limited to plans with emission budget trading programs where compliance by affected EGUs with the emission standards will ensure that, on a cumulative basis, the state interim and final mass-based CO_2 goals are achieved.[851] This approach allows for CO_2 allowance banking across plan performance periods, including from the interim period to the final period. As a result, CO_2 emissions by affected EGUs could differ from the state mass-based CO_2 goal during an individual plan performance period, but on a cumulative basis CO_2 emissions from affected EGUs would not exceed what is allowable if the interim and final

[851] Emission budget trading programs in such plans establish CO_2 emission budgets equal to or less than the state mass CO_2 goal, as specified for the interim plan performance period (including specified levels in interim steps 1 through 3) and the final 2-year plan performance periods.

CO_2 goals are achieved.

Also as discussed in section VIII.D, states that choose a state measures plan must submit an annual report no later than July 1 following the end of each calendar year in the interim period. This annual report must include the status of the implementation of programmatic milestones identified in the state plan submittal. The annual report that follows the end of each reporting period (i.e., 2022-2024, 2025-2027, and 2028-2029) must also include an emissions performance comparison for the reporting period, as described above for the emission standards plan. As discussed in section VIII.D, the emission comparison required in the July 1, 2030 report must compare the actual emissions from affected EGUs over the interim period (2022-2029) with the interim CO_2 emission performance rates or state CO_2 emission goal. The report is not required to include a comparison for the interim step 3 period, but must include the actual emissions from affected EGUs during the interim step 3 period. Beginning with the final period of 2030 and onward, states using a state measures plan must submit a biennial report no later than July 1 following the end of each reporting period with an emission performance comparison for each reporting period, consistent with the reporting requirements for emission standards plans.

In the June 2014 proposal, the EPA proposed that a state report is due to the EPA no later than July 1 of the year immediately following the end of each reporting period. The EPA requested comment on the appropriate frequency of reporting of the different proposed reporting elements, considering both the goals of minimizing unnecessary burdens on states and ensuring program effectiveness. In particular, the agency requested comment on whether full reports containing all of the elements should only be required every 2 years rather than annually and whether these reports should be submitted electronically, to streamline transmission.

The EPA mainly received adverse comments for requiring annual state reporting; commenters stated that this requirement was too burdensome for both states and the EPA. Commenters also requested that the EPA extend the due date of the annual report from July 1 to at least December 31. Commenters stated that because of the timing of current data collection and the need to leave time to organize and submit the reports, allowing only 6 months after the close of the year is problematic. Commenters asked that the EPA consider reducing the amount of data required if annual reporting was required.

Considering the comments received and the goals of minimizing unnecessary burdens on states and ensuring program effectiveness, the EPA has reduced the frequency of reporting of emissions data to every 3 years for the first two interim steps and every 2 years thereafter. However, the EPA is finalizing that state reports are due to the EPA no later than July 1 following the end of each reporting period. The EPA believes states can design their state plans to receive the data and information needed for these reports in a timely manner so that this requirement can be met. Furthermore, some of the state reporting requirements, such as reporting of EGU emissions, can be met through existing reporting mechanisms (ECMPS) and would not place additional burdens on states.

3. Consequences if actual emission performance does not meet the CO_2 emission performance rates or state CO_2 emission goal

The EPA recognizes that, under certain scenarios, an approved state plan might fail to achieve a level of emission performance that meets the emission guidelines or the level of performance established in a state plan for an interim milestone. Despite successful implementation of certain types of plans, emissions under the plan could turn out to be higher than projected at the time of plan approval because actual conditions vary from assumptions used when projecting emission performance. Emissions also could theoretically exceed projections because affected entities under a state plan did not fulfill their responsibilities, or because the state did not fulfill its responsibilities.

The final rule specifies the consequences in the event that actual emission performance under a state plan does not meet, or is not on track to meet, the applicable interim and interim step CO_2 emission performance rates or state goals in 2022-2029, or does not meet the applicable final CO_2 emission performance rates or state CO_2 emission goal in 2030-2031 or later. The determination that a state is not on track to meet the applicable interim goal or interim step goals in 2022-2029 or the applicable final goal in 2030-2031 or later, or the CO_2 emission performance rates, will be made through the actual performance checks to be included in state reports of performance data described in section VIII.D.2.a above.

For emission standards plans, the final rule specifies that corrective measures must be enacted once triggered. Corrective measures apply only to emission standard plans in which full compliance by affected EGUs would not necessarily lead to achievement of the emission performance rates or CO_2 emission goals.[852] For such plans, corrective measures are triggered if actual CO_2 emission performance by affected EGUs is deficient by

[852] To be specific, corrective measures requirements apply to all emission standard plan designs that do not mathematically assure that the plan performance level will be achieved when all affected EGUs are in compliance with their emission standards, regardless of electricity production and electricity mix. Corrective measures requirements apply, for example, to emission standards plans that include standards on affected EGUs that differ from the emission performance rates in the guidelines. Backstop requirements apply to state measures plans.

10 percent or more relative to the specified level of emission performance in the state plan for the step 1 or step 2 interim performance periods. Corrective measures also are triggered if actual emission performance fails to meet the specified level in the plan for the 8-year interim period 2022-2029, or for any 2-year final goal performance period (beginning in 2030). In such cases, the state report must include a notification to the EPA that corrective measures have been triggered. If, in the event of such an exceedance, the EPA determines that corrective measures have been triggered and the state has failed to notify the EPA, the EPA will inform the affected EGUs that corrective measures have been triggered.[853]

When corrective measures are triggered, if the state plan does not already contain corrective measures, the state must submit to the EPA a plan revision including corrective measures that adjust requirements or add new measures. The corrective measures must both ensure future achievement of the CO_2 emission performance rates or state CO_2 emission goal and achieve additional emission reductions to offset any emission performance shortfall that occurred during a performance period. The shortfall must be made up as expeditiously as practicable.

[853] The EPA notes that as part of the proposed federal plan rulemaking, it is proposing a regulatory mechanism to call plans in the instances of substantial inadequacy to meet applicable requirements or failure to implement an approved plan.

The state plan revision submission must explain how the corrective measures both make up for the shortfall and address the state plan deficiency that caused the shortfall. The state must submit the revised plan to the EPA as expeditiously as practicable and within 24 months after submitting the state report indicating the exceedance. The 24-month time period allows time to identify corrective measures and make rule changes through state regulatory processes. The EPA will then act on the plan revision within 12 months, consistent with other plan revisions and with the timing for final plan submittals originally submitted by states. The state must implement corrective measures within 6 months of the EPA's approval of a plan revision adding them.

For states using the state measures approach, the EPA is finalizing the backstop requirement as described in section VIII.C.3 of this preamble. As discussed in section VIII.D.2, the determination that a state using the state measures approach is not on track to meet the applicable interim goal or interim step goals in 2022–2029, or the applicable final goal in 2030–2031 or later, is based on checks that must be included in state reports that must be submitted annually during the interim period and biennially during the final period. The state must annually report on its progress in meeting its programmatic milestones during the interim period. In addition, the state must report actual emission performance checks, similar to the requirements discussed above for emission standards plans, in 2025, 2028, 2030, and every 2 years thereafter. If, at the time of the state report to the EPA, the state did not meet the programmatic milestones for the reporting period, or the performance check shows that the plan's actual CO_2 emission performance warrants implementation of backstop requirements,[854] the state must include in the state report a notification to the EPA that the backstop has been triggered. If, in the event of such an exceedance, the EPA determines that the backstop has been triggered and the state has failed to notify the EPA, the EPA will inform the affected EGUs that the backstop has been triggered.[855]

For multi-state plans, corrective measure or backstop provisions would be required for the same plan approaches for which those provisions are required in individual state plans.

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[854] As explained in section VIII.C.3.b., state measures plans must require the backstop to take effect if actual CO_2 emission performance fails to meet the level of emission performance specified in the plan over the 8-year interim performance period (2022-2029), or for any 2-year final goal performance period. The plan also must require the backstop to take effect if actual emission performance is deficient by 10 percent or more relative to the performance levels that the state has chosen to specify in its plan for the interim step 1 period (2022-2024) or the interim step 2 period (2025-2027).

[855] The EPA notes that as part of the proposed federal plan rulemaking, it is proposing a regulatory mechanism to call plans in the instances of substantial inadequacy to meet applicable requirements or failure to implement an approved plan.

For multi-state plans using plan approaches to which corrective measures or backstop requirements apply, all states that are party to the multi-state plan would be subject to corrective action or backstop requirements, and requirements to make up the past CO_2 emission performance shortfall, if those requirements were triggered. This is because multi-state plans are joint plans (even if created through separate state submittals). That would not be the case for coordinated individual state plans linked through interstate ERC or emission allowance trading. In the case of coordinated individual state plans, for plan types subject to corrective measure or backstop requirements, the state where the CO_2 emission performance deficiency occurs would be required to implement corrective measures or backstop requirements for affected EGUs, as applicable, and remedy the past CO_2 emission performance shortfall.

Multiple commenters requested that corrective measures not be required in the case of a catastrophic, uncontrollable event. We recognize that there are potential system emergencies that cannot be anticipated that could cause a severe stress on the electricity system for a length of time such that the multi-year requirements in a state plan may not be achievable by certain affected EGUs without posing an otherwise unmanageable risk to reliability. We are finalizing a reliability safety valve, which includes an initial period of up to 90 days during which a reliability-critical affected EGU or EGUs will not be required to meet the emission standard established for it under the state plan but rather will meet an alternative standard. While the initial 90-day period is in use, the emissions of the affected EGU or EGUs that exceed their obligations under the approved state plan will not be counted against the state's overall goal or emission performance rate for affected EGUs and will not be counted as an exceedance that would otherwise trigger corrective measures under an emission standard plan type or an exceedance that would trigger a backstop under a state measures plan type. Use of the reliability safety valve will not alter or abrogate any other obligations under the approved state plan. After the initial period of up to 90 days, the reliability-critical affected EGU is required to continue to operate under the original state plan emission standard or an alternative standard as part of the reliability safety valve, and the state must revise its plan to accommodate changes needed to respond to ongoing reliability requirements and to ensure than any emissions excess of the applicable state goals or performance rates occurring after the initial period of up to 90 days are accounted for and offset. See section VIII.G.2.e of this preamble.

Multiple commenters supported the inclusion of strong enforcement measures for ensuring the interim and final goals are met, including the required use of corrective measures when triggered. Other commenters provided feedback as to the percentage that actual emission performance would need to exceed the level of emission performance specified in the statewide plan to trigger corrective measures. Some commenters supported the trigger that we are finalizing (actual emissions or emission rate performance that is 10 percent or more than the specified level of emission performance in the state plan for the interim step 1 or step 2 performance periods), while some recommended a lower or higher trigger.

The agency is finalizing the trigger at the level of 10 percent for the interim step 1 or step 2 performance periods. Ten percent is a reasonable level to ensure that when deficiencies in state plan performance begin to emerge, corrective measures (or backstop requirements) will be implemented promptly to avoid emissions shortfalls (or minimize the extent of shortfalls) relative to the 8-year interim goal and the final goal, which reflect the BSER. The 10 percent figure also provides latitude for a state's emission improvement trajectory during the interim period to deviate a bit from its planned path without triggering these requirements, as the state initiates or ramps up programs to meet the 8-year interim goal and final goal.

The EPA requested comment on whether the agency should promulgate a mechanism under CAA section 111(d) similar to the SIP call mechanism in CAA section 110. Under this approach, after the agency makes a finding of the plan's failure to achieve the CO_2 emission performance rates or state CO_2 emission goal during a performance period, the EPA would require the state to cure the deficiency with a new plan within a specified period of time. If the state still lacked an approved plan by the end of that time period, the EPA would have the authority to promulgate a federal plan under CAA section 111(d)(2)(A). 79 FR 34830, 34908/1-2 (June 18, 2014).

The EPA intends that planned revisions to the part 60 implementing regulations will clarify (among other things) whether the EPA has authority to call for plan revisions under section 111(d) when a state's plan is not complying with the requirements of this guideline, and if so, precisely what procedures should apply. The EPA is proposing these revisions to the 111(d) implementing regulations in the notice of proposed rulemaking for the federal plan. The EPA is not taking final action now on this issue or the related change to the implementing regulations.

a. Legal basis for corrective measures. The EPA discussed the concept of corrective measures in our 1992 General Preamble for the Implementation of Title I of the CAA Amendments of 1990. 57 FR 13498 (Apr. 16, 1992). The General Preamble sets out four general principles that apply to all SIPs, "including those involving emissions trading, marketable permits and allowances." *Id.* at 13568. The fourth principle, accountability, means (among other things) that "the SIP must contain means … to track emission changes at sources and provide for corrective action if emissions reductions are not achieved according to the plan." In the General Preamble, we noted that Part D of Title I explicitly provided for this in certain instances by requiring milestones and contingency measures.

Some commenters noted that the contingency measures explicitly required by part D are required to be adopted in the attainment plan and ready to implement when a milestone is not achieved or the area fails to attain the relevant NAAQS. These commenters therefore concluded that corrective measures for 111(d) plans should likewise already be adopted in the 111(d) plan and ready to implement. We disagree. Under Part D, contingency measures are not expected to fully bring the area into attainment. In fact, this would not be possible given the difficulty of predicting in advance exactly what measures would be needed to fully attain. A better analogue in Part D for the corrective measures in these guidelines is the primary way Part D addresses failure to attain: the state is required to revise its plan in various ways within a certain time in order to bring about attainment. See, e.g., section 179(d). This is analogous to what we are requiring for corrective measures. Thus, part D contingency measures are unlike the corrective measures in this rule.

However, the requirement to revise an attainment plan in response to failure to attain differs somewhat from the corrective measures in these guidelines. Under these guidelines, the corrective measures must make up the difference by which the plan fell short of the goal, including any prior shortfall that had accumulated if the plan fell short of the goal in prior years. There is no corresponding requirement in attainment planning to increase the stringency of the plan by an amount that somehow makes up for any shortfall in attainment from prior years; instead the revised plan must demonstrate attainment going forward, and other more stringent requirements (such as requirements for best available control measures) may be triggered.

This distinction is the natural result of the difference between these guidelines and NAAQS attainment planning. In this case, we are finalizing guidelines representing technology-based standards for a pollutant with cumulative and long-lasting effects. If a plan falls short of a performance goal, then in effect the standards of performance in the plan have failed to reflect the BSER over the corresponding period. Due to the cumulative effects of CO_2, it is possible to remedy this failure by requiring the plan to be revised in such a way that the standards of performance in the revised plan will reflect the BSER over the cumulative plan period, and this can be done by requiring the revised plan to make up the shortfall from the previous period. In short, the flexibility that these guidelines provide should not come at the cost of allowing the standards of performance to reflect less than the BSER over the long run.[856]

Some commenters noted that 111(d) does not contain explicit provisions regarding corrective measures, and they therefore inferred that the EPA is not authorized to require them. That inference is mistaken. The requirement for 111(d) plans to "provide for implementation and enforcement" of the standards of performance is ambiguous and does not directly speak to whether corrective measures should or should not be required. There is therefore a gap for the EPA to fill. While the discussion above about Part D does not independently provide any authority to fill this gap, the fact that Congress created a scheme with stages of planning in Part D suggests that it would be reasonable, if appropriate, to fill this gap in 111(d) in a similar way.

In this guideline, it is appropriate for emission standards

[856] Similar considerations apply to the requirement under the state measures approach to revise the plan to make up the shortfall.

plans to fill this gap with corrective measures if triggered. There are two ways an emission standards plan can provide for implementation of standards of performance that achieve the CO_2 emission performance rates or requisite state CO_2 emission performance goal. First, the state can set emission standards that necessarily achieve the performance rates or goal, even if the affected EGUs in the future vary in their relative amounts of electricity generated. Second, the state can set emission standards that are demonstrated to achieve the performance rates or goal based on assumptions about the relative amounts of electricity generated, but which may turn out to not actually achieve the goal even if all affected EGUs comply. This is analogous to an attainment plan that demonstrated attainment by the applicable attainment date, but due to unpredicted economic changes actually failed to attain. In this second case, the EPA interprets the ambiguous language "provide for implementation . . . of standards of performance" in the context of achieving the performance rate or emissions goal, to mean that at the time the plan is submitted it must contain some mechanism to check the progress of the plan and correct course. The EPA has determined that, for this particular rule, the minimum mechanism is the set of milestones and provisions for corrective measures specified in this rule. Indeed, not requiring corrective measures in the case of deficient plan performance would undercut the viability of state plan options other than emission standard plans with uniform rates applied to all affected EGUs within the state.

4. Out-year requirements: Maintaining or improving the level of emission performance required by the emission guidelines

The agency is determining CO_2 emission performance rates and state CO_2 emission goals for affected EGU emission performance based on application of the BSER during specified time periods. This raises the question of whether affected EGU emission performance should be maintained at the 2030 level – or instead should be further improved - once the final CO_2 emission performance rate or state CO_2 emission goal is met in 2030. This involves questions of performance rate and goal-setting as well as questions about state planning. The EPA believes that Congress either intended the emission performance improvements required under CAA section 111(d) to be maintained or, through silence, authorized the EPA to reasonably require maintenance. Other CAA section 111(d) emission guidelines set emission limits that do not expire. Therefore, the EPA is finalizing that the level of emission performance for affected EGUs represented by the final CO_2 emission performance rates or state CO_2 emission goal must continue to be maintained in the years after 2030.

As noted above, the state plan must demonstrate that plan measures are projected to achieve the final emission performance level by 2030. In addition, the state plan must identify requirements that continue to apply after 2030 and are likely to maintain affected EGU emission performance meeting the final goal. The state plan would be considered to provide for maintenance of emission performance consistent with the final goal if the plan measures used to demonstrate projected achievement of the final goal by 2030 will continue in force and not sunset. After implementation, the state is required to compare actual plan performance against the final goal on a 2-year average basis starting in 2030, and to implement corrective measures or a backstop if triggered.

In the proposal, the EPA noted that "CAA section 111(b)(1)(B) calls for the EPA, at least every eight years, to review and, if appropriate, revise federal standards of performance for new sources" in order to assure regular updating of performance standards as technical advances provide technologies that are cleaner or less costly. The proposal "requests comment on the implications of this concept, if any, for CAA section 111(d)." 79 FR 34830, 34908/3 (June 18, 2014).

We acknowledge the obligation to review section 111(b) standards as stated. The EPA is not finalizing any position with respect to any implications of this concept for section 111(d). We are promulgating rules for section 111(d) state plans that will establish standards of performance for existing sources to which a section 111(b) standard of performance would apply if such sources were new sources, within the definition in section 111(a)(2) of "new source." It is not necessary to address at this time whether subsequent review and/or appropriate revision of the corresponding section 111(b) standard of performance have any implications for review and/or revision of this rule.

a. Legal basis for maintaining emission performance. In the proposal, the EPA proposed "that the level of emission performance for affected EGUs represented by the final goal should continue to be maintained." The EPA explained that "Congress either intended the emission performance improvements required under CAA section 111(d) to be permanent or, through silence, authorized the EPA to reasonably require permanence. Other CAA section 111(d) emission guidelines set emission limits to be met permanently." 79 FR 34830, 34908/2 (June 18, 2014). We also requested comment on whether "we should establish BSER-based state performance goals that extend further into the future (e.g. beyond the proposed planning period), and if so, what those levels of improved performance should be." *Id.* at 34908/3.

We received adverse comment on establishing BSER-based state performance goals beyond the proposed planning period. Commenters argued that we did not have a sufficient basis at this time to determine what those future goals should be. We agree and have decided not to establish such goals. We are finalizing, though, that the level of emission performance for affected EGUs represented by the final goal should continue to be maintained, for the reasons given in our proposal and quoted above.

The general structure of the CAA supports our interpretation. Section 111(d) plans establish standards of performance that reflect the BSER, a technology-based standard. Generally speaking, in the future technology will only improve, and correspondingly the CAA does not provide explicit processes to relax technology-based standards. In contrast, the provisions in Part D of title I that address attainment of health-based standards, the NAAQS, explicitly provide that once the NAAQS are attained, emission reduction measures may be relaxes so long as the NAAQS are maintained. The absence in section 111(d) of explicit provisions for future relaxation of emission reduction measures, as compared to Part D, supports our interpretation that the emission reductions continue to be on-going after the CO_2 emission performance rates or state CO_2 emission goals are achieved in 2030. This is consistent with our past practice for section 111(d) rules, which do not contain any provision that in the future removes or relaxes the promulgated guidelines. In light of the persistence of CO_2 as a pollutant and its long-term impacts, it is particularly critical in these guidelines to explicitly provide for continuing emission reductions.

G. Additional Considerations for State Plans

1. Consideration of a facility's "remaining useful life" and "other factors"

This section discusses the way in which the final emission guidelines address the CAA section 111(d)(1) provision requiring the Administrator, in promulgating 111(d) regulations, to "permit the State in applying a standard of performance to any particular source under a [111(d)] plan . . . to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."

The final guidelines permit a state, in developing its state plan, to fully consider and take into account the remaining useful life of an affected EGU and other factors in establishing the requirements that apply to that EGU, as discussed further below. Therefore, consideration of facility-specific factors and in particular, remaining useful life, does not justify a state making further adjustments to the performance rates or aggregate emission goal that the guidelines define for affected EGUs in a state and that must be achieved by the state plan. Thus, these guidelines do not provide for states to make additional goal adjustments based on remaining useful life and other facility-specific factors because they can fully consider these factors in designing their plans.

a. <u>Statutory and regulatory backdrop</u>. This section describes the statutory and existing regulatory background concerning facility-specific considerations in implementation of section 111(d).

Section 111(d)(1)(A) requires states to submit a plan that "establishes standards of performance" for existing sources. Under section 111(d)(1)(B), the plan must also "provide for implementation and enforcement of such standards of performance." Finally, the last sentence of section 111(d)(1) provides: "Regulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."

The EPA's 1975 implementing regulations[857] addressed a number of facility-specific factors that might affect requirements for an existing source under section 111(d). Those regulations provide that for designated pollutants, standards of performance in state plans must be as stringent as the EPA's emission guidelines. Deviation from the standard might be appropriate where the state demonstrates with respect to a specific facility (or class of facilities):

(1) Unreasonable cost of control resulting from plant

[857] 40 FR 53340 (Nov. 17, 1975).

age, location, or basic process design;

(2) Physical impossibility of installing necessary control equipment; or

(3) Other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable.

This provision was amended in 1995 (60 FR 65387, December 19, 1995), and is now prefaced with the language "Unless otherwise specified in the applicable subpart on a case-by-case basis for particular designated facilities or classes of facilities." 40 CFR 60.24(f).

b. <u>Our proposal regarding the implementing regulations</u>. Our proposal stated that the reference to "[u]nreasonable cost of control resulting from plant age" in 60.24(f) "implements" the statutory provision on remaining useful life. We also stated that the implementing regulations "provide the EPA's default structure for implementing the remaining useful life provision of CAA section 111(d)." We noted that the prefatory language "unless otherwise specified in the applicable subpart" gives the EPA discretion to alter the extent to which the implementing rules applied if appropriate for a particular source category and guidelines. We requested comment on our analysis of the existing implementing regulations and any implications for our regulatory text in respect to how these guidelines relate to those regulations.

Commenters stated, among other things, that the sentence concerning "remaining useful life" was added in the 1977 CAA Amendments and that therefore it could not be said that provisions from the 1975 implementing regulations "implement" the sentence. The EPA does not think as a general matter that it is necessarily impossible that a pre-statutory amendment rule could continue to serve as a reasonable implementation of a post-statutory amendment provision. However, we also think it is appropriate, as we suggested in the June 2014 proposal, to specify in the applicable subpart for these guidelines that the provisions in 60.24(f) should not apply to the class of facilities covered by these guidelines. As a result, regardless of whether the implementing regulations appropriately implement the "remaining useful life" provision in general, the relevant consideration is that, as we now explain, these particular guidelines "permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."

c. <u>How these emission guidelines permit states to consider remaining useful life and other facility-specific factors</u>. The EPA notes that, in general, the implementing regulation provisions for remaining useful life and other facility-specific factors are relevant for emission guidelines in which the EPA specifies a presumptive standard of performance that must be fully and directly implemented by each individual existing source within a specified source category. Such guidelines are similar to a CAA section 111(b) standard in their form. For example, the EPA emission guidelines for sulfuric acid plants, phosphate fertilizer plants, primary aluminum plants, Kraft pulp plants, and municipal solid waste landfills specify emission limits for sources.[858] In the case of such emission guidelines, some individual sources, by virtue of their age or other unique circumstances, may warrant special accommodation.

In these final guidelines for state plans to limit CO_2 from affected EGUs, however, the agency does not specify presumptive performance rates that each individual EGU is to achieve in the absence of trading. Instead, these guidelines provide collective performance rates for two classes of affected EGUs (steam generating units and stationary combustion turbines), and give

[858] See "Phosphate Fertilizer Plants; Final Guideline Document Availability," 42 FR 12022 (Mar. 1, 1977); "Standards of Performance for New Stationary Sources; Emission Guideline for Sulfuric Acid Mist," 42 FR 55796 (Oct. 18, 1977); "Kraft Pulp Mills, Notice of Availability of Final Guideline Document," 44 FR 29828 (May 22, 1979); "Primary Aluminum Plants; Availability of Final Guideline Document," 45 FR 26294 (Apr. 17, 1980); "Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills, Final Rule," 61 FR 9905 (Mar. 12, 1996).

states the alternative of developing plans to achieve a state emission goal for the collective group of all affected EGUs in a state. Providing states with the ability to consider facility-specific factors such as remaining useful life in designing their state plans is one of the fundamental reasons that the EPA designed the final rule in this way. In addition, the significant revisions since proposal to address achievability concerns (e.g., moving the start date from 2020 to 2022, and other changes in interim and final state goals summarized in the next section) will help to ensure that states in practice can consider remaining useful life and other facility-specific factors in setting EGU requirements. Of course, EGUs vary considerably in age, so remaining useful life is potentially relevant to regulation of some units and not others.

The guidelines capitalize on the inherent flexibility offered by the CO_2 emission performance rates and by the state CO_2 emission goals approach, allowing states flexibility on the form of the EGU standards that they include in CAA section 111(d) plans. A state could select a form of standards (e.g., marketable credits or permits, retirement of certain older facilities after their useful life, etc.) that avoids or diminishes concerns about facility-specific factors such as remaining useful life. If a state adopted the CO_2 emission performance rates for fossil fuel-fired electric utility steam generating units and stationary combustion turbines in conjunction with rate-based trading, though, the state would be taking remaining useful life into consideration by allowing affected EGUs to comply using ERCs. In effect, under a trading program with repeating compliance periods, a facility with a short remaining useful life has a total outlay that is proportionately smaller than a facility with a long remaining useful life, simply because the first facility would need to comply for fewer compliance periods and would need proportionately fewer ERCs than the second facility. Buying ERCs would avoid excessive up-front capital expenditures that might be unreasonable for a facility with a short remaining useful life, and would reduce the potential for stranded assets.

In addition to providing states with flexibility on the form of the standards of performance in their plans, the guidelines leave to each state the design of the specific requirements that fall on each affected EGU in applying those standards. To the extent that an emission standard that a state may wish to adopt for affected EGUs raises facility-specific issues, the state may make adjustments to a particular facility's requirements on facility-specific grounds, so long as any such adjustments are reflected (along with any necessary compensating emission reductions to meet the state goal) in the state's CAA section 111(d) plan submission.

Finally, we note that these guidelines permit states to use a rate or mass CO_2 emission goal, and that each of these pathways allow states multiple design choices. Under either pathway states can take into consideration remaining useful life and seek to avoid stranded assets.

The EPA believes that this approach to permitting states to consider remaining useful life is appropriate because it reflects, and is compatible with, the interconnected nature of the electricity system.

Although this discussion emphasizes state flexibility on plan design, it is important to note that the main intended beneficiaries of state flexibility are the affected EGUs themselves. As a key case in point, the EPA has endeavored to craft the final guidelines to support and facilitate state plans that include trading systems, including interstate trading systems that can help EGUs continue to operate with the flexibility that they currently enjoy on regional grid levels.

Trading can provide affected EGUs that have a limited remaining useful life with the flexibility to comply through purchasing allowances or ERCs, thereby avoiding major capital expenditures that would create long-term debt. By buying allowances or ERCs, affected EGUs with a limited remaining useful life contribute to achieving emission reductions from the source category during the years that they operate. During its lifetime, a facility with a short remaining useful life will need fewer total credits or allowances than an otherwise comparable facility with a long remaining useful life, but the annualized cost to the two facilities is the same.[859]

In part to help states address remaining useful life considerations, the final guidelines facilitate state plans that employ trading in multiple ways:

- By allowing trading under emission standards plans and state measures plans, and under rate-based plans and mass-based plans;
- By defining national EGU performance rates that make it easier for states to set up rate-based trading regimes that allow for interstate trading of ERCs;
- By clearly defining the requirements for mass-based and rate-based trading systems to ensure their integrity; and
- By providing information on potential allocation approaches for mass-based trading.

In addition, the EPA is separately proposing model trading rules for rate-based and mass-based trading to assist states with

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[859] Trading of course has other benefits beyond helping to address remaining useful life concerns. For example, trading can lower costs of achieving a given level of emission reduction and can provide economic incentives for innovation and development of cleaner technologies.

design of these programs in the section 111(d) context.

d. Why remaining useful life and other facility-specific factors do not warrant adjustments in the guidelines' performance rates and state goals. Under the final guidelines, remaining useful life and other facility-specific considerations do not provide a basis for adjusting the CO_2 emission performance rates, or the state's rate-based or mass-based CO_2 emission goals, nor do they affect the state's obligation to develop and submit an approvable CAA section 111(d) plan that adopts the CO_2 emission performance rates or achieves the goal by the applicable deadline. After considering public comments discussed below and in the response to comments document, the EPA has retained this aspect of the proposed rule for the reasons described below.

As noted above, the final guidelines provide aggregate emission goals for affected EGUs in each state, in addition to the CO_2 emission performance rates. The guidelines also reflect a number of changes from proposal to address concerns about achievability of proposed state goals that were raised in public comments, many of which were explicitly prompted by consideration of the remaining useful life issue. The result is to afford states with broad flexibility to design requirements for affected EGUs to achieve the CO_2 emission performance rates or state CO_2 emission goals in ways that avoid requiring major capital expenditures, or imposing unreasonable costs, on those affected EGUs that have a limited remaining useful life. State plans may use any combination of the emissions reduction methods represented by the building blocks, and may also choose to employ emission reduction methods that were not assumed in calculating state goals.

To be more specific, the EPA notes that a state is not required to achieve the same level of emission reductions with respect to any one building block as assumed in the EPA's BSER analysis. A state may use any combination of measures, including those not specifically factored into the BSER by the EPA. The EPA has estimated reasonable rather than maximum possible implementation levels for each building block in order to establish EGU emission rates and state goals that are achievable while allowing states to take advantage of the flexibility to pursue some building blocks more aggressively, and others less aggressively, than is reflected in the agency's computations, according to each state's needs and preferences. The guidelines provide further flexibility by allowing state plans to use emission reduction methods not reflected in the BSER. A description of multiple emission reduction methods is provided in sections VIII.I-K.

e. <u>Response to key comments on remaining useful life</u>. In response to the proposed guidelines, some commenters said that the proposed state goals were unachievable and therefore too stringent to provide states, as a practical matter, with the flexibility to consider remaining useful life for individual units. These commenters said the result would be premature retirements and stranded assets.

In the final guidelines, the EPA has addressed the comments about lack of practical flexibility to consider remaining useful life by revising key elements of the guidelines in ways that will ensure that the CO_2 emission performance rates and state CO_2 emission goals are achievable considering cost. At the same time, the final guidelines maintain the broad flexibility of each state to design its own compliance pathway, taking into account any facility-level concerns – including remaining useful life – in designing EGU requirements.

The changes to the BSER and goal-setting methodologies include:

- Starting the interim goal period in 2022 rather than 2020, which allows more lead time for states and regulated entities and helps to ensure that the interim goal is achievable
- Revising the goal-setting formula and the state goals themselves
- Updating analyses of achievable levels of improvement through the building blocks that together represent the

BSER, while keeping them at reasonable, rather than maximum, levels (thus creating headroom which can, and is intended to, help to accommodate the range of ages of different facilities)

- Providing an explicit phase-in schedule for meeting the revised interim goals, while also allowing a state the option of choosing its own emission reduction trajectory

The final guidelines also contain changes to avoid certain inconsistencies between the goal-setting methodology and accounting of reductions under state plans that could have made state goals less achievable for some states.

Together, the changes described above help to ensure that the CO_2 emission performance rates and state CO_2 emission goals established in the final guidelines are achievable, and leave states with the practical ability to issue rules that take into account the remaining useful life of affected EGU.

As explained in the Legal Memorandum accompanying this rule, the EPA believes that Congress intended the remaining useful life provision to provide a mechanism for states to avoid the imposition of unreasonable retrofit costs on existing sources with relatively short remaining useful lives, a scenario that could result in stranded assets. However, commenters on the proposed rule raised a different stranded assets concern not primarily related to retrofit costs -- a concern that the proposed rule could cause changes in economic competitiveness of particular EGUs that would prompt their retirement before the end of their economically useful lives. These commenters said the proposed state goals were so stringent that states would have no choice but to adopt requirements that would result in retirements of coal-fired capacity that had been built relatively recently or had recently made pollution control investments. In response to these comments, the EPA has conducted a stranded assets analysis which demonstrates that the CO_2 emission performance rates and state goals in the final guidelines provide sufficient flexibility to states to address stranded asset concerns. The EPA shares the goal of minimizing stranded assets. Although nothing in section 111(d) explicitly bars a guideline that results in some facilities becoming uneconomic before the end of their useful lives, the EPA nonetheless has striven to design the guidelines so as to give states flexibility to develop plans that include, for example, differential treatment of affected EGUs or opportunities to rely on emissions trading, to allow power companies to recover their investments in generation units.

For purposes of the stranded assets analysis, the EPA considered a potential “stranded asset” to be an investment in a coal-fired EGU (or in a capital-intensive pollution control installed at such an EGU) that retires before it is fully depreciated. Book life is the period over which long-lived assets are depreciated for financial reporting purposes. The agency estimated typical book life by researching financial statements of utility and merchant generation companies in filings to the Securities and Exchange Commission. The agency estimated the book life of coal-fired EGUs to be 40 years, and assumed a 20-year book life for pollution control retrofits. The book life of coal-fired EGUs (coal steam and IGCC) is twice as long as the debt life and the depreciation schedule used for federal tax purposes. Although the book life for environmental retrofits is often 15 years, the agency conservatively assumed 20 years in this analysis.

The analysis examined coal generation in the three large regional interconnections of the U.S. The analysis found that in both 2025 and 2030, for each region, the amount of 2012 coal generation included in the final guidelines' emission performance rate calculation -- specifically, the generation remaining after the BSER calculation -- is greater than the amount of 2012 generation from coal-fired EGUs that are not fully depreciated in those years under the book life assumptions described above. This shows that the final rule allows flexibility for states to preserve these units as part of their plans.

To put this analysis in perspective: The EPA's role is to set emission guidelines that meet the statutory requirements, which includes consideration of cost in identifying the BSER, as the EPA has done in these guidelines. States have a broad degree of flexibility to design plans to achieve the rates in the emission guidelines in a manner that meets their policy priorities, including ensuring cost-effective compliance. Although not a required component of the EPA's consideration of cost, this analysis shows that the CO_2 emission performance rates in the final guidelines can be met without the retirement of affected EGUs before the end of their book life, and without the retirement of affected EGUs before the end of the book life of capital-intensive pollution control retrofits installed on those EGUs. Thus, according to this analysis, the CO_2 emission performance rates and state CO_2 emission goals need not result in stranded assets. The EPA recognizes that power plant economics are determined by many aspects of markets that are outside of the EPA's control, such as wholesale power prices and capacity prices, and that the compliance path of least cost may involve retiring assets that have not fully depreciated. Nonetheless, this analysis further demonstrates the extent of flexibility available to states in designing their plans to best serve the policy priorities of the state. Details are available in a memo to the docket.[860]

Several commenters said that the statute does not authorize the EPA to require other facilities to achieve greater reductions to compensate for a facility that warrants relief based on remaining useful life. One said that consideration of remaining useful life and other relevant factors is a one-way ratchet that provides relief to sources that cannot achieve the BSER, and that the EPA turns that approach on its head by prohibiting a state from providing such relief to a specific facility unless it can identify another facility to "punish" by requiring additional emissions reductions to offset that relief.

The EPA disagrees with these comments, which proceed from an incorrect premise. The EPA is not determining a BSER-based emission level achievable by each individual facility without trading, and then requiring better-than-BSER from some facilities to make up to worse-than-BSER performance that a state authorizes for other facilities because of a short remaining useful life. Rather, as previously noted, the guidelines set CO_2 emission performance rates and state CO_2 emission goals that represent the average or aggregate emission

[860] Memorandum to Clean Power Plan Docket titled "Stranded Assets Analysis" dated July 2015.

level achievable by affected EGUs based on regional average estimates of the impact of applying the BSER to collective groupings of affected EGUs.[861] In estimating the amount of improvement achievable through each building block (e.g., improvement in heat rate or amount of generation shift to lower-emitting EGUs), the EPA has estimated the average level achievable by EGUs in a region rather than attempting to estimate the level achievable by each and every affected EGU in the absence of trading. Thus, the fact that an individual facility may be unable, for example, to achieve the average level of heat rate improvement assumed in goal-setting is consistent with the EPA's analysis, and does not undermine the EPA's determination of CO_2 emission performance rates and state CO_2 emission goals. The Legal Memorandum discusses additional reasons that the agency disagrees with comments that the guideline must permit adjustments in the guidelines' CO_2 emission performance rates and state CO_2 emission goals based on remaining useful life considerations.

An additional reason that the EPA believes that

[861] The EPA expects that states that choose to adopt the national CO_2 emission performance rates for all of their EGUs would permit ERC trading, rather than requiring each facility to meet the applicable rate without trading. In effect, the presence of trading means that the EGU performance rates will be achieved on average by the EGUs involved in trading, rather than be achieved by each facility in the absence of trading.

consideration of remaining useful life and other facility-specific factors does not warrant adjustments to state goals is that the design of the guidelines does not mandate that states impose requirements that would call for substantial capital investments at affected EGUs late in their useful life. Multiple methods are available for reducing emissions from affected EGUs that do not involve capital investments by the owner/operator of an affected EGU. For example, generation shifts among affected EGUs, and addition of new RE generating capacity do not generally involve capital investments by the owner/operator at an affected EGU. Additional emission reduction methods available to states that do not entail significant capital costs at affected EGUs are discussed elsewhere in this preamble.

Heat rate improvements at affected EGUs do require capital investments. However, states have flexibility to design their plan requirements; they are not required to mandate heat rate improvements at plants that have limited remaining useful life. In fact, a state can choose whether or not to require heat rate improvements at all. The agency also notes that capital expenditures for heat rate improvements would be much smaller than capital expenditures required for example, for purchase and installation of scrubbers to remove SO_2; a fleet-wide average cost for heat rate improvements based primarily on best practices at coal-fired generating units would not likely exceed

\$100/kW, compared with a typical SO_2 wet scrubber cost of \$500/kW (costs vary with unit size).[862] Even if a state did choose to adopt requirements for heat rate improvements, the proposed guidelines would allow states to regulate affected EGUs through flexible regulatory approaches that do not require affected EGUs to incur large capital costs (e.g., averaging and trading programs). Under the EPA's final approach - establishing state goals and providing states with flexibility in plan design – states have flexibility to make exactly the kind of judgments necessary to avoid requiring capital investments that would result in stranded assets.

Remaining useful life and other factors, because of their facility-specific nature, are potentially relevant as states determine requirements that are directly applicable to affected EGUs. If relief is due a particular facility, the state has an available toolbox of emission reduction methods that it can use to develop a section 111(d) plan that will achieve the CO_2 emission performance rates or state CO_2 emission goals on time. The EPA therefore concludes that the remaining useful life of affected EGUs, and the other facility-specific factors

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[862] Heat rate improvement methods and related capital costs are discussed in the GHG Mitigation Measures TSD; SO_2 scrubber capital costs are from the documentation for the EPA's IPM Base Case v5.13, Chapter 5, Table 5-3, available at http://www.epa.gov/airmarkets/documents/ipm/Chapter_5.pdf.

identified in the existing implementing regulations, should not be regarded as a basis for adjusting the CO_2 emission performance rates or a state CO_2 emission goal, and should not relieve a state of its obligation to develop and submit an approvable plan that achieves that goal on time.

f. <u>Legal considerations regarding remaining useful life</u>. Section 111(d)(1) requires the EPA in promulgating section 111(d) regulations to "permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies." Here, we discuss the legal basis for determining that the emission guidelines are consistent with this statutory requirement. For details, please see the Legal Memorandum.

Section 111(d)(1) only requires that EPA emission guidelines permit states to take into account remaining useful life (among other factors), but section 111(d)(1) does not specify how the EPA must permit that. In other words, the meaning of the provision and the way that the EPA is to implement it in promulgating guidelines are not specified further in the provision. The provision is ambiguous and capable of implementation in several ways, and therefore the EPA has discretion to interpret and apply it. Furthermore, section

111(d)(1) does not suggest that states must be given carte blanche to consider remaining useful life in any way that can be imagined. As detailed above in sections VIII.G.1.c-e, these guidelines permit states to take into account remaining useful life in a number of reasonable ways and thus the guidelines satisfy the statutory obligation.

The phrase "remaining useful life" also appears in the visibility provisions of section 169A. There, in determining best available retrofit technology (BART), the state (or the EPA) must take into consideration (among other factors) "the remaining useful life of the source." 42 USC 7491(g)(2); see also *id.* (g)(1) (reasonable progress). In the context of the visibility program, we have interpreted this provision to mean that the remaining useful life should be considered when calculating the annualized costs of retrofit controls. *See* 40 CFR Pt. 51, App. Y, IV.D.4.k.1. This annualized cost is then used to determine a cost effectiveness, in dollars per ton of pollutant removed on an annual basis. As a result, a technology with a large initial capital cost that might have a reasonable cost-effectiveness for a facility with a long remaining useful life would have a much higher and possibly unreasonable cost-effectiveness for a facility with a short remaining useful life.

Although section 111(d)(1) is different than section 169A(g)(2) and need not be interpreted in the same way, we would note (as discussed in detail in sections VIII.G.1.c-e, section 5.11 of the Response to Comments document, and the Legal Memorandum) that (for example) a trading program under these section 111(d) guidelines only requires compliance on a periodic basis and does not require any initial capital expenditures. Thus, over the life of the facility, a facility with a short remaining useful life will need fewer total credits or allowances than an otherwise comparable facility with a long remaining useful life, but the annualized cost to the two facilities is the same. In other words, under a trading program remaining useful life of a source is automatically accounted for in the way it is accounted for under the visibility program.

Some commenters stated that the EPA's interpretation of remaining useful life is impermissible. These commenters claimed that states, if they wish to take into account remaining useful life at one affected EGU, must relax the stringency of the emission standard for that EGU. Then, the state would be compelled to increase the stringency of emission standards at other affected EGUs in order to achieve the state performance goal. According to these commenters, section 111(d) does not allow this outcome.

First, the commenters are mistaken in their premise. As discussed in section VIII.G.1, section 5.11 of the Response to Comments document, the Legal Memorandum, and in the example immediately above, states can impose the exact same emission standards on two affected EGUs and still take into account remaining useful life through the availability of trading. In other words, states need not relax an emission standard here and strengthen an emission standard there in order to take into account remaining useful life. Thus, these guidelines permit states to take into account remaining useful life without any of the effects commenters are concerned about.

Second, even if states decide to relax emission standards at one EGU, on the basis of remaining useful life or any other factor, nothing in the last sentence of section 111(d)(1) prohibits these guidelines from requiring the state plan to still meet the CO_2 emission performance rates or state CO_2 emission goal. In fact, that sentence is completely silent on the issue. Thus, the EPA has the discretion to determine what should be the concomitant effects if a state chooses to consider remaining useful life in a particular way. In this case the concomitant effect of a state relaxing one emission standard may be that the state must make up for it elsewhere in order to meet the goal, but nothing in section 111(d)(1), including the statutory requirement to permit consideration of remaining useful life, prohibits that outcome.

2. Electric reliability

The final rule features overall flexibility, a long planning and implementation horizon, and a wide range of options for states and affected EGUs to achieve the CO_2 emission performance rates or state CO_2 emission goal. This design reflects, among other things, the EPA's commitment to ensuring that compliance with the final rule does not interfere with the industry's ability to maintain the reliability of the nation's electricity supply. Comments from state, regional and federal reliability entities, power companies and others, as well as consultation with the Department of Energy (DOE) and Federal Energy Regulatory Commission (FERC), helped inform a number of changes made in this final rule to address reliability. In addition, FERC conducted one national and three regional technical conferences on the proposed rule in which the EPA participated and at which the issue of reliability was raised by numerous participants.

As discussed throughout the preamble and TSDs, the electricity sector is undergoing a period of intense change. While the change in the resource mix has accelerated in recent years, wind, solar, other RE, and EE resources have been reliably participating in the electric sector for a number of years. Many of the potential changes to the electric system that the final rule may encourage, such as shifts to cleaner sources of power and efforts to reduce electricity demand, are already well underway in the electric industry. To the extent that the final rule accelerates these changes, there are multiple features well embedded in the electricity system that ensure that electric system reliability will be maintained. Electric system reliability is continually being considered and planned for. For example, in the Energy Policy Act of 2005, Congress added a section to the Federal Power Act to make reliability standards mandatory and enforceable by FERC and the North American Electric Reliability Corporation (NERC), the Electric Reliability Organization which FERC designated and oversees. Along with its standards development work, NERC conducts annual reliability assessments via a 10-year forecast and winter and summer forecasts; audits owners, operators, and users for preparedness; and educates and trains industry personnel. Numerous other entities such as FERC, DOE, state PUCs, ISOs/RTOs, and other planning authorities also consider the reliability of the electric system. There are also numerous remedies that are routinely employed when there is a specific local or regional reliability issue. These include transmission system upgrades, installation of new generating capacity, calling on demand response, and other demand-side actions.

Additionally, planning authorities and system operators constantly consider, plan for, and monitor the reliability of the electricity system with both a long-term and short-term perspective. Over the last century, the electric industry’s efforts regarding electric system reliability have become multidimensional, comprehensive, and sophisticated. Under this approach, planning authorities plan the system to assure the availability of sufficient generation, transmission, and distribution capacity to meet system needs in a way that minimizes the likelihood of equipment failure.[863] Long-term system planning happens at both the local and regional levels with all segments of the electric system needing to operate together in an efficient and reliable manner. In the short-term, electric system operators operate the system within safe operating margins and work to restore the system quickly if a disruption occurs.[864] Mandatory reliability standards apply to how the bulk electric system is planned and operated. For example, transmission operators and balancing authorities have to develop, maintain, and implement a set of plans to mitigate operating emergencies.[865]

As the electricity market changes and new challenges emerge, electric system regulators and industry participants make changes to how the electric system is designed and operated

[863] Casazza, J. and Delea, F., *Understanding Electric Power Systems: An Overview of the Technology, the Marketplace, and Government Regulations*, IEEE Press, at 160 (2010).
[864] *Id.*
[865] NERC Reliability Standard EOP-001-2.1b — Emergency Operations Planning, available at http://www.nerc.net/standardsreports/standardssummary.aspx.

to respond to these challenges. For example, expressing reliability and rate concerns about fuel assurance issues, FERC recently issued an order requiring ISOs/RTOs to report on the status of their efforts to address market and system performance associated with fuel assurance.[866] In February of 2015, Midcontinent Independent System Operator (MISO), California Independent System Operator Corporation (CAISO), New York Independent System Operator (NYISO), Southwest Power Pool (SPP), ISO New England (ISO-NE), and PJM Interconnection (PJM) each filed a report with FERC highlighting their efforts to respond to fuel assurance concerns.[867] This is just one of many examples where electric system regulators and industry participants recognize a potential reliability issue and are proactively searching for solutions.

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[866] *Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators*, 149 FERC ¶ 61,145 (2014). FERC generally defines fuel assurance as "generator access to sufficient fuel supplies and the firmness of generator fuel arrangements". *Id.* P 5.

[867] For example, ISO-NE and PJM each filed "pay-for-performance" proposals to address fuel assurance in their regions. FERC recently acted on ISO-NE market rule changes providing increased market incentives in capacity, energy, and ancillary services markets for generators to be available to meet their obligations during reserve shortages. *ISO New England Inc.*, 147 FERC ¶ 61,172 (2014). Additionally, FERC conditionally approved a PJM "pay-for-performance" proposal that creates a new capacity product to provide greater assurance of delivery of energy and reserves during emergency conditions, establishing credits for superior performance and charges for poor performance. *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208 (2015).

The EPA's approach in this final rule is consistent with our commitment to ensuring that compliance with the final rule does not interfere with the industry's ability to maintain the reliability of the nation's electricity supply. Many aspects of the final rule's design are intended to support system reliability, especially the long compliance period and the basic design that allows states and affected EGUs flexibility to include a large variety of approaches and measures to achieve the environmental goals in a way that is tailored to each state's and utility's energy resources and policies. Despite the flexibility built into the design of the proposal, and the long emission reduction trajectory, many commenters expressed concerns that the proposed rule could jeopardize electric system reliability. We note that the EPA has received similar comments in EPA rulemakings dating as far back as the 1970s. The EPA has always taken and continues to take electric system reliability comments very seriously. These reoccurring comments with regard to reliability notwithstanding, the electric industry has done an excellent job of maintaining reliability, including when it has had to comply with environmental rules with much shorter compliance periods and much less flexibility than this final rule provides. Now, more than ever, the electric industry has tools available to maintain reliability, including mandatory and enforceable reliability standards.[868]

As with numerous prior CAA regulations affecting the electric power sector, environmental requirements for this industry are accommodated within the existing extensive framework established by federal and state law to ensure that electricity production and delivery are balanced on an ongoing basis and planned sufficiently to ensure reliability and affordability into the future. In addition, changes that the EPA is making in this final rule respond directly to the comments and the suggestions that we received on reliability and provide further assurance that implementation of the final rule will not

[868]For example, Andrew Ott, then Executive Vice President-Markets and current President of PJM, an RTO with a substantial amount of coal-fired capacity and generation, discussed the success of PJM's market design in assuring that PJM met and exceeded target reserve margins while MATS was being implemented. *See* Statement of Andrew Ott, PJM Executive Vice President-Markets, FERC Technical Conference on Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, AD13-7-000, at 3, 7 (Sept. 25, 2013), *available at* http://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=6944&CalType= &CalendarID=116&Date=09/25/2013&View=Listview. At the FERC national Clean Power Plan Technical Conference, Michael J. Kormos, PJM Executive Vice President-Operations, said that PJM's markets have proven, "resilient enough to respond to different policy initiatives. . . Whether it is the Sulfur Dioxide Trading Program of the 1990s, the MATS rule or individual state RPS initiatives, the markets have been able to send the appropriate price signals that produce competitive outcomes." *See* Michael J. Kormos, PJM Executive Vice President, Statement at FERC Technical Conference on EPA's Clean Power Plan, AD15-4-000, at 3 (Feb. 19, 2015), *available at* http://www.ferc.gov/CalendarFiles/20150213081650-Kormos,%20PJM.pdf.

create reliability concerns.

First, the final rule allows significant flexibility in how the applicable CO_2 emission performance rates or the statewide CO_2 goals are met. Given the differing characteristics of the electric grid within each state and region, there are many paths to meeting the final rule's requirements that can be taken while continuing to maintain a reliable electricity supply. As further described elsewhere in section VIII, states can develop plans to meet the CO_2 emission performance rates or state CO_2 emission goals by choosing from a variety of state plan types and approaches that afford states and affected EGUs appropriate flexibility. EE and other measures that were not included in the determination of the BSER can strengthen a state's ability to establish a plan to meet the CO_2 emission performance rates or state CO_2 emission goals by providing a considerable amount of headroom above the levels of the rates and goals. EE especially, because it reduces load, can provide assurance that reliability can and will be maintained. Additionally, the final rule offers opportunities for trading among affected EGUs within and between states, and other multi-state approaches that will further support electric system reliability.

Second, the final rule provides sufficient time to ensure system reliability. The final rule retains the 2030 date for the final period, which commenters largely supported as reasonable and not a concern for reliability, and addresses one of the key issues that commenters pointed to as a reliability-related concern by both moving the start of the interim period from 2020 to 2022 and adjusting the interim goals to provide a more gradual phasing-in of the initial reduction requirement and thus a more gradual emissions reduction trajectory or glide path to the final 2030 goals. These changes deliver on the intent of the proposal to afford states and affected EGUs the latitude to determine their own emissions reduction schedules over the interim period. Both FERC's May 15, 2015 letter[869] and the comment record made it clear that providing sufficient time for planning and implementation is essential to ensuring electric system reliability. The EPA has responded by providing additional time to allow for planning and implementation of the final rule requirements, while at the same time allowing enough time between the beginning of the interim period and 2030 to achieve state goals or emission performance rates. We note that the final rule does not require that all states have met their interim goal or performance rate by 2022 but rather that they meet it on average or cumulatively, as appropriate, during the 2022 to 2029 period.

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[869] On May 15, 2015, the five FERC Commissioners sent a letter to Acting Assistant Administrator Janet McCabe regarding the EPA's Clean Power Plan proposal. *See* FERC letter, *available at* http://ferc.gov/media/headlines/2015/ferc-letter-epa.pdf.

As a result of these changes, the states themselves will have a meaningful opportunity – which, again, many commenters suggested the timing and stringency of the proposal failed to create despite our intent to do so – to determine the timing, cadence and sequence of actions needed for states and sources to meet final rule requirements while accommodating the ongoing activity needed to ensure system reliability. The final rule provides more than 6 years before reductions are required and an 8-year period from 2022 to 2029 to meet interim goals. Moreover, while the final rule requires each state to submit a plan by September 6, 2016, we recognize that some states may need more than 1 year to complete all of the actions needed for their final state plans, including consideration of reliability. Therefore, states have the opportunity to receive an extension for submitting a final plan. If the state needs additional time to submit a final plan, then the state may submit an initial submittal by September 6, 2016, that must address three required components sufficiently to demonstrate that a state is able to undertake steps and processes necessary to timely submit a final plan by the extended date of September 6, 2018.

Third, we are including in the final rule a requirement that each state demonstrate in its final state plan submittal that it has considered reliability issues in developing its plan. This was suggested by a number of commenters, and we agree that it is a useful element to state plan development.

Fourth, the final rule provides a mechanism for a state to seek a revision to its plan in order to address changes in circumstances that could have reliability impacts if not accommodated in the plan. The long compliance timeframe, with several interim steps, naturally provides opportunities for states, working with their utilities and reliability entities, to assess how implementation is proceeding, identify unforeseen changes that may warrant plan revisions, and work with the EPA to make necessary revisions. Similarly, the ready availability of emissions trading as a compliance tool affords EGUs ample flexibility to integrate compliance with both routine and critical reliability needs.

Fifth, in response to a variety of comments, we are providing a reliability safety mechanism that provides a path for a state to come to the EPA during an immediate, unforeseen, emergency situation that threatens reliability to notify the EPA that an affected EGU or EGUs may need to temporarily comply with modified emission standards to respond to this kind of reliability concern.

Sixth and finally we are committed to maintaining an ongoing relationship with FERC and DOE as this final rule is implemented to help ensure continued reliable electric generation and transmission.

We provide more details about these various elements of the final rule, as well as other features of the rule that support system reliability, below.

a. Summary of key comments. The EPA received a number of comments regarding the proposed rule and electric reliability. Many commenters provided specific, useful ideas regarding changes that could be made to the proposal to specifically address their reliability concerns. For example, many commenters state that allowing additional time to comply could help in meeting the final rule requirements while addressing their reliability concerns. Some commenters suggest that additional time would allow them to evaluate potential reliability impacts and system changes that need to be made to comply with final rule requirements while allowing affected EGUs time to meet interim CO_2 emissions goals. The EPA also received comment that market-based approaches have features that could help support reliability, and therefore we should encourage states to join or form regional market-based programs. Commenters also stated that the EPA should require states to consult with grid operators who would analyze the impact of state plans on reliability. A number of commenters also suggested that the EPA should include some sort of reliability safety valve in the final rule. We note that many participants at the FERC technical conferences on the proposed rule also discussed a reliability safety valve in great detail with many suggestions for how such a reliability mechanism could be designed. The EPA appreciates these and all the comments we received regarding the interaction of the proposal and electric reliability. We have carefully considered all comments, consulted further with FERC and incorporated many of the suggested changes in this final rule.

b. Final rule flexibility. In issuing this final rule, the EPA considered public comments on the potential interaction between the proposal and electric reliability. While we have made every effort to develop guidelines that would allow states and utilities to steer clear of potential reliability disruptions, a number of commenters argued that the possibility of an unanticipated reliability event cannot be entirely eliminated. It is important to note that there are many factors that influence system reliability and, given the complexity of the electric grid, electric system planners and operators likely will not completely avoid reliability issues, even in the absence of these guidelines. The EPA designed the final rule to ensure to the greatest extent possible that actions taken by states and affected EGUs to comply with the final rule do not increase potential reliability issues or complicate their resolution. In fact, to the extent that meeting final rule requirements results in the reduction of demand, upgrades in transmission efficiency and infrastructure, and investment in new, more efficient technologies, the outcome could be that the system is more robust and faces fewer risks to electric reliability.

One specific concern raised by many commenters is that the proposed plan development schedule may not leave sufficient time to conduct reliability planning between the development of state plans and the proposed start of the interim period in 2020. To address these concerns and to support a more effective reliability planning process, the EPA is moving the start of the interim period from 2020 to 2022 and adjusting the interim goals to provide a gradually phased-in initial reduction requirement and a more gradual glide path to the final 2030 goals. This more gradual application of the BSER over the 2022-2029 interim period provides the state with substantial latitude in selecting the emission reduction glide path for affected EGUs over that period. As noted above, the final rule also provides states with up to 3 years to adopt and submit their final state plans, and afterwards states can, if necessary, revise their plans, as discussed in section VIII.E.7. This timing gives system planners and operators the opportunity to do what they have already been doing; looking ahead to forecast potential contingencies that pose reliability risks and identifying those actions needed to mitigate those risks. The final rule allows states to develop a pathway over the interim period that reflects their own circumstances, such as reflecting planned additions and changes in generation mix and potentially taking advantage of opportunities for trading of credits or allowances by affected EGUs within and between states. Because achievement of the emission rates or goals can be demonstrated over several years, state plans can accommodate situations where, for example, it may take time to develop new generation, pipelines, or transmission while still providing many options for meeting the final rule requirements and planning for the reliability of the system.

c. Considering reliability during state plan development process. Under CAA section 111(d)(1)(B), state plans must provide for the implementation and enforcement of standards of performance for affected EGUs. The EPA does not believe a state that establishes standards of performance for affected EGUs without taking reliability concerns into consideration satisfactorily provides for the implementation of such standards of performance as required by CAA section 111(d)(1)(B), as a serious reliability issue would disrupt the state's implementation of the state plan. Therefore, the EPA is requiring that each state demonstrate as part of its final state plan submission that it has considered reliability issues while developing its plan in order to ensure that standards of performance can be implemented and enforced as required by the

CAA. If system reliability is threatened, the ability of affected EGUs to meet the requirements of this final rule could be compromised if they are required to operate beyond the emission standards established in state plans in order to maintain the reliability of the electric grid. The requirement that states consider reliability as part of the development of state plans is therefore designed to ensure that state plans are flexible enough to avoid this kind of potential conflict between maintaining reliability and providing for the implementation of emission standards for affected EGUs as required by the CAA.

A number of commenters, notably ISOs and RTOs, also discussed reliability concerns in the context of state plans and pointed out that planning and anticipation of change are among the essential ingredients of ensuring the ongoing reliability of the electricity system. To that end, they recommended that as states are developing state plans, their activity include the consideration of the reliability needs of the region in which affected EGUs operate and of the potential impact of actions to be taken in compliance with state plans. Therefore, we are requiring that each state demonstrate in its final state plan submittal that it has considered reliability issues in developing its plan. One particularly effective way in which states can make this demonstration is by consulting with the relevant ISOs/RTOs or other planning authorities as they develop their plans and documenting this consultation process in their state plan submissions. If a state chooses to consider reliability through consultation with the ISO/RTO or other planning authority, the EPA recommends that the state request that the planning authority review the state plan at least once during the plan development stage and provide its assessment of any reliability implications of the plan. Additionally, we encourage states that are considering reliability through an ISO/RTO or other planning authority consultation process to have a continuing dialogue with those entities during development of their final state plan. While following the recommendations of the planning authority would not be mandatory, the state should document its consultation process, any response and recommendations from the planning authority, and the state’s response to those recommendations in its final state plan submittal to the EPA. This consultation is designed to inform how the state might adjust its plan for meeting the CO_2 reduction requirements under this guideline; the consultation is not a basis for relaxing that requirement. While we consider this process to be an effective way for a state to demonstrate that it considered reliability in developing its final state plan, a state may provide other comparable support for a demonstration that it has considered reliability during the state plan development process.[870] Also as discussed elsewhere in this preamble, the EPA encourages states to include state utility regulators and the state energy offices in the development of the state plan. These agencies have expertise that can help to assure that state plans complement the state's power sector. The EPA believes that this requirement to demonstrate consideration of reliability will provide an effective reliability evaluation in the state plan development process. It should further help states avoid any conflicts between state plans and the maintenance of reliability during implementation of the state plan and associated emission standards. Finally, we also encourage states as they develop their plans to consider, to the extent possible, other potential issues that may impact affected EGUs. For example, an affected EGU may be in an ISO/RTO that puts certain deadlines on generators that may not line up perfectly with state plan deadlines.

d. <u>State plan modifications</u>. If, during the implementation of a state plan, a reliability issue cannot be addressed within the range of actions or mechanisms encompassed in an approved state plan, the state can submit a plan revision to the EPA to amend its plan. In such a circumstance, the state plan may need to be

[870] While the EPA is requiring that the states demonstrate that they have considered reliability in developing their plans, state plan submissions will not be evaluated substantively regarding reliability impacts.

adjusted to enable affected EGUs to continue to meet final rule requirements without causing an otherwise unmanageable reliability threat. In all cases the plan revision must still ensure the affected EGUs meet the emission performance level set out in the 111(d) final rule. Whether or not these circumstances occur will depend in part upon how each state designs its state plan. States that design plans with a high level of flexibility, such as market-based plans or multi-state plans, are less likely to face a potential conflict between state plan requirements and the maintenance of reliability. States that participate in multi-state programs will be better able to weather unexpected reliability risks.

Events not anticipated at the time of the final plan submittal - such as the retirement of a large low- or zero-emitting unit - may trigger the request for state plan revisions. It may also be the case that affected EGU-specific emission standards in a state plan are proving to be too inflexible to allow the plan to accommodate market or other changes in the power sector. In such instances, there should be a lead time between the announced retirement of the unit and the need to amend the state plan. Therefore, the state should be able to utilize the revisions process that the EPA provides.

The EPA will review a plan revision per the implementing regulation requirements of 40 CFR part 60.28. If the state's request for a state plan revision must be addressed in an expedited manner to assure a reliable supply of electricity, the state must document the risks to reliability that would be addressed by the plan revision by providing the EPA with a separate analysis of the reliability risk from the ISO/RTO or other planning authority. This analysis should be accompanied by a statement from the ISO/RTO or other planning/reliability authority that there are no practicable alternative resolutions to the reliability risk. In this case, the EPA will conduct an expedited review of the state plan revision.[871]

e. <u>Reliability safety valve</u>. In this section we describe a reliability safety valve, available to states with affected EGUs providing reliability-critical generation in emergency circumstances. Specifically and as discussed below the reliability safety valve provides i) a 90-day period during which the affected EGU will not be required to meet the emission standard established for it under the state plan but rather will meet an alternative standard, and ii) a period beginning after the initial 90 days during which the reliability-critical affected EGU may be required to continue to operate under an alternative standard rather than under the original state plan

[871] The EPA will still undertake notice and comment rulemaking per the requirements of the Administrative Procedures Act when acting on such state plan revision, but intends to prioritize review of plan revisions needed to address reliability concerns.

emission standard, as needed in light of the emergency circumstances, and the state must during this period revise its plan to accommodate changes needed to respond to ongoing reliability requirements. Any emissions in excess of the applicable state goals or performance rates occurring after the initial 90-day period must be accounted for and offset.

Many commenters expressed concerns that a serious, unforeseen event could occur during the final rule implementation period that would require immediate reliability-critical responses by system operators and affected EGUs that would result in unplanned or unauthorized emissions increases. After reviewing the comments, we believe that it is highly unlikely that there would be a conflict between activities undertaken under an approved state plan and the maintenance of electric reliability, except in the case of a state plan that puts relatively inflexible requirements on specific EGUs. While some have pointed out that severe weather or other short-term events could potentially conflict with state plans, we note that most of those events are of short duration and would not require major – if any - adjustments to emission standards for affected EGUs or to state plans. For example, during an event like the extreme cold experienced in periods of the winter of 2013-2014, affected EGUs may need to run at a higher level for a short period of time to accommodate increased demand and/or short-term unavailability of other generators. However, because compliance by affected EGUs will be demonstrated over 2-3 years, such a short-term event would not cause affected EGUs to be out of compliance with their applicable emission standards. States can also ensure that this is true by developing plans that allow adequate compliance flexibility to accommodate such short-term events. We note that we have included in this final rule a number of different features designed to facilitate emissions trading between and among EGUs on an interstate basis – and have done so, in no small part, in response to comments from states and stakeholders seeking to put in place or operate under state-level and interstate emissions trading regimes. Affected EGUs operating in those circumstances and operating, in addition, subject to state plans that incorporate flexible glide paths and trading would be able to accommodate an unanticipated reliability event.

We recognize, however, that affected EGUs operating in a state with a relatively inflexible state plan could face unanticipated system emergencies that could cause a severe stress on the electricity system for a length of time such that the requirements in that state’s plan may not be achievable by certain affected EGUs without posing an otherwise unmanageable risk to reliability. In particular, there could be extremely serious events, outside the control of affected EGUs, that would require an affected EGU or EGUs operating under an inflexible state plan to temporarily operate under modified emission standards to respond to this kind of reliability concern. Examples of such an event could include, a catastrophic event that damages critical or vulnerable equipment necessary for reliable grid operation; a major storm that floods and causes severe damage to a large NGCC plant so that it must shut down; or a nuclear unit that must cease generating unexpectedly and therefore other affected EGUs need to run so as to exceed their requirements under the approved state plan. This is not an all-inclusive list, but the examples illustrate several key attributes of the kinds of circumstances in which the reliability safety valve would apply. First, the event creating the reliability emergency would be unforeseeable, brought about by an extraordinary, unanticipated, potentially catastrophic event. Second, the relief provided would be for EGUs compelled to operate for purposes of providing generation without which the affected electricity grid would face some form of failure. Third, the EGU or EGUs in question would be subject to the requirements of a state plan that imposes emissions constraints such that the EGU or EGUs' operation in response to the reliability emergency resulted in levels of emissions that violated those constraints. We do not anticipate that EGUs operating under a plan that permitted emissions trading would meet these criteria.

The final guidelines provide a reliability safety valve for these types of situations. If an emergency situation arises, the state must submit an initial notification to the appropriate EPA regional office within 48 hours that it is necessary to modify the emission standards for a reliability-critical affected EGU or EGUs for up to an initial 90 days. The notification must include a full description, to the extent it is known at the time, of the emergency situation that is being addressed. It must also identify with particularity the affected EGU or EGUs that are required to run to assure reliability. It must also specify the modified emission standards at which the affected EGU or EGUs will operate. The EPA will consider this notification to be an approved short-term modification to the state plan, allowing the EGU to operate at an emission standard that is an alternative to the emission standard originally specified in the relevant state plan, subject to confirmation by the further documentation described below.[872]

Within 7 days of submitting the initial notification, the state must submit a second notification providing documentation

[872] The EPA reserves the right to review such notification, and in the event that the EPA finds such notification is improper, the EPA may disallow the short-term modification and affected EGUs must continue to operate under the original approved state plan emission standards.

to the appropriate EPA regional office that includes a full description of the reliability concern and why an unforeseen, emergency situation that threatens reliability requires the affected EGU or EGUs to operate under modified emission standards (including discussion of why the flexibilities provided under the state's plan are insufficient to address the concern). The state must also describe in its documentation how it is coordinating or will coordinate with relevant reliability coordinators and planning authorities to alleviate the problem in an expedited manner, and indicate the maximum time that the state anticipates the affected EGU or EGUs will need to operate in a manner inconsistent with its or their obligations under the state's approved plan, and the modified emission standards or levels at which the affected EGU or EGUs will be operating at during this period if it has changed from the initial notification. The documentation must also include a written concurrence from the relevant reliability coordinator and/or planning authority confirming the existence of the imminent reliability threat and supporting the temporary modification request or an explanation of why this kind of concurrence cannot be provided. Additionally, if the relevant planning authority has conducted a system-wide or other analysis of the reliability concern, the state must include that information in its request. If the state fails to submit this documentation on a timely basis, the EPA will notify the state, which must then notify the affected EGU(s) that they must operate or resume operations under the original approved state plan emission standards.

It is important to note that the affected EGUs must continue to monitor and report their emissions and generation pursuant to requirements in this final rule and under the state plan during any short-term modification. For the duration of the up to 90-day short-term modification, the emissions of the affected EGU or EGUs that exceed their obligations under the approved state plan will not be counted against the state's overall goal or emission performance rate for affected EGUs. Such a modification will not alter or abrogate any other obligations under the approved state plan.

During this short term modification period, the EPA expects that the source, the state and the relevant reliability coordinator and/or planning authority will assess whether the reliability issue can be addressed in a way that would allow the EGU or EGUs to resume operating under the original approved state plan within the 90-day period or whether revisions to the state plan need to be made to address the unexpected circumstances for the longer term (the unexpected unavailability of a nuclear unit, for example).

The EPA recognizes that an emergency may persist past 90 days. At least 7 days before the end of the initial 90-day reliability safety valve period, the state must notify the appropriate EPA regional office whether the reliability concern has been addressed and that the EGU or EGUs can resume meeting the original emission standards established in the state plan prior to the short-term modification.

If there still is a serious, ongoing reliability issue at the end of the short-term modification period that necessitates the EGU or EGUs to emit beyond the amount allowed under the state plan, the state must provide to the EPA a notification that it will be submitting a state plan revision and submit the plan revision as expeditiously as possible, specifying in the notice the date by which the revision will be submitted. The state must document the ongoing emergency with a second written concurrence from the relevant reliability coordinator and/or planning authority confirming the continuing urgent need for the EGU or EGUs to operate beyond the requirements of the state plan and that there is no other reasonable way of addressing the ongoing reliability emergency but for the EGU or EGUs to operate under an alternative emission standard than originally approved under the state plan. In this event, the EPA will work with the state on a case-by-case basis to identify an emission standard for the affected EGU or EGUs for the period before a new state plan revision is approved. After the initial 90-day period, any excess emissions beyond what is authorized in the original approved state plan will count against the state's overall goal or emission performance rate for affected EGUs.

The EPA intends for this reliability safety valve to be used only in exceptional situations. In addition, this reliability safety valve applies only to this final rule and has no effect on CAA requirements to which the state or the affected EGUs are otherwise subject. As discussed earlier, we are providing states with the flexibility to design programs that incorporate the level of flexibility that allow affected EGUs to meet compliance obligations while responding to reliability needs, even in emergency situations. This flexibility means that a conflict between the requirements of the state plan and maintenance of reliability should be extremely rare. We recognize, however, that a state with an inflexible plan could be faced with more than one emergency and in this case the reliability safety valve may be used more than once. If the state finds that a second reliability emergency arises that conflicts with the state plan, the state must submit a revision to its state plan so that the state plan is flexible enough to assure that such conflicts do not recur and that the state is providing for the implementation of the standards of performance for affected EGUs as required by the CAA.

f. Coordination among federal partners. The EPA, DOE, and FERC have agreed to coordinate efforts to help ensure continued reliable electricity generation and transmission during the implementation of the final rule. The three agencies have developed a coordination strategy that reflects their joint understanding of how they will work together to monitor final rule implementation, share information, and resolve any difficulties that may be encountered. This strategy is based on the successful working relationship that the three agencies established in their joint effort to work together to monitor reliability during MATS implementation.

g. <u>Analyses of the reliability impacts of the proposal</u>. The EPA appreciates that a large number of entities from many different industry perspectives have published reports and analysis with respect to electric reliability and the 111(d) proposed rule. We take concerns about reliability very seriously, and we appreciate the attention given to this issue in the comments and shared with us in public forums. It is important to note that these studies were conducted prior to promulgation of this final rule, and thus were only able to consider electric reliability with respect to the proposal. The EPA has made changes and improvements to the proposal in response to comments and new information, and some of the changes are relevant to the final rule's potential effect on electric reliability. One notable change pertains to the start of the interim period, which is now 2022 rather than 2020. Another important change to the final rule is a more gradual phase-in of the BSER for affected EGUs over the interim period (from 2022 through 2029). The final rule also provides considerable flexibility and multiple pathways to states, including allowing their EGUs to use multi-state trading and other approaches, which would allow essential units to continue to meet their compliance obligation while generating even at unplanned but reliability-critical levels. In addition, we have included in the final rule a reliability safety valve provision that can be utilized in certain emergency situations. These changes, in addition to already existing industry mechanisms and planning requirements, will help to ensure that industry will be able to maintain electric reliability. The EPA is confident that the final rule will cut harmful electric power plant pollution while maintaining a reliable electric grid because the final rule provides industry with the time and flexibility needed to continue its current and ongoing planning and investing to modernize and upgrade the electric power system.

In June of 2015, M.J. Bradley & Associates issued a report that enumerated a set of useful guiding principles for studying and evaluating the reliability impacts of the final rule.[873] The

[873] M.J. Bradley & Associates, *Guiding Principles for Reliability Assessments Under EPA's Clean Power Plan* (June 3, 2015), *available at* http://www.mjbradley.com/node/295.

report enumerated six principles: (1) a study should be transparent about the assumptions and data used; (2) a study should accurately reflect the existing status of the grid in its modeling assumptions; (3) a study should clearly identify the base case and not confuse what will happen as a result of the final rule with what would have happened anyway; (4) where possible, a study should contain sensitivities and probabilities as they are looking into the future which is necessarily uncertain; (5) a study should reflect the flexibility provided to states to allow them to design compliance approaches to maximize reliability; and (6) a study should provide realistic and reliability-focused results. These principles are helpful to keep in mind when reviewing recent studies.

NERC published its analyses of the proposed rule in November 2014 and again in April 2015.[874] The EPA appreciates NERC's attention to, and interest in, the proposed rule. However, we note that like some other studies, NERC assumes

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[874] North American Electric Reliability Corporation, *Potential Reliability Impacts of EPA's Proposed Clean Power Plan* (Nov. 5, 2014), *available at* http://www.nerc.com/news/Pages/Reliability-Review-of-Proposed-Clean-Power-Plan-Identifies-Areas-for-Further-Study,-Makes-Recommendations-for-Stakeholders.aspx; North American Electric Reliability Corporation, *Potential Reliability Impact of EPA's Proposed Clean Power Plan: Phase 1* (Apr. 21, 2015), *available at* http://www.nerc.com/news/Pages/Assessment-Uses-Scenario-Analysis-to-Identify-Potential-Reliability-Risks-from-Proposed-Clean-Power-Plan.aspx.

considerably less flexibility than actually is provided to states and EGUs in this final rule. The final rule provides states with considerable time and latitude in designing plans that are tailored to the system in which their EGUs operate, which should be reflected in any reliability analysis. Also, the NERC study does not fully reflect the current electric grid. For example, the amount of RE generation that NERC assumes for 2020 is similar to levels of generation that we see today whereas projections for 2020 are considerably higher.[875] Further, NERC conflates retirements that may happen as a result of the rule with those that are already planned. The Brattle Group has also reviewed NERC's November 2014 initial analysis of the proposed rule, noting that it is important to distinguish between concerns about the building blocks and reliability concerns about compliance with state plans.[876] The Brattle Group concluded that there are real world solutions to NERC's concerns. These include making use of the many flexible options available to states under the rule to mitigate reliability risks.

Multiple ISOs/RTOs also provided analyses of the proposed

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[875] EIA, Annual Energy Outlook 2015, PRIL 2015.
[876] Brattle Group, *EPA's Clean Power Plan and Reliability, Assessing NERC's Initial Reliability Review* (Feb. 2015), *available at* http://info.aee.net/hs-fs/hub/211732/file-2486162659-pdf/PDF/EPAs-Clean-Power-Plan--Reliability-Brattle.pdf?t=1434398407867.

rule, including MISO, PJM, ERCOT, and SPP.[877] For example, MISO conducted an analysis of coal units at risk for retirement, finding that 14 GW of coal may be at risk.[878] SPP performed a resource adequacy analysis that assumes planned retirements plus the EPA's projected retirements, but did not similarly account for the building of new generation capacity.[879] While we appreciate MISO's and SPP's concerns regarding retirements and the potential that reserves will fall below reserve requirement levels, it is important to consider the many ways in which states can develop plans that account for their potential reliability concerns. The final rule continues to give states

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[877] *See* MISO, *Analysis of EPA's Proposal to Reduce* CO_2 Emissions from Existing Units (Nov. 12, 2014), *available at* https://www.misoenergy.org/Library/Repository/Communication%20Material/EPA%20Regulations/AnalysisofEPAProposalReduceCO2Emissions.pdf; PJM, *PJM Interconnection Economic Analysis of the EPA Clean Power Plan Proposal* (Mar. 2, 2015), *report listed at* http://www.pjm.com/documents/reports.aspx; SPP, *SPP's Reliability Impact Assessment of the EPA's Proposed Clean Power Plan*, (Oct. 8, 2014), *available at* http://www.spp.org/publications/CPP%20Reliability%20Analysis%20Results%20Final%20Version.pdf; ERCOT, *ERCOT Analysis of the Clean Power Plan* (Nov. 17, 2014), *available at* http://www.ercot.com/content/news/presentations/2014/ERCOTAnalysis-ImpactsCleanPowerPlan.pdf; and

[878] MISO, *Analysis of EPA's Proposal to Reduce* CO_2 *Emissions from Existing Units*, at 14 (Nov. 12, 2014), *available at* https://www.misoenergy.org/Library/Repository/Communication%20Material/EPA%20Regulations/AnalysisofEPAProposalReduceCO2Emissions.pdf.

[879] SPP, *SPP's Reliability Impact Assessment of the EPA's Proposed Clean Power Plan*, (Oct. 8, 2014), *available at* http://www.spp.org/publications/CPP%20Reliability%20Analysis%20Results%20Final%20Version.pdf.

significant flexibility in how they comply with requirements, including both BSER measures and measures that were not included in the determination of the BSER as a means to comply. For example, demand-side EE measures can greatly assist states and affected EGUs in meeting the standards and/or state plan. Many studies assume that state plans will simply apply the BSER and do not recognize the large number of compliance approaches and opportunities that states and affected EGUs have available to them. The Analysis Group recently analyzed reliability considerations in MISO as the region considers how to comply with the final rule.[880] The Analysis Group found that despite the large amount of coal-fired generating capacity that will likely be retired in MISO in the coming years, the entities responsible for electric system reliability in MISO are prepared to collaboratively address any reliability issues that arise and that there is a "strong tool kit for managing 'Essential Reliability Services' needed to assure high-quality electric service."[881]

[880] Analysis Group, *Electric System Reliability and EPA's Clean Power Plan: The Case of MISO* (June 8, 2015), *available at* http://www.analysisgroup.com/uploadedfiles/content/insights/publishing/analysis_group_clean_power_plan_miso_reliability.pdf.
[881] Analysis Group, *Electric System Reliability and EPA's Clean Power Plan: The Case of MISO*, at 2 (June 8, 2015), *available at* http://www.analysisgroup.com/uploadedfiles/content/insights/publishing/analysis_group_clean_power_plan_miso_reliability.pdf.

ERCOT also performed an analysis, modeling numerous scenarios.[882] ERCOT stated that its modeling identified two potential reliability problems – impacts of units retiring and increased levels of renewable generation on the ERCOT grid.[883] As noted above, the final rule gives additional time for compliance, providing needed time to obtain new or replacement generation necessary as some existing generators retire. Moreover, affected EGUs needed for reliability should be able to employ the flexibilities afforded to them as they seek lower and zero-emitting generation. Finally, we note that ERCOT has a history of notable success in integrating RE into its electric grid, giving ERCOT significant expertise regarding challenges that may arise with the addition of new RE in order to comply with the final rule. In fact, a recent Brattle Group report used ERCOT as a case study for how to effectively integrate a large number of RE into the electric grid.[884]

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[882] ERCOT, *ERCOT Analysis of the Clean Power Plan* (Nov. 17, 2014), *available at* http://www.ercot.com/content/news/presentations/2014/ERCOTAnalysis-ImpactsCleanPowerPlan.pdf.

[883] ERCOT, *ERCOT Analysis of the Clean Power Plan*, at 9 (Nov. 17, 2014), *available at* http://www.ercot.com/content/news/presentations/2014/ERCOTAnalysis-ImpactsCleanPowerPlan.pdf.

[884] Brattle Group, *Integrating Renewable Energy Into the Electricity Grid: Case Studies Showing How System Operators are Maintaining Reliability* (June 2015), *available at* http://info.aee.net/integrating-renewable-energy-into-the-electricity-grid.

PJM conducted its own analysis at the request of the Organization of PJM States (OPSI).[885] This analysis is consistent with many of the M.J. Bradley guiding principles. PJM designed various scenarios to capture the impact of the proposed rule under a series of assumptions. Because the EPA had not yet issued the final rule, PJM cautioned against using the report as a reliability analysis or predictor of the future. PJM stated that, since 2007, PJM's capacity markets have helped to attract 35,000 MWs of additional generation. Even though 26,000 MWs will retire between 2009 and 2016, the PJM capacity market has procured sufficient resources to maintain reliability.

WECC also produced a study which is part of a longer-term, phased effort.[886] The assumptions, methodology, and limitations were all clearly presented, and there was extensive involvement by a range of stakeholders. WECC stated that it is embarking on a phased-study process that seeks to "provide the industry with unbiased and independent analysis of this issue."[887] WECC

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[885] PJM, *PJM Interconnection Economic Analysis of the EPA Clean Power Plan Proposal* (Mar. 2, 2015), *report listed at* http://www.pjm.com/documents/reports.aspx.

[886] WECC, *EPA Clean Power Plan: Phase I – Preliminary Technical Report* (Sept. 19, 2014), *available at* https://www.wecc.biz/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/140912_EPA-111(d)_PhaseI_Tech-Final.pdf&action=default&DefaultItemOpen=1.

[887] WECC, *EPA Clean Power Plan: Phase I – Preliminary Technical Report*, at 1 (Sept. 19, 2014), *available at* https://www.wecc.biz/_layouts/15/WopiFrame.aspx?sourcedoc=/Relia

concluded that the effects of the proposal on resource adequacy may be minimal but that resource adequacy cannot be fully assessed without realistic and/or proposed compliance scenarios.[888]

Analysis Group analyzed the proposed rule, finding that it provides states and affected EGUs with a wide range of options and operational discretion that can prevent reliability issues while also reducing carbon pollution and costs.[889] Analysis Group noted that some of the concerns raised by stakeholders about the proposed rule assume "inflexible implementation, are based upon worst-case scenarios, and assume that policy makers, regulators, and market participants will stand on the sidelines until it is far too late to act" to ensure reliability.[890] It stated that these assumptions are not consistent with past actions.

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bility/140912_EPA-111(d)_PhaseI_Tech-Final.pdf&action=default&DefaultItemOpen=1.

[888] WECC, *EPA Clean Power Plan: Phase I – Preliminary Technical Report*, at 30 (Sept. 19, 2014), *available at* https://www.wecc.biz/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/140912_EPA-111(d)_PhaseI_Tech-Final.pdf&action=default&DefaultItemOpen=1.

[889] Analysis Group, *Electric System Reliability and EPA's Clean Power Plan Tools and Practices* (Feb. 2015), *available at* http://www.analysisgroup.com/uploadedfiles/content/insights/publishing/electric_system_reliability_and_epas_clean_power_plan_tools_and_practices.pdf.

[890] Analysis Group, *Electric System Reliability and EPA's Clean Power Plan Tools and Practices*, at ES-3 (Feb. 2015), *available at* http://www.analysisgroup.com/uploadedfiles/content/insights/publishing/electric_system_reliability_and_epas_clean_power_plan_tools_and_practices.pdf.

We appreciate the time that multiple entities took to analyze and consider the potential impacts of the proposed rule. As we issue the final rule and states draft plans to implement the rule, we look forward to further analysis by these and other groups. Such analysis can provide states with needed resources to help them design state plans that will augment the efforts of the industry to maintain electric reliability.

3. Consideration of effects on employment and economic development

States in designing their state plans should consider the effects of their plans on employment and overall economic development to assure that the opportunities for economic growth and jobs that the plans offer are manifest. To the extent possible, states should try to assure that any communities that can be expected to experience job losses can also take advantage of the opportunities for job growth or otherwise transition to healthy, sustainable economic growth. The EPA’s illustrative analysis indicates that there may be some additional job losses in sectors related to coal extraction and generation that are attributable to implementation of this rule. At the same time, the EPA’s illustrative analysis indicates that there may be new jobs in the utility power sector associated with both improving the efficiency of fossil fuel-fired power plants, construction and operation of new natural gas-fired and RE production, and actions to increase demand-side EE. Consideration of these effects in the context of the particulars of the state plan can help states craft plans that, to the extent possible, meet multiple environmental, economic, and workforce development goals.

The Partnerships for Opportunity and Workforce and Economic Revitalization (POWER) Initiative is a new interagency effort led by the Economic Development Administration in the Department of Commerce. POWER was launched to respond to current trends in the power sector: "The United States is undergoing a rapid energy transformation, particularly in the power sector. This transformation is producing cleaner air and healthier communities, and spurring new jobs and industries. At the same time, it is impacting workers and communities who have relied on the coal industry as a source of good jobs and economic prosperity, particularly in Appalachia, where competition with other coal basins provides additional pressure."[891] The POWER Initiative aligns, leverages, and targets economic and workforce development assistance to communities and workers affected by changes in the coal industry and the utility power sector. The POWER Initiative is competitively awarding planning assistance and implementation grants with funding from the Department of

[891] http://www.eda.gov/power/.

Commerce, Department of Labor, Small Business Administration, and the Appalachian Regional Commission to partnerships anchored in impacted communities. These grants will help communities organize themselves, develop comprehensive strategic plans that chart their economic future, and execute coordinated economic and workforce development activities based on their strategic plans.[892]

In addition to POWER, however, the EPA encourages states to use economic and labor market analysis to identify where they can deploy strategies to: 1) provide a range of employment and training assistance to workers, and economic development assistance to communities affected by the rapid changes underway in the power sector and closely related industries, to diversify their economies, attract new sources of investment, and create new jobs; and 2) mobilize existing education and training resources, including those of community and technical colleges and registered apprenticeship programs, to ensure that both incumbent and new workers are trained for the skills necessary to meet employer demand for new workers in the utility, construction and related sectors, that such training includes career pathways for members of low-income communities and other

[892] https://www.whitehouse.gov/the-press-office/2015/03/27/fact-sheet-partnerships-opportunity-and-workforce-and-economic-revitaliz.

vulnerable communities to attain employment in these sectors, and that such training results in validated skill certifications for workers.

4. Workforce considerations

Some stakeholders commented that, to ensure that emission reductions are realized, it is important that construction, operations and other skilled work undertaken pursuant to state plans is performed to specifications, and is effective, safe, and timely. A good way to ensure a highly proficient workforce is to require that workers have been certified by: 1) an apprenticeship program that is registered with the U.S. DOL, Office of Apprenticeship or a state apprenticeship program approved by the DOL; 2) a skill certification aligned with the U.S. DOE Better Building Workforce Guidelines and validated by a third party accrediting body recognized by DOE; or 3) other skill certification validated by a third party accrediting body.

5. Tenth Amendment legal considerations

Some commenters have raised concerns that the emission guidelines and requirements for 111(d) state plans violate principles of federalism embodied in the U.S. Constitution, particularly the Tenth Amendment. These commenters claim that states will be unconstitutionally “coerced” or “commandeered” into taking certain actions in order to avoid the prospect of either a federal 111(d) plan applying to sources in the state, or of losing federal funds.

We disagree on both fronts. First, the prospect of a federal plan applying to sources in a state does not "coerce" or "commandeer" that state into submitting its own satisfactory plan. Far from violating principles of federalism, this rule provides states with the initial opportunity to submit a satisfactory state plan, and provides states flexibility in developing that plan. If a state declines to take advantage of that opportunity, affected EGUs in that state will instead be subject to a federal plan that satisfies statutory requirements.[893] This approach is consistent with ordinary cooperative federalism regimes that federal courts have routinely upheld against Tenth Amendment challenges.[894]

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[893] Among other things, a federal plan will implement standards of performance subject to specific statutory requirements. *See* 42 U.S.C. § 7411(a)(1). The APA and CAA would prohibit the imposition of any federal plan that is "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." 5 U.S.C. § 706(2)(a). Particularly given these independent constraints on the EPA's authority with respect to any potential federal plan, the prospect of any such plan would not commandeer states or coerce them into submitting their own state plans.

[894] *See, e.g.*, *Hodel v. Va. Surface Mining & Reclamation Ass'n, Inc.*, 452 U.S. 264, 283–93 (1981); *Texas v. EPA*, 726 F.3d 180, 196–97 (D.C. Cir. 2013) (noting that "Supreme Court precedent repeatedly affirm[s] the constitutionality of federal statutes that allow States to administer federal programs but provide for direct federal administration if a State chooses not to administer it").

Second, states that decline to take certain actions under this rule will not face the prospect of sanctions, such as withdrawn federal highway funds. CAA section 111 does not contain sanctions provisions, and we are finalizing revisions to these emission guidelines making explicit that the EPA will not withhold federal funds from a state on account of that state's failure to submit or implement an approvable 111(d) state plan.

Some commenters pointed to section 110(m) as a possible source of the EPA's sanction authority.[895] Section 110(m) grants the EPA discretionary authority to withhold some federal highway funds under certain conditions. However, section 110(m) requires the EPA to adopt regulations to "establish criteria for exercising" this discretionary authority, and the only EPA regulations implementing section 110(m) apply to SIPs submitted under section 110.[896]

The EPA never intended to even imply that we would contemplate using this authority to encourage state participation in this rule under section 111. To the contrary, we believe that imposition of a federal plan rather than sanctions is the appropriate path in the context of this

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[895] Other commenters point to CAA section 179 as a possible direct source of this sanctions authority. However, the mandatory sanctions outlined in section 179 clearly apply only in the contexts of nonattainment SIPs and responses to SIP Calls made under CAA section 110(k)(5). *See* 42 U.S.C. § 7509(a).
[896] 40 CFR 52.30 (defining "plan or plan item").

program. Accordingly, regardless of whether the EPA could theoretically apply discretionary sanctions against states in the section 111(d) context, the final rule forbids the agency from exercising any such authority. We have included in this rule a provision that prohibits the agency from imposing sanctions in the event that a state fails to submit or implement a satisfactory plan under this rule. As states consider whether to take advantage of the opportunity to develop state plans, they can be assured that the EPA will not withdraw federal funding should they decline to participate.

6. Title VI

States that are recipients of EPA financial assistance must comply with all federal nondiscrimination statutes that together prohibit discrimination on the bases of race, color, national origin (including limited-English proficiency), disability, sex and age. These laws include: Title VI of the Civil Rights Act of 1964; Section 504 of the Rehabilitation Act of 1973; Section 13 of the Federal Water Pollution Control Act Amendments of 1972; Title IX of the Education Act Amendments of 1972; and the Age Discrimination Act of 1975. Compliance with these nondiscrimination statutes is a recipient's separate and distinct obligation from compliance with environmental regulations. In other words, all recipients are required to ensure that all aspects of their state plans do not violate any of the federal nondiscrimination statutes, including Title VI.

The EPA's Office of Civil Rights (OCR) is responsible for carrying out compliance with these federal nondiscrimination statutes and does so through a variety of means including: complaint investigation; agency-initiated compliance reviews; pre-grant award assurances and audits; and technical assistance and outreach activities. Anyone who believes that any of the federal nondiscrimination laws enforced by OCR have been violated by a recipient of EPA financial assistance may file an administrative complaint with the EPA's OCR.

H. Resources for States to Consider in Developing Plans

As part of the stakeholder outreach and comment processes, the EPA asked states what the agency could do to facilitate state plan development and implementation. In addition, after the comment period closed, the EPA continued to consult with state organizations including the Association of Air Pollution Control Agencies (AAPCA), Environmental Council of the States (ECOS), National Association of Clean Air Agencies (NACAA), National Association of Regulatory Utility Commissioners (NARUC), National Association of State Energy Officials (NASEO) and the National Governors Association (NGA).

Some states indicated that they wanted the EPA to create resources to assist with state plan development, especially resources related to accounting for RE and demand-side EE in state plans. They requested clear methodologies for estimating emission reductions from RE and demand-side EE policies and programs so that these could be included as part of their compliance strategies. Stakeholders said that these tools and metrics should build upon the EPA’s “Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans,” as well as the State Energy Efficiency Action Network’s “Energy Efficiency Program Impact Evaluation Guide.” In addition, stakeholders requested clear guidance on how to measure the impacts of RE and demand-side EE programs using established EM&V protocols.

The EPA also heard that states would like guidance on plan development to be released at the same time as this final rule. This guidance should include allowable programs and policies for compliance, examples of compliance pathways, clear information on multi-state plan development, and identification of tools.

As a result of this feedback, in consultation with U.S. DOE and other federal agencies, the EPA continued to refine its toolbox of decision support resources at: http://www2.epa.gov/www2.epa.gov/cleanpowerplantoolbox. The site includes information on regulatory requirements, including state plan guidance and state plan decision support. The state plan guidance section serves as a central repository for the final emission guidelines, RIA, guidance documents, TSDs and other supporting materials. The state plan decision support section includes information to help states evaluate different approaches and measures they might consider as they initiate plan development. This section includes, for example, a summary of existing state climate and RE and demand-side EE policies and programs, information on electric utility actions that reduce CO_2, and tools and information to estimate the emissions impact of RE and demand-side EE programs.

The EPA notes that our inclusion of a measure in the toolbox does not mean that a state plan must include that measure. In fact, inclusion of measures provided at the website does not necessarily imply the approvability of an approach or method for use in a state plan. States will need to demonstrate that any measure included in a state plan meets all relevant criteria and adequately addresses elements of the plan components discussed in section VIII.D of this preamble.

I. Considerations for CO_2 Emission Reduction Measures that Occur at Affected EGUs

This section describes a range of emission reduction actions that may be taken at affected EGUs that reduce CO_2 emissions from an affected EGU and/or improve its CO_2 emission rate, and the accounting treatment for these actions in a state plan. Some of these actions do not necessitate additional accounting, monitoring or reporting requirements. Such actions are discussed in section VIII.I.1 below, and include heat rate improvements, fuel switching from one fossil fuel to another, integration of RE into EGU operations, and combined heat and power (CHP) expansion or retrofit. Other actions, however, do necessitate additional accounting, monitoring, or reporting requirements. These include use of CCS, CCU and biomass, as discussed in section VIII.I.2 below.

The discussion in this section applies for both rate-based and mass-based plans. Additional accounting considerations for mass-based plans are discussed in section VIII.J. Additional accounting considerations for rate-based plans, including how actions that substitute for generation from affected EGUs or avoid the need for generation from affected EGUs may be used in a state plan to adjust the CO_2 emission rate of an affected EGU, are discussed in section VIII.K.

1. Actions without additional accounting and reporting requirements

Many actions will reduce the reported CO_2 emissions or CO_2 emission rate of an affected EGU, without the need for additional accounting or monitoring and reporting requirements beyond the required CEMS tracking of actual stack CO_2 emissions and tracking of actual energy output.[897] The effect of these actions will result in changes in reported CO_2 emissions and/or energy output by an affected EGU. These actions include:

- heat rate improvements;
- fuel switching to a fossil fuel with lower carbon content (e.g., from coal to natural gas);
- integrated RE;[898] and
- CHP, including retrofit of an affected EGU to a CHP configuration, or revising the useful energy outputs (electrical and thermal) at an affected EGU already operating in a CHP configuration.[899]

Heat rate improvements, fuel switching, integrating RE and CHP would not require any additional accounting or monitoring

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[897] Monitoring and reporting requirements for affected EGU CO_2 emissions and useful energy output are addressed in section VIII.F.

[898] "Integrated RE" refers to RE that is directly incorporated into the mechanical systems and operation of the EGU. An example is a solar thermal energy system used to preheat boiler feedwater. Such approaches reduce the amount of fossil fuel heat input per unit of useful energy output.

[899] The emission reduction potential from CHP stems from the unit using less fuel for producing useful electrical and thermal outputs than would be required to run separate electrical and thermal units. The emission reduction would depend on the type of affected EGU and available steam hosts in the vicinity of the affected EGU. A conventional combustion turbine generator, for example, converted into a CHP unit could effectively result in a reduction of 25 percent or more in the reported CO_2 emission rate. The potential retrofitted EGU CHP market consists of converted simple cycle turbines, older steam plants in urban areas, and combined cycle units near beneficial thermal loads.

and reporting, because under the emission guidelines affected EGUs are already required to monitor and report CO_2 emissions at the stack level, and to monitor and report useful energy outputs. Stack monitoring would reflect reductions in CO_2 emissions from efficiency improvements, changes in fuel use (including incorporation of RE), and other on-site changes.

2. Actions with additional accounting and reporting requirements

Certain actions that may be taken at an affected EGU to reduce CO_2 emissions, specifically application of CCS and CCU, and use of biomass, require additional accounting and reporting.

a. Application of CCS. Affected EGUs may utilize retrofit CCS technology to reduce reported stack CO_2 emissions from the EGU.[900] Affected EGUs that apply CCS under a state plan must meet the same monitoring, recordkeeping and reporting requirements for sequestered CO_2 as new units that implement CCS to meet final standards of performance under CAA section 111(b) for new EGUs.[901] Specifically, the final CAA section 111(b) rule for new sources requires that, if a new affected EGU uses CCS to meet

[900] Addition of retrofit CCS technology should not trigger CAA section 111(b) applicability for modified or reconstructed sources. Pollution control projects do not trigger NSPS modifications and addition of CCS technology does not count toward the capital costs of reconstruction for NSPS.

[901] Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units.

the applicable CO_2 emission limit, the EGU must report in accordance with 40 CFR part 98 subpart PP (Suppliers of Carbon Dioxide), and the captured CO_2 must be injected at a facility or facilities that report in accordance with 40 CFR part 98 subpart RR (Geologic Sequestration of Carbon Dioxide).[902,903] See 40 CFR part 60.46Da(h)(5) and part 60.5555(d). Taken together, these requirements ensure that the amount of captured and sequestered CO_2 will be tracked as appropriate at project- and national-levels, and that the status of the CO_2 in its sequestration site will be monitored, including air-side monitoring and reporting. As detailed in the preamble for the CAA section 111(b) standards for new EGUs, the EPA found that there is ample evidence that CCS is technically feasible and that partial CCS can be implemented at a new fossil fuel-fired steam generating EGU at a cost that is reasonable and that is consistent with the cost of

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[902] The final CAA section 111(b) rule finalizes amendments to subpart PP reporting requirements, specifically requiring that the following pieces of information be reported: (1) the electronic GHG Reporting Tool identification (e-GGRT ID) of the EGU facility from which CO_2 was captured, and (2) the e-GGRT ID(s) for, and mass of CO_2 transferred to, each GS site reporting under subpart RR. As noted, the final 111(b) rule also requires that any affected EGU unit that captures CO_2 to meet the applicable emission limit must transfer the captured CO_2 to a facility that reports under 40 CFR part 98 subpart RR.

[903] Under final requirements in the CAA 111(b) NSPS, any well receiving CO_2 captured from an affected EGU, be it a Class VI or Class II well, must report under subpart RR. A UIC Class II well’s regulatory status does not change because it receives such CO_2, nor does it change by virtue of reporting under subpart RR.

other dispatchable, non-NGCC generating options. In the June 2014 proposal, the EPA noted that CCS technology at existing EGUs would entail additional considerations beyond those at issue for newly constructed EGUs. Specifically, the cost of integrating a retrofit CCS system into an existing facility may be expected to be substantial, and some existing EGUs may have space limitations and thus may not be able to accommodate the expansion needed to install the equipment to implement CCS. Further, the EPA noted that aggregated costs of applying CCS as a component of the BSER for the large number of existing fossil fuel-fired steam EGUs would be substantial and would be expected to affect the cost and potentially the supply of electricity on a national basis. Because there are lower-cost systems of emission reduction available to reduce emissions from existing plants, the EPA did not propose nor finalize CCS as a component of the BSER for existing EGUs.

However, the EPA noted that CCS may be a viable CO_2 mitigation technology at some existing sources and that it would be available to states and to sources as a compliance option. Numerous commenters agreed with the EPA's proposed determination that CCS technology is not part of the BSER building blocks for existing EGUs. Other commenters opposed inclusion of CCS requirements in state plans and provided specific reasons why CCS would not be applicable in certain states. Many commenters felt that CCS technology is not adequately demonstrated and is not economically practical at this time. Other commenters argued that CCS is an available technology and that it can be implemented at more EGUs than predicted by EPA modeling.

Some commenters noted that there are opportunities to reduce the cost of CCS implementation by selling the captured CO_2 for use in Enhanced Oil Recovery (EOR) operations. One commenter expressed concern that federal requirements under the Greenhouse Gas Reporting Program – specifically the requirement (mentioned above) to report under 40 CFR part 98 subpart RR – would foreclose, rather than encourage, the use of captured CO_2 for EOR. The EPA received similar public comments on the CAA 111(b) proposal for new EGUs. The EPA disagrees with the commenters' assertions and addressed those in the preamble for the final standards of performance and in the Response-to-Comments (RTC) document for the CAA 111(b) NSPS rulemaking. The EPA noted that the cost of compliance with subpart RR is not significant enough to offset the potential revenue for the EOR operator from the sale of produced oil for CCS projects that are reliant on EOR. The costs associated with subpart RR are relatively modest, especially in comparison with revenues from an EOR field.

After consideration of the variety of comments we received on this issue, we are confirming our proposal that CCS is not an element of the BSER, but it is an available compliance measure for a state plan. EGUs implementing CCS would need to follow reporting requirements established in the final CAA section 111(b) rule for new affected EGUs.

b. Application of CCU. The EPA received comments suggesting that carbon capture and utilization (CCU) technologies should also be allowed as a CO_2 emission rate adjustment measure for affected EGUs.

Potential alternatives to storing CO_2 in geologic formations are emerging and may offer the opportunity to offset the cost of CO_2 capture. For example, captured anthropogenic CO_2 may be stored in solid carbonate materials such as precipitated calcium carbonate (PCC) or magnesium or calcium carbonate, bauxite residue carbonation, and certain types of cement through mineralization. The carbonate materials produced can be tailored to optimize performance in specific industrial and commercial applications. For example, these carbonate materials have been used in the construction industry and, more recently and innovatively, in cement production processes to replace Portland cement.

The Skyonics Skymine® project, which opened its demonstration project in October 2014, is an example of captured CO_2 being used in the production of carbonate products. This plant converts CO_2 into commercial products. It captures over 75,000 tons of CO_2 annually from a San Antonio, Texas, cement plant and converts the CO_2 into other products including sodium carbonate and sodium bicarbonate.[904] Other companies – including Calera[905] and New Sky[906] – also offer commercially available technology for the beneficial use of captured CO_2. These processes can be utilized in a variety of industrial applications – including at fossil fuel-fired power plants.

However, consideration of how these emerging alternatives could be used to meet CO_2 emission performance rates or state CO_2 emission goals would require a better understanding of the ultimate fate of the captured CO_2 and the degree to which the method permanently isolates the captured CO_2 or displaces other CO_2 emissions from the atmosphere.

Several commenters also suggested that algae-based CCU (i.e., the use of algae to convert captured CO_2 to useful products – especially biofuels) should be recognized for its potential to reduce emissions from existing fossil-fueled EGUs.

Unlike geologic sequestration, there are currently no uniform monitoring and reporting mechanisms to demonstrate that these alternative end uses of captured CO_2 result in overall reductions of CO_2 emissions to the atmosphere. As these alternative technologies are developed, the EPA is committed to

[904] http://skyonic.com/technologies/skymine.
[905] http://www.calera.com/beneficial-reuse-of-co2/process.html.
[906] http://www.newskyenergy.com/index.php/products/carboncycle.

working collaboratively with stakeholders to evaluate the efficacy of alternative utilization technologies, to address any regulatory hurdles, and to develop appropriate monitoring and reporting protocols to demonstrate CO_2 reductions.

In the meantime, state plans may allow affected EGUs to use qualifying CCU technologies to reduce CO_2 emissions that are subject to an emission standard, or those that are counted when demonstrating achievement of the CO_2 emission performance rates or a state rate-based or mass-based CO_2 emission. State plans must include analysis supporting how the proposed qualifying CCU technology results in CO_2 emission mitigation from affected EGUs and provide monitoring, reporting, and verification requirements to demonstrate the reductions. The EPA would then review the appropriateness and basis for the analysis and the verification requirements in the course of its review of the state plan.

c. <u>Application of biomass co-firing and repowering</u>. The EPA received multiple comments supporting the use of biomass feedstocks as a means of reducing CO_2 emissions within state plans. Several commenters also asserted that states should be able to determine how biomass can be used in their plans. Additionally, the EPA received a range of comments regarding the valuation of CO_2 emissions from biomass combustion. Some argued that all biomass feedstocks should be considered "carbon neutral," while others maintained that only the full stack emissions from biomass combustion should be counted. As discussed in the next section, the revised *Framework for Assessing Biogenic Carbon Dioxide for Stationary Sources*[907] and 2012 Science Advisory Board peer review of the *2011 Draft Framework* find that it is not scientifically valid to assume that all biogenic feedstocks are "carbon neutral, but that the net biogenic CO_2 atmospheric contribution of different biomass feedstocks can vary and depends on various factors, including feedstock type and characteristics, production practices, and, in some cases, the alternative fate of the feedstock.[908] Other comments focused on the use of sustainably-derived agricultural and forest biomass feedstocks, including stakeholders who supported and those against such feedstocks as approvable elements, and those who wanted further definition of these feedstocks. As discussed above and in more detail below, these final guidelines provide that states can include qualified biomass in their plans and include provisions for how qualified biomass feedstocks or feedstock categories will be determined. The EPA will review the appropriateness and basis for determining qualified biomass feedstocks or feedstock categories in its review of the approvability of a state plan.

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[907] www.epa.gov/climatechange/downloads/Framework-for-Assessing-Biogenic-CO2-Emissions.pdf.
[908] www.epa.gov/climatechange/ghgemissions/biogenic-emissions.html.

(1) Considerations for use of biomass in state plans.

The EPA recognizes that the use of some biomass-derived fuels can play a role in controlling increases of CO_2 levels in the atmosphere. The use of some kinds of biomass has the potential to offer a wide range of environmental benefits, including carbon benefits. However, these benefits can typically only be realized if biomass feedstocks are sourced responsibly and attributes of the carbon cycle related to the biomass feedstock are taken into account.

In November 2014, the agency released a second draft of the technical report, *Framework for Assessing Biogenic Carbon Dioxide for Stationary Sources*. The revised *Framework,* and the EPA's Science Advisory Board (SAB) peer review of the *2011 Draft Framework*, finds that it is not scientifically valid to assume that all biogenic feedstocks are "carbon neutral" and that the net biogenic CO_2 atmospheric contribution of different biogenic feedstocks generally depends on various factors related to feedstock characteristics, production, processing and combustion practices, and, in some cases, what would happen to that feedstock and the related biogenic emissions if not used for energy production.[909] The revised Framework also found that the

[909] Specifically, the SAB found that "There are circumstances in which biomass is grown, harvested and combusted in a carbon neutral fashion but carbon neutrality is not an appropriate a

production and use of some biogenic feedstocks and subsequent biogenic CO_2 emissions from stationary sources will not inevitably result in increased levels of CO_2 to the atmosphere, unlike CO_2 emissions from combustion of fossil fuels.

The SAB peer review panel agreed that the use of biomass feedstocks derived from the decomposition of biogenic waste in landfills, compost facilities or anaerobic digesters did not constitute a net contribution of biogenic CO_2 emissions to the atmosphere. And further, information considered in preparing the second draft of the Framework, including the SAB peer review and stakeholder input, supports the finding that use of waste-derived feedstocks[910] and certain forest-derived industrial byproducts (such as those without alternative markets) are likely to have minimal or no net atmospheric contributions of biogenic CO_2 emissions, or even reduce such impacts, when

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priori assumption; it is a conclusion that should be reached only after considering a particular feedstock's production and consumption cycle. There is considerable heterogeneity in feedstock types, sources and production methods and thus net biogenic carbon emissions will vary considerably." www.epa.gov/climatechange/ghgemissions/biogenic-emissions.html.

[910] Types of waste-derived biogenic feedstocks may include: landfill gas generated through the decomposition of MSW in a landfill; biogas generated from the decomposition of livestock waste, biogenic MSW, and/or other food waste in an anaerobic digester; biogas generated through the treatment of waste water, due to the anaerobic decomposition of biological materials; livestock waste; and the biogenic fraction of MSW at waste-to-energy facilities.

compared with an alternate fate of disposal.

In addition, as detailed in the President's Climate Action Plan,[911] part of the strategy to address climate change includes efforts to protect and restore our forests, as well as other critical landscapes including grasslands and wetlands, in the face of a changing climate. This country's forests currently play a critical role in addressing carbon pollution, removing more than 13 percent of total U.S. GHG emissions each year.[912] Conservation and sustainable management can help ensure our forests and other lands will continue to remove carbon from the atmosphere while also improving soil and water quality, reducing wildfire risk and enhancing forests' resilience in the face of climate change.

Many states have recognized the importance of forests and other lands for climate resilience and mitigation, and have developed a variety of sustainable forestry policies, RE incentives and standards, and GHG accounting procedures. Some states, for example Oregon and California, have programs that recognize the multiple benefits that forests provide, including biodiversity and ecosystem services protection as well as

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[911] www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf.

[912] www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Chapter-6-Land-Use-Land-Use-Change-and-Forestry.pdf.

climate change mitigation through carbon storage. Oregon has several programs focused on best forest management practices and sustainability, including the Oregon Indicators of Sustainable Forests, that promote environmentally, economically and socially sustainable management of state forests. California's Forest Practice Regulations support sustained production of high-quality timber while considering ecological, economic and social values, and the state's Greenhouse Gas Reduction Fund provides resources for forestry projects to improve forest health, maintain carbon storage and avoid GHG emissions from pests, wildfires and conversion to non-forest uses.

Several states focus on sustainable bioenergy, as seen with the sustainability requirements for eligible biomass in the Massachusetts RPS, which, among other requirements, limits old growth forest harvests. Many states employ complementary programs that together work to address sustainable forestry practices. For example, Wisconsin uses a state forest sustainability framework that provides a common system to measure the sustainability of the state's public and private forests, in conjunction with a series of voluntary best management guideline manuals for sustainable woody biomass and agriculturally-derived biomass. In addition to state-specific programs, some states also actively participate in sustainable forest management or certification programs through third-party entities such as the Sustainable Forestry Initiative (SFI) and the Forest Stewardship Council (FSC). For example, in addition to other state sustainability programs, New York has certified more than 780,000 acres of state forestland to both SFI and FSC's sustainable forest management programs. SFI and FSC have certified more than 63 and 35 million acres of forestland across the U.S., respectively.

These examples demonstrate how states already use diverse strategies to promote sustainable forestry and agricultural management while realizing their unique economic, environmental and RE goals. As states evaluate options for meeting the emission guidelines, they may consider how sustainably-derived biomass and sustainable forestry and agriculture programs, such as the examples highlighted above, may help them control increases of CO_2 levels in the atmosphere. In addition, the EPA's work on assessing biogenic CO_2 emissions from stationary sources may also help inform states' efforts to assess the role of different biogenic feedstocks in their plans and broader climate strategies.[913]

The EPA is engaging in a second round of targeted peer review on the revised Framework with the SAB in 2015.[914] As part

[913] As highlighted in a November 2014 memorandum to the EPA's Regional Air Division Directors. www.epa.gov/climatechange/ghgemissions/biogenic-emissions.html.
[914] www.epa.gov/sab.

of this technical process, and as the EPA and states implement these emission guidelines, the EPA will continue to assess and closely monitor overall bioenergy demand and associated landscape conditions for changes that might have negative impacts on public health or the environment.

(2) Additional considerations and requirements for biomass fuels.

The EPA anticipates that some states may consider the use of certain biomass-derived fuels used in electricity generation as a way to control increases of CO_2 levels in the atmosphere, and will include them as part of their state plans to meet the emission guidelines. Not all forms of biomass are expected to be approvable as qualified biomass (i.e., biomass that can be considered as an approach for controlling increases of CO_2 levels in the atmosphere). Affected EGUs may use qualified biomass in order to control or reduce CO_2 emissions that are subject to an emission standard requirement, or those that are counted when demonstrating achievement of the CO_2 emission performance rates or a state rate-based or mass-based CO_2 emission goal.

State plan submissions must describe the types of biomass that are being proposed for use under the state plan and how those proposed feedstocks or feedstock categories should be considered as “qualified biomass” (i.e., a biomass feedstock that is demonstrated as a method to control increases of CO_2

levels in the atmosphere). The submission must also address the proposed valuation of biogenic CO_2 emissions (i.e., the proposed portion of biogenic CO_2 emissions from use of the biomass feedstock that would not be counted when demonstrating compliance with an emission standard, or when demonstrating achievement of the CO_2 emission performance rates or a state rate-based or mass-based CO_2 emission goal).

With regard to assessing qualified biomass proposed in state plans, the EPA generally acknowledges the CO_2 and climate policy benefits of waste-derived biogenic feedstocks and certain forest- and agriculture-derived industrial byproduct feedstocks, based on the conclusions supported by a variety of technical studies, including the revised *Framework for Assessing Biogenic Carbon Dioxide for Stationary Sources.* The use of such waste-derived and certain industrial byproduct biomass feedstocks would likely be approvable as qualified biomass in a state plan when proposed with measures that meet the biomass monitoring, reporting and verification requirements discussed below and other measures as required elsewhere in these emission guidelines.

Given the importance of sustainable land management in achieving the carbon goals of the President's Climate Action Plan, sustainably-derived agricultural and forest biomass feedstocks may also be acceptable as qualified biomass in a state plan, if the state-supplied analysis of proposed qualified feedstocks or feedstock categories can adequately demonstrate that such feedstocks or feedstock categories appropriately control increases of CO_2 levels in the atmosphere and can adequately monitor and verify feedstock sources and related sustainability practices. Information in the revised Framework, the second SAB peer review process, and the state and third party programs highlighted in the previous section can assist states when considering the role of qualified biomass in state plan submittals.

Regardless of what biomass feedstocks are proposed, state plans must specify how biogenic CO_2 emissions will be monitored and reported, and identify specific EM&V, tracking and auditing approaches for qualified biomass feedstocks. As discussed in section VIII.D.2, state plan submittals must include CO_2 emission monitoring, reporting and recordkeeping measures. In the case of sustainably-derived forest- and agriculture-derived feedstocks, this will also include measures for verifying feedstock type, origin and associated sustainability practices. Section VIII.K describes how state plan submittals must specify the requirements and procedures that EM&V measures must meet. As discussed in section VIII.K, the EPA is addressing potential EM&V measures for qualified biomass in EPA's model trading rule and draft EM&V guidance, such as measures that would ensure that biomass-related biogenic CO_2 benefits are quantifiable, verifiable, non-duplicative, permanent and enforceable.

State plan submittals must ensure that all biomass used meets the state plan requirements for qualified biomass and associated biogenic CO_2 benefits, such as using robust, independent third party verification and establishing measures to maintain transparency, including disclosure of relevant documentation and reports. State plan submittals must include measures for tracking and auditing performance to ensure that biomass used meets the state plan requirements for qualified biomass and associated biogenic CO_2 benefits. Details on how to adjust CO_2 rates through the use of qualified biomass feedstocks are provided in section VIII.K.1.

The EPA will review the appropriateness and basis for proposed qualified biomass and biomass treatment determinations and related accounting, monitoring and reporting measures in the course of its review of a state plan. The EPA's determination that a state plan satisfactorily proves that proposed biomass fuels qualify would be based in part on whether the plan submittal demonstrates that proposed state measures for qualified biomass and related biogenic CO_2 benefits are quantifiable, verifiable, enforceable, non-duplicative and permanent. The EPA recognizes that CCS technology (described above in section VIII.I.2.a) could be applied in conjunction with the use of qualified biomass.

(3) Biomass co-firing.

Affected EGUs may use qualified biomass co-fired with fossil fuels at an affected EGU. As discussed above in this section, not all forms of biomass are expected to be approvable and states should propose biomass feedstocks and treatment of biogenic CO_2 emissions in state plans, along with supporting analysis where applicable. The EPA will review the appropriateness and basis for such determinations and accounting measures in the course of its review of a state plan.

An affected EGU using qualified biomass as a fuel must monitor and report both its overall CO_2 emissions and its biogenic CO_2 emissions. If biomass is to be used as means to control increases of CO_2 levels in the atmosphere in a state plan, the plan must specify requirements for reporting biogenic CO_2 emissions from affected EGUs.

(4) Biomass repowering.

Affected EGUs could fully repower to use primarily qualified biomass. The characteristics of affected EGUs, as discussed in section IV.D, include the use of at least 10 percent fossil fuel for applicability of these emission guidelines. An EGU repowering with at least 90 percent biomass fuels instead of fossil fuels becomes a non-affected EGU.[915] An EGU repowering with less than 90 percent biomass would remain an affected EGU and therefore need to propose biomass feedstocks and treatment of biogenic CO_2 emissions in state plans, along with supporting analysis where applicable.

J. Additional Considerations and Requirements for Mass-Based State Plans

This section discusses considerations and requirements for different types of mass-based state plans. This includes mass-based state plans using emission budget trading programs, and coordination among such programs where states retain individual mass CO_2 emission goals. CAA section 111(d) requires states to submit, in part, a plan that establishes standards of performance for affected EGUs which reflect the BSER. The state plan must be satisfactory with respect to this requirement in order for the EPA to approve the plan. As previously described, states meet the statutory requirements of 111(d) and the requirements of the final emission guidelines by establishing emission standards for affected EGUs that meet the performance rates, which reflect the application of BSER as determined by

[915] For such an EGU to be considered non-affected, the EGU must be subject to a federally enforceable or practically enforceable condition, expressed in (for example) a construction permit or otherwise, that limits the amount of fossil fuel that may be used to 10 percent or less.

the EPA. This final rule allows states to alternatively establish emission standards that meet rate-based or mass-based goals. The state goals must be equivalent to the performance rates in order to reflect the application of the BSER as required by the statute and the final emission guidelines. Therefore, a state choosing a mass-based implementation must address leakage as part of its mass-based plan in order to satisfactorily establish emission standards for affected EGUs that reflect the BSER as set by the EPA.

1. Accounting for CO_2 emission reduction measures in mass-based state plans

As discussed in section VIII.I, measures that occur at affected EGUs will result in CO_2 emission reductions that are automatically accounted for in reported CO_2 emissions. Other measures that provide substitute generation for affected EGUs or avoid the need for generation from affected EGUs, such as demand-side EE, are automatically accounted for under a mass-based plan to the extent that these measures reduce reported CO_2 emissions from affected EGUs. Unlike under a rate-based plan, no additional accounting is necessary in order to recognize these emission reductions.

2. Use of emission budget trading programs

This section addresses the use of emission budget trading programs in a mass-based state plan, including provisions required for such programs and the design of such programs in the context of a state plan. This includes program design approaches that ensure achievement of a state mass-based CO_2 emission goal (or mass-based CO_2 goal plus new source CO_2 emission complement) (section VIII.J.2.b), as well as how states can use emission budget trading programs with broader source coverage and other flexibility features in a state plan, such as the programs currently implemented by California and the RGGI participating states (section VIII.J.2.c). Section VIII.J.2.d addresses other considerations for the design of emission budget trading programs that states may want to consider, such as allowance allocation approaches. Section VIII.J.3 addresses multi-state coordination among emission budget trading programs used in states that retain their individual state mass-based CO_2 goals.

a. <u>State plan provisions required for a mass-based emission budget trading program approach</u>.For a mass-based emission trading program approach, the state plan would include as its federally enforceable emission standards requirements that specify the emission budget and related compliance requirements and mechanisms. These requirements would include: CO_2 emission monitoring, reporting, and recordkeeping requirements for affected EGUs; provisions for state allocation of allowances; provisions for tracking of allowances, from issuance through submission for compliance; and the process for affected EGUs to demonstrate compliance (allowance "true-up" with reported CO_2 emissions). Mass-based emission standards that take the form of an emission budget trading program must be quantifiable, verifiable, enforceable, non-duplicative and permanent. These requirements are described in more detail at section VIII.D.2.

Where a state plan establishes mass-based emission standards for affected EGUs only, the emission standards and the implementing and enforcing measures may be included in the state plan as the full set of requirements implementing the emission budget trading program. Where an emission budget trading program in a state plan addresses affected EGUs and other fossil fuel-fired EGUs or emission sources, pursuant to the approaches described in sections VIII.J.2.b-d below, the requirements that must be included in the state plan are the federally enforceable emission standards in the state plan that apply specifically to affected EGUs, and the requirements that specifically require affected EGUs to participate in and comply with the requirements of the emission budget trading program. This includes the requirement for an affected EGU to surrender emission allowances equal to reported CO_2 emissions, and meet monitoring and reporting requirements for CO_2 emissions, among other requirements. These requirements may be submitted as part of the federally enforceable state plan through mechanisms with the appropriate legal authority and effect, such as state regulations, Title V permit requirements for affected EGUs, and other possible instruments that impose these requirements specifically with respect to affected EGUs. Under this approach, the full set of regulations establishing the emission budget trading program that applies to affected EGUs and other fossil fuel-fired EGUs and other emission sources (if relevant) must be described as supporting documentation in the state plan submittal for EPA to evaluate the approvability of the plan by determining whether the affected EGUs will achieve the requisite goal.

b. Requirement for emission budget trading programs to address potential leakage. In Section VII.D, the EPA specifies that potential emission leakage must be addressed in a state plan with mass-based emission standards. The EPA received comments suggesting various solutions to this concern, such as the inclusion of new sources under the rule and quantitative adjustments to mass CO_2 goals for affected EGUs. In response to this issue, the EPA has sought to give states flexibility in how they meet this requirement and base the acceptable solutions on what will best suit a state's unique characteristics and state plan structure.

To address the potential for emission leakage to new sources under a mass-based plan approach, which could prevent a mass-based program from successfully achieving a mass-based CO_2 goal consistent with BSER, the EPA is requiring that a state submitting a plan that is designed to meet a state mass-based CO_2 goal for affected EGUs demonstrate that the plan addresses and mitigates the risk of potential emission leakage to new sources. The following options provide sufficient demonstration that potential emission leakage has been addressed in a mass-based state plan:[916]

1. Regulate new non-affected fossil EGUs as a matter of state law in conjunction with emission standards for affected EGUs in a mass-based plan. If a state adopts an EPA-provided mass budget[917] that includes the state mass-based CO_2 goal for affected EGUs plus a new source CO_2 emission complement, this option could be presumptively approvable.
2. Use allocation methods in the state plan that counteract incentives to shift generation from affected EGUs to unaffected fossil-fired sources. If a state adopts allowance set-aside provisions exactly as they are outlined in the finalized model rule, this option could

[916] The first two options need not be mutually exclusive; they can both be implemented as part of a mass-based plan.
[917] In Table 14, we have provided a mass budget for each state that includes the state mass-based CO_2 goal and a projection for a new source CO_2 emission complement.

be presumptively approvable.

3. Provide a demonstration in the state plan, supported by analysis, that emission leakage is unlikely to occur due to unique state characteristics or state plan design elements that address and mitigate the potential for emission leakage.

In the first option, states may choose to regulate new non-affected fossil fuel-fired EGUs, as a matter of state law, in conjunction with federally enforceable emission standards for affected EGUs under a mass-based plan. This regulation of both new and existing sources, as part of a state plan approach, is conceptually analogous to a method that has been adopted by the mass-based systems adopted by California and the RGGI participating states. To address potential emission leakage under this option, the mass-based plan includes federally enforceable emission standards for affected EGUs, and the supporting documentation for the plan describes state-enforceable regulations for, at a minimum, all new grid-connected fossil fuel-fired EGUs that meet the applicability standards for EGUs subject to CAA section 111(b). States have the option of regulating a wider array of sources if they choose, as a matter of state law.

For this option, a state must adopt, as a matter of state law, a mass CO_2 emission budget of sufficient size to cover both affected EGUs under the existing source mass CO_2 goal provided in this final rule, along with sufficient CO_2 emission tonnage to cover projected new sources. There are two pathways that states can use for adopting such an emission budget that applies to both affected EGUs and new sources. The EPA is providing a mass budget for each state that account for the state's mass CO_2 goal for affected EGUs and a complementary emission budget for new sources, referred to as the new source CO_2 emission complement. States that both adopt the EPA-provided mass budget, based on the state mass-based CO_2 goal for affected EGUs plus the new source CO_2 emission complement, and regulate new sources under this emission budget as a matter of state law, in conjunction with federally enforceable emission standards for affected EGUs as part of the mass-based state plan may be able to submit a presumptively approvable plan. Such a plan would include federally enforceable emission standards for affected EGUs, and in the supporting documentation of the plan, would describe that the state is regulating new sources under a mass CO_2 emission budget that is equal to or less than the state mass-based CO_2 goal for affected EGUs plus the EPA-specified CO_2 emission complement, in conjunction with the federally enforceable emission standards for affected EGUs. If the state plan is designed to achieve the EPA provided mass budget, plan performance will be evaluated based on whether the existing affected EGUs, regulated under the federally enforceable state plan, and new sources regulated as a matter of state law, together meet the total mass budget that includes the state's mass CO_2 goal for affected EGUs and a complementary emission budget for new sources.

EPA-specified mass CO_2 emission budgets for each state, including the state's mass CO_2 goal and a new source CO_2 emission complement, are provided in Table 14 below. The derivation of the new source CO_2 emission complements is explained in a TSD titled New Source Complements to Mass Goals, which is available in the docket.

Table 14. New Source Complements to Mass Goals

State	**New Source Complements (Short Tons of CO_2)**		**Mass Goals[918] + New Source Complements (Short Tons of CO_2)**	
	Interim	**Final**	**Interim**	**Final**
Alabama	856,524	755,700	63,066,812	57,636,174
Arizona	1,424,998	2,209,446	34,486,994	32,380,196
Arkansas	411,315	362,897	34,094,572	30,685,529
California	2,846,529	4,413,516	53,873,603	52,823,635
Colorado	1,239,916	1,922,478	34,627,799	31,822,874
Connecticut	135,410	119,470	7,373,274	7,060,993
Delaware	78,842	69,561	5,141,711	4,781,386

918 The state mass CO_2 goals can be found in Table 13 in section VII.

Florida	1,753,276	1,546,891	114,738,005	106,641,595
Georgia	677,284	597,559	51,603,368	46,944,404
Idaho	94,266	146,158	1,644,407	1,639,013
Illinois	818,349	722,018	75,619,224	67,199,174
Indiana	939,343	828,769	86,556,407	76,942,604
Iowa	298,934	263,745	28,553,345	25,281,881
Kansas	260,683	229,997	25,120,015	22,220,822
Kentucky	752,454	663,880	72,065,256	63,790,001
Louisiana	484,308	427,299	39,794,622	35,854,321
Maine	40,832	36,026	2,199,016	2,109,968
Maryland	170,930	150,809	16,380,325	14,498,436
Massachusetts	225,127	198,626	12,972,803	12,303,372
Michigan	623,651	550,239	53,680,801	48,094,302
Minnesota	286,535	252,806	25,720,126	22,931,173
Mississippi	410,440	362,126	27,748,753	25,666,463
Missouri	668,637	589,929	63,238,070	56,052,813
Montana	421,674	653,801	13,213,003	11,956,908
Nebraska	216,149	190,706	20,877,665	18,463,444
Nevada	770,417	1,194,523	15,114,508	14,718,107
New Hampshire	71,419	63,012	4,314,910	4,060,591
New Jersey	313,526	276,619	17,739,906	16,876,364
New Mexico	527,139	817,323	14,342,699	13,229,925
New York	522,227	460,753	34,117,555	31,718,182

North Carolina	692,091	610,623	57,678,116	51,876,856
North Dakota	245,324	216,446	23,878,144	21,099,677
Ohio	949,997	838,170	83,476,510	74,607,975
Oklahoma	581,051	512,654	45,191,382	41,000,852
Oregon	453,663	703,399	9,096,826	8,822,053
Pennsylvania	1,257,336	1,109,330	100,588,162	90,931,637
Rhode Island	70,035	61,791	3,727,420	3,584,016
South Carolina	344,885	304,287	29,314,508	26,303,255
South Dakota	46,513	41,038	3,995,462	3,580,518
Tennessee	358,838	316,598	32,143,698	28,664,994
Texas	5,328,758	8,516,408	213,419,599	198,105,249
Utah	981,947	1,522,500	27,548,327	25,300,693
Virginia	450,039	397,063	30,030,110	27,830,174
Washington	531,761	824,490	12,211,467	11,563,662
West Virginia	602,940	531,966	58,686,029	51,857,307
Wisconsin	364,841	321,895	31,623,197	28,308,882
Wyoming	1,185,554	1,838,190	36,965,606	33,472,602
Lands of the Navajo Nation	809,562	1,255,217	25,367,354	22,955,804
Lands of the Uintah and Ouray Reservation	84,440	130,923	2,645,885	2,394,354
Lands of the Fort Mojave Tribe	37,162	57,619	648,264	646,138
Total	**33,717,871**	**41,187,289**	**1,878,255,620**	**1,709,291,348**

States can, in the alternative, provide their own projections for a new source CO_2 emission complement to their mass-based CO_2 goals for affected EGUs. In the supporting documentation for the state plan submittal, the state must specify the new source budget, specify the analysis used to derive such a new source CO_2 emission complement, and the state must demonstrate that under the state plan affected EGUs in the state will meet the state mass-based CO_2 goal for affected EGUs as a result of being regulated under the broader CO_2 emission cap that applied to both affected EGUs and new sources. Such a projection should take into account the mass goal quantification method outlined in section VII.C and the CO_2 Emission Performance Rate and Goal Computation TSD, including the fact that the mass-based state goals already incorporate a significant growth in generation from historical levels. The EPA will evaluate the approvability of the plan based on whether the federally enforceable emission standards for affected EGUs in conjunction with the state-enforceable regulatory requirements for new sources will result in the affected EGUs meeting the state mass-based CO_2 goal. If, rather than designing a plan to achieve the EPA provided mass budget, the state uses its own projections for a new source complement and the plan is approved to meet this new source complement, plan performance will be evaluated based on whether the existing affected EGUs, regulated under the federally enforceable state plan, meet the state's mass CO_2 goal for affected EGUs.

The second demonstration option allows states to use allowance allocation methods that counteract incentives to shift generation from affected EGUs to unaffected fossil-fired sources. These allocation approaches must be specified in state plans as part of the provisions for state allocation of allowances required under a mass-based plan approach (see section VIII.J.2.a). The EPA is proposing the inclusion of two allocation strategies as part of the mass-based approach in the proposed federal plan and model rule: updating output-based allocations and an allowance set-aside that targets RE. These options are described in more detail below. If a state were to adopt allowance set-aside provisions exactly as they are outlined in the finalized model rule, they could be considered presumptively approvable. The allowance allocation alternative for addressing leakage was chosen for the federal plan and model rule proposal because EPA does not have authority to extend regulation of and federal enforceability to new fossil fuel-fired sources under CAA section 111(d), and therefore we cannot include them under a federal mass-based plan approach.

An updating output-based allocation method allocates a portion of the total CO_2 emission budget to affected EGUs based, in part, on their level of electricity generation in a recent period or periods. Therefore, the total allocation to an EGU that is eligible to receive allowances from an output-based allowance set-aside is not fixed, but instead depends on its generation. Under this approach, each eligible affected EGU may receive a larger allowance allocation if it generates more. Therefore, eligible affected EGUs will have an incentive to generate more in order to receive more allowances, aligning their incentive to generate with new sources.

This allocation method can be implemented through the creation of a set-aside that reserves a subset of the total allowances available to sources, and distributes them based upon the criteria described above. Because the total number of allowances is limited, this allocation approach will not exceed the overall state mass-based CO_2 goal for affected EGUs. Instead, it merely modifies the distribution of allowances in a manner designed to mitigate potential emission leakage.

The other allocation strategy included as part of the mass-based approach in the proposed federal plan and model rule is a set-aside of allowances to be allocated to providers of incremental RE. A set-aside can also be allocated to providers of demand-side EE, or to both RE and demand-side EE. The increased availability of RE generation can serve as another source of generation to satisfy electricity demand. Increased demand-side EE will reduce the demand that sources need to meet.

Therefore, both RE and demand-side EE can serve to reduce the incentive that new sources have to generate, and therefore align their incentives with affected EGUs. Thus, increased RE and demand-side EE, supported by a dedicated set-aside, can also serve to address potential emission leakage.

If a state is submitting a plan with an allocations approach that differs from that of the finalized model rule, the state should also provide a demonstration of how the specified allocation method will provide sufficient incentive to counteract potential emission leakage.

Finally, a state can provide a demonstration that emission leakage is unlikely to occur, without implementing either of the two strategies above, as a result of unique factors, such as the presence of existing state policies addressing emission leakage or unique characteristics of the state and its power sector that will mitigate the potential for emission leakage. This demonstration must be supported by credible analysis. The EPA will determine if the state has provided a sufficient demonstration that potential emission leakage has already been adequately addressed, or if additional action is required as part of the state plan.

Aside from the possible incentives for emission leakage addressed in this section, there may be other potential generation incentives across states and unit subcategories that could increase CO_2 emissions, particularly in an environment where various states are implementing a variety of state plan approaches in a shared grid region. Some examples of these incentives, particularly those that were specified by commenters, are discussed in section VIII.L. That section also describes how the EPA has structured this final rule to either prevent or minimize the potential for foregone emission reductions from differential incentives that may result from state plan implementation. These safeguards include placing restrictions on interstate trading when there could be a risk of such differential incentives. Additionally, the nature of the CO_2 emission performance rates and state rate-based CO_2 goals helps to minimize these potential effects, as does the MWh-accounting method for adjusting the CO_2 emission rates of affected EGUs under rate-based plans.

However, without a better understanding of the different mechanisms that states may ultimately choose to meet the emission guidelines, and how different requirements in different states may interact, the EPA cannot project every potential differential incentive that could lead to a loss of CO_2 emission reductions. Therefore, once program implementation begins, the EPA will assess how emission performance across states may be affected by the interaction of different regulatory structures implemented through state plans. Based upon that evaluation, the

EPA will determine whether there are potential concerns and what course of action may be appropriate to remedy such concerns.

c. Emission budget trading programs that ensure achievement of a state CO_2 goal. A mass-based emission budget trading program can be designed such that compliance by affected EGUs will achieve the state mass-based CO_2 goal. Under this approach, a state plan would establish CO_2 emission budgets for affected EGUs during the interim and final plan performance periods that are equal to or lower than the applicable state mass-based CO_2 goals specified in section VII. A mass-based emission budget trading program can also be designed such that compliance by affected EGUs in conjunction with new fossil fuel-fired EGUs meeting applicable requirements under state law will achieve a mass-based CO_2 goal plus new source CO_2 emission complement. Under this approach, a state would establish CO_2 emission budgets under state law for affected EGUs plus new sources during the interim and final plan performance periods that are equal to or lower than the applicable state mass-based CO_2 emission goal plus the new source CO_2 emission complement specified in Table 14 in section VIII.J.2.b above, and describe such emission budgets in the supporting documentation of the state plan. Under either program, compliance periods for affected EGUs (or for affected EGUs plus new fossil fuel-fired EGUs meeting applicable requirements under state law) would also be aligned with the interim and final plan performance periods. This approach would limit total CO_2 emissions from affected EGUs (or total CO_2 emissions from affected EGUs and new fossil fuel-fired EGUs meeting applicable requirements under state law) during the interim and final plan performance periods to an amount equal to or less than the state's mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement).

Under this approach, compliance by affected EGUs with the mass-based emission standards in a plan would ensure that the state achieves its mass-based CO_2 goal for affected EGUs (or mass-based CO_2 goal plus new source CO_2 emission complement). No further demonstration would be necessary by the state to demonstrate that its plan would achieve the state's mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement).

For this type of plan, where the emission budget is equal to or less than the state mass CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement),[919] the EPA would assess achievement of the state goal based on compliance by affected EGUs with the mass-based emission standards, rather than reported CO_2 emissions by affected EGUs during the interim plan

[919] As specified for the interim plan performance period (including specified levels in interim steps 1 through 3) and the final two-year plan performance periods.

performance periods and final plan performance periods. This approach would allow for allowance banking between performance periods, including the interim and final performance periods outlined in this final rule.

Banking provisions have been used extensively in rate-based environmental programs and mass-based emission budget trading programs. This is because banking reduces the cost of attaining the requirements of the regulation. The EPA has determined that the same rationale and outcomes apply under a CO_2 emission rate approach, in that allowing banking will reduce compliance costs. Banking encourages additional emission reductions in the near-term if economic to meet a long-term emission rate constraint, which is beneficial due to social preferences for environmental improvements sooner rather than later. It is also beneficial when addressing pollutants that are long-lived in the atmosphere, such as CO_2, and where increasing atmospheric concentration of the pollutant leads to increasing adverse atmospheric impacts.

Banking also provides long-term economic signals to affected emission sources and other market participants where actions taken today will have economic value in helping meet tighter emission constraints in the future, provided those emission sources expect that the banked ERCs or emission allowances may be used for compliance in the future. Linking short-term and long-term economic incentives, which allows owners or operators of affected EGUs and other market participants to assess both short-term and long-term incentives when making decisions about compliance approaches or emission reduction investments, reduces long-term compliance costs for affected EGUs and ratepayer impacts. In addition, the increased temporal flexibility provided by banking would further help address potential electric reliability concerns, as banked ERCs can be used to meet emission standard requirements for an affected EGU.

d. Addressing emission budget trading programs with broader source coverage and other flexibility features. As described in section VIII.C above, under the emission standards plan type, a mass-based emission budget trading program with broader source coverage and other flexibility features may be designed such that compliance by affected EGUs (or compliance by affected EGUs plus new fossil fuel-fired EGUs meeting applicable requirements under state law) would assure achievement of the applicable state mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement).[920]

However, emission budget trading programs, including those

[920] Section VIII.J.2.a describes how state plan submittals must include as requirements, or describe as part of supporting documentation, relevant aspects of such emission budget trading programs.

currently implemented by California and the RGGI participating states, include a number of different design elements that functionally expand the emission budget under certain circumstances. If a state chose, it could apply such mass-based emission standards, in the form of an emission budget trading program that differs in design from that outlined in section VIII.J.2.c above. These types of emission budget trading programs must be submitted as a part of a state measures plan type. Where an emission budget trading program addresses affected EGUs and other fossil fuel-fired EGUs, the requirements that must be included in the state plan are the federally enforceable emission standards in the state plan that apply specifically to affected EGUs, and the requirements that specifically require affected EGUs to participate in and comply with the requirements of the emission budget trading program. This includes the requirement for an affected EGU to surrender emission allowances equal to reported CO_2 emissions, and meet monitoring and reporting requirements for CO_2 emissions, among other requirements. These requirements may be submitted as part of the federally enforceable state plan through mechanisms with the appropriate legal authority and effect, such as state regulations, relevant Title V permit requirements for affected EGUs, and other possible instruments that impose these requirements specifically with respect to affected EGUs.[921] Under this approach, the full set of regulations establishing the emission budget trading program that applies to affected EGUs and other fossil fuel-fired EGUs and other mission sources (if relevant) must be described as supporting documentation in the state plan submittal. This structure is appropriate to ensure that states with an emission budget trading program that addresses both affected EGUs and other fossil fuel-fired EGUs do not inappropriately submit requirements regarding entities other than affected EGUs for inclusion in the federally enforceable state plan.

Such state programs could include a number of different design elements. This includes broader program scope, where a program includes other emission sources beyond affected EGUs subject to CAA section 111(d) and new fossil fuel-fired EGUs, such as industrial sources. Programs might also include design elements that make allowances available in addition to the established emission budget. This includes project-based offset allowances or credits from GHG emission reduction projects outside the covered sector and cost containment reserve

[921] This approach for establishing federally enforceable emission standards based on requirements for affected EGUs subject to a broader emission budget trading program that also covers non-affected emission sources is addressed in section VIII.J.2.d. above.

provisions that make additional allowances available at specified allowance prices.[922]

In the case where an emission budget trading program contains elements that functionally expand the emission budget in certain circumstances, compliance by affected EGUs with the mass-based emission standards would not necessarily ensure that CO_2 emissions from affected EGUs do not exceed the state's mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement). However, states could modify such programs to remove flexibility mechanisms that functionally expand the emission budget, such as out-of-sector offsets and certain cost containment reserve mechanisms, and submit the program under an emission standards plan type.

Where a state chooses to retain such flexibility mechanisms as part of an emission budget trading program, the program may only be implemented as part of a state measures plan type because these state flexibility mechanisms would not assure CO_2 emissions from affected EGUs do not exceed the state's mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2

[922] For example, both the California and RGGI programs allow for the use of allowances awarded to GHG offset projects to be used to meet a specified portion of an affected emission source's compliance obligation. The RGGI program contains a cost containment allowance reserve that makes available additional allowances up to a certain amount, at specified allowance price triggers.

emission complement). A description of the state measures plan type and related requirements is provided in section VIII.C.3.

Under this type of approach, the state would be required to include a demonstration,[923] in its state plan submittal, of how its plan would achieve the state mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement). This demonstration would include a projection of the total CO_2 emissions from the fleet of affected EGUs that would occur as a result of compliance with the emission standards in the plan. Section VIII.D.2 discusses how such demonstrations could address design elements of emission budget trading programs with broader scope and additional compliance flexibility mechanisms, such as those included in the California and RGGI programs. Once the plan is implemented, if the mass-based CO_2 goal is not achieved during a plan performance period, the backstop federally enforceable emission standards included in the state plan that apply to affected EGUs would be implemented, as described in section VIII.C.3.b.[924]

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[923] A demonstration of how a plan will achieve a state's rate-based or mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement) is one of the required plan components, as described in section VIII.D.2.

[924] Achievement of the state mass-based CO_2 goal would be determined based solely on stack CO_2 emissions from affected EGUs. Where a state program includes the ability of an affected emission source to use GHG offsets to meet a portion of its allowance compliance obligation, no "credit" is applied to

e. Considerations for mass-based emission budget trading programs. The EPA notes that while an emission budget trading program included in an emission standards plan must be designed to achieve a state mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement), states have wide discretion in the design of such programs, provided the emission standards included in the plan are quantifiable, verifiable, enforceable, non-duplicative, and permanent.

(1) Allowance allocation. A key example is state discretion in the CO_2 allowance allocation methods included in the program.[925] This includes the methods used to distribute CO_2 allowances and the parties to which allowances are distributed. For example, if a state chose, it could include CO_2 allowance allocation provisions that provide incentives for certain types of complementary activities, such as RE generation, that help achieve the overall CO_2 emission limit for affected EGUs established under the program. In addition, a state could use its allocation provisions to encourage investments in RE and

reported CO_2 emissions by the affected EGU. The use of offset allowances or credits in such programs merely allows an affected EGU to emit a ton of CO_2 in the amount of submitted offset allowances or credits. In all cases, there is no adjustment applied to reported stack emissions of CO_2 from an affected EGU when determining compliance with its emission limit.

[925] Allowance allocation refers to the methods used to distribute CO_2 allowances to the owners or operators of affected EGUs and/or other market participants.

demand-side EE in low-income communities. States could also use CO_2 allowance allocation provisions to provide incentives for early action, such as RE generation or demand-side EE savings that occur prior to the beginning of the interim plan performance period in 2022. For example, a state could include CO_2 allowance allocation provisions where CO_2 allowances are distributed to RE generators based on MWh of RE generation that occurs prior to 2022. Such provisions might be addressed through a finite set-aside of CO_2 allowances that are available for allocation under these provisions. This set-aside could be additional to a set-aside created by the state for the CEIP discussed in section VIII.B.2.

(2) Facility-level compliance. If a state chose, it could evaluate compliance (i.e., allowance true-up) under its emission budget trading program at the facility level, rather than at the individual unit level. The EPA has adopted facility-level compliance in the emission budget-trading programs it administers, including the Acid Rain Program (70 FR 25162), Clean Air Interstate Rule (70 FR 25162), and Cross-State Air Pollution Rule (76 FR 48208). Under this approach, states would still track reported unit-level CO_2 emissions – while evaluating compliance at the facility level – allowing them to track increases and decreases of CO_2 emissions at individual EGUs.

3. Multi-state coordination: mass-based emission trading

programs.

An individual state may provide for the use of CO_2 allowances issued by another state(s) for compliance with the mass-based emission standards in its plan. This type of state plan would include regulatory provisions that enable affected EGUs to use allowances issued in other states for compliance under the state's emission budget trading program. This type of state plan must also indicate how CO_2 allowances will be tracked from issuance through use for compliance, through either a joint tracking system, interoperable tracking systems, or use of an EPA-administered tracking system.[926]

Two different implementation approaches could be used to create such links. A state could submit a "ready-for-interstate-trading" plan using an EPA-approved tracking system, but the plan would not identify links with other states. A state could also submit a plan with specified bilateral or multilateral links that explicitly identify partner states.

Interstate allowance linkages would not affect the approvability of each state's individual plan. However,

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[926] The emission standards in each individual state plan must include regulatory provisions that address the issuance of CO_2 allowances and tracking of CO_2 allowances from issuance through use for compliance. The description here addresses how those regulatory provisions will be implemented through the use of a joint tracking system, interoperable tracking systems, or an EPA-administered tracking system.

different considerations apply for the approvability of an individual plan with such links, based on whether the emission budget trading program in the plan applies only to affected EGUs or includes other emission sources, and if the plan is designed to meet a state mass-based CO_2 goal for affected EGUs only or to meet a mass-based CO_2 goal plus a new source CO_2 emission complement).

Under the first "ready-for-interstate-trading" implementation approach, a state would indicate in its state plan that its emission budget trading program will be administered using an EPA-approved (or EPA-administered) emission and allowance tracking system.[927] State plans using a specified EPA-approved tracking system would be deemed by the EPA as ready for interstate linkage upon approval of the state plan. No additional EPA approval would be necessary for states to link their emission budget trading programs, and affected EGUs in those states could engage in interstate trading subsequent to EPA plan approval.

A state would indicate in its plan submittal that its emission budget trading system will use a specified EPA-approved

[927] The EPA would designate tracking systems that it has determined adequately address the integrity elements necessary for the issuance and tracking of emission allowances. Under this approach, a state could include in its plan such a designated tracking system, which has already been reviewed by the EPA.

tracking system. The state would also indicate in the regulatory provisions for its emission budget trading program that it would recognize as usable for compliance any emission allowance issued by any other state with an EPA-approved state plan that also uses the specified EPA-approved tracking system.

States could also adopt such a collaborative emission trading approach over time (through appropriate state plan revisions if the plan is not already structured as ready-for-interstate-trading), without requiring all of the original participating states to revise their EPA-approved plans.

Under the second implementation approach, a state could specify the other states from which it would recognize issued emission allowances as usable for compliance with its emission budget trading program. The state would indicate in the regulatory provisions for its emission budget trading program that emission allowances issued in other identified partner states may be used by affected EGUs for compliance. Such plans must indicate how allowances will be tracked from issuance through use for compliance, through either a joint tracking system, interoperable tracking systems, or EPA-administered tracking system. The EPA would assess the design and functionality of this tracking system(s) when reviewing individual submitted state plans.

Under this approach, states could also join such a collaborative emission trading approach over time. However, all participating states would need to revise their EPA-approved plans. If the expanded linkage is among previously approved plans with mass-based emission standards, approval of the plan revision would be limited to assessing the functionality of the shared tracking system or interoperable tracking systems in order to maintain the integrity of the linked programs.[928]

a. Considerations for linked emission budget trading programs. For individually submitted plans, interstate emission allowance linkages would not affect the approvability of each state's plan. However, approvability of an individual linked plan would differ based on the structure of the emission budget trading program included in the plan. These differences for plan approvability address distinctions among programs that include only affected EGUs and programs that cover a broader set of emission sources, as well as if the plan is designed to meet a state mass-based CO_2 goal for affected EGUs only or to meet a mass-based CO_2 goal plus a new source CO_2 emission complement. Differences in approval criteria are necessary to ensure that each individual state plan demonstrates it will achieve a

[928] Depending on the specific regulatory provisions in the emission standards in their approved state plans, participating states may also need to revise their implementing regulations (and by extension their state plans) to accept CO_2 emission allowances issued by new partner states as usable for compliance with their mass-based emission standards.

state's mass-based CO_2 emission goal for affected EGUs (or mass-based CO_2 goal plus new source CO_2 emission complement). The accounting applied to individual plans to assess whether a state achieves its mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement) will also differ, based on whether an emission budget trading program includes only affected EGUs (or affected EGUs and applicable new fossil fuel-fired EGUs) or a broader set of emission sources. These considerations are addressed below, for both types of emission budget trading programs.

(1) <u>Links among emission budget trading programs that only include affected EGUs</u> or affected EGUs and applicable new fossil fuel-fired EGUs. Where the emission budget trading programs in each plan apply only to affected EGUs subject to the final rule (or emission budget trading programs that apply to affected EGUs under the state plan and applicable new fossil fuel-fired EGUs under state law), and include compliance timeframes for affected EGUs that align with the interim and final plan performance periods, both plans would functionally be meeting an aggregated multi-state mass-based goal (or aggregated mass-based CO2 goal plus new source CO2 emission complement), but without formally aggregating the goal (or aggregated mass-based CO2 goal plus new source CO2 emission complement). CO2 emissions from affected EGUs in both states could not exceed the total combined CO2

emission budgets under the emission standards in the two states. A net "import" of CO2 allowances from one state would mean that allowable CO2 emissions in the other net "exporting" state are less than that state's established emission budget. On a multi-state basis, CO2 emissions from affected EGUs could not exceed the sum of the states' emission budgets.

Under this approach, if the emission budget for the mass-based emission standard in each plan is equal to or lower than the state's mass-based CO_2 goal (or aggregated mass-based CO_2 goal plus new source CO_2 emission complement, if applicable), compliance by affected EGUs with the mass emission standard in a state[929] would ensure that cumulatively the mass CO_2 goals (or mass-based CO_2 goals plus new source CO_2 emission complements) of the linked states are achieved. As a result, achievement of an individual state's mass CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement) would be assessed by the EPA based on compliance by affected EGUs with the mass-based emission standards in the state plan, rather than reported CO_2 emissions by affected EGUs in the state.[930]

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[929] Compliance by an affected EGU with the emission standard is demonstrated based on surrender to the state of a number of CO_2 allowances equal to its reported CO_2 emissions.
[930] This approach is warranted because under such linked programs, CO_2 emissions from affected EGUs in one state that exceed a state's mass CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement) would be accompanied by CO_2

The same accounting approach will apply for such plans in all cases, even if the state is linked to another state emission budget trading program that includes a broader set of emission sources (e.g., sources beyond affected EGUs, or beyond affected EGUs plus applicable new fossil fuel-fired EGUs), as described below. In all cases, where a state plan includes an emission budget trading program that applies only to affected EGUs (or beyond affected EGUs plus applicable new fossil fuel-fired EGUs), and includes compliance timeframes that align with plan performance periods, achievement of a state mass CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement) will be assessed by the EPA based on whether affected EGUs comply with the mass-based emission standard, rather than reported CO_2 emissions from affected EGUs.

(2) <u>Links with emission budget trading programs that include a broader set of emission sources</u>. State plans may involve emission budget trading programs that include affected EGUs, applicable new fossil fuel-fired EGUs if a plan includes a new source CO_2 emission complement, and other non-affected emission sources.[931]

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emissions from affected EGUs in another linked state that are below that state's mass CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement).

[931] This may apply under both an emission standards plan and a state measures plan. Section VIII.J.2.a describes how state plan

Generally, such plans must demonstrate that the mass-based CO_2 goal for affected EGUs (or mass-based CO_2 goal plus new source CO_2 emission complement) in a state will be achieved, as a result of implementation of the emission budget trading program.[932] Where a program includes other non-affected emission sources (i.e., non-affected emission sources that are not subject to a new source CO_2 emission complement) and is linked with other programs,[933] the state plan submittal must include a demonstration that the mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement) will be achieved, considering the emission allowance links with other programs. The EPA, in determining the approvability of each state's plan under this approach, would evaluate the linkages between plans. Specifically, the EPA would evaluate whether the linkages would

submissions must include as requirements, or describe as part of supporting documentation, relevant aspects of such emission budget trading programs.

932 Under a program that applies to affected EGUs and other emission sources, compliance by affected EGUs with the emission standard – a requirement to surrender emission allowances equal to reported emissions – will not assure that a state's CO_2 mass goal (or mass-based CO_2 goal plus new source CO_2 emission complement) is achieved. As a result, a further demonstration is required in the plan that compliance by affected EGUs with the program will result in CO_2 emissions from affected EGUs that are at or below a state's CO_2 mass goal (or mass-based CO_2 goal plus new source CO_2 emission complement).

933 Section VIII.J.2.a describes how state plan submittals must include as requirements, or describe as part of supporting documentation, relevant aspects of such emission budget trading programs.

enable the affected EGUs (or affected EGUs in conjunction with applicable new fossil fuel-fired EGUs) in each participating state to meet the state's applicable mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement).

During plan implementation, the EPA would assess whether the affected EGUs in a state achieved the state's mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement) as follows. Reported CO_2 emissions from affected EGUs under such plans must be at or below a state's mass-based CO_2 emission goal (or mass-based CO_2 goal plus new source CO_2 emission complement) during an identified plan performance period, with the following state accounting adjustments for net "import" and net "export" of CO_2 allowances:

- <u>Net "imports" of CO_2 allowances</u>: Reported CO_2 emissions from affected EGUs in a state may exceed the state CO_2 mass goal (or mass-based CO_2 goal plus new source CO_2 emission complement) during an identified plan performance period in the amount of an adjustment for the net "imported" CO_2 allowances during the plan performance period. The adjustment represents the CO_2 emissions (in tons) equal to the number of net "imported" CO_2 allowances.[934] Under this adjustment, such allowances must be issued by a state with

[934] Net "imports" and "exports" of CO_2 allowances are defined and explained below.

an emission budget trading program that only applies to affected EGUs (or affected EGUs plus applicable new fossil fuel-fired EGUs). Net "imports" of allowances are determined through review of tracking system compliance accounts.

- <u>Net "exports" of CO_2 allowances</u>: Reported CO_2 emissions from affected EGUs in a state during an identified plan performance period must be equal to or less than the CO_2 mass goal (or mass-based CO_2 goal plus new source CO_2 emission complement) minus an adjustment for the "exported" CO_2 allowances during the plan performance period. The adjustment represents CO_2 emissions (in tons) equal to the number of net "exported" CO_2 allowances. Net "exports" of allowances are determined through review of tracking system compliance accounts.

Where CO_2 emissions from affected EGUs exceed these levels (based on reported CO_2 emissions with applied plus or minus adjustments for net CO_2 allowance "imports" or "exports") over the 8-year interim period or during any final plan reporting period, or by 10 percent or more during the interim step 1 or step 2 periods, a state would be considered to, in the case of the interim and final periods, not have met its CO_2 mass goal during an identified plan performance period, and in the case of the interim step periods, to not be on course to meet the final goal. As a result, under a state measures state plan, implementation of the backstop federally enforceable emission standards for affected EGUs in the state plan would be triggered.

A net transfer of CO_2 allowances during a plan performance period represents the net number of CO_2 allowances (issued by a respective state) that are transferred from the compliance accounts of affected EGUs in that state to the compliance accounts of affected EGUs in another state.[935] This net transfer is determined based on compliance account holdings at the end of the plan performance period.[936] For example, assume two states, State A and State B, with emission budgets of 1,000 tons of CO_2.

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[935] A net transfer metric is applied as of the end of the plan performance period. This net accounting as of a specified date is necessary because multiple individual allowance transfers may occur among accounts during a plan performance period, representing normal trading activity. In addition, net transfers are based on compliance account holdings, because these represent the CO_2 allowances directly available at that point in time for use by an affected EGU for complying with its emission limit. Emission budget trading programs typically allow non-affected entities to hold allowances in general accounts. These parties are free to hold and trade CO_2 allowances, providing market liquidity. General account holdings are not assessed as part of a periodic state net transfer accounting, as these allowances may subsequently be transferred to other accounts in multiple states and do not represent allowances currently held by an affected EGU that can be used for complying with its emission limit.

[936] Compliance account holdings, as used here, refer to the number of CO_2 allowances surrendered for compliance during a plan performance period, as well as any remaining CO_2 allowances held in a compliance account as of the end of a plan performance period.

Each state issues 1,000 CO_2 allowances. At the end of a plan performance period, affected EGUs in State A collectively hold 500 CO_2 allowances in their compliance accounts that were issued by State A. Affected EGUs in State B collectively hold in their compliance accounts 500 CO_2 allowances issued by State A and 1,000 CO_2 allowances issued by State B. In this simplified example, a net transfer of 500 CO_2 allowances has occurred between State A and State B. State A has "exported" 500 CO_2 allowances to State B, while State B has "imported" 500 CO_2 allowances from state A.

K. Additional Considerations and Requirements for Rate-Based State Plans

This section discusses considerations and requirements for rate-based state plans. This section discusses eligibility, accounting, and quantification and verification requirements (EM&V) for the use of CO_2 emission reduction measures that provide substitute generation for affected EGUs or avoid the need for generation from affected EGUs in rate-based state plans. These measures may be used to adjust the CO_2 emission rate of an affected EGU under a rate-based state plan. This adjustment may occur when an affected EGU is demonstrating compliance with a rate-based emission standard, or when a state is demonstrating achievement of the CO_2 emission performance rates or applicable rate-based state CO_2 emission goal in the emission guidelines. This section also discusses requirements for state plans that include rate-based emission trading programs, including approaches and requirements for coordination among such programs where states retain individual state rate-based CO_2 emission goals.

1. Adjustments to CO_2 emission rates in rate-based state plans

Section VIII.K.1.a below describes the basic accounting method for adjusting a CO_2 emission rate, as well as eligibility requirements for measures that may be used for adjusting a CO_2 emission rate. Section VIII.K.1.b addresses measures that may not be used to adjust the CO_2 emission rate of an affected EGU in a state plan, and explains the basis for this exclusion. Section VIII.K.1.c addresses measures that reduce CO_2 emissions outside the electric power sector. Such measures may not be counted under either a rate-based or mass-based state plan.

a. <u>Measures taken to adjust the CO_2 emission rate of an affected EGU</u>. This section describes how measures that substitute for generation from affected EGUs or avoid the need for generation from affected EGUs may be used in a state plan to adjust the CO_2 emission rate of an affected EGU. This section discusses the required accounting method for adjusting a CO_2 emission rate, as well as general eligibility requirements that apply to different categories of measures that may be used to adjust a CO_2 emission rate. Where relevant, this section also discusses additional specific accounting methods and other relevant requirements that apply to different categories of measures.

A CO_2 emission rate adjustment may be applied in different rate-based state plan contexts. For example, in a rate-based emission trading program, adjustments may be applied through the use of ERCs.[937] Regardless of the type of plan in which an adjustment is applied, the same basic accounting and general eligibility requirements described in this section will apply.

As discussed in this section, a wide range of actions may be taken to adjust the reported CO_2 emission rate of an affected EGU in order to meet a rate-based emission standard and/or demonstrate achievement of a state CO_2 rate-based emissions goal. All of the measures described in this section will substitute for generation from affected EGUs or avoid the need for generation from affected EGUs, thereby reducing CO_2 emissions. This includes RE measures included in the EPA's determination of the BSER, as well as other measures that were not included in the determination of the BSER, such as other RE resources, demand-side EE, CHP, WHP, electricity transmission and

[937] ERCs may be issued for the measures presented in this section, as well as to affected EGUs that emit at a CO_2 emission rate below their assigned emission rate limit. ERC issuance and trading is discussed in detail in section VIII.K.2. That section addresses the accounting method for ERC issuance to affected EGUs that perform below their assigned CO_2 emission rate.

distribution improvements, nuclear energy, and international RE imports connected to the grid in the contiguous U.S., as discussed elsewhere in this preamble.

The EPA believes that the broad categories of measures listed in this section address the wide range of actions that are available to reduce CO_2 emissions from affected EGUs under a rate-based state plan. However, the actions that a state could include in a rate-based state plan are not necessarily limited to those described in this section. Other specific actions not listed here may be incorporated in a state plan, provided they meet the general eligibility requirements listed in this section, as well as the other relevant requirements in the emission guidelines.[938] Nor are states required to include in their plans all of the actions that are described in this section.

This section discusses the basic accounting method for adjusting the reported CO_2 emission rate of an affected EGU, through the use of measures that substitute for or avoid generation from affected EGUs. That method is based on adding MWh from such measures to the denominator of an affected EGU's reported CO_2 emission rate (lb CO_2/MWh). Those additional MWh are based on quantified and verified electricity generation or

[938] These requirements are discussed in section VIII.D.

electricity savings from eligible measures, and in the case of an affected EGU's compliance with its emission standard, are reflected in ERCs. This section also addresses eligibility requirements for resources that are used to adjust an affected EGU's CO_2 emission rate.

(1) General accounting approach for adjusting a CO_2 emission rate.

In this final rule, the reported CO_2 emission rate of an affected EGU may be adjusted based on quantified and verified MWh from qualifying zero-emitting and low-emitting resources, as described in sections VIII.K.1.a.(2)-(10) below. These MWh are added to the denominator of an affected EGU's reported CO_2 emission rate, resulting in a lower adjusted CO_2 emission rate.

The measures described in these sections reduce mass CO_2 emissions from affected EGUs by substituting zero- or low-emitting generation for generation from affected EGUs, or by avoiding the need for generation altogether (in the case of resources that lower electricity demand through improved demand-side EE and DSM). In both of these cases, generation from an affected EGU is replaced, through substitute generation or a reduction in electricity demand. To the extent that qualifying zero-emitting and low-emitting resources result in reduced generation and CO_2 emissions from an individual affected EGU, those emission impacts are reflected in lower reported CO_2

emissions and a reduction in MWh generation from the affected EGU. However, while there will be a reduction in CO_2 emissions at the affected EGU, the fact that both CO_2 emissions and MWh generation are reduced means that such impacts do not alter the reported CO_2 emission rate of the affected EGU. As a result, the MWh of replacement generation must be added to the denominator of the reported CO_2 emission rate in order to represent those impacts in the form of an adjusted CO_2 emission rate. In this manner, adding MWh from these resources to the denominator of an affected EGU's CO_2 emission rate allows mass CO_2 emission reductions from these measures to be fully reflected in an adjusted CO_2 emission rate.

The following provides a simple calculation example of how MWh of replacement generation added to the denominator of an affected EGU's reported CO_2 emission rate results in a lower adjusted CO_2 emission rate. Assume an affected EGU with CO_2 emissions of 200,000 lb and electric generation of 100 MWh during a reporting period. The affected EGU's reported CO_2 emission rate is 2,000 lb/MWh (200,000 lb CO_2/100 MWh = 2,000 lb/MWh). When complying with its rate-based emission limit, the affected EGU submits 10 ERCs, representing 10 MWh of replacement generation.[939] Adding 10 MWh of replacement generation to the reported MWh generation of the affected EGU results in an adjusted CO_2 emission rate of 1,818 lb CO_2/MWh (200,000 lb CO_2/110 MWh = 1,818 lb CO_2/MWh).

In the case of rate-based CO_2 emission standards, an affected EGU demonstrates compliance with the emission standards if the affected EGU's adjusted CO_2 emission rate calculated in the aforementioned manner is less than or equal to the applicable CO_2 emission standard rate.[940] The CO_2 emission performance rates or rate-based CO_2 goal in the emission guidelines are met if the adjusted CO_2 emission rate of affected EGUs in a state is at or below the specified CO_2 emission rate in a state plan that applies for an identified plan performance period.

Numerous commenters requested that the EPA ensure consistency between goal-setting calculations and the methodology used to demonstrate achievement of a CO_2 emission rate under a state plan. This approach for adjusting a CO_2 emission rate corresponds with how RE, the one component of the BSER that involves adjustment of a CO_2 emission rate, is

[939] Requirements for the issuance of ERCs and a further discussion of how ERCs are used in compliance with rate-based emission limits are addressed in section VIII.K.2.

[940] Any ERCs used to adjust a CO_2 emission rate must meet requirements in the emission guidelines.

represented in the CO_2 emission performance rates in the emission guidelines. Specifically, in the calculation of final CO_2 emission performance rates, the MWhs of RE are reflected in two adjustments of the rate: a reduction of CO_2 emissions from affected EGUs in the numerator and a one-to-one replacement of affected EGU generation in the denominator, where it is assumed that replaced generation from an affected EGU is subtracted from the denominator and the same number of zero-emitting MWh are added.[941]

When demonstrating achievement of a CO_2 emission performance rate, the reported CO_2 emissions already reflect the actual emission reductions from the deployment of qualifying zero-emitting and low-emitting resources across the regional grid; a further adjustment of CO_2 emissions would double count CO_2 emissions impacts across the grid. Consistent with the EPA's calculation of the CO_2 emission performance rates and state rate-based CO_2 goals in the emission guidelines, the zero-emitting MWhs (from substitute generation or a reduction in electricity demand) must still be added to the denominator of a reported CO_2 emission rate to calculate an adjusted CO_2 emission rate that appropriately reflects the replaced generation. Thus, the resultant rate, where the numerator reflects CO_2 emission

[941] For a detailed discussion of this method, see Section VI.C.3. Form of the Performance Rates, in the Equation section.

reductions from qualifying measures, and the denominator reflects replaced generation, is consistent with the goal-setting calculation.

Several commenters suggested that the EPA consider the regional nature of the electricity grid and how RE and demand-side EE impacts generation and CO_2 emissions across the grid when accounting for the impacts of RE and demand-side EE measures in a rate-based plan approach. This MWh accounting structure corresponds with the regional treatment of RE resources in the BSER that provide substitute generation in the EPA-calculated CO_2 emission performance rates in the emission guidelines. Consistent with assumptions used in calculating the CO_2 emission performance rates in the emission guidelines, affected EGUs and states can take full credit for the MWh resulting from eligible measures they are responsible for deploying, no matter where those measures are implemented. CO_2 emission reductions from the eligible measures may occur across the region; however, an affected EGU or a state may only take credit for avoided CO_2 emissions at that affected EGU or set of EGUs in question, as reflected in the reported stack CO_2 emissions of affected EGUs.

Because of the separate accounting of MWhs and CO_2 emissions, with emission impacts inherent in reported stack CO_2 emissions and zero-emitting MWh impacts requiring explicit adjustments, the accounting method corresponds with the use of

MWh-denominated ERCs in the rate-based emission trading framework specified in this rule. The accounting method only requires a quantification of the MWh generated or avoided by an eligible measure, and thus credits or adjustments can be denominated in MWh and do not need to represent an approximation of the CO_2 emission reductions that result from those MWhs. This creates a crediting system or rate adjustment process that is simpler to implement than one that requires an approximation of avoided CO_2 emissions.

The MWh accounting method also creates a crediting system or rate adjustment process that is indifferent to the rate-based CO_2 emission goals of individual states, or the specific CO_2 emission rate standards that states may apply, and the relative stringency of those goals or standards. Use of ERCs in rate-based emission trading programs is addressed in detail in section VIII.K.2. As a result, the MWh accounting method addresses interstate effects, because it inherently accounts for how generation replacement and CO_2 emission reduction impacts may cross state borders. For example, if the accounting method was informed by avoided CO_2 emission rates, it could create perverse incentives for development of zero- or low-emitting resources in states that result in the greatest calculated estimate of CO_2 emission reductions for each replacement MWh. Instead, this accounting method is indifferent to avoided CO_2 emission rates and creates the same number of zero-emitting credits or adjustment for each MWh of energy generation or savings, wherever they occur. For a detailed discussion on how the accounting method addresses interstate effects, see section VIII.L.

(2) General eligibility requirements for resources used to adjust a CO_2 emission rate.

The EPA is finalizing certain general eligibility requirements for resources used to adjust a CO_2 emission rate. These requirements align eligibility with certain factors and assumptions used in establishing the BSER, and by extension, application of the BSER to the performance levels established for affected EGUs in the emission guidelines, as well as state rate and mass CO_2 goals. As a result, the requirements ensure that measures that may be used in a state plan are treated consistently (to the extent possible) with the EPA's assessment of the BSER.[942] These general requirements also address potential interactions among rate and mass plans, as discussed more fully in section VIII.L.

As discussed in the sections that follow, the general

[942] For example, eligibility requirements include installation dates for eligible RE measures that may be used in a state plan. These dates generally align with the dates used for broadly defining incremental RE resources that were considered in establishing the BSER.

eligibility criteria address:

- the date from which eligible measures may be installed (e.g., installation of RE generating capacity and installation of EE measures);
- the date from which MWh from eligible measures may be counted, and applied toward adjusting a CO_2 rate; and
- the need to demonstrate that eligible measures replace or avoid generation from affected EGUs.

(a) <u>Eligibility date for installation of RE/EE and other measures and MWh generation and savings</u>.

Incremental emission reduction measures, such as RE and demand-side EE, can be recognized as part of state plans, but only for the emission reductions they provide during a plan performance period. Specifically, this means that measures installed in any year after 2012 are considered eligible measures under this final rule, but only the quantified and verified MWh of electricity generation or electricity savings that they produce in 2022 and future years, may be applied toward adjusting a CO_2 emission rate. For example, MWh generation in 2022 from a wind turbine installed in 2013 may be applied toward adjusting a CO_2 emission rate. This 2012 date applies to all eligible measures that are used to adjust a CO_2 emission rate under a state plan. For example, eligible measures, such as CHP, nuclear power and DSM, also must be installed after 2012, but only their generation or savings produced in 2022 and after can be used to adjust a CO_2 emission rate.

As discussed in section VIII.C.2.a, a MWh of generation or savings that occurs in 2022 or a subsequent year may be carried forward (or "banked") and applied in a future year. For example, a MWh of RE generation that occurs in 2022 may be applied to adjust a CO_2 emission rate in 2023 or future years, without limitation.[943] These MWh may be banked from the interim to final periods.

This eligibility date criterion is consistent with the date of installation for "incremental" RE capacity that is included in the BSER building block 3, which is the basis for RE MWh incorporated in the CO_2 emission performance rates for affected EGUs in the emission guidelines. For more information on RE in the BSER, see section V.E.

Many commenters asserted that proposed state goals did not sufficiently account for actions states take that reduce CO_2 emissions prior to the first plan performance period, and therefore requested that MWhs of electricity generation or electricity savings that occur prior to the first plan performance period be eligible to apply toward adjusting the CO_2

[943] Similarly, as discussed in section VIII.C.2.b.(2).(a), allowances may be banked in a mass-based trading program.

emission rates of affected EGUs. The EPA recognizes the importance of early state action as the basis for significant CO_2 emission reductions and as a key part of enabling state plans to achieve the CO_2 emission performance levels or state CO_2 goals. The ability to count eligible measures installed in 2013 and subsequent years for the MWhs they generate during a plan performance period provides significant recognition for early action, corresponding with the BSER framework that is based on cost-effective actions that many sources are already doing, while still conforming to CO_2 performance rates and state goals that are forward-looking. In order to provide additional incentives for early investment in RE and demand-side EE, the EPA is also establishing the CEIP, as discussed in section VIII.B.2. ERCs distributed by states and the EPA through this program may also be used by affected EGUs to demonstrate compliance with an emission standard, and may be banked from the interim to final periods.

Commenters concerns about treatment of early actions are further addressed by changes from proposal to the BSER assumptions and the methodology used by the EPA to establish the CO_2 emission performance levels and rate-based state CO_2 goals in the emission guidelines. The specifics of these changes are addressed in section V.A.3. Three examples of those changes are provided below.

First, affected EGUs that have maximized their CO_2 emission reduction opportunities available through early action will be better positioned to meet the BSER CO_2 emission performance rates or state goal applied to affected EGUs in their state. For example, a steam generating unit that has already reduced its CO_2 emission rate through a heat rate improvement may have a CO_2 emission rate of 2,000 lb/MWh whereas its rate was 2,100 lb/MWh prior to the improvement. Therefore, it has less distance to cover to meet its CO_2 emission performance rate.

Second, generation from existing RE capacity installed prior to 2013 has been excluded from the EPA's calculation of the CO_2 emission performances rates in the emission guidelines. That RE generating capacity will still provide zero-emitting generation to the grid meeting demand that will not need to be addressed by existing affected EGUs and will better position states and affected EGUs to meet the CO_2 performances rates or state rate- or mass-based CO_2 goals.

Third, commenters expressed concern that demand-side EE targets as part of proposed state goals reflected an assumption of installation of increased EE measures starting in 2017, which seemed to be an implicit requirement to take action prior to the performance period. Because demand-side EE is not used in calculating the CO_2 emission performance rates in the final emission guidelines, this is no longer a concern. Furthermore, eligible demand-side EE actions that occur after 2012 can be applied toward adjusting the CO_2 emission rates of affected EGUs, providing a significant compliance option that is not assumed in emission performance rates or state goals.

(b) Demonstration that measures substitute for grid generation.

Eligible measures must be grid-connected. This eligibility criterion aligns with RE generation in building block 3 of the BSER, which substitutes for the need for generation from affected EGUs.

All EE measures must result in electricity savings at a building, facility, or other end-use location that is connected to the electricity grid. EE measures only avoid electric generation from grid-connected EGUs if the electrical loads where the efficiency improvements are made are interconnected to the grid.

Commenters sought clarity on this issue, so the EPA is providing this requirement as part of the final rule. Some commenters advocated for the inclusion of measures that were not grid connected as eligible resources, arguing that some of these measures substituted for non-affected EGUs and resulted in reductions in CO_2 emissions. However, eligible measures must be able to substitute for generation from affected EGUs as defined under this rule, and thus must be tied to the electrical grid.

(c) Geographic eligibility.

All eligible emission reduction measures, including RE generation and demand-side EE, may occur in any state, with certain limitations, as described below. To the extent these measures are tied to a state plan,[944] these measures may be used to adjust a CO_2 emission rate, regardless of whether the associated generation or electricity savings occur inside or outside the state.[945] This approach is generally consistent with the approach used in building block 3 of the BSER, which reflects regionally available RE. It also recognizes that emission reduction measures have impacts on electricity generation across the electricity system, both within and beyond a state's borders. A more in-depth discussion of the basis for treatment of in-state and out-of-state measures is provided in section VIII.L.

State plans must demonstrate that emission standards and

[944] As used here, a measure is "tied to a state plan" if it is issued an ERC under approved procedures in a rate-based emission standards plan or represents quantified and verified MWh energy generation or energy savings achieved by an approved state measure in a state measures plan.

[945] For example, under a rate-based emission standard with credit trading, ERCs may be issued for qualifying actions that occur both inside and outside the state, provided the measures meet requirements of EPA-approved state regulations and the provider applies to the state for the issuance of ERCs. Similarly, under a state measures plan, a state might include state requirements such as an RPS, where compliance with the RPS can be met through out-of-state RE generation.

state measures (if applicable) are non-duplicative. Given the geographic eligibility approach described here, this includes a demonstration that a state plan does not allow recognition of a MWh, for use in adjusting the CO_2 emission rate of an affected EGU, if the MWh is being or has been used for such a purpose under another state plan. Discussion of how such a demonstration can be made in the context of a rate-based emission trading program is in section VIII.D.2.b.

The EPA received many comments on the treatment of in-state and out-of-state RE and demand-side EE. Most commenters recommended crediting of both in-state and out-of-state RE and demand-side EE measures, similar to the final rule approach for eligible emission reductions measures. Commenters argued that this approach makes sense based on the nature of the interconnected electricity grid and allows states and utilities to fully account for their RE and demand-side EE efforts, whether that RE or EE, and its related impacts, occurs inside or outside of their state. Some commenters expressed concerns that, at proposal, states with significant RE resources had large amounts of existing RE capacity included in their state CO_2 goals, but that RE was functionally credited to other states for use in meeting their goals because it was associated with measures (such as an RPS) likely to be included in another state's plan. This concern has been addressed through changes in the BSER RE assumptions in the final rule. This includes regionalization of the RE building block, and removal of existing RE capacity constructed prior to 2012 from the building block. The result of these changes is that the RE incorporated in the BSER is more equally shared across states.

(i) Measures that occur in states with mass-based plans.

As discussed above, eligible measures for adjusting the CO_2 emission rate of an affected EGU may occur in any state, with certain conditions. This includes a condition that applies to eligible measures that occur in a state with an EPA-approved plan that is meeting a state mass-based CO_2 goal. Eligible measures that could be used to adjust a CO_2 emission rate under a rate-based state plan which are located in a state with a mass-based plan are restricted from being counted under another state's rate-based plan. An exception is made for RE measures that occur in such mass-based states, because of its unique role in BSER. RE measures must meet additional eligibility criteria in order to be used to adjust the CO_2 emission rate of an affected EGU in a state with a rate-based plan. This exception only applies to RE; other emission reduction measures that were not included in the determination of the BSER located in mass-based states, including demand-side EE, are restricted from ERC issuance in rate-based states.

These criteria are intended to address the fact that eligible measures should lead to substitution of generation from affected EGUs, with related impacts on CO_2 emissions from affected EGUs. Where states with mass-based plans implement mass-based CO_2 emission standards, CO_2 emissions reductions from affected EGUs must occur in order to comply with these emission standards and, unlike the rate-based approach, zero- and low-emitting MWhs do not play a specified role in demonstrating that the mass-based standards have been met.[946] Since they are not counted in the mass-based demonstration, eligible measures located in mass-based states could be used in a state with a rate-based plan to adjust the CO_2 emission rate of affected EGUs. Such adjustments would obviate the need for comparable CO_2 emission reductions at affected EGUs in the rate-based state or the use of other measures to make a rate adjustment. In this scenario, to the extent that eligible measures substitute solely for generation from affected EGUs in a state with mass-based emission limits, and are also used to adjust the reported CO_2 emission rate of affected EGUs in a rate-based state, no incremental CO_2 emissions reductions would occur in the rate-based state as a result of the eligible measures.[947] The result

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[946] Where such measures substitute for generation from affected EGUs subject to a mass CO_2 emission limit, such measures reduce the cost of meeting those mass emission limits, but do not result in incremental CO_2 emission reductions.
[947] As used here, incremental emission reductions refers to

would be forgone CO_2 emission reductions that would otherwise occur across the two states. These dynamics are further addressed in section VIII.L.

For RE measures located in a mass-based state to have some or all of its generation counted under a rate-based plan in another state, it must be demonstrated that the generation was delivered to the grid to meet electricity load in a state with a rate-based plan.[948] Some examples of documentation that can serve as a demonstration include a power delivery contract or power purchase agreement. The EPA is giving states flexibility regarding the nature of this demonstration, but a state plan must describe the nature of the required demonstration and have it be approved by the EPA.

Under an emission standards plan, this demonstration must be made by the provider of the RE measure seeking ERC issuance under the rate-based emission standards in a rate-based state, as part of the eligibility application for the measure.[949] The rate-based state must include in its state plan provisions that describe a sufficient demonstration of geographic eligibility

emission reductions that are above and beyond what would be achieved solely through compliance with the emission standards in the mass-based state.

[948] This does not need to necessarily be the state where the MWh of energy generation from the measure is used to adjust the CO_2 emission rate of an affected EGU.

[949] Requirements for ERC issuance are addressed in section VIII.K.2.

for the RE generation under rate-based emission standards.

Further examples of eligible demonstrations and how they should be outlined in state plans are provided in section VIII.L.

(ii) Measures that occur in states, including areas of Indian country, that do not have affected EGUs.

States, including areas of Indian country, that do not have any affected EGUs within their borders may be providers of credits for generation from zero- or low-emitting resources to adjust CO_2 emission rates. In its supplemental proposal for the proposed rulemaking, the EPA sought comment on whether or not jurisdictions without affected fossil fuel generation units subject to the proposed emission guidelines should be authorized to participate in state plans. Commenters were supportive of allowing those jurisdictions without affected EGUs the opportunity to participate in state plans. CO_2 reduction measures in areas without affected EGUs have the potential to provide cost-effective opportunities to reduce emissions and should be available on a voluntary basis to affected EGUs. Commenters noted that some tribes, for example, have many untapped RE resources that could be developed, and they should be able to realize the benefits of contributing to a state plan. Commenters stated that because of the integrated nature of the U.S. electricity grid, it is appropriate to allow all jurisdictions with the ability to contribute to and benefit from CO_2 emission reductions or CO_2 emission rate adjustments.

For participating states, they must adhere to EM&V standards, installation dates, and any other criteria that apply to all states. Section VIII.K.3 below identifies and discusses the EM&V requirements used to quantify MWh savings from generation from zero- or low-emitting sources.

States, including areas of Indian country, that do not have any affected EGUs may provide ERCs to adjust CO_2 emissions provided they are connected to the contiguous U.S. grid and meet the other requirements for eligibility. To qualify for ERCs from zero or low-emitting resources, it must be demonstrated that the generation was delivered to the grid to meet electricity load in a state with a rate-based plan.[950] Some examples of documentation that can serve as a demonstration include a power delivery contract or power purchase agreement. The EPA is giving states flexibility regarding the nature of this demonstration, but a state plan must describe the nature of the required demonstration and have it be approved by the EPA.

In addition to generation from zero- or low-emitting resources, demand-side EE resources in areas of Indian country

[950] This does not need to necessarily be the state where the MWh of energy generation from the measure is used to adjust the CO_2 emission rate of an affected EGU.

located within the borders of states with rate-based emission standards for affected EGUs may also be issued ERCs. In these instances, the area of Indian country is located within the rate-based service area subject to a rate-based state plan. The ERCs from demand-side EE resources must meet the eligibility requirements to adjust a CO_2 emission rate, including installation date and EM&V requirements described below in section VIII.K.3. If the area of Indian country is located within the borders of a state that is meeting a mass-based CO_2 goal, then the demand-side EE resources are not eligible to be issued ERCs. Similarly, demand-side EE resources in any state with a mass-based CO_2 goal are not eligible to provide ERCs.

Non-contiguous states and territories may not be providers of ERCs to the contiguous U.S. states. As discussed previously in section VII.F, we have not set CO_2 emission performance goals for Alaska, Hawaii, Guam, or Puerto Rico in this final rule at this time.

(iii) Measures that occur outside the U.S.

The EPA will work with states using the rate-based approach that are interested in allowing the use of RE from outside the U.S. to adjust CO_2 emission rates. In these cases, all conditions for creditable domestic RE must be met, including that RE resources must be incremental and installed after 2012, and all EM&V standards must be met. In addition, the country generating the ERCs must be connected to the U.S. grid, and there must be a power purchase agreement or other contract for delivery of the power with an entity in the U.S. RE generation capacity outside the U.S. that existed prior to 2012 but was not exported to the U.S. is not considered new or incremental generation and, therefore, not eligible for adjusting CO_2 emission rates under this rule. For example, a new transmission interconnection to existing RE in Canada would not be considered incremental, but a new interconnection to RE where the RE was built after 2012 would be considered incremental. See below in section VIII.K.1.a.(3) for more specifics regarding the use of incremental hydroelectric power in a rate-based approach.

The EPA received comments encouraging the use of international zero-emitting electricity imports in state plans, particularly hydroelectric power from Canada. Canada currently provides states such as Minnesota and Wisconsin with RE through existing grid connections. New projects are in various stages of development to increase generating capacity, which could be called upon as a base load resource to supplement variable forms of RE generation. Commenters said that the EPA should permit the use of all incremental hydropower—both domestic and international—towards EGU CO_2 emission rate adjustments providing that double-counting can be prevented; and the EPA acknowledges this may be allowable, as long as the specified criteria have been met.

(3) RE.

RE measures may be used to adjust a CO_2 emission rate, provided they meet the general eligibility requirements outlined above and the MWh electricity generation is properly quantified and verified.[951] As used in this section, RE includes electric generating technologies using RE resources, such as wind, solar, geothermal, hydropower, biomass and wave and tidal power. A capacity uprate at an existing RE facility (i.e., an uprate to generating capacity originally installed as of 2012 or earlier) is eligible to adjust a CO_2 emission rate. The capacity uprate must occur after 2012. Such uprates to capacity represent incremental capacity added after 2012.

Quantification and accounting criteria for incremental RE (and nuclear generation) are as follows. The incremental generating capacity (in nameplate MW) is divided by the total uprated generating capacity (in nameplate MW) and then multiplied by generation output (in MWh) from the uprated generator. For example, if a hydroelectric power plant expands generating nameplate capacity from 100 MW to 125 MW and generation output

[951] All state plans must demonstrate that measures included in the plan are quantifiable and verifiable. See section VIII.K.2 for discussion of requirements for the issuance of ERCs, and section VIII.K.3 for discussion of EM&V requirements for use of RE relied on in a state plan.

increased to 1,000 MWh, then 200 MWh ((25 MW/125 MW) * 1,000 MWh) is eligible for use in adjusting a CO_2 emission rate, regardless of the overall level of generation for the period.[952]

Many commenters supported using RE deployment as measures to adjust the CO_2 emission rate of affected EGUs. Some commenters specifically agreed with the EPA’s determination that only new and incremental RE (including hydropower) should be used to adjust CO_2 emission rates. Those commenters objected to counting existing RE that are already embedded in the baseline emissions and generation mix. A significant number of commenters supported the integration of RE into a rate-based credit trading system.

Certain additional requirements apply for hydropower and biomass (including waste-to-energy) RE, as described below.

(a) Hydroelectric power.

Consistent with other types of RE, new hydroelectric power generating capacity installed after 2012 is eligible for use in adjusting a CO_2 emission rate.

Relicensed facilities are considered existing capacity and, therefore, are not eligible for use in adjusting a CO_2 emission rate, unless there is a capacity uprate as part of the relicensed permit. In such a case, only the incremental capacity

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[952] For example, the overall generation from the uprated hydroelectric power plant may be higher or lower than generation levels that occurred at the plant prior to the capacity uprate.

is eligible for use in adjusting a CO_2 emission rate.

The EPA noted that many commenters preferred that generation from hydropower displace generation from fossil sources. One commenter suggested that existing zero-emitting sources, including hydropower, do not reduce emissions from existing fossil generation, but that new or uprated zero-emitting sources would, because of their low variable rate, reduce fossil emissions. Several commenters recommended allowing incremental generation from new or uprated zero-emitting sources, including hydropower, be available for compliance.

(b) Biomass.

RE generating capacity installed after 2012 that uses qualified biomass as a fuel source is eligible for use in adjusting a CO_2 emission rate.[953] As discussed in section VIII.I.2.c., if a state intends to allow for the use of biomass as a compliance option for an affected EGU to meet a CO_2 emission standard, a state must propose qualified biomass feedstocks and treatment of biogenic CO_2 emissions in its plan, along with supporting analysis and quality control measures, and the EPA will review the appropriateness and basis for such determinations in the course of its review of a state plan. Where an RE generating unit uses qualified biomass, as

[953] As with other RE, only generating capacity installed after 2012 would be eligible for use in adjusting a CO_2 emission rate.

designated in an approved state plan, MWh generation from the unit could be used to adjust the reported CO_2 emission rate of an affected EGU. Total MWh generation from an RE generating unit that uses qualified biomass must be prorated based on either the heat input supplied from qualified biomass as a proportion of total heat input or on the proportion of biogenic CO_2 emissions compared to total stack CO_2 emissions from the RE generating unit. Either approach must incorporate the approved valuation of biogenic CO_2 emissions from qualified biomass in the plan (i.e., the proportion of biogenic CO_2 emissions from use of qualified biomass feedstock that would not be counted)

Section VIII.K describes the requirements and procedures for EM&V, and discusses how all eligible resources must demonstrate how they will quantify and verify MWh savings using best-practice EM&V approaches. One way to make this demonstration for eligible resources could be to use the presumptively approvable EM&V approaches that are included in the final model trading rule.

(c) Waste-to-energy.

Qualified biomass may include the biogenic portion of MSW combusted in a waste-to-energy facility.[954] With regard to assessing qualified biomass proposed in state plans, the EPA

[954] As with other RE, only generating capacity installed after 2012 would be eligible for use in adjusting a CO_2 emission rate.

generally acknowledges the CO_2 emissions and climate policy benefits of waste-derived biomass, which includes biogenic MSW inputs to waste-to-energy facilities. The process and considerations for the use of biomass in state plans are discussed in section VIII.I.2.c.

MSW can be directly combusted in waste-to-energy facilities to generate electricity as an alternative to landfill disposal. In the U.S., almost all incineration of MSW occurs at waste-to-energy facilities or industrial facilities where the waste is combusted and energy is recovered.[955] Total MSW generation in 2012 was 251 million tons, but of that total volume generated, almost 87 million tons were recycled and composted.[956] Increasing demand for electricity generated from waste-to-energy facilities could increase competition for and generation of waste stream materials - including discarded organic waste materials – which could work against programs promoting waste reduction or cause diversion of these materials from existing or future efforts promoting composting and recycling. The EPA and many states have recognized the importance of integrated waste materials management strategies that emphasize a hierarchy of waste

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[955] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012. http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html.

[956] http://www.epa.gov/osw/nonhaz/municipal/pubs/2012_msw_fs.pdf.

prevention, starting with waste reduction programs as the highest priority and then focusing on all other productive uses of waste materials to reduce the volume of disposed waste materials.[957] For example, Oregon and Vermont have strategies that emphasize waste prevention, followed by reuse, then recycling and composting materials prior to treatment and disposal.[958]

Information in the revised *Framework for Assessing Biogenic CO_2 Emissions from Stationary Sources* and other technical studies and tools (e.g., EPA Waste Reduction Model, EPA Decision Support Tool) should assist both states and the EPA in assessing the role of biogenic feedstocks used in waste-to-energy processes, where use of such feedstocks is included in a state plan.[959]

When developing their plans, states planning to use waste-to-energy as an option for the adjustment of a CO_2 emission rate should assess both their capacity to strengthen existing or implement new waste reduction, reuse, recycling and composting programs, and measures to minimize any potential negative impacts of waste-to-energy operations on such programs. States must include that information in their plan submissions. The EPA

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[957] http://www.epa.gov/wastes/nonhaz/municipal/hierarchy.htm.

[958] http://www.anr.state.vt.us/dec/wastediv/WastePrevention/main.htm.

[959] http://epa.gov/epawaste/conserve/tools/warm/Warm_Form.html, https://mswdst.rti.org/.

will reject as qualified biomass any proposed waste-to-energy component of state plans if states do not include information on their efforts to strengthen existing or implement new waste reduction as well as reuse, recycling and composting programs, and measures to minimize any potential negative impacts of waste-to-energy operations on such programs. Only electric generation at a waste-to-energy facility that is related to the biogenic fraction of MSW and that is added after 2012 is eligible for use in adjusting a CO_2 emission rate.

A state plan must include a method for determining the proportion of total MWh generation from a waste-to-energy facility that is eligible for use in adjusting a CO_2 emission rate. The EPA will evaluate the method as part of its evaluation of the approvability of the state plan. Measuring the proportion of biogenic to fossil CO_2 emissions can be performed through sampling and testing of the biogenic fraction of the MSW used as fuel at a waste-to-energy facility (e.g., via ASTM D-6866-06 testing or other methods - ASTM, 2006; Bohar, et al. 2010), or based on the proportion of biogenic CO_2 emissions to total CO_2 emissions from the facility. For an example of the former method, if the biogenic fraction of MSW is 50 percent by input weight, only the proportion of MWh output attributable to the biogenic portion of MSW at the waste-to-energy facility may be used to adjust an affected EGU CO_2 emission rate. Alternatively, as an example of the latter method, if biogenic CO_2 emissions represent 50 percent of total reported CO_2 emissions, a facility would need to estimate the fraction of biogenic to fossil MSW utilized and the net energy output of each component (based on relative higher heating values) to determine the percent of the MWh output from the waste-to-energy facility that may be used to adjust an affected EGU's CO_2 emission rate. Section VIII.K describes the requirements and procedures for EM&V, and discusses how all eligible resources must demonstrate how they will quantify and verify MWh savings using best-practice EM&V approaches. One way to make this demonstration for eligible resources could be to use the presumptively approvable EM&V approaches that are included in the final model trading rule.

The EPA received multiple comments supporting the use of waste-to-energy as part of state plans. Some commenters expressed concern that non-biogenic materials, such as plastics and metal, would be incinerated along with biogenic materials. As discussed above, only electric generation related to the biogenic fraction of MSW at a waste-to-energy facility added after 2012 is eligible for use in adjusting a CO_2 emission rate. The EPA also received comments that expressed concern about the potential negative impacts on recycling and waste reduction efforts, while other commenters asserted that waste-to-energy practices encourage recycling programs. Some commenters also expressed concern about what treatment would be approvable for emissions from waste-to-energy practices. As discussed above, potential negative impacts from waste-to-energy production on recycling, waste reduction, and composting programs should be evaluated and efforts to mitigate negative impacts must be discussed in the supporting documentation of state plans.

(4) DSM.

Avoided MWh that result from DSM may be used to adjust a CO_2 emission rate. Eligible DSM actions are those that are zero-emitting and avoid, rather than shift, the use of electricity by an electricity end-user.[960] The MWh that may be used for such an adjustment are determined based on the MW of demand reduction multiplied by the hours during which such a demand reduction is achieved (MW of demand reduction x hours = MWh avoided). DSM measures must be appropriately quantified and verified, in accordance with requirements in the emission guidelines, as discussed in section VIII.K.3.

(5) Energy storage.

Energy storage may not be directly recognized as an

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[960] An example is a utility direct load control program, such as those where customer air conditioning units are cycled during periods of peak electricity demand. Actions that shift electricity demand from one time of day to another, without reducing net electricity use, are not eligible, as these measures do not avoid electricity use from the grid. Use of emitting generators as a DSM measure is also not eligible.

eligible measure that can be used to adjust a CO_2 emission rate, because storage does not directly substitute for electric generation from the grid or avoid electricity use from the grid.[961] The electric generation that is input to an energy storage unit may be used to adjust a CO_2 emission rate, but the output from the energy storage unit may not.[962] However, energy storage can be used as an enabling measure that facilitates greater use of RE, which can be used to adjust a CO_2 emission rate. For example, utility scale energy storage may be used to facilitate greater grid penetration of RE generating capacity and can also be used to store RE generation that may have otherwise been shed in times of excess generating capacity. Likewise, on-site energy storage at an electricity end-user can enable greater use of RE to meet on-site electricity demand.[963]

The EPA received multiple comments regarding the overall merits of energy storage. Consistent with the discussion above,

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[961] Energy storage depends on a generation source, either from a utility-scale EGU (e.g., a fossil EGU, a wind turbine, etc.) or a distributed generation source at an electricity end-user (e.g., a PV system installed at a building).

[962] This approach focuses on counting the qualifying electric generation, which may be an input to an energy storage unit. Counting both the generation input to energy storage and the output from the energy storage unit would be a form of double counting. The electric generation that is stored may be counted; the subsequent output from the storage unit may not.

[963] For example, battery storage at a building with solar PV can enable the PV system to meet the building's entire electrical load, by storing energy during times of peak PV system output for later use when the sun is not shining.

the majority of commenters observed that storage technology enables greater grid penetration of RE and supports more efficient and effective operations of both RE and fossil-fuel plants. Commenters further noted that energy storage can provide RE to the grid when it is most needed, while simultaneously taking pressure off fossil-fuel plants to respond to sudden shifts in demand. Despite broad acknowledgment of the benefits of storage, public comments underscore its indirect and supporting role in providing zero-emission MWh to the grid (consistent with the EPA's decision to exclude energy storage as an eligible measure that can be used to adjust a CO_2 emission rate).

(6) Transmission and distribution (T&D) measures.

Electricity T&D measures that improve the efficiency of the T&D system and/or reduce electricity use may be used to adjust a CO_2 emission rate. This includes T&D measures that reduce losses of electricity during delivery from a generator to an end-user (sometimes referred to as "line losses"[964]) and T&D measures that

[964] T&D system losses (or "line losses") are typically defined as the difference between electricity generation to the grid and electricity sales. These losses are the fraction of electricity lost to resistance along the T&D lines, which varies depending on the specific conductors, the current, and the length of the lines. The Energy Information Administration (EIA) estimates that national electricity T&D losses average about 6 percent of the electricity that is transmitted and distributed in the U.S. each year.

reduce electricity use at the end-user, such as conservation voltage reduction (CVR).[965] The EPA received many comments in support of advanced energy technologies, including energy storage and transmission and distribution upgrades, and including these technologies in the suite of potential measures that states could consider for emission rate adjustments in their state plans. Comments pointed out that in addition to helping achieve emission standards, T&D efficiency improvements make the grid more robust and flexible, as well as delivering environmental benefits. In many parts of the country, grid operators, transmission planners, transmission owners and regulators are already taking steps to expand and modernize T&D networks. Commenters suggested that the EPA clarify the eligibility and criteria under which such measures would be permitted in a state plan.

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[965] Volt/VAR optimization (VVO) refers to coordinated efforts by utilities to manage and improve the delivery of power in order to increase the efficiency of electricity distribution. VVO is accomplished primarily through the implementation of smart grid technologies that improve the real-time response to the demand for power. Technologies for VVO include load tap changers and voltage regulators, which can help manage voltage levels, as well as capacitor banks that achieve reductions in transmission line loss. VVO efforts are often closely related to CVR, which are actions taken to reduce initial delivered voltage levels in feeder transmission lines while remaining within the 114 volt to 126 volt range (for normal 120-volt service) required at the customer meter, per the ANSI C84.1 standards.

To be eligible, T&D measures must be installed after 2012. This general eligibility requirement is discussed above in section VIII.K.1.a. The MWh of avoided losses or reduction in end-use that result from T&D measures must be appropriately quantified and verified, as discussed in section VIII.K.3.

(7) Demand-side EE, including water system efficiency.

Demand-side EE measures may be used to adjust a CO_2 emission rate, provided they meet the general eligibility requirements outlined above and the MWh electricity savings are properly quantified and verified.[966] As used in this section, demand-side EE may include a range of eligible measures, provided that the measures can be quantified and verified in accordance with the EM&V requirements in the emission guidelines, which are addressed in section VIII.K.3. Examples of demand-side EE measures include, but are not limited to, EE measures that reduce electricity use in residential and commercial buildings, industrial facilities, and other grid-connected equipment. Water efficiency programs that improve EE at water and wastewater treatment facilities also provide demand-side EE savings opportunities. EE measures, for the purposes of this section,

[966] All state plans must demonstrate that measures included in the plan are quantifiable and verifiable. See section VIII.K.2 for discussion of requirements for the issuance of ERCs, and section VIII.K.3 for discussion of EM&V requirements for use of demand-side EE relied on in a state plan.

may consist of EE measures installed as the result of individual EE projects, such as those implemented by energy service companies, as well as multiple EE measures installed through an EE deployment program (e.g. appliance replacement and recycling programs, and behavioral programs) administered by electric utilities, state entities, and other private and non-profit entities.[967] EE measures, for the purposes of this section, may also consist of state or local requirements that result in electricity savings, such as building energy codes and state appliance and equipment standards. Other interventions that result in electricity savings may also be considered an EE measure for the purposes of this section, provided the intervention can be specified and quantified and verified in accordance with EM&V requirements in the emission guidelines.

Numerous commenters expressed support for including demand-side EE as an eligible measure states and affected EGUs can use to meet the emission guidelines. Commenters touted the value of demand-side EE as a resource that delivers energy savings, lowers bills, creates jobs and reduces CO_2 emissions. Commenters called for the EPA to allow for the use of a broad range of demand-side EE measures to meet the emission guidelines,

[967] EE programs may also be implemented by other entities. Eligible EE measures that are deployed through EE programs are not limited to those EE measures deployed through EE programs administered by the types of entities listed here.

including, but not limited to, utility and non-utility EE deployment programs; energy savings performance contracts; measures that reduce electricity use in residential and commercial buildings, industrial facilities and other grid-connected equipment; state and local requirements that result in electricity savings, such as building energy codes and state appliance and equipment standards; appliance replacement and recycling programs; and behavioral programs. The EPA also received comments supporting the use of water sector EE programs and projects. Commenters identified water and wastewater utilities as particularly well-suited for participating in EE programs and providing a source of electricity savings. Investments such as replacing pumps and other aging equipment and repairing leaks can result in greater EE. The EPA agrees that these electricity savings should be eligible for adjustments to CO_2 emission rates at affected EGUs.

(8) Nuclear power.

As is discussed in section V.A.3, upon consideration of comments received, the EPA has not included nuclear generation from either existing or under construction units in the determination of the BSER. In addition to comments received on the provisions for determining the BSER, the EPA also received comments requesting that the EPA allow all generation from nuclear generating units to be recognized as an eligible measure that can be used to adjust a CO_2 emission rate. Commenters also recommended that the EPA consider nuclear generating units and RE generating units in a consistent manner for CO_2 emission rate adjustments in state plans. We agree with comments that nuclear generation and RE should be treated consistently when it comes to CO_2 emission rate adjustments.

The EPA has determined that generation from new nuclear units and capacity uprates at existing nuclear units will be eligible for use in adjusting a CO_2 emission rate, just like new and uprated capacity RE. However, consistent with the reasons discussed for not including the preservation of existing nuclear capacity in the BSER – namely, that such preservation does not actually reduce existing levels of CO_2 emissions from affected EGUs – preserving generation from existing nuclear capacity is not eligible for use in adjusting a CO_2 emission rate.

In contrast, any incremental zero-emitting generation from new nuclear capacity would be expected to replace generation from affected EGUs and, thereby, reduce CO_2 emissions; and the continued commitment of the owner/operators to completion of the new units and improving the efficiency of existing units through uprates can play a key role in state plans. Therefore, consistent with treatment of other low- and zero-emitting generation, new nuclear power generating capacity installed after 2012 and incremental generation resulting from nuclear uprates after 2012 are measures eligible for adjusting a CO_2 emission rate. However, existing nuclear units (i.e., those that originally commenced operation in 2012 or earlier years) that receive operating license extensions are not eligible for use in adjusting a CO_2 emission rate, except where such units receive a capacity uprate as a result of the relicensing process. Only the incremental capacity from the uprate is eligible for use to adjust a CO_2 emission rate.

Applicable generation (in MWh) from incremental nuclear power is determined in the same manner as that described for incremental RE above.

(9) Combined heat and power (CHP) units.

Electric generation from non-affected CHP units[968] may be used to adjust the CO_2 emission rate of an affected EGU, as CHP units are low-emitting electric generating resources that can replace generation from affected EGUs. Electrical generation from non-affected CHP units that meet the eligibility criteria

[968] The accounting considerations described in this section are for a "topping cycle" CHP unit. A topping cycle CHP unit refers to a configuration where fuel is first used to generate electricity and then heat is recovered from the electric generation process to provide additional useful thermal and/or mechanical energy. A CHP unit can also be configured as a "bottoming cycle" unit. In a bottoming cycle CHP unit, fuel is first used to provide thermal energy for an industrial process and the waste heat from that process is then used to generate electricity. Some waste heat power (WHP) units are also bottoming cycle units and the accounting treatment for bottoming cycle CHP units is provided with the WHP description below.

under section VIII.K.1.a can be used to adjust the reported CO_2 emission rate of an affected EGU.

Where a state plan provides for the use of electrical generation from eligible non-affected CHP units to adjust the reported CO_2 emission rate of an affected EGU, the state plan must provide a required calculation method for determining the MWh that may be used to adjust the CO_2 emission rate. This proposed accounting method must adequately address the considerations discussed below. The EPA will review whether a state's proposed accounting method for electric generation from eligible non-affected CHP units is approvable per the requirements of the final emission guidelines, as part of its overall plan review of the rate-based emission standards and implementing and enforcing measures in the state plan. The EPA notes that the proposed model rule for a rate-based emission trading program includes a proposed accounting method for non-affected CHP units. The accounting method provided in a final model rule could be a presumptively approvable accounting approach.

The proposed accounting method in a state plan must address the following considerations. The accounting approach proposed in a state plan must take into account the fact that a non-affected CHP unit is a fossil fuel-fired emission source, as well as the fact that the incremental CO_2 emissions related to electrical generation from a non-affected CHP unit are typically very low. In accordance with these considerations, a non-affected CHP unit's electrical MWh output that can be used to adjust the reported CO_2 emission rate of an affected EGU should be prorated based on the CO_2 emission rate of the electrical output associated with the CHP unit (a CHP unit's "incremental CO_2 emission rate") compared to a reference CO_2 emission rate. This "incremental CO_2 emission rate" related to the electric generation from the CHP unit would be relative to the applicable CO_2 emission rate for affected EGUs in the state and would be limited to a value between 0 and 1.

This low CO_2 emission rate for electrical generation from a non-affected CHP unit is a product of both the fact that CHP units are typically very thermally efficient and the fact that a portion of the CO_2 emissions from a non-affected CHP unit would have occurred anyway from an industrial boiler used to meet the thermal load in the absence of the CHP unit. In contrast, the CHP unit also provides the benefit of electricity generation while resulting in very low incremental CO_2 emissions beyond what would have been emitted by an industrial boiler. As a result, the accounting method proposed in a state plan should not presume that CO_2 emission reductions occur outside the electric power sector, but instead only would account for the CO_2 emissions related to the electrical production from a CHP unit that is used to substitute for electrical generation from affected EGUs.

Non-affected CHP units can use qualified biomass fuels. As described in section VIII.I.2.c, states must submit state plan requirements regarding qualified biomass feedstocks and treatment of biogenic CO_2 emissions in state plans, along with supporting analysis and quality control measures, and the EPA would review the appropriateness and basis for such determinations in the course of its review of the approvability of a state plan. Considerations for qualified biomass included in state plans are discussed in section VIII.I.2.c, while accounting requirements for RE using biomass are provided in section VIII.K.1.a.(3)(b).

Most comments received on CHP recommended that the EPA explicitly describe how CHP can be accounted for in a state plan. Commenters described the CO_2 emission reductions achieved through CHP's thermal efficiency and the precedent set in other federal and state rules that have included CHP as a compliance option. Some commenters pointed out that without such a description, states would not be able to readily take advantage of the CO_2 emission reductions that result from the use of CHP.

(10) WHP.

WHP units that meet the eligibility criteria under section VIII.K.1 may be used to adjust the CO_2 emission rate of an affected EGU. There are several types of WHP units. There are units, also referred to as bottoming cycle CHP units, where the fuel is first used to provide thermal energy for an industrial process and the waste heat from that process is then used to generate electricity.[969] There are also WHP facilities where the waste heat from the initial combustion process is used to generate additional power. Under both configurations, unless the WHP unit supplements waste heat with fossil fuel use, there is no additional fossil fuel used to generate this additional power. As a result, there are no incremental CO_2 emissions associated with that additional power generation. As a result, the incremental electric generation output from the WHP facilities could be considered zero-emitting, for the purposes of meeting the emission guidelines, and the MWh of electrical output could be used to adjust the CO_2 emission rate of an affected EGU.[970] The MWh of electrical output from a WHP unit that can be recognized may not exceed the MWh of industrial or

[969] In such a configuration, the waste heat stream could also be generated from a mechanical process, such as at natural gas pipeline compressors.
[970] This only applies where no additional fossil fuel is used to supplement the use of waste heat in a WHP facility. Where fossil fuel is used to supplement waste heat in a WHP application, MWh of electrical generation that can be used to adjust the CO_2 emission rate of an affected EGU must be prorated based on the proportion of fossil fuel heat input to total heat input that is used by the WHP unit to generate electricity.

other thermal load that is being met by the WHP unit, prior to the generation of electricity.[971] Most commenters that addressed WHP noted the benefits of WHP at the same time that they discussed the benefits of CHP. The commenters reflected that WHP is another potential compliance option and requested it be discussed explicitly as a compliance option that can be used to meet the emission guidelines. The comments discussed WHP benefits but did not elaborate on a preferred accounting method for MWh of electrical generation from WHP that could be used to adjust the CO_2 emission rate of an affected EGU.

b. Measures that may not be used to adjust a CO_2 emission rate. This section addresses measures that may not be used to adjust a CO_2 emission rate. New, modified, and reconstructed EGUs covered under the CAA section 111(b) final Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units rule are not approvable sources of electric generation for adjusting the CO_2 emission rate of an affected EGU under a rate-based state plan. As discussed earlier in section VII.D of this preamble, a key concern under this rule is leakage to new units that are not covered by the emission guidelines. Emissions leakage, or increased CO_2 emissions due to

[971] This limitation prevents oversizing the thermal output of a WHP unit to exceed the useful industrial or other thermal load it is meeting, prior to generation of electricity.

increased utilization of unaffected sources, is contradictory to objectives of this rule and should, therefore, be minimized. Allowing affected EGUs to adjust their emission rates as a result of lower-emitting new NGCC units not covered under this section 111(d) rule would not mitigate leakage concerns, and could even exacerbate the situation. Consequently, new EGUs covered under the CAA section 111(b) rule are not allowable measures in state plans because the EPA believes it would result in increased emission leakage.

The EPA received comments both supporting and opposing the use of new NGCC units in state plans. In addition to leakage concerns, commenters expressed concern with the potential incentives created by including new NGCC capacity in the BSER or as a compliance mechanism in state plans. Some commenters suggested that including new NGCC capacity in the BSER or for compliance would distort market incentives to build new NGCC units, particularly if new units were allowed to generate ERCs that could be sold to affected EGUs. These commenters suggested that the additional incentive for new NGCC units could make existing NGCC units less competitive. Other commenters suggested that including new NGCC capacity in state plans would promote generation from new CO_2-emitting units at the expense of new zero-emitting units, increasing overall emissions within a state. This effect would be exacerbated if state plans allowed new NGCC units to be treated as "zero-emitting" for purposes of compliance -- as suggested by other commenters. In addition, commenters expressed concern that the EPA's inclusion of new NGCC capacity in setting the BSER or in compliance could negatively impact ratepayers over the long-term by sending the wrong signal to industry and resulting in stranded assets if, in the future, carbon emissions become more expensive or the EPA proposes to incorporate sources built under the forthcoming section 111(b) standard into the section 111(d) program. Commenters also expressed concern that including generation from new NGCC units could create unreasonable uncertainty, given limitations on the ability to accurately project new NGCC builds, could create undue pressure on natural gas prices, and could create unfair disparities in the compliance opportunities afforded different states. In light of the emissions leakage concerns, and in consideration of these comments, the EPA is not allowing shifting generation to new NGCC units to be used as a measure for adjusting CO_2 emission rates for affected EGUs in rate-based state plans.

In addition, other new and existing non-affected fossil fuel-fired EGUs that are not subject to CAA section 111(b) or 111(d), such as simple cycle combustion turbines, may not be used to adjust the CO_2 emission rate of an affected EGU. While generation from such units could substitute for generation from affected EGUs, the EPA has determined that additional incentives for such generation, in the form of an explicit adjustment to the CO_2 rate of an affected EGU, are not necessary or warranted. Providing for such an adjustment could create perverse incentives for the construction of new simple cycle combustion turbines that are not subject to the applicability criteria of the final Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units rule. These units could provide only limited adjustment credit, as operation beyond a certain capacity factor threshold would trigger applicability under CAA section 111(b). Further, providing for the ability to generate adjustment credits would provide incentives for construction of less efficient fossil generating capacity than would likely otherwise be constructed (e.g., addition of a simple cycle combustion turbine rather than a NGCC unit). In addition, providing for the ability to generate adjustment credits could create perverse incentives for the continued operation of less efficient existing fossil generating capacity. Such outcomes run counter to the objectives of this final rule.

c. Measures that reduce CO_2 emissions outside the electric power sector. Measures that reduce CO_2 emissions outside the electric power sector may not be counted toward meeting a CO_2 emission performance level for affected EGUs or a state CO_2 goal, under either a rate-based or mass-based approach, because all of the emission reduction measures included in the EPA's determination of the BSER reduce CO_2 emissions from affected EGUs. Examples of measures that may not be counted toward meeting a CO_2 emission performance level for affected EGUs or a state CO_2 goal include GHG offset projects representing emission reductions that occur in the forestry and agriculture sectors,[972] direct air capture, and crediting of CO_2 emission reductions that occur in the transportation sector as a result of vehicle electrification.

2. Requirements for rate-based emission trading approaches

As made clear in the proposal,[973] all emission standards in a state plan must be quantifiable, verifiable, enforceable, non-duplicative and permanent.[974] This requirement is applicable to emission standards that include a rate-based emission trading program. The State Plan Considerations TSD for the proposal also explained that in order to ensure a plan is enforceable, a state plan must: identify in its plan the entity or entities

[972] We note, however, that the final emission guidelines allow state measures like emission budget trading programs to include out-of-sector GHG offsets. For example, both the California and RGGI programs allow for the use of allowances awarded to GHG offset projects to be used to meet a specified portion of an affected emission source's compliance obligation. The RGGI program contains a cost containment allowance reserve that makes available additional allowances up to a certain amount, at specified allowance price triggers.
[973] 79 FR 34830, 34913.
[974] These requirements are described in detail in section VIII.D.2.

responsible for meeting compliance and other enforceable obligations under the plan; include mechanisms for demonstrating compliance with plan requirements or demonstrating that other binding obligations are met; and provide a mechanism(s) for legal action if affected EGUs are not in compliance with plan requirements or if other entities fail to meet enforceable plan obligations. A state plan using a rate-based emission trading approach must therefore include rate-based emission standards for affected EGUs along with related implementation and compliance requirements and mechanisms.[975] These related requirements include those applicable to rate-based emission standards more broadly: CO_2 emission monitoring, reporting, and recordkeeping requirements for affected EGUs, including requirements for monitoring and reporting of useful energy output. By satisfactorily addressing these requirements, state plans including a rate-based emission trading program will be able to meet the statutory requirements of CAA section 111(d) regarding the need for state plans to provide for the implementation and enforcement of emission standards, as well as meet the requirement that each emission standard be quantifiable, verifiable, non-duplicative, permanent, and

[975] As described below, these requirements would likely be provided in a state plan in the form of state regulations, but could potentially be provided in another form.

enforceable with respect to each affected EGU.

The EPA also specifically proposed that for state plans that rely on measures that avoid EGU CO_2 emissions, such as RE and demand-side EE measures, the state will also need to include quantification, monitoring, and verification provisions in its plan for these measures. The EPA is finalizing requirements specific to rate-based emission trading programs as requirements the EPA has determined are necessary to assure the integrity of a rate-based approach that includes an emission trading program, and therefore assures a state plan using such an approach appropriately provides for the implementation and enforcement of rate-based emission standards in accordance with CAA section 111(d).[976] These specific requirements for a rate-based emission trading program include provisions for issuance of ERCs by the state and/or its designated agent; provisions for tracking ERCs, from issuance through submission for compliance; and the administrative process for submission of ERCs by the owner or operator of an affected EGU to the state, in order to adjust its reported CO_2 emission rate when demonstrating compliance with a

[976] By "integrity of a rate-based emission trading program", the EPA is referring to elements in the design and administration of a program necessary to assure that emission standards implemented using a rate-based emission trading approach are quantifiable, verifiable, enforceable, non-duplicative, and permanent.

rate-based emission standard.[977] These requirements must be submitted for inclusion in the federally enforceable plan, per the statutory requirement that states provide for the implementation and enforcement of emission standards. A rate-based trading program would provide for the implementation and enforcement of rate-based emission standards for a state plan that allows its affected EGUs to adjust a rate by the use of an ERC.

The EPA will review a state plan submittal including a rate-based emission trading program to assure that the plan contains the requirements necessary to assure the integrity of a rate-based approach, and therefore provide for the implementation and enforcement of rate-based emission standards. These requirements are discussed in more detail in this section.

The EPA also notes it is proposing model rules for both mass-based and rate-based emission trading programs. State plans that include the finalized model rule for a rate-based emission trading program could be presumptively approvable as meeting the requirements of CAA section 111(d) and these emission guidelines. The EPA would evaluate the approvability of such plans through independent notice and comment rulemaking.

A state may issue ERCs to an affected EGU that performs at

[977] See section VIII.K.1 for a discussion of the accounting method used to adjust a CO_2 emission rate.

a CO_2 emission rate below a specified CO_2 emission rate, as well as to providers of qualifying measures that provide substitute generation for affected EGUs or avoid the need for generation from affected EGUs. This latter category includes providers of qualifying RE and demand-side EE measures, as well as other types of measures, as discussed in section VIII.K.1.a.[978]

ERCs may be used by an affected EGU to adjust its reported CO_2 emission rate when demonstrating compliance with a rate-based emission standard. This adjustment is made by adding MWh to the denominator of an affected EGU's reported CO_2 emission rate, in the amount of submitted ERCs, resulting in a lower adjusted rate. To demonstrate compliance with a rate-based emission standard, an affected EGU would report its CO_2 lb/MWh emission rate to the state regulatory body, and would also surrender to the state any ERCs it wishes to use to adjust its reported emission rate. The state regulator would then cancel the submitted ERCs. The affected EGU would add the MWh the ERCs represent to the denominator of its reported CO_2 lb/MWh emission

[978] As used in this section, the term "EE program" refers to an EE deployment program. An EE program involves deployment of multiple EE measures or EE projects, such as utility- or state-administered EE incentive programs that accelerate the deployment of EE technologies and practices. As used in this section, the term "EE/RE project" refers to a discrete EE project (e.g., an EE upgrade to a commercial building or set of buildings) or a RE generator (e.g., a single wind turbine or group of turbines).

rate to demonstrate compliance with its emission standard. The state regulator could facilitate its evaluation of the affected EGU's compliance (as well as evaluation by the affected EGU, the EPA, and others) by providing functionality in its tracking system to run such compliance calculations. If the affected EGU's adjusted CO_2 emission rate is equal to or lower than its applicable emission rate standard, the affected EGU would be in compliance.

a. Issuance of ERCs to affected EGUs. ERCs may be issued to affected EGUs that emit below a specified CO_2 emission rate, as discussed below. For issuance of ERCs to affected EGUs, the state plan must specify the accounting method and administrative process for ERC issuance. This includes the calculation method for determining the number of ERCs to be issued to an affected EGU, based on reported CO_2 emissions and MWh energy output, in comparison to a reference CO_2 emission rate. The reference rate is a specified CO_2 lb/MWh emission rate that an affected EGU's reported CO_2 emission rate is compared to, when determining the amount of ERCs that may be issued to an affected EGU.

Following determination of the number of ERCs an affected EGU is eligible to receive, based on an affected EGU's reported CO_2 emission rate compared to a specified reference rate, the state regulatory body would issue those ERCs into a tracking system account held by the owner or operator of the affected

EGU. Tracking system requirements are addressed below at section VIII.K.2.c.

The accounting method that may be applied in a state plan differs depending on whether a state plan includes a single rate-based emission standard that applies to all affected EGUs (e.g., if a plan is designed to meet a state rate-based CO_2 goal) or separate rate-based emission standards that apply to subcategories of affected EGUs, namely fossil fuel-fired electric utility steam generating units and stationary combustion turbines. In both cases, ERCs are issued in MWh, based on the difference between an affected EGU's reported CO_2 emission rate (in CO_2 lb/MWh) and a specified CO_2 lb/MWh emission rate that the reported rate is compared to (referred to as a "reference rate"). The reference rate may be an affected EGU's assigned CO_2 emission limit rate or another CO_2 emission rate, as described below. Where an affected EGU's reported CO_2 emission rate is lower than the specified reference CO_2 emission rate, ERCs may be issued.

Where a state plan includes emission standards in the form of a single rate-based emission standard that applies to all affected EGUs, the reference rate is the CO_2 emission rate limit for affected EGUs. In this instance, ERCs may be issued based on an affected EGU's reported CO_2 emission rate as a proportion of the emission limit rate. For example, if the emission rate limit is 2,000 lb CO_2/MWh and the affected EGU emits at a rate of 1,000 lb CO_2/MWh, 0.5 MWh would be awarded for every MWh generated by the affected EGU. ERCs would be issued to affected EGUs in whole MWh increments. The calculation method is as follows:

ERCs[979] = reported MWh by affected EGU[980] x ((CO_2 emission rate limit for affected EGUs[981] – affected EGU reported CO_2 emission rate[982])/ CO_2 emission rate limit for affected EGUs)

For the example above, the calculation is as follows:

ERCs = MWh reported x (2,000 – 1,000)/2,000 = MWh reported x 0.5

If the affected EGU in this example generated 1,000,000 MWh, 500,000 ERCs would be issued.

Where a state plan includes separate emission standards for subcategories of affected EGUs, specifically affected fossil fuel-fired electric utility steam generating units and stationary combustion turbines, the reference rate differs for affected fossil fuel-fired electric utility steam generating units and stationary combustion turbines. Additionally, if the state plan applies emission standards for its affected EGUs that

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[979] For all calculations in this section, where the result is a negative value, no ERCs would be issued.

[980] This term represents the reported MWh by the affected EGU on an annual basis.

[981] This term represents the "reference rate."

[982] This term represents the annual reported CO_2 emission rate of the affected EGU.

are equal to the subcategorized CO_2 emission performance rates there is a unique opportunity for the adjustment of an affected EGU's emission rate using ERCs that are generated as a result of building block 2 incremental NGCC unit operation. The EPA is requiring state plans to account for incremental NGCC generation in ERC generation if a state plan applies the subcategorized CO_2 emission performance rates to its affected EGUs as emission standards. Additionally, the EPA is requiring that a NGCC unit is not able to use ERCs generated by it or any other NGCC unit's building block 2 incremental generation.

For affected steam generating units, the reference CO_2 emission rate is the assigned CO_2 emission rate limit for steam generating units, and the following accounting method for generating ERCs applies:

ERCs[983] = reported MWh x ((steam generating unit CO_2 emission rate limit[984] – steam generating unit reported CO_2 emission rate)/ steam generating unit CO_2 emission rate limit).

For an affected NGCC stationary combustion turbine in a subcategorized rate-based emission trading program, the following equation provides a required accounting method for

[983] For all calculations in this section, where the result is a negative value, no ERCs would be issued.
[984] The "reference rate."

generating ERCs based on operation with respect to the NGCC unit's emission standard:

ERCs = NGCC unit's reported MWh x ((NGCC unit's CO_2 emission standard[985] – NGCC unit's reported CO_2 emission rate)/ NGCC unit's CO_2 emission standard)

According to this equation, ERC issuance is assessed based on the difference between the CO_2 emission rate standard for the NGCC unit[986] and the reported CO_2 emission rate of the affected NGCC unit. In other words, affected NGCC stationary combustion turbines earn ERCs for generation when they perform at an emission rate better than the reference rate for stationary combustion turbines, similarly to how affected steam units can earn ERCs.

To account for incremental generation for a NGCC stationary combustion turbine to generate ERCs in a subcategorized rate-based emission trading program, a state must use the incremental operation of an affected NGCC unit quantified for building block 2 to allow a NGCC unit to generate ERCs based on its expected incremental generation.

A state plan that provides for the use of ERCs issued based on incremental affected NGCC generation must provide a required

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[985] The "reference rate."
[986] This is the CO_2 emission performance rate for affected stationary combustion turbines in the emission guidelines.

calculation method that allows for issuance of ERCs based on the ability of incremental generation from affected stationary combustion turbines to substitute for generation from affected steam generating units (as represented in building block 2), while also respecting the fact that affected stationary combustion turbines must also meet an assigned CO_2 emission rate limit for the entirety of its MWh energy output. This accounting method must reflect the application of the BSER, as described in section V, and the accounting method must not create incentives to rearrange dispatch between existing NGCC units to generate additional ERCs without changing the overall level of NGCC generation.

The EPA will review whether a state's accounting method is approvable per the requirements of the statute and this final rule as part of its overall plan review of the rate-based emission standards and implementing and enforcing measures in the state plan. The EPA notes that the proposed model rule for a rate-based emission trading program includes a proposed accounting method and takes comments on alternatives. The accounting method provided in a final model rule could be a presumptively approvable approach for issuance of ERCs based on the ability of incremental generation from affected stationary combustion turbines to substitute for generation from affected steam generating units. A state's accounting requirements for generation of ERCs based on incremental affected NGCC generation must maintain consistency with the EPA’s application of the BSER when calculating CO_2 emission performance rates for affected stationary combustion turbine and steam generating units. In particular, a state’s accounting method must maintain consistency of accounting in a state rate-based CO_2 emission standard with the EPA’s application of building block 2 in calculating CO_2 emission performance rates for affected fossil fuel-fired electric utility steam generating units and stationary combustion turbines, which is based on use of incremental generation from affected stationary combustion turbine to replace generation from affected steam generating units.

b. Issuance of ERCs for RE, demand-side EE, and other measures. ERCs may be issued for qualifying measures.[987] For issuance of ERCs for qualifying measures, state plan requirements for ERC issuance must include a two-step process. In the first step of the process, a potential ERC provider submits an eligibility application for a qualifying program or project[988] to the

[987] Qualifying measures that can be used to adjust the CO_2 emission rate of an affected EGU are discussed at section VIII.K.1, and include RE, demand-side EE, and other measures, such as DSM, CHP and incremental nuclear generation.
[988] For example, for an EE/RE program or project, as described in this section for illustrative purposes. The requirements described in this section for EE/RE programs and projects also

administering state regulator (or its agent[989]). The state regulator reviews the application to determine whether, in this example, an EE/RE program or project meets eligibility requirements for the issuance of ERCs.[990] An eligibility application must include a description of the program or project, a projection of the MWh generation or energy savings anticipated over the life of the program or project, and an EM&V plan that meets state plan requirements. The EM&V plan must describe how MWh of RE generation or energy savings resulting from the program or project will be quantified and verified.[991] A

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apply for all other eligible qualifying measures discussed in section VIII.K.1.

[989] As used here, an agent is a party acting on behalf of the state, based on authority vested in it by the state, pursuant to the legal authority of the state. A state could designate an agent to provide certain limited administrative services, or could choose to vest an agent with greater authority. Where an agent issues an ERC on behalf of the state, such issuance would have the same legal effect as issuance of an ERC by the state.

[990] The entity implementing the EE/RE program or project (referred to in the preamble as a "provider") would submit the application. This is the identified entity to which ERCs would ultimately be issued, to a tracking system account held by the entity. Such entities could include a wide variety of parties that implement EE/RE programs and projects, including owners or operators of affected EGUs, electric distribution companies, independent power producers, energy service companies, administrators of state EE programs, and administrators of industrial EE programs, among others.

[991] The verification process includes confirmation that quantified MWh are non-duplicative and permanent (i.e., are not being used in any other state plan to demonstrate compliance with an emission standard or achievement of an emission performance rate or state CO_2 emission goal).

state, in its emission standard regulations, must include requirements for EM&V plans that are consistent with the requirements in the emission guidelines for EE/RE measures and other eligible measures, as discussed in sections VIII.K.1 and VIII.K.3.

The EPA has determined that state requirements for an eligibility application must include review of the application by an independent verifier, approved by the state as eligible per the requirements of the final emission guidelines to provide such verification, prior to submittal. This requirement builds on the approach used for assessing GHG offset projects, both in international emission trading programs and the GHG emission budget trading programs implemented by California and the RGGI participating states.[992] An assessment by an independent verifier would be included as a component of an eligibility application.

The EPA has determined that independent verification requirements are necessary to ensure the integrity of state rate-based emission trading programs included in a state plan, given the wide range of eligible measures that may generate ERCs

[992] Information about the verification process for GHG offsets under the RGGI program, including verifier accreditation requirements and access to relevant documents, is available at http://www.rggi.org/market/offsets/verification. Similar information about the verification process for GHG offsets under the California program is available at http://www.arb.ca.gov/cc/capandtrade/offsets/verification/verification.htm.

and the broad geographic locations in which those measures may occur. Inclusion of an independent verification component provides technical support for state regulatory bodies to ensure that eligibility applications and M&V reports are thoroughly reviewed prior to issuance of ERCs. Inclusion of an independent verification component is also consistent with similar approaches required by state PUCs for the review of demand-side EE program results and GHG offset provisions included in state GHG emission budget trading programs.

State plans with rate-based emission trading programs must include requirements regarding the qualification status of an independent verifier. An independent verifier is a person (including any company, any corporate parent or subsidiary, any contractors or subcontractors, and the actual person) who has the appropriate technical and other qualifications to provide verification reports. The independent verifier must not have, or have had, any direct or indirect financial or other interest in the subject of its verification report or ERCs that could impact its impartiality in performing verification services. State plans must require that a person be approved by the state as an independent verifier, as defined by this final rule, as eligible to perform the verifications required under the approved state plan. State plans must also include a mechanism to temporarily or permanently revoke the qualification status of an independent verifier, such that it can no longer provide verification services related to an eligibility application or M&V report for at least the duration of the period it does not meet the qualification requirements for independent verifiers in an approved state plan. The EPA's proposed model rate-based emission trading rule contains provisions addressing accreditation and conflicts of interest for independent verifiers. State plans that adopt the finalized model rule could be presumptively approvable with respect to these requirements regarding independent verifiers.

The state's eligibility requirements and application procedures must ensure that only eligible actions may generate ERCs and that documentation is submitted only once for each program or project, and to only one state program.[993] These provisions will ensure that actions that are eligible for the issuance of ERCs are "non-duplicative."[994] The tracking system used to administer a state's rate-based emission trading system must provide transparent, electronic, public access to information about program and project eligibility applications, including EM&V plans, and regulatory approval status.

[993] This includes ensuring that multiple parties do not submit an eligibility application for the same EE program or project, or for the same RE generator.

[994] Emission standards must be "non-duplicative" as described in section VIII.D.2.

In the second step of the process, following implementation of the RE/EE program or project (as described in this example) that was approved in step one, the RE/EE provider periodically submits a M&V report to the state regulatory body documenting the results of the program or project in MWh of electric generation or energy savings.[995] These results are quantified according to the EM&V plan that was approved as part of step one. These results are verified by an accredited independent verifier, and its verification assessment must be included as part of the M&V report submitted to the state regulatory body. The administering state regulator (or its agent) then reviews the M&V report, and determines the number of ERCs (if any) that should be issued, based on the report. Finally, the state regulatory body (or its agent) issues ERCs to the provider of the approved program or project. These ERCs are issued to the tracking system account held by the program or project provider.

State plan requirements must ensure that only one ERC is issued for each verified MWh. This is addressed through registration in the tracking system of programs and projects

[995] State rate-based emission trading program regulations must specify the frequency for submission of M&V reports for approved qualified measures that have been deemed eligible to generate ERCs. These reporting periods should be annual, but a state could consider shorter or longer periods, depending on the type of ERC resource.

that have been qualified for the issuance of ERCs, to ensure that documentation is submitted only once for each RE/EE action, and to only one state program.[996] The tracking system must provide transparent electronic public access to submitted M&V reports and regulatory approvals related to such reports.[997] Such reports are the basis for issuance of ERCs.

c. Tracking system requirements. State requirements must include provisions to ensure that ERCs issued to any eligible entity are properly tracked from issuance to submission by affected EGUs for compliance (where ERCs are "surrendered" by the owner or operator of an affected EGU and "retired" or "cancelled" by the administering state regulatory body), to ensure they are only used once to meet a regulatory obligation. This is addressed through specified requirements for tracking system account holders, ERC issuance, ERC transfers among accounts, compliance true-up for affected EGUs,[998] and an accompanying tracking system that meets requirements specified in the emission trading

[996] EE/RE programs and projects, and other eligible measures, with an approved eligibility application would be designated in a tracking system as qualified programs or projects. Qualified programs and projects may be issued ERCs, based on approved M&V reports.

[997] This must include electronic Internet access to such information in the tracking system.

[998] "Compliance true-up" refers to ERC submission by an owner or operator of an affected EGU to adjust a reported CO_2 emission rate, and determination of whether the adjusted rate is equal to or lower than the applicable rate-based emission standard.

program regulations. Each issued ERC must have a unique identifier (e.g., serial number) and the tracking system must provide for traceability of issued ERCs back to the program or project for which they were issued.

The EPA received a number of comments from states and stakeholders about the value of the EPA's support in developing and/or administering tracking systems to support state administration of rate-based emission trading systems. This could include regional systems and/or a national system. The EPA is exploring options for providing such support and is conducting an initial scoping assessment of tracking system support needs and functionality.

d. Effect of improperly issued ERCs. Because the goal of this rulemaking is the actual reduction of CO_2 emissions, it is fundamental that ERCs represent the MWh of energy generation or savings they purport to represent. To this end, only valid ERCs that actually meet the standards articulated in this rule may be used to satisfy any aspect of compliance by an affected EGU with emission standards. Despite safeguards included in the structure of ERC issuance and tracking systems, such as the review of eligibility applications and M&V reports, and state issuance of ERCs, ERCs may be issued that do not, in fact, represent eligible zero-emission MWh as required in the emission guidelines. A variety of situations may result in such improper

ERC issuance, ranging from simple paperwork errors to outright fraud.

An approvable state plan that allows affected EGUs to comply with their emission standards in part through reliance on ERCs must include provisions making clear that an affected EGU may only demonstrate compliance with an ERC that actually represents the one MWh of energy generation or savings that it purports to represent and otherwise meets the emission guidelines.

e. Banking of ERCs. ERCs issued in 2022 or a subsequent year may be carried forward (or "banked") and used for demonstrating compliance in a future year.[999] For example, an ERC issued for a MWh of RE generation that occurs in 2022 may be applied to adjust a CO_2 emission rate in 2023 or future years without limitation. ERCs may be banked from the interim plan performance period to the final plan performance period. Banking provides a number of advantages while ensuring that the same output-weighted average CO_2 emission rates of the interim and final state CO_2 goals are achieved over the course of a state plan.

[999] States also have the option to participate in the CEIP, under which they can issue ERCs for MWh generation or savings that occur in 2020-2021 for measures implemented following submission of a final state plan, and receive matching ERCs from a federal pool. See section VIII.B.2 for a detailed discussion. The ERCs issued under this program can also be banked during and between the interim and final compliance period.

Banking provisions have been used extensively in rate-based environmental programs and mass-based emission budget trading programs.[1000] This is because banking reduces the cost of attaining the requirements of the regulation. The EPA has determined that the same rationale and outcomes apply under a CO_2 emission rate approach, in that allowing banking will reduce compliance costs. Banking encourages additional emission reductions in the near-term if economic to meet a long-term emission rate constraint, which is beneficial due to social preferences for environmental improvements sooner rather than later.[1001] State plans must specify whether the state is allowing or restricting the banking of ERCs between compliance periods for affected EGUs. State plans must also prohibit borrowing of any ERCs from future compliance periods by affected EGUs or eligible resources.

[1000] Banking under mass-based emission budget trading programs, and the rationale for banking provisions, is addressed below in section VIII.J.2.c.

[1001] The absence of banking creates an incentive to defer both relatively low-cost and higher-cost CO_2 emission reduction actions until a later period when emission rate limits become more stringent, rather than incentives to undertake the low-cost activities sooner in order to further delay the high cost actions. Under a rate-based emission trading program, banking will encourage ERC providers to generate larger numbers of ERCs in early years of a plan performance period, in anticipation of rising ERC prices over time, when demand for ERCs is expected to increase as rate-based CO_2 emission standards become more stringent.

f. Considerations for ERC issuance. The EPA notes that state-administered and state-overseen EE programs, such as those administered by state-regulated electric distribution utilities, could play a key role in supplying energy savings to a rate-based emission trading system in the form of ERCs. These programs have been the primary means for delivering EE programs and energy savings at scale, and also allow for a state to conduct a portfolio planning process to guide EE program design and focus in a manner that best provides multiple benefits to electricity ratepayers in a state. Such portfolio planning processes typically treat EE as an energy resource comparable to electricity generation.

The EPA also notes that non-ERC certificates may be issued by states and other bodies for MWh of energy generation and energy savings that are used to meet other state regulatory requirements, such as state RPS and EERS, or by individuals to make environmental or other claims in voluntary markets.

The EPA defines an ERC in the emission guidelines as a tradable compliance instrument that represents a zero-emission MWh (for the purposes of meeting the emission guidelines) from a qualifying measure that may be used to adjust the reported CO_2 emission rate of an affected EGU subject to a rate-based emission standard in an approved state plan under CAA section 111(d). The sole purpose of an ERC is for use by an affected EGU in demonstrating compliance with a rate-based emission standard in such an approved state plan.

An ERC is issued separately from any other instruments that may be issued for a MWh of energy generation or energy savings from a qualifying measure. Such other instruments may be issued for use in meeting other regulatory requirements (e.g., such as state RPS and EERS requirements) or for use in voluntary markets. An ERC may be issued based on the same data and verification requirements used by existing REC and EEC tracking systems for issuance of RECs and EECs.

The EPA notes that the definitions of other instruments, such as RECs, differ (as established under state statute, regulations, and PUC orders) and that requirements under state regulatory programs that use such instruments, such as state RPS, also differ. As a result, states may want to assess, when developing their state plan, how such existing instruments may interact with ERCs. For example, a state may want to assess how issuance of ERCs pursuant to a state plan may interact with compliance with a state RPS by entities affected under relevant state RPS regulations or PUC orders. The interaction of other instruments and ERCs may also impact existing or future arrangements in the private marketplace. Actions taken by states, separate from the design of their state plan, could address a number of these potential interactions. For example, state RPS regulations that specify a REC for a MWh of RE generation, and the attributes related to that MWh, may or may not explicitly or implicitly recognize that the holder of the REC is also entitled to the issuance of an ERC for a MWh of electricity generation from the eligible RE resource. This could impact existing and future RE power purchase agreements or REC purchase agreements. Such interactions among existing instruments and ERCs could also impact how marketing claims are made in the voluntary RE market. How a state might choose to address these potential interactions will depend on a number of factors, including the utility regulatory structure in the state, existing statutory and regulatory requirements for state RPS, and existing RE power purchase agreements and REC contracts.

g. Program review. The EPA is requiring that states periodically review the administration of their rate-based emission trading programs. The results of these program reviews must be submitted by states to the EPA as part of their required reports on the implementation of their state plans, as described in sections VIII.D.a.(5) and VIII.D.2.b.(4), and must be made publicly available. Such a review submitted as part of a required state report provides for the implementation of rate-based emission standards per the requirements of CAA section 111(d)(2). For a rate-based emission trading program, the review must cover the reporting period addressed in the state's periodic reports to the EPA on plan implementation.

The program review must address all aspects of the administration of a state's rate-based emission trading program, including the state's evaluations and regulatory decisions regarding eligibility applications for ERC resources and M&V reports (and associated EM&V activities), and the state's issuance of ERCs. The program review must assess whether the program is being administered properly in accordance with the state's approved plan; whether ERC eligibility applications and M&V reports are being properly evaluated and acted upon (i.e., approved or disapproved); whether reported annual MWh of generation and savings from qualified ERC resources are being properly quantified, verified, and reported in accordance with approved EM&V plans, and whether appropriate records are being maintained. The program review must also address determination of the eligibility of verifiers by the state and the conduct of verifiers, including the quality of verifier reviews. Where significant deficiencies are identified by the state's program review, those deficiencies must be rectified by the state in a timely manner.

States must collect, compile, and maintain sufficient data in an appropriate format to support the periodic program review. The EPA will review the results of each program review. The EPA may also audit a state's administration of its rate-based emission trading program and pursue appropriate remedies where significant deficiencies are identified.

3. EM&V requirements for RE, demand-side EE, and other measures used to adjust a CO_2 rate

This section discusses EM&V for RE, demand-side EE, and other measures that are used to generate ERCs or otherwise adjust an emission rate.[1002] EM&V is applied for purposes of quantifying and verifying MWh in rate-based state plans, as described below. Rate-based state plans must require that eligible resources document in EM&V plans and M&V reports how all MWh saved and generated from eligible measures will be quantified and verified. Additionally, with respect to EM&V, the EPA's proposed model rule identifies certain industry best practices that, upon finalization, could be adopted as presumptively approvable components of a state plan.[1003]

[1002] EM&V is defined to mean the set of procedures, methods, and analytic approaches used to quantify the MWh from demand-side EE and RE and other measures, and thereby ensure that the resulting savings and generation are quantifiable and verifiable.

[1003] The EPA recognizes that EM&V best practices are routinely evolving to reflect changes in markets, technologies and data availability. Therefore the agency is providing draft EM&V guidance with the proposed model rule, which can be updated over time to address any such changes to best practices. The guidance can also identify and describe alternative quantification approaches that may be approved for use, provided that such approaches meet the requirements of the finalized EM&V requirements.

As discussed in section VIII.K.1, quantified and verified MWh of RE generation, EE savings,[1004] and other eligible measures may be used to adjust a CO_2 emission rate when demonstrating compliance with the emission guidelines. In states implementing emission standard type plans with rate-based trading, affected EGUs adjust their reported emission rate using ERCs, which represent MWh that are quantified and verified according to the EM&V requirements described in this section. The EPA will evaluate the overall approvability of the state plan taking into consideration whether the state's submitted EM&V requirements satisfy these final emission guidelines.

a. Discussion of proposed EM&V approach and public comment. The EPA proposed that a state plan that incorporates RE and demand-side EE measures must include an EM&V plan that explains how the effect of these measures will be determined in the course of plan implementation. The proposal sought comment on the suitability of current state and utility EM&V approaches for RE and demand-side EE programs in the context of an approvable state plan, and on whether harmonization of state approaches, or

[1004] In the context of demand-side EE, "measure" refers to an installed piece of equipment or system at an end-use energy consumer facility, a strategy intended to affect consumer energy use behaviors, or a modification of equipment, systems or operations that reduces the amount of electricity that would have delivered an equivalent or improved level of end-use service in the absence of EE.

supplemental actions and procedures, should be required in an approvable state plan, provided that supporting EM&V documentation meets applicable minimum requirements. In the proposal, the EPA also indicated that it would issue guidance to help states, sources, and project providers quantify and verify MWh savings and generation resulting from zero-emitting RE and demand-side EE efforts.

The proposal and associated "State Plans Considerations" TSD[1005] suggested that the EPA's EM&V requirements could leverage existing industry practices, protocols, and tracking mechanisms currently utilized by the majority of states implementing RE and demand-side EE. The EPA further noted that many state regulatory bodies and other entities already have significant EM&V infrastructure in place and have been applying, refining, and enhancing their evaluation and quality assurance approaches for over 30 years, particularly with regard to the quantification and verification of energy savings resulting from utility-administered EE programs. The proposal also observed that the majority of RE generation is typically quantified and verified using readily available, reliable, and transparent methods such as direct metering of MWh.

[1005] See discussion beginning on p. 34 of the State Plan Considerations TSD for the Clean Power Plan Proposed Rule: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-state-plan-considerations.

As a result, the agency took comment on whether this infrastructure is appropriate in the context of approvable state plans for use in rate-based state plans that include RE, demand-side EE, and other measures. The majority of commenters addressing this question responded affirmatively, indicating that existing EM&V infrastructure is appropriate to assure quality, credibility, and integrity. However, commenters also noted that EM&V methods are routinely improving and changing over time, and that the EPA's requirements and guidance should be responsive to such changes, should avoid locking in outdated methods, and should be updated to maintain relevance.

Another point made by commenters is that, despite the observed improvements in EM&V over time, quantification knowledge is more robust for some EE program and policy types than for others. Additionally, there is relatively limited experience applying EM&V protocols and procedures to emission trading programs, where each MWh of replaced generation that can be bought and sold by a regulated source. As a result, the EPA's final emission guidelines and proposed model rule include a number of safeguards and quality-control features that are intended to ensure the accuracy and reliability of quantified EE savings.

b. <u>Requirements for EM&V and M&V submittals</u>. As discussed in section VIII.K.2, these final guidelines require that state plans include a requirement that EM&V plans and M&V reports be submitted to the state for rate-based emission trading programs. States must require that at the initiation of an eligible measure, project providers must develop and submit to the state an EM&V plan that documents how requirements for quantification and verification will be carried out over the period that MWh generation or savings are produced. States must also require that after a project or program is implemented, the provider must submit periodic M&V reports to confirm and describe how each of the requirements was applied. These reports must also specify the actual MWh savings or generation results, as quantified by applying EM&V methods on a retrospective (ex-post) basis. States may not allow MWh values that are quantified using ex-ante (pre-implementation) estimates of savings. As previously described, the EPA took comment on the suitability of current state and utility EM&V approaches for RE and demand-side EE programs in the context of an approvable state plan. These final requirements regarding EM&V plans and M&V reports are intended to leverage and closely resemble those already in routine use.

For energy generating resources, including RE resources, states may leverage the programs and infrastructure they have in place for achievement of their RPS and take advantage of registries in place for the issuance and tracking of RECs. Many existing REC tracking systems already include well-established safeguards, documentation requirements, and procedures for registry operations that could be adapted to serve similar functions in relation to the final emission guidelines. For example, a key element of RPS compliance in many states that parallels the final rule's requirements is that each generating unit must be uniquely identified and recorded in a specified registry to avoid the double counting of credits at the time of issuance and retirement. In addition, the existing reports and documentation from tracking systems may, together with eligible independent third party verification reports, serve as the substantive basis for eligibility applications, EM&V plans and M&V reports for the issuance of ERCs to energy generating resources for affected EGUs to meet their obligations under the final rule. With respect to actual monitoring requirements, many existing REC registries include provisions for the monitoring of MWh of generation that would be appropriate to meet state plan requirements pursuant to the final rule, such as requirements to use a revenue quality meter.

For demand-side EE, states must require that EM&V plans that are developed for purposes of adjusting an emission rate under this final rule include several specific components. The EPA notes these components reflect existing provisions in a wide range of publicly or rate-payer funded EE programs and energy service company projects. One of these components state plans must require is a demonstration of how savings will be quantified and verified by applying industry best-practice protocols and guidelines, as well as an explanation of the key assumptions and data sources used. State plans must require EM&V plans to include and address the following:

- A baseline that represents what would have happened in the absence of the EE intervention, such as the equipment that would most likely have been installed – or that a typical consumer or building owner would have continued using – in a given circumstance at the time of EE implementation
- The effects of changes in independent factors affecting energy consumption and savings; that is, factors not directly related to the EE action, such as weather, occupancy, or production levels
- The length of time the EE action is anticipated to continue to remain in place and operable, effectively providing savings (in years)

Examples and discussion of industry best-practices for executing each of the above-listed components is provided in the EPA's draft EM&V guidance for demand-side EE, which is being released in conjunction with the proposed model rule. The model trading rule defines certain EM&V provisions for demand-side EE, as well as specific provisions for non-affected CHP and RE resources, including incremental hydroelectric power, biomass RE facilities, and waste-to-energy facilities, that may be presumptively approvable upon finalization.

The EPA notes that state plans incorporating the finalized model rule for rate-based emission trading programs could be presumptively approvable as meeting the requirements of CAA section 111(d) and the EM&V provisions in these emission guidelines. The EPA will evaluate the approvability of such state plans through independent notice and comment rulemaking.

c. Skill certification standards. Using a skilled workforce to implement demand-side EE and RE projects and other measures intended to reduce CO_2 emissions, and to evaluate, measure, quantify and verify the savings associated with EE projects or the additional generation from performance improvements at existing RE projects are both important in existing best industry practices. Several commenters pointed out that skill certification standards can help to assure quality and credibility of demand-side EE, RE, and other CO_2 emission reduction projects. The EPA also recognizes that a skilled workforce performing the EM&V is important to substantiate the authenticity of emissions reductions.

The EPA is therefore recommending in conjunction with the EM&V requirements discussed in this section, that states are encouraged to include in their plans a description of how states will ensure that the skills of workers installing demand-side EE and RE projects or other measures intended to reduce CO_2 emissions as well as the skills of workers who perform the EM&V of demand-side EE and RE performance will be certified by a third party entity that:

1) Develops a competency based program aligned with a job task analysis and certification scheme;
2) Engages with subject matter experts in the development of the job task analysis and certification schemes that represent appropriate qualifications, categories of the jobs, and levels of experience;
3) Has clearly documented the process used to develop the job task analysis and certification schemes, covering such elements as the job description, knowledge, skills, and abilities;
4) Has pursued third-party accreditation aligned with consensus-based standards, for example ISO/IEC 17024.

Examples of such entities include: parties aligned with the Department of Energy's (DOE) Better Building Workforce Guidelines and validated by a third party accrediting body recognized by DOE; or by an apprenticeship program that is registered with the federal Department of Labor (DOL), Office of Apprenticeship; or with a state apprenticeship program approved by the DOL, or by another skill certification validated by a third party accrediting body. This can help to substantiate the authenticity of emission reductions due to demand-side EE and RE and other CO_2 emission reduction measures.

4. Multi-state coordination: rate-based emission trading programs

Individual rate-based state plans may provide for the interstate transfer of ERCs, which would enable an ERC issued by one state to be used for compliance by an affected EGU with a rate-based emission standard in another state. Such plans would include regulatory provisions in each state's emission standard requirements that indicate that ERCs issued in other partner states may be used by affected EGUs for compliance. Such plans must indicate how ERCs will be tracked from issuance through use for compliance, through either a joint tracking system, interoperable tracking systems, or an EPA-administered tracking system.[1006]

The approaches described in this section are only allowed for states that impose rate-based emission limits for affected

[1006] The emission standards in each individual state plan must include regulatory provisions that address the issuance of ERCs and tracking of ERCs from issuance through use for compliance, as described in section VIII.K.2. The description here addresses how those regulatory provisions will be implemented through the use of a joint tracking system, interoperable tracking systems, or an EPA-administered tracking system.

EGUs that are equal to the CO_2 emission performance levels in the emission guidelines. This approach is necessary to ensure that each state that is allowing for the interstate transfer of ERCs is implementing rate-based emission standards for affected EGUs at the same lb CO_2/MWh level.[1007] This assures that all the participating states are issuing ERCs to affected fossil steam and NGCC units that emit below their assigned emission standards on the same basis.

This approach avoids providing different incentives, in the form of issued ERCs, to affected steam generating units and NGCC units in different states that have comparable CO_2 emission rates. Providing different incentives to similar affected EGUs across states could create distortionary effects that lead to shifts in generation among states based on the different CO_2 emission rate standards applied by states to similar types of affected EGUs. Providing for the interstate trading of ERCs in this instance would exacerbate these distortionary effects by providing arbitrage opportunities.

[1007] As noted above in section VIII.C.6, states also have the option of implementing a multi-state plan with a single rate-based emission standard that applies to all affected EGUs in the participating states. This approach would also allow for interstate transfers of ERCs. Under this approach, a rate-based multi-state plan would include emission standards for affected EGUs based on a weighted average rate-based emission goal, derived by calculating a weighted average CO_2 emission rate based on the individual rate-based goals for each of the participating states and 2012 generation from affected EGUs.

When demonstrating that a state's CO_2 emission goal is achieved as a result of plan implementation, a state with linkages to other states would be required to demonstrate that any ERCs issued by another state that are used by affected EGUs in the state for compliance with its rate-based CO_2 emission standards were issued by states with an EPA-approved state plan.[1008]

States could implement these linkages among state plans with rate-based emission trading systems through three different implementation approaches: (1) plans that are "ready-for-interstate-trading;" (2) plans that include specified bilateral or multilateral linkages; and (3) plans that provide for joint ERC issuance among states with materially consistent regulations. These approaches are summarized below:

- Ready-for-interstate-trading plans: A state plan recognizes ERCs issued by any state with an EPA-approved plan that also uses a specified EPA-approved[1009] or EPA-administered

[1008] This could be done by reference to data in the tracking system used to implement a state's rate-based emission trading program that identifies the origin of each ERC (e.g., by serial identifier).
[1009] The EPA would designate tracking systems that it has determined adequately address the integrity elements necessary for the issuance and tracking of ERCs, as described in section VIII.K.2. Under this approach, a state could include in its plan such a designated tracking system, which has already been reviewed by the EPA.

tracking system. Plans are approved individually. A state plan need not designate the individual states by name from which it would accept issued ERCs. States can join such a coordinated approach over time, without the need for plan revisions.[1010]

- Specified bilateral linkage: States recognize ERCs issued by named partner states. Partner states must demonstrate that they use a shared tracking system, interoperable tracking systems, or an EPA-administered tracking system. Plans are approved individually, including review of the shared tracking system or interoperable tracking systems.
- Joint ERC issuance: States implement materially consistent rate-based emission trading program regulations and share a tracking system. States coordinate their review of submissions for ERC issuance[1011] and their issuance of ERCs

[1010] The EPA notes that it is proposing a model rule for a rate-based emission trading program that could be used by states interested in implementing a ready-for-interstate-trading plan approach. A state plan that included the finalized rate-based model rule could be presumptively approvable as meeting the requirements of CAA section 111(d) and the emission guidelines. If a state plan also met the requirements described in this section for ready-for-interstate-trading plans, it could be approved as ready-for-interstate trading.
[1011] This refers to eligibility applications and M&V reports, which are required submittals for non-affected EGU entities seeking the issuance of ERCs. Where affected EGUs are issued ERCs for emission performance below a specified CO_2 emission rate, these ERCs are issued by the individual state in which

to the shared tracking system. Issued ERCs are recognized as usable for compliance in all states using the shared tracking system. Plans are approved individually, including review of the shared tracking system.

These implementation approaches are designed to streamline the process for linking emission trading programs, avoid or limit the need for plan revisions as new states join a collaborative emission trading approach, and facilitate the development of regional or broader multi-state markets for ERCs.[1012]

L. Treatment of Interstate Effects

This section discusses how differing characteristics across states and sources could create risks of increased emissions under this rule through double counting of emission reduction measures or through foregone emission reductions due to movement

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they are subject to a rate-based emission standard. Requirements for ERC issuance are discussed in section VIII.K.2.

[1012] The EPA also notes that individual state plans may utilize RE and demand-side EE (and other eligible measures), that occur in other states, as described in section VIII.L addressing interstate effects. Under an individual state plan, ERCs could be issued for RE and demand-side EE measures that occur in other states, provided the EE/RE provider submits the measures to the state and the measures meet requirements in the state's rate-based emission trading program requirements. The multi-state approaches described above provide additional flexibility for states to informally and formally coordinate their implementation of rate-based plans across states while retaining individual rate-based state goals.

of generation from source to source. The section also discusses how the final rule addresses these concerns: first, through the characteristics of goal-setting and the framework of state plans, and second, through specific requirements intended to minimize the risk of double counting and increased emissions.[1013]

The section is structured as follows. First, this section discusses the dynamics that cause these risks to potentially arise. Second, it provides a discussion of how the risks of double counting and foregone reductions are minimized through the following provisions: the nature of the final emission performance rates, multi-state plan options that limit distortionary effects, the structure of mass-based plan and rate-based plan accounting for emission reductions measures, and specified restrictions on the counting in a rate-based plan of emission reduction measures located in a mass-based state. Finally, the section discusses how the rate-based accounting framework minimizes incentives to develop emission reduction measures in particular states due to differences in rates.

In the June 2014 proposal, the EPA acknowledged that emission reduction measures implemented under a state plan will

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[1013] This section does not discuss emission leakage and how it is addressed by this final rule. See section VII.D for a discussion of emission leakage and its impact on state goal equivalence. See section VIII.J for a discussion of requirements for mass-based plans to address leakage.

likely have impacts across many affected sources both within and across state boundaries due to the dynamic and interstate nature of the electric grid. These interactions may be driven in part due to differences in power sector dynamics across states, including the types of affected EGUs in a state, the availability of eligible zero-emitting resources, and the costs of different compliance options and existing policies in states. These state-level characteristics play out across dynamic regional grids that provide electricity across states. EGUs are dispatched both within and across state borders and are constantly adjusting behavior in response to available generation and electricity demand on the regional grid. Whenever CO_2 emission reduction measures, such as RE or demand-side EE, are implemented, the measure can affect EGU generation and CO_2 emissions across the regional grid. These impacts can change across multiple affected EGUs on a minute-to-minute, hour-to-hour, and day-to-day basis as electricity demand changes and different generating resources are dispatched. These impacts will also change in the long-term, as the generating fleet and load behavior change over a period of years. Interactions among EGUs across states may be further driven by the plan types (i.e., rate-based or mass-based) and the individual characteristics of the plans that states choose to adopt.

In the context of this complex environment of federal and state policies and interstate grids, commenters expressed concern about the risk of double-counting of measure impacts, particularly across state plans. Commenters stated that there is potential for distortionary incentives that could undermine overall CO_2 emission reductions (often termed emissions "leakage"). Commenters requested that the EPA ensure that states avoid double-counting and minimize leakage effects when demonstrating achievement of state goals.

The EPA acknowledges that some amount of shifts in generation between sources within and across state borders will inevitably be present and unavoidable in the context of this rule and may affect how affected EGUs achieve the applicable CO_2 performance rates or state goals under a state plan. In fact, the definition of the BSER is premised upon shifts in generation across sources, particularly shifts from higher- to lower-emitting units that result in overall emission reductions. However, in the context of these shifts, the extent to which the movement of generation may be driven not by the potential to capture lower-cost emission reduction but by arbitrage across different emission rates, causing inefficiencies in the power markets and possibly eroding overall emission reductions, should be minimized.

In particular, the EPA has determined final emission performance rates that serve to reduce relative differences between state goals, and thus also focus the potential for generation shifting between affected EGUs on achieving the emission reductions quantified in the BSER. In the proposal, goals differed more substantially between states based upon an assessment of what emission reduction potential units could access located within their state. Commenters observed that due to the interconnected nature of the power sector, units are not limited to such emission reduction measures within their state, and indeed any operational decisions that units take necessarily influence operational decisions at other units throughout the interconnected grid. As a result, in the final rule, we are finalizing CO_2 emission performance rates, informed by regional emission reduction potential, for fossil fuel-fired electric utility steam generating units and stationary combustion turbines that are applied consistently across all affected EGUs. As the same source category-specific performance rates are applied to all units in the contiguous U.S. regardless of the state in which they are located, any differences between state goals in this final rule stem only from the relative prevalence in each state of fossil fuel-fired electric utility steam generating units and stationary combustion turbines. Consequently, there is substantially less incentive in this final rule for units to shift generation across state lines based solely on differences in state goals, since there is substantially less difference between the final rule's state goals, and since those state goals are themselves premised on nationally consistent source category-specific performance rates.

The EPA has also incorporated elements into the rule that seek to minimize double-counting and the distortionary effects that could potentially increase emissions. First, states have the option to adopt multi-state plans that reflect regional interactions while eliminating chances for double counting and providing a level playing field for trading of rate-based ERCs or mass-based allowances. Second, in the method for rate-based plan compliance, the rule provides a general accounting approach for adjusting an affected EGU's or state's CO_2 rate that inherently acts to minimize state differences. These points are further discussed below.

For both rate-based and mass-based approaches, the rule provides states with the option of creating either "ready-for-interstate-trading" plans or multi-state plans. These options for states working together provide opportunities to enable protections against double counting and minimize the presence of distortionary effects.

"Ready-for-interstate-trading" and multi-state plans engage multiple states in the same system for the purpose of trading mass-based allowances or issuing and trading rate-based ERCs.

This allows for efficient implementation of protections against double counting provided in state plan requirements, as multiple state are participating in the same tracking systems. This is particularly useful in the context of rate-based ERC issuance and tracking, where it must be ensured that the ERCs being generated are unique across rate-based plans.

This final rule also reduces distortionary effects within the context of multi-state plans. It does so by restricting states to interstate trading with equivalently denominated mass-based allowances or rate-based ERCs. In a mass-based context, all affected EGUs will trade uniform mass-based allowances, whether in a "ready-for-interstate-trading" plan or multi-state plan. In a rate-based plan context, "ready-for-interstate-trading" states must all adopt as their goal the CO_2 emission performance rates as their joint goal. This assures that all the participating states are issuing ERCs using the same subcategorized performance rates, and that the sources in each state have equivalent incentives for trading ERCs. Similarly, under multi-state plans, the relevant states must choose to adopt identical rates, either the CO_2 emission performance rates or a weighted average goal rate based on the rate-based goals of all the states involved. These requirements along with a method for calculating a weighted average goal rate are specified in section VIII.C.5.

Under all types of state plans, states must ensure that the emission reduction measures counted as part of meeting their plan requirements are not duplicative of any measures that are counted by another state, in order to avoid double counting of the MWhs of generation or energy savings that these measure produce. Depending on the accounting method used to reflect these measures in state goals, interstate effects could still allow for the double counting of the emission reductions resulting from these measures, particularly if mathematical adjustments were made to stack emissions to reflect these reductions. Depending on how these measures are accounted for, the reductions could be counted by both the state that deployed the measure, and the state that reports a reduction in fossil generation or reported emissions. In this final rule, the MWh-based general accounting approaches for both mass-based and rate-based plans have been specifically designed to eliminate the risk of double counting of reductions, because emission reduction measures are accounted for only through their inherent impact on stack emissions for affected EGUs.

Mass-based plans rely exclusively on reported stack emissions for determining whether a mass-based CO_2 emission goal is achieved. This means that under a mass-based plan any emission reduction measures that are implemented are automatically accounted for in reduced stack emissions of CO_2

from affected EGUs, which avoids concerns about counting the same mass reductions in two different mass-based states.

In a rate-based plan, there needs to be an explicit adjustment of reported CO_2 emission rates from affected EGUs, to reflect the measures that substitute low- or zero-emitting generation or energy savings for affected EGU generation. States with rate-based plans must demonstrate that measures used to adjust their CO_2 emission rate, such as RE and demand-side EE, are non-duplicative. The proposal attempted to address this issue in part by limiting demand-side EE that states could claim to in-state measures. In fact, those in-state measures still have an impact outside of the state and under the proposal's approach, states would have been restricted from taking credit for all the measures they have put in place that reduce CO_2 emissions. Therefore, the EPA is finalizing a treatment that allows states to count all in-state and out-of-state measures, while addressing interstate effects through the structure of the rule's accounting approach for adjusting the CO_2 emission rate of an affected EGU, detailed in section VIII.K.1 above, used to show that the state has met its obligation under its state plan.

The general accounting approach for adjusting the CO_2 emission rate of an affected EGU inherently accounts for the regional nature of how substitute generation and energy savings will impact affected EGU generation and CO_2 emissions. The following discussions refer to the substituting generation and energy savings in question as RE and demand-side EE, but this method can apply to other measures that were not included in the determination of the BSER that substitute for affected EGU generation. The adjusted CO_2 emission rate gives credit to the affected EGU or state for the MWhs of RE and demand-side EE it is responsible for deploying, by allowing those MWhs to be added to the denominator of the CO_2 rate, but makes no adjustment to the numerator. Instead, the numerator reflects reported stack emissions, which will reflect the extent to which RE and demand-side EE reduced the affected EGU's generation and emissions, without needing to account for the state in which the RE or demand-side EE originated, or approximating exactly how it impacted the regional grid. Double-counting of CO_2 emission reductions is prevented because the reported emissions from each unit are represented in the numerator of each of those units' emission rates, and those real emissions capture whatever emission reduction impact occurred with regard to any particular MWh of RE or demand-side EE. Because the general accounting approach disallows any adjustment to any EGU's reported emissions, it is not possible for the real emission reductions prompted by any particular measure to be double-counted.

Double-counting of MWhs in the denominator can be avoided because it is relatively straightforward to quantify the MWhs that the affected EGU is responsible for deploying and add them to the denominator, and this method aligns well with the MWh-denominated trading system described in this final rule. As long as it is assured that the MWhs of RE and demand-side EE are only being claimed by one affected EGU or state, as is outlined in section VIII.K, then there is no double-counting of MWh. Therefore, the accounting method avoids double counting of both CO_2 emission reductions and MWhs, the two characteristics of RE and demand-side EE measures that affect CO_2 emission rates. For further discussion of the MWh-based accounting method, including a calculation example, see section VIII.K.1.

There may also be interactions between mass-based and rate-based plans regarding counting measures, specifically where measures that provide substitute or avoided generation, such as RE and demand-side EE, are located in a mass-based state and can also be used by a rate-based state in meeting the CO_2 performance rates or state goals. The EPA received comments on this particular issue, and many expressed concerns that this use of mass-based resources in a rate-based state would result in double-counting of emission reductions.

Commenters provided analyses specifying how two states can benefit from the same RE and demand-side EE measures as a result of rate- and mass-based plan interactions. Some commenters considered this double-counting of emission reductions, and requested specific mathematical adjustments of reported generation or CO_2 emissions from affected EGUs under either rate-based or mass-based state plans in order to eliminate double-counting.

The EPA has determined that, in the context of interactions among rate-based and mass-based plans, there is not explicit double-counting of the CO_2 emission reductions associated with counting measures located in mass-based states, considering the accounting methods outlined in this final rule. First, as discussed above, the accounting method for adjusting the CO_2 emission rate only counts the MWhs generated by a measure to adjust the MWh in the denominator of its reported CO_2 emission rate. The CO_2 emissions impacts of the measures will be reflected in the rate-based state only to the extent that the MWhs resulted in lower reported CO_2 emissions from an affected EGU in the rate-based state. To the extent that measures that provide substitute or avoided generation reduce generation from affected EGUs in a mass-based state, the effect of those measures is reflected in lower reported CO_2 emissions of the mass-based EGUs. The CO_2 emission reductions reflected in the rate and the mass state will necessarily be mutually exclusive, because both are based on reported stack emissions. Additionally, the mechanism in the mass-based state that is assuring CO_2 emission reductions is the mass budget, which is met by affected EGUs adjusting their generation. Low- or zero-emitting MWhs from resources like RE and demand-side EE can serve load in the mass-based state and play a role in lowering compliance costs, but they play no direct role in mass-based compliance. As a result, no double-counting of emission reductions can take place.

Though there is no risk of double-counting emissions, some commenters expressed the concern that overall CO_2 emissions reductions would be foregone in situations where a source in a rate-based state counts the MWh from measures in a mass-based state, but the generation from that measure acts solely to serve load in the mass-based state. In that scenario, expected CO_2 emission reduction actions in the rate-based state are foregone as a result of counting MWh that resulted in CO_2 emission reductions in a mass-based state. Therefore the EPA is restricting the ability of rate-based states to claim emission reduction measures, such as RE and demand-side EE, located in mass-based states.

While the EPA understands this concern regarding foregone reductions, we do not believe it is appropriate to restrict RE crediting unilaterally between rate-based and mass-based states. Such a restriction could cut some states off from regional RE supplies that are assumed in the BSER building block 3 and incorporated in the CO_2 emission performance rates and state CO_2 goals. Allowing crediting between rate- and mass-based states, as long as the risk of foregone CO_2 emission reduction actions in rate-based states are minimized, will assure a supply of eligible RE MWhs that will further enable affected EGUs and states to meet obligations under the final rule. Therefore, the EPA has determined that it is appropriate for rate-based states to count MWhs from RE located in mass-based states, subject to the condition that the generation in question was intended to meet electricity load in a state with a rate-based plan.[1014] This may apply to some or all of the generation from an individual RE installation. To assure that the RE generation in question meets this condition, the EPA is requiring that RE generation from RE installations located in a mass-based state can only be counted in a rate-based state if the electricity generated is delivered with the intention to meet load in a state with a rate-based plan, and was treated as a generation resource used to serve regional load that included the rate-based state. This can be demonstrated through, for example, the provision of a power delivery contract or power purchase agreement in which an entity in the rate-based state contracts for the supply of the MWhs in question. The EPA is providing flexibility to states regarding the nature of the required demonstration, though the state must

[1014] This does not need to necessarily be the state where the MWh of energy generation from the RE measure is used to adjust the CO_2 emission rate of an affected EGU.

specify eligible demonstrations for approval in state plans. Under an emission standards plan, this demonstration would be made by the provider of the measure seeking ERC issuance to the rate-based state.

The following are examples of how requirements for a demonstration could be established in state plans and used to allow RE in a mass-based state to be counted in a rate-based state. For an emission standards state plan, a state could specify in the regulations for the rate-based emission standards included in its state plan that it will require an RE provider that seeks the issuance of ERCs to show that load-serving entities in the rate-based state have contracted for the delivery of the RE generation that occurs in a mass-based state to meet load in a rate-based state. Under this approach, an RE provider in a mass-based state could submit as part of an eligibility application a delivery contract or power purchase agreement showing that the generation was procured by the utility, and was treated as a generation resource used to serve regional load that included the rate-based state. This documentation would be sufficient demonstration to allow the RE generating resource to meet this additional geographic eligibility requirement for the amount of generation in question. All quantified and verified RE MWhs submitted for ERC issuance would need to be associated with that power purchase contract or agreement, and this fact would need to be demonstrated in the M&V reports submitted for issuance of ERCs.

The ability for a rate-based state to count MWhs located in a mass-based state under the above conditions is limited to RE. Rate-based states are not allowed to claim demand-side EE or any other emission reduction measures that were not included in the determination of the BSER located in mass-based states for ERC issuance. While this limits rate-based sources' access to additional resources, providing that access would result in a risk of foregone reductions. Further, unlike RE, there is no obligation related to demand-side EE and other measures that were not included in the determination of the BSER incorporated in the CO_2 emission performance rates or state rate-based goals which would necessitate facilitating access to those resources. This treatment also does not apply to fossil-fuel fired EGUs, such as NGCC units. If a mass-based emission standard has been applied to an affected EGU, there is no valid way to calculate whether it has MWh that are eligible for crediting, as is possible under a rate-based plan.

Finally, as stated earlier, commenters also expressed concern about the potential for relative increases in emissions to occur given relative differences between sources and states. These differences could include states' goals under either the rate- or mass-based approaches, or states' accounting of new sources. These differences could induce increased generation in one state over another because the costs of compliance and relative costs of generation would vary between states. There was particular concern regarding how these differences would provide incentives for increasing generation at new fossil sources and expanding utilization of existing affected EGU generation in states that have less stringent goals, and that this movement of generation would result in increased emissions overall. This could potentially result in the achievement of performance rates but with fewer overall CO_2 emissions reductions than projected nationally under the proposal.

Commenters suggested that the issuance and trading of emission credits across states under a rate-based approach would result in incentives to create credits, through the development of RE for example, in certain states with higher state goals, and this could also be a source of increased overall emissions. They noted that RE siting would thus not occur in the most optimal locations. The commenters assumed that zero-emitting credits are denominated in mass units by multiplying the number of MWh by some emission rate: either the state goal rate, the current state emission rate, a regional emission rate, or a calculated marginal rate. If those rates were higher in any states, zero-emitting MWhs would create more mass-denominated credits in those states, and thus RE and demand-side EE would be more valuable.

The incentive to target the location of zero-emitting generation or energy savings between states based on variation in its emission reduction value has been minimized by the fact that states participating in rate-based interstate trading must adopt the same emission performance rates or rate-based state goals. It is further minimized, even outside of an interstate trading framework, by the nature of the accounting method finalized in this rule. As explained above regarding the general accounting approach and the trading framework, we are adjusting rates using calculated MWhs, not based upon an emission reduction approximation as commenters outlined above. Not only does the method allow emission reductions to be accounted for as they occur across the grid, but it means the ERCs being traded across states represent one MWh of zero-emitting generation in whatever state it originated, and its value is unaffected by any emission rate associated with its state of origin. Thus, the finalized accounting and trading methods minimize the relative incentives for generating zero-emitting ERCs in a particular state based upon the rates that apply to that state.

IX. Community and Environmental Justice Considerations

In this section we provide an overview of the actions that the agency is taking to help ensure that vulnerable communities are not disproportionately impacted by this rulemaking.[1015]As described in the Executive Summary, climate change is an environmental justice issue. Low-income communities and communities of color already overburdened with pollution are likely to be disproportionately affected by, and less resilient to, the impacts of climate change. This rulemaking will provide broad benefit to communities across the nation, as its purpose is to reduce GHGs, the most significant driver of climate change. While addressing climate change will provide broad benefits, it is particularly beneficial to low-income populations and some communities of color (in particular, populations defined jointly by ethnic/racial characteristics and geographic location) where people are most vulnerable to the impacts of climate change (a more robust discussion of the impacts of climate change on vulnerable communities is provided in the Executive Order 12898 section XII.J of this preamble).

[1015] In this preamble, the EPA discusses environmental justice in two sections. Section XI.J specifically addresses how the agency has met the directives under Executive Order 12898. The EPA defines environmental justice as the fair treatment and meaningful involvement of all people regardless of race, color, national origin or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. This section of the preamble addresses actions that the agency is taking related to environmental justice and other issues (e.g., increased electricity costs) that may affect communities covered by Executive Order 12898 as well as other communities.

While climate change is a global phenomenon, the adverse effects of climate change can be very localized, as impacts such as storms, flooding, droughts, and the like are experienced in individual communities.

Vulnerable communities also often receive more than their fair share of conventional air pollution, with the attendant adverse health impacts. The changes in electricity generation that will result from this rule will further benefit communities by reducing existing air pollution that directly contributes to adverse localized health effects. These air quality improvements will be achieved through this rule because the electric generating units that emit the most GHGs also have the highest emissions of conventional pollutants, such as SO_2, NOx, fine particles, and HAP. These pollutants are known to contribute to adverse health outcomes, including the development of heart or lung diseases, such as asthma and bronchitis, increased susceptibility to respiratory and cardiac symptoms, greater numbers of emergency room visits and hospital admissions, and premature deaths.[1016] The EPA expects that the reductions in utilization of higher-emitting units likely to occur during the implementation of state plans will produce significant reductions in emissions of conventional pollutants, particularly

[1016] Six Common Air Pollutants. http://www.epa.gov/oaqps001/urbanair/

in those communities already overburdened by pollution, which are often low-income communities, communities of color, and indigenous communities. These reductions will have beneficial effects on air quality and public health both locally and regionally. Further, this rulemaking complements other actions already taken by the EPA to reduce conventional pollutant emissions and improve health outcomes for overburdened communities.

By reducing millions of tons of CO_2 emissions that are contributing to global GHG levels and providing strong leadership to encourage meaningful reductions by countries across the globe, this rule is a significant step to address health and economic impacts of climate change that will fall disproportionately on vulnerable communities. By reducing millions of tons of conventional air pollutants, the rule will lead to better air quality and improved health in those communities. We heard from many commenters who recognize and welcome those benefits.

There are other ways in which the actions that result from this rulemaking may affect communities in positive or potentially adverse ways and we also heard about these from commenters.

While the agency expects overall emission decreases as a result of this rulemaking, we recognize that some EGUs may operate more frequently, as a result of this rulemaking. To the extent that we project increases in utilization as a result of this rulemaking, we expect these increases to occur generally in lower-emitting NGCC units, which have minimal or no emissions of SO_2 and HAP, lower emissions of particulate matter, and much lower emissions of NOx compared to higher-emitting steam units. We acknowledge the concerns that have been raised on this point but also the difficulty in anticipating prior to plan implementation where those impacts might occur. In addition to providing for a robust state planning process with opportunity for meaningful input, the EPA is encouraging states to evaluate the actual impacts of their plans once implemented and, as described below, the EPA intends to conduct an assessment of whether and where emission increases may that may result from plan implementation and to work with states to mitigate adverse impacts, if any, in overburdened communities.

In addition to the many positive anticipated health benefits of this rulemaking, it also will increase the use of clean energy and will encourage EE. These changes in the electricity generation system, which are already occurring but may be accelerated by this program, are expected to have other positive benefits for communities. The electricity sector is, and will continue to be, investing more in RE and EE. The construction of renewable generation and the implementation of EE programs such as residential weatherization will bring investment and employment opportunities to the communities where they take place. We recognize that certain communities whose economies may be affected by changes in the utility and related sectors may be particularly impacted by the final rule. The EPA encourages states to make an effort to engage with these communities, including workers and their representatives in these sectors, including EE. It is important to ensure that all communities share in the benefits of this program. And while we estimate that its benefits will greatly exceed its costs (as noted in the RIA for this rulemaking), it is also important to ensure that to the extent there are increases in electricity costs, that those do not fall disproportionately on those least able to afford them.

The EPA has engaged with community groups throughout this rulemaking, and we received many comments on the issues outlined above from community groups, environmental justice organizations, faith-based organizations, public health organizations, and others.[1017] This input has informed this final rulemaking and prompted the EPA to consider other steps that the agency can take in the short and long term to assist states and

[1017] Detailed information on the outreach conducted as part of this rulemaking is provided in section I of this preamble.

stakeholders to consider environmental justice and impacts to communities in plan development and implementation.

It has also prompted us to work with our federal partners to make sure that states and communities have information on federal resources available to assist communities. We describe these resources below, as well as resources that the EPA will be providing to assist communities in accessing EE/RE and financial assistance programs. In our discussion below we also provide models of programs that other states are currently using to assist communities in accessing available resources that states could use when developing their plans.

Finally, and importantly, we recognize that communities must be able to participate meaningfully in state plan development. In this section, we discuss the requirements in the final rule for states, as they develop their plans, to provide opportunities for public involvement, and resources available to states and communities to enhance the success of the public process.

A. Proximity Analysis

The EPA is committed to assisting states and communities to develop plans that ensure there are no disproportionate, adverse impacts on overburdened communities. To provide information fundamental to beginning that process, the EPA has conducted a proximity analysis for this final rulemaking that summarizes demographic data on the communities located near power plants.[1018] The EPA understands that, in order to prevent disproportionately, high and adverse human health or environmental effects on these communities, both states and communities must have information on the communities living near facilities, including demographic data, and that accessing and using census data files requires expertise that some community groups may lack. Therefore, the EPA used census data from the American Community Survey (ACS) 2008-2012 to conduct a proximity analysis that can be used by states and communities as they develop state plans and as they later assess the final plans' impacts. The analysis and its results are presented in the EJ Screening Report for the Clean Power Plan, which is located in the docket for this rulemaking at EPA-HQ-OAR-2013-0602.

The proximity analysis provides detailed demographic information on the communities located within a 3-mile radius of each affected power plant in the U.S. Included in the analysis is the breakdown by percentage of community characteristics such as income and minority status. The analysis shows a higher percentage of communities of color and low-income communities living near power plants than national averages. It is important to note that the impacts of power plant emissions are not

[1018] The proximity analysis was conducted using the EPA's environmental justice mapping and screening tool, EJSCREEN.

limited to a 3-mile radius and the impacts of both potential increases and decreases in power plant emissions can be felt many miles away. Still, being aware of the characteristics of communities closest to power plants is a starting point in understanding how changes in the plant's air emissions may affect the air quality experienced by some of those already experiencing environmental burdens.

Although overall there is a higher fraction of communities of color and low-income populations living near power plants than national averages, there are differences between rural and urban power plants. There are many rural power plants that are located near small communities with high percentages of low-income populations and lower percentages of communities of color. In urban areas, nearby communities tend to be both low-income communities and communities of color. In light of this difference between rural and urban communities proximate to power plants and in order to adequately capture both the low-income and minority aspects central to environmental justice considerations, we use the terms "vulnerable" or "overburdened" when referring to these communities. Our intent is for these terms to be understood in an expansive sense, in order to capture the full scope of communities, including indigenous communities most often located in rural areas, thatare central to our environmental justice and community considerations.

As stated in the Executive Order 12898 discussion located in section XII.J of this preamble, the EPA believes that all communities will benefit from this final rulemaking because this action directly addresses the impacts of climate change by limiting GHG emissions through the establishment of CO_2 emission guidelines for existing affected fossil fuel-fired power plants. The EPA also believes that the information provided in the proximity analysis will promote engagement between vulnerable communities and their states and will be useful for states as they begin developing their plans. In addition to providing the proximity analysis in the docket of this rulemaking, the EPA will disseminate the proximity analysis to states and will make it publicly available on its Clean Power Plan (CPP) Community Portal. Furthermore, the EPA has also created an interactive mapping tool that illustrates where power plants are located and provides information on a state level. This tool is available at: http://cleanpowerplanmaps.epa.gov/CleanPowerPlan/.

Additionally, the EPA encourages states to conduct their own analyses of community considerations when developing their plans. Each state is uniquely knowledgeable about its own communities and well-positioned to consider the possible impacts of plans on vulnerable communities within its state. Conducting state-specific analyses would not only help states assess possible impacts of plan options, but it would also enhance a state's understanding of the means to engage these communities that would most effectively reach them and lead to valuable exchanges of information and concerns. A state analysis, together with the proximity analysis conducted by the EPA, would provide a solid foundation for engagement between a state and its communities.

Such state-specific analyses need not be exhaustive. An examination of the options a state is considering for its plan, and any projections of likely resulting increases in power plant emissions affecting low-income populations, communities of color populations, or indigenous communities, would be informative for communities. The analyses could include available air quality monitoring data and information from air quality models, and, if available, take into account information about local health vulnerabilities such as asthma rates or access to healthcare. Alternatively, a simple analysis may consider expected EGU utilization in geographic proximity to overburdened communities. The EPA will provide states with information on its publicly available environmental justice screening and mapping tool, EJ SCREEN, which they may use in conducting a state-specific analysis. The EPA will also provide states with resources containing examples of analyses that other states have conducted to examine the impacts of their programs on overburdened communities. Additionally, the EPA encourages states to submit a copy of their analysis if they choose to conduct one, with their initial and final plan submittals.

B. Community Engagement in State Plan Development

In sections VIII.D-E of this preamble, the EPA explains that states need to engage meaningfully with communities and other stakeholders during the initial and final plan submittal processes. Meaningful engagement includes outreach to vulnerable communities, sharing information and soliciting input on state plan development and on any accompanying assessments such as those described above, and selecting methods for engagement to support communities' involvement at critical junctures in plan formulation and implementation. This engagement also includes providing the public the opportunity to comment on the state's initial submittal and responding to significant comments received, including comments from vulnerable communities, as well as conducting a public hearing and responding to comments before a final state plan is submitted. Additionally, the EPA expects that states will conduct outreach meetings, which could include public hearings or listening sessions, before the initial submittal is made. The EPA also encourages states to provide background information about their proposed final state plan or their initial state plan in the appropriate languages in advance of their public hearing and at their public hearing. The EPA recommends that states provide translators and other resources at their public hearings, to ensure that members of the public can provide oral feedback.

In the initial submittal, the final rule requires that states provide information to the agency about the community engagement they have undertaken and the means by which they intend to involve vulnerable communities and other stakeholders as they develop their final plan. Furthermore, as noted in section VIII.E of this preamble, in determining if states are eligible for a 2-year extension for submission of final plans, the rule requires that states demonstrate how they are meaningfully engaging vulnerable communities and other interested stakeholders as part of their public participation process. The EPA consulted its May 2015, *Guidance on Considering Environmental Justice During the Development of Regulatory Actions*, when crafting this rulemaking and recommends that states consult it to assist them in engaging meaningfully with vulnerable communities.[1019] Additionally, states in their initial submittal and 2017 update must show how they identified the communities with whom they are engaging as they develop their plans. Some suggested actions that states could take to engage actively with the public, including conducting meaningful

[1019] Guidance on Considering Environmental Justice During the Development of Regulatory Actions. http://epa.gov/environmentaljustice/resources/policy/considering-ej-in-rulemaking-guide-final.pdf. May 2015.

engagement with vulnerable communities, are outlined in section VIII.E of this preamble. Additionally, as outlined in section VIII.D, the final plan submitted by states must include an overview of the public hearing(s) conducted and information on how the state ensured that the hearing(s) were accessible to stakeholders including vulnerable communities.

The EPA is committed to supporting states in effectively engaging with communities as they develop and implement their plans. The EPA will provide training and other resources throughout the implementation process that will assist states and communities in understanding plan requirements and options for plan development. These trainings will be a continuation of those that the EPA has already conducted with communities and states both pre- and post-proposal. The EPA will reach out to a wide variety of community stakeholders, including groups representing environmental justice communities, faith-based organizations, academic organizations working with vulnerable and overburdened communities, affordable housing advocates, public health professionals, public health organizations, and other community stakeholders.

C. Providing Communities with Access to Additional Resources

In addition to providing resources to states, the EPA encourages states to be aware of existing efforts undertaken by other states aimed at providing low-income communities access to financial and technical assistance programs for EE and RE, and to consider similar approaches that may make sense for their own states. The EPA encourages states to consider targeting economic development resources to communities that are likely to be negatively affected by ongoing changes in the utility and related sectors in support of efforts to diversify their economies, attract new sources of investment, and create new jobs.

One example of a program targeted at low-income communities is the Maryland EmPOWER Low Income Energy Efficiency Program (LIEEP).[1020] The LIEEP program administered by the Maryland Department of Housing and Community Development (DHCD) helps low-income households through free installation of energy conservation materials (i.e., installation, hot water system improvements, lighting retrofits, furnace cleaning, tuning and safety repairs, refrigerator retrofits, etc.).[1021] Funding for this program is provided by EmPOWER Maryland partners: Baltimore Gas and Electric, Southern Maryland Electric Cooperative, Delmarva Power, Allegheny Energy and Pepco.[1022] This program is available to both homeowners and renters.[1023] Additionally, the

[1020] EmPOWER Maryland Low Income Energy Efficiency Programs (LIEEP). http://www.mdhousing.org/website/Programs/lieep/Default.aspx.
[1021] Ibid.
[1022] Ibid.
[1023] Ibid.

Maryland Department of Housing provides low-income families with home heating bill assistance and furnace repairs and replacements through the Maryland Energy Assistance Program (MEAP).[1024] Maryland's Electric Universal Service Program (EUSP) helps low-income electric customers with their electric bills.[1025]

Another example of a program is EmPower New York, which provides no-cost energy solutions to low-income populations.[1026] Currently there are about 100,000 people who are receiving assistance. Both homeowners and renters are eligible to receive assistance under this program. The types of assistance available include EE upgrades (plugging leaks, adding insulation, replacing inefficient refrigerators and freezers and new energy-efficient lighting). Other states, like the State of Colorado's Energy Outreach Colorado program, offer similar resources for low-income populations.[1027]

In 2013, the New York State Energy and Research Development Authority (NYSERDA) was able to secure a triple-A rated financial guarantee from the state's Clean Water State Revolving Fund (SRF) for a $24 million bond issue. Proceeds funded residential EE loans that were available to all utility

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[1024] Energy Assistance. http://www.dhr.state.md.us/blog/?page_id=4326.
[1025] Ibid.
[1026] EmPower New York. http://www.nyserda.ny.gov/All-Programs/Programs/EmPower-New-York
[1027] Energy Outreach Colorado. http://www.energyoutreach.org/about

customers, including low-income households. SRF eligibility was based on the beneficial impact of EE investment in reducing atmospheric deposition on impaired water bodies consistent with Section 319 of the Clean Water Act.

As discussed below, there are also many federal programs that can help low-income populations access the benefits of RE, EE, and the economic benefits of a cleaner energy economy.

In the coming months, the EPA will continue to provide information and resources for communities and states on existing federal, state, local, and other financial assistance programs to encourage EE/RE opportunities that are already available to communities. For example the EPA will provide a catalog of current or recent state and local programs that have successfully helped communities adopt EE/RE measures. The goal of these resources is to help vulnerable communities gain the benefits of this rulemaking by encouraging that states use these types of tools in their state plans. The use of these RE/EE tools can also help low-income households reduce their electricity consumption and bills.

The EPA recognizes the potential impacts that this rulemaking could have on jobs in communities. Therefore, in section VIII.G of this preamble, the EPA has outlined that states, in designing their state plans, should consider the effects of their plans on employment and overall economic development to realize the opportunities for economic growth and jobs that the plans offer. To the extent possible, states should try to assure that communities that may be expected to experience job losses can also take advantage of the opportunities for job growth or otherwise transition to healthy, sustainable economic growth (e.g., with regard to delivering EE measures and installing rooftop solar panels). Additionally, as part of the resources that we will be providing to states and low-income communities, the EPA will provide information on the Administration's Partnerships for Opportunity and Workforce and Economic Revitalization (POWER) Initiative and other programs that specifically target economic development assistance to communities affected by changes in the coal industry and the utility power sector.[1028]

D. Federal Programs and Resources Available to Communities

Federal agencies have a history of bringing EE and RE to low-income communities. Earlier this summer, the Administration announced a new initiative to scale up access to solar energy and cut energy bills for all Americans, in particular low- and moderate-income communities, and to create a more inclusive solar workforce. As part of this new initiative, the U.S. Department of Energy (DOE), the U.S. Department of Housing and

[1028] http://www.eda.gov/power

Urban Development (HUD), U.S. Department of Agriculture (USDA), and the EPA launched a National Community Solar Partnership to unlock access to solar energy for the nearly 50 percent of households and businesses that are renters or do not have adequate roof space to install solar systems, with a focus on low- and moderate- income communities. The Administration also set a goal to install 300 megawatts (MW) of RE in federally subsidized housing by 2020 and plants to provide technical assistance to make it easier to install solar energy on affordable housing, including clarifying how to use federal funding for EE and RE. To continue enhancing employment opportunities in the solar industry for all Americans, AmeriCorps is providing funding to deploy solar energy and create jobs in underserved communities, and DOE is working to expand solar energy education and opportunities for job training.

These recent announcements build on the many existing federal programs and resources available to improve EE and accelerate the deployment of RE in vulnerable communities. Some examples of these resources include: the Department of Energy's Weatherization Assistance Program, Health and Human Service's Low Income Home Energy Assistance Program, the Department of Agriculture's Energy Efficiency and Conservation Loan Program, High Cost Energy Grant Program, and the Rural Housing Service's Multi-Family Housing Program.

HUD supports EE improvements and the deployment of RE on affordable housing through its Energy Efficient Mortgage Program, Multifamily Property Assessed Clean Energy Pilot with the State of California, PowerSaver Program, and the use of Section 108 Community Development Block Grants. The Department of Treasury provides several tax credits to support RE development and EE in low-income communities, including the New Markets Tax Credit Program and the Low-Income Housing Tax Credit. The EPA's RE-Powering America's Land Initiative promotes the reuse of potentially contaminated lands, landfills and mine sites – many of which are in low-income communities – for RE through a combination of tailored redevelopment tools for communities and developers, as well as site-specific technical support. The EPA's Green Power Partnership is increasing community use of renewable electricity across the country and in low-income communities. The EPA partners with EE programs throughout the country that leverage ENERGY STAR to deliver broad consumer energy-saving benefits, of particular value to low-income households who can least afford high energy bills. ENERGY STAR also works with houses of worship to reduce energy costs – savings that can then be repurposed to their community mission, including programs and assistance to residents in low-income communities. The EPA will be working with these federal partners and others to ensure that states and vulnerable communities have access to information on these programs and their resources.

The federal government also has a number of programs to expand employment opportunities in the energy sector, including for underserved populations. Examples of these include HUD, DOE, and the Department of Education's "STEM, Energy, and Economic Development" program; DOE's Diversity in Science and Technology Advances National Clean Energy in Solar (DISTANCE-Solar) Program; Grid Engineering for Accelerated Renewable Energy Deployment (GEARED); the Department of Labor's Trade Adjustment Assistance Community College and Career Training (TAACCCT), Apprenticeship USA Advancing Apprenticeships in the Energy Field, Job Corps Green Training and Greening of Centers, and YouthBuild; and the EPA's Environmental Workforce Development and Job Training (EWDJT) program.

E. Multi-pollutant planning and Co-Pollutants

As outlined in the final Clean Power Plan, states and sources have continued obligations to meet all other CAA requirements addressing conventional pollutants. Because the CAA envisions control of these other pollutants as a continuous process (through provisions such as periodic review of the NAAQS and residual risk requirements under the MACT program), the EPA believes that the Clean Power Plan provides an opportunity for states to consider strategies for meeting future CAA planning obligations as they develop their plans under this rulemaking. Multi-pollutant strategies that incorporate criteria pollutant reductions over the planning horizons specific to particular states, jointly with strategies for reducing CO_2 emissions from affected EGUs needed to meet Clean Power Plan requirements over the time horizon of this rule, may accomplish greater environmental results with lower long-term costs. Such strategies may also provide opportunities for states, communities, and affected facilities to consider the most effective means of meeting these obligations while limiting or eliminating localized emission increases that would otherwise affect overburdened communities. Furthermore, this type of multi-pollutant approach has been suggested by states and regulated sources in past rulemakings as a tool to determine the best system of emission reductions. The EPA recommends that states consider such strategies in consultation with their communities, affected facilities, and other stakeholders.

Air quality in a given area is affected by emissions from nearby sources and may be influenced by emissions that travel hundreds of miles and mix with emissions from other sources.[1029] In the Cross-State Air Pollution Rule the EPA used its authority to reduce emissions that significantly contribute to downwind exposures. The RIA for the final Cross-State Air Pollution Rule anticipates substantial health benefits for the population across a wide region. Similarly, the EPA believes that, like the Cross-State Air Pollution Rule, this rulemaking will result in significant health benefits because it will reduce co-pollutant emissions of SO2 and NOx on a regional and national basis.[1030] Thus, localized increases in NOx emissions may well be more than offset by NOx decreases elsewhere in the region that produce a net improvement in ozone and particulate concentrations across the area.

Another effect of the final CO_2 emission guidelines for affected existing fossil fuel-fired EGUs may be increased utilization of other, unmodified EGUs - in particular, high efficiency gas-fired EGUs - with relatively low GHG emissions per unit of electrical output. These plants may operate more hours during the year and could emit pollutants, including pollutants whose environmental effects would be localized and regional rather than global as is the case with GHG emissions. Changes in utilization already occur in response to energy

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[1029] 76 FR 48348.
[1030] 76 FR 48347.

demands and evolving energy sources, but the final CO_2 emission guidelines for affected existing fossil fuel-fired EGUs can be expected to cause more such changes. Increased utilization of solid fossil fuel-fired units generally would not increase peak concentrations of $PM_{2.5}$, NOx, or ozone around such EGUs to levels higher than those that are already occurring because peak hourly or daily emissions generally would not change; however, increased utilization may make periods of relatively high concentrations more frequent. It should be noted that the gas-fired sources likely to be dispatched more frequently have very low emissions of primary PM, SO_2, and HAP per unit of electrical output and that they must continue to comply with other CAA requirements that directly address the conventional pollutants, including federal emission standards, rules included in SIPs, and conditions in Title V operating permits, in addition to the guidelines in this final rulemaking. Therefore, local (or regional) air quality for these pollutants is not likely to be significantly affected.

For natural gas-fired EGUs, the EPA found that regulation of HAP emissions "is not appropriate or necessary because the impacts due to HAP emissions from such units are negligible based on the results of the study documented in the utility

RTC."[1031] Because gas-fired EGUs emit essentially no mercury, increased utilization will not increase methyl mercury concentrations in water bodies near these affected EGUs. In studies done by DOE/NETL comparing cost and performance of coal- and NGCC-fired generation, they assumed SO_2, NOx, PM (and Hg) emissions to be "negligible." Their studies predict NOx emissions from a NGCC unit to be approximately 10 times lower than a subcritical or supercritical coal-fired boiler.[1032] Many, although not all, NGCC units are also very well controlled for emissions of NOx through the application of after combustion controls such as selective catalytic reduction.

F. Assessing Impacts of State Plan Implementation

It is important to the EPA that the implementation of state plans be assessed in order to identify whether they cause any adverse impacts on communities already overburdened by disproportionate environmental harms and risks. The EPA will conduct its own assessment during the implementation phase of this rulemaking to determine whether the implementation of state plans developed pursuant to this rulemaking and other air quality rules are, in fact, reducing emissions and improving air

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[1031] 65 FR 79831.

[1032] "Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity" Rev 2a, September 2013 Revision 2, November 2010 DOE/NETL-2010/1397.

quality in all areas or whether there are localized air quality impacts that need to be addressed under other CAA authorities. Furthermore, the EPA recommends that states conduct evaluations of their own to determine the impacts of their plans on overburdened communities. An example of one such approach to assessing a state plan for reducing GHGs is the California Air Resources Board's (CARB), *First Update on the Climate Change Scoping Plan: Building on the Framework Pursuant to AB32: The California Global Warming Solutions Act of 2006,* which outlines ongoing evaluations that it will conduct to determine the impacts of its programs (throughout the implementation stages) on overburdened communities.[1033] CARB's Adaptive Management Plan for the Cap-and-Trade Program is one particular evaluation, which is intended to assess any localized emissions increases resulting from the program so that the state can appropriately respond.[1034] The EPA recommends that states consider CARB's approaches and other programs as models for conducting ongoing assessments of the impacts of their state plans on overburdened communities. The EPA will provide training for states and

[1033] *First Update on the Climate Change Scoping Plan: Building on the Framework Pursuant to AB32: The California Global Warming Solutions Act of 2006*. http://www.arb.ca.gov/cc/scopingplan/2013_update/first_update_climate_change_scoping_plan.pdf. May 2014.

[1034] *Adaptive Management Plan for the Cap-and-Trade Regulation*. http://www.arb.ca.gov/cc/capandtrade/adaptive_management/plan.pdf. October 2011.

communities on resources that they can use to assess options for plan development and implementation that appropriately consider localized impacts, especially effects of co-pollutants, as well as training on how to develop and carry out these evaluations.

This training will include guidance in accessing the publicly available information that sources and states currently report that can help with ongoing assessments of state plan impacts. For example, unit-specific emissions data and air quality monitoring data are readily available. This information, together with the assessment that the EPA will conduct in the implementation phase of this rulemaking and other analyses that states may develop, will enable states and communities to monitor any disproportionate emissions that may result in adverse impacts and to address them.

G. EPA Continued Engagement

The EPA is committed to helping ensure that this action will not have disproportionate adverse human health or environmental effects on vulnerable communities. Throughout the implementation phase of this rulemaking, the agency will continue to provide trainings and resources to assist communities and states as they engage with one another. Additionally, we will provide states with recommendations on best practices for engaging with vulnerable communities. The EPA, through its outreach efforts during implementation, will continue to solicit feedback from communities and states on topics for which they would like additional trainings and resources.

The EPA will also provide states with resources containing examples of analyses that other states have conducted to examine the impacts of their programs on vulnerable communities, as well as information on its publicly available environmental justice screening and mapping tool, EJ SCREEN. States are encouraged to use this preliminary information as well as other available information to conduct their own analyses. As described above, the EPA will assess the impacts of this rulemaking during its implementation. The EPA will house this assessment, along with the proximity analysis and other information generated throughout the implementation process, on its Clean Power Plan (CPP) Community Portal that will be linked to this rulemaking's website (www.epa.gov/cleanpowerplan). In addition, the EPA has expanded its set of resources that are being developed to help states and communities understand the breadth of policy options and programs that have successfully brought EE/RE to overburdened communities. The EPA is committed to continuing its engagement with states and communities from the beginning of plan development through plan implementation.

A more detailed discussion concerning the application of Executive Order 12898 in this rulemaking can be found in section

XI.J of this preamble. A summary of the EPA's interactions with communities is in the EJ Screening Report for the Clean Power Plan, available in the docket of this rulemaking. Furthermore, the EPA's responses to public comments, including comments received from communities, are provided in the response to comments documents located in the docket for this rulemaking.

In summary, the EPA in this final rulemaking has designed an integrative approach that helps to ensure that vulnerable communities are not disproportionately impacted by this rulemaking. The proximity analysis that the agency has conducted for this rulemaking is a central component of this approach. Not only is the proximity analysis a useful tool to help identify overburdened communities that may be impacted by this rulemaking, states can use this tool as they engage with communities in the development of their plans, consider a multi-pollutant approach, help low-income communities access EE/RE and financial assistance programs and assess the impacts of their state plans. Additionally, in order to continue to ensure that vulnerable communities are not disproportionately impacted by this rulemaking, the EPA will also be conducting its own assessment during the implementation phase. Furthermore, the EPA will continue to engage with communities and states throughout the implementation phase of this rulemaking to help ensure that vulnerable communities are not disproportionately impacted.

X. Interactions with Other EPA Programs and Rules

A. Implications for the New Source Review Program

The new source review (NSR) program is a preconstruction permitting program that requires major stationary sources of air pollution to obtain permits prior to beginning construction. The requirements of the NSR program apply both to new construction and to modifications of existing major sources. Generally, a source triggers these permitting requirements as a result of a modification when it undertakes a physical or operational change that results in a significant emission increase and a net emissions increase. NSR regulations define what constitutes a significant net emissions increase, and the concept is pollutant-specific. As a result of the decision in *Utility Air Regulatory Group (UARG) v. Environmental Protection Agency (EPA)*, 134 S. Ct. 2427 (2014), a modification that increases only GHG emissions above the applicable level will not trigger the requirement to obtain a PSD permit. Under existing EPA regulations, a modifying major stationary source would trigger PSD permitting requirements for GHGs if it undergoes a change or change in the method of operation (modification) that results in a significant increase in the emissions of a pollutant other than GHGs and results in a GHG emissions increase of 75,000 tons per year CO_2e as well as a GHG emissions increase on a mass basis. Once it has been determined that a change triggers the requirements of the NSR program, the source must obtain a permit prior to making the change. The pollutant(s) at issue and the air quality designation of the area where the facility is located or proposed to be built determine the specific permitting requirements.

As part of its CAA section 111(d) plan, a state may impose requirements that require an affected EGU to undertake a physical or operational change to improve the unit's efficiency that results in an increase in the unit's dispatch and an increase in the unit's annual emissions. If the emissions increase associated with the unit's changes exceeds the thresholds in the NSR regulations for one or more regulated NSR pollutants, including the netting analysis, the changes would trigger NSR.

While there may be instances in which an NSR permit would be required, we expect those situations to be few. As previously discussed in this preamble, states have considerable flexibility in selecting varied measures as they develop their plans to meet the goals of the emission guidelines. One of these flexibilities is the ability of the state to establish emission standards in their CAA section 111(d) plans in such a way so that their affected sources, in complying with those standards, in fact would not have emissions increases that trigger NSR. To achieve this, the state would need to conduct an analysis consistent with the NSR regulatory requirements that supports its determination that as long as affected sources comply with the emission standards in their CAA section 111(d) plan, the source's emissions would not increase in a way that trigger NSR requirements.

For example, a state could decide to use demand-side measures or increase reliance on RE as a way of reducing the future emissions of an affected source initially predicted (without such alterations) to increase its emissions as a result of a CAA section 111(d) plan requirement. In other words, a state plan's incorporation of expanded use of cleaner generation or demand-side measures could yield the result that units that would otherwise be projected to trigger NSR through a physical change that might result in increased dispatch would not, in fact, increase their emissions, due to reduced demand for their operation. The state could also, as part of its CAA section 111(d) plan, develop conditions for a source expected to trigger NSR that would limit the unit's ability to move up in the dispatch enough to result in a significant net emissions increase that would trigger NSR (effectively establishing a synthetic minor limit).[1035]

In addition, in this final rule, we have also adjusted the date of the period for mandatory reductions to 2022, instead of 2020, and provided states with flexibility with respect to the glide path. This obviates concerns that there is insufficient time for sources that may need permits to obtain them and allows additional planning time for these changes to be undertaken in a manner that does not trigger PSD. As a result of such flexibility and anticipated state involvement, we expect that a limited number of affected sources would trigger NSR when states implement their plans.

B. Implications for the Title V Program

In the preamble to the June 18, 2014 proposal, the EPA discussed the issue of excessive title V fees resulting inadvertently as a consequence of the promulgation of the first section 111 standard to regulate GHGs. Specifically, the EPA

[1035] Certain stationary sources that emit or have the potential to emit a pollutant at a level that is equal to or greater than specified thresholds are subject to major source requirements. *See, e.g.,* CAA sections 165(a)(1), 169(1), 501(2), 502(a). A synthetic minor limitation is a legally and practicably enforceable restriction that has the effect of limiting emissions below the relevant level and that a source voluntarily obtains to avoid major stationary source requirements, such as the PSD or Title V permitting programs. *See, e.g.,* 40 CFR 52.21(b)(4), 51.166(b)(4), 70.2 (definition of “potential to emit”).

explained that when the first section 111 standard is promulgated for GHGs, if we do not revise 40 CFR parts 70 and 71 (the operating permit rule), then certain permitting authorities would be required to charge emissions-based fees for GHGs, resulting in fees that would be far in excess of what is required to cover the reasonable costs of the permitting programs. To avoid this situation, the EPA proposed as part of the re-proposed carbon pollution standards for newly constructed fossil fuel-fired power plants (70 FR 1429-1519; January 8, 2014) to exempt GHGs from the list of air pollutants that are subject to fee calculation requirements under the operating permit rules. Also, we proposed several options to impose a smaller fee adjustment for GHGs that would be reasonable and designed to recover the costs of addressing GHGs in permitting without being excessive.

In a separate action in today's *Federal Registe*r **[INSERT THE FEDERAL REGISTER REFERENCE FOR THE FINAL GHG NEW SOURCE RULE]**, the EPA is finalizing changes to the operating permits rules to address the title V fee issue. In particular, we are taking final action to exempt GHGs from emissions-based fee calculation requirements under the operating permit rules. In addition, we are also finalizing a modest GHG fee adjustment to recover the costs of addressing GHGs in permitting. The GHG adjustments we are finalizing are based on accounting for the number of permit actions that require a GHG assessment in a given period, rather than accounting for emissions levels of GHGs. Finally, the EPA is also finalizing the addition of text within 40 CFR part 60, subpart TTTT, to clarify that the fee pollutant for operating permit purposes is GHG (as defined in 40 CFR 70.2 and 71.2) to add clarity to our regulations and to avoid the potential need for possible future rulemakings to adjust the title V fee regulations if any constituent of GHG, other than CO_2, becomes subject to regulation under CAA section 111 for the first time.

This title V fee issue is a one-time occurrence resulting from the promulgation of the first CAA section 111 standard to regulate GHGs (the standards of performance for new, modified, and reconstructed EGUs, also promulgated in today's *Federal Register*). The title V fee issue is not an issue for any other subsequent CAA section 111 regulations, such as this section 111(d) standard; thus, there is no need to address any title V fee issues in this final rule as part of this action.

In the proposal, the EPA discussed that the section 111 rules would have no effect on the applicability thresholds for GHG under the operating permit rules. After the proposal for this rulemaking was published, the U.S. Supreme Court issued its opinion in *UARG v EPA*, 134 S.Ct. 2427 (June 23, 2014), and in accordance with that decision, the D.C. Circuit subsequently issued an amended judgment in *Coalition for Responsible Regulation, Inc. v. Environmental Protection Agency*, Nos. 09-1322, 10-073, 10-1092 and 10-1167 (D.C. Cir., April 10, 2015). Those decisions support the same overall conclusion, as the EPA discussed in the proposal, with respect to the effect of this final section 111 rule on the applicability thresholds for GHGs under the operating permits rules, though for different reasons.

With respect to title V, the Supreme Court said that EPA may not treat GHGs as an air pollutant for purposes of determining whether a source is a major source required to obtain a title V operating permit. In accordance with that decision, the D.C. Circuit's amended judgment vacated the title V regulations under review in that case to the extent that they require a stationary source to obtain a title V permit solely because the source emits or has the potential to emit GHGs above the applicable major source thresholds. The D.C. Circuit also directed the EPA to consider whether any further revisions to its regulations are appropriate in light of *UARG v. EPA*, and, if so, to undertake to make such revisions. These court decisions make clear that promulgation of CAA section 111 requirements for GHGs will not result in EPA imposing a requirement that stationary sources obtain a title V permit solely because such sources emit or have the potential to emit GHGs above the applicable major source thresholds.

C. Interactions with Other EPA Rules

Fossil fuel-fired EGUs are, or potentially will be, impacted by several other recently finalized or proposed EPA rules.[1036] The EPA recognizes the importance of assuring that each of the rules described below can achieve its intended environmental objectives in a commonsense, cost-effective manner, consistent with underlying statutory requirements, and while assuring a reliable power system. Executive Order 13563, "Improving Regulation and Regulatory Review," issued on January 18, 2011, states that "[i]n developing regulatory actions and identifying appropriate approaches, each agency shall attempt to promote... coordination, simplification, and harmonization. Each agency shall also seek to identify, as appropriate, means to achieve regulatory goals that are designed to promote innovation." Within the EPA, we are paying careful attention to the interrelatedness and potential impacts on the industry, reliability and cost that these various rulemakings can have.

1. Mercury and Air Toxics Standards (MATS)

On February 16, 2012, the EPA issued the MATS rule (77 FR 9304) to reduce emissions of toxic air pollutants from new and existing coal- and oil-fired EGUs. The MATS rule will reduce

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[1036] We discuss other rulemakings solely for background purposes. The effort to coordinate rulemakings is not a defense to a violation of the CAA. Sources cannot defer compliance with existing requirements because of other upcoming regulations.

emissions of heavy metals, including mercury, arsenic, chromium, and nickel; and acid gases, including hydrochloric acid and hydrofluoric acid. These toxic air pollutants, also known as hazardous air pollutants or air toxics, are known to cause, or suspected of causing, damage nervous system damage, cancer, and other serious health effects. The MATS rule will also reduce SO_2 and fine particle pollution, which will reduce particle concentrations in the air and prevent thousands of premature deaths and tens of thousands of heart attacks, bronchitis cases and asthma episodes.

New or reconstructed EGUs (i.e., sources that commence construction or reconstruction after May 3, 2011) subject to the MATS rule are required to comply by April 16, 2012 or upon startup, whichever is later.

Existing sources subject to the MATS rule were required to begin meeting the rule’s requirements on April 16, 2015. Controls that will achieve the MATS performance standards are being installed on many units. Certain units, especially those that operate infrequently, may be considered not worth investing in given today’s electricity market, and are closing. The final MATS rule provided a foundation on which states and other permitting authorities could rely in granting an additional, fourth year for compliance provided for by the CAA. States report that these fourth year extensions are being granted. In addition, the EPA issued an enforcement policy that provides a clear pathway for reliability-critical units to receive an administrative order that includes a compliance schedule of up to an additional year, if it is needed to ensure electricity reliability.

2. Cross-State Air Pollution Rule (CSAPR)

The CSAPR requires states to take action to improve air quality by reducing SO_2 and NO_X emissions that cross state lines. These pollutants react in the atmosphere to form fine particles and ground-level ozone and are transported long distances, making it difficult for other states to attain and maintain the NAAQS. The first phase of CSAPR became effective on January 1, 2015, for SO_2 and annual NO_X, and May 1, 2015, for ozone season NO_X. The second phase will become effective on January 1, 2017, for SO_2 and annual NO_x, and May 1, 2017, for ozone season NO_x. Many of the power plants participating in CSAPR have taken actions to reduce hazardous air pollutants for MATS compliance that will also reduce SO_2 and/or NO_x. In this way these two rules are complementary. Compliance with one helps facilities comply with the other.

3. Requirements for Cooling Water Intake Structures at Power Plants (316(b) Rule)

On May 19, 2014, the EPA issued a final rule under section 316(b) of the Clean Water Act (CWA) (33 U.S.C. section 1326(b)) (referred to hereinafter as the 316(b) rule.) The rule was published on August 15, 2014 (79 FR 48300; August 15, 2014), and became effective October 14, 2014. The 316(b) rule establishes new standards to reduce injury and death of fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities.[1037] The 316(b) rule subjects existing power plants and manufacturing facilities that withdraw in excess of 2 million gallons per day) of cooling water, and use at least 25 percent of that water for cooling purposes, to a national standard designed to reduce the number of fish destroyed through impingement and a national standard for establishing entrainment reduction requirements. All facilities subject to the rule must submit information on their operations for use by the permit authority in determining 316(b) permit conditions. Certain plants that withdraw very large volumes of water will also be required to conduct additional studies for use by the permit authority in determining the site-specific entrainment reduction measures for such facilities. The rule provides significant flexibility for compliance with the impingement standards and, as a result, is not projected to

[1037] CWA section 316(b) provides that standards applicable to point sources under sections 301 and 306 of the Act must require that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.

impose a substantial cost burden on affected facilities. With respect to entrainment, the rule calls upon the permitting authority to establish appropriate entrainment reduction measures, taking into account, among other factors, remaining useful plant life and quantified and qualitative social benefits and cost. The permit writer may also consider impacts on the reliability of energy delivery within the facility’s immediate area. Existing sources subject to the 316(b) rule are required to comply with the impingement requirements as soon as practicable after the entrainment requirements are determined. They must comply with applicable site-specific entrainment reduction controls based on the schedule of requirements established by the permitting authority.

4. Disposal of Coal Combustion Residuals from Electric Utilities (CCR Rule)

On December 19, 2014, the EPA issued the final rule for the disposal of coal combustion residuals from electric utilities. The rule provides a comprehensive set of requirements for the safe disposal of coal combustion residuals (CCRs), commonly known as coal ash, from coal-fired power plants. The CCR rule is the culmination of extensive study on the effects of coal ash on the environment and public health. The CCR rule establishes technical requirements for existing and new CCR landfills and surface impoundments under Subtitle D of the Resource

Conservation and Recovery Act, the nation's primary law for regulating solid waste.

These regulations address the risks from coal ash disposal -- leaking of contaminants into ground water, blowing of contaminants into the air as dust, and the catastrophic failure of coal ash surface impoundments by establishing requirements for where CCR landfills and surface impoundments may be located, how they must be designed, operated and monitored, when they must be inspected, and how they must be closed and cared for after closure. Additionally, the CCR rule sets out recordkeeping and reporting requirements, as well as the requirement for each facility to establish and post specific information to a publicly-accessible website. The final rule also supports the responsible recycling of CCRs by distinguishing safe, beneficial use from disposal.

5. Steam Electric Effluent Limitation Guidelines and Standards (SE ELG Rule)

The EPA is reviewing public comments and working to finalize the proposed SE ELG rule which will impact existing fossil fuel-fired EGUs. In 2013, the EPA proposed the SE ELG rule (78 FR 34432; June 7, 2013) to strengthen the controls on discharges from certain steam electric power plants by revising technology-based effluent limitations guidelines and standards for the steam electric power generating point source category.

The current regulations, which were last updated in 1982, do not adequately address the toxic pollutants discharged from the electric power industry, nor have they kept pace with process changes that have occurred over the last three decades. Existing steam electric power plants currently contribute 50-60 percent of all toxic pollutants discharged to surface waters by all industrial categories regulated in the U.S. under the CWA. Furthermore, power plant discharges to surface waters are expected to increase as pollutants are increasingly captured by air pollution controls and transferred to wastewater discharges. The proposed regulation, which includes new requirements for both existing and new generating units, would reduce impacts to human health and the environment by reducing the amount of toxic metals and other pollutants currently discharged to surface waters from power plants. The EPA intends to take final action on the proposed rule by September 30, 2015.

The EPA is endeavoring to enable EGUs to comply with applicable obligations under other power sector rules as efficiently as possible (e.g., by facilitating their ability to coordinate planning and investment decisions with respect to those rules) and, where possible, implement integrated compliance strategies. For example, in the proposed SE ELG rule, the EPA describes its thinking on how it might effectively harmonize the potential requirements of that rule with the requirements of the final CCR rule. Because these two rules affect similar units and may be met with similar compliance strategies, common-sense implementation timeframes were established in the CCR final rule so that utilities would not be required to make major decisions about CCR units without first understanding the implications that such decisions would have for meeting the surface water protection requirements of the final ELG rule. The EPA is taking into account these new CCR requirements for coal ash as it develops the final SE ELG rule. The EPA's goal in harmonizing the SE ELG and CCR rules is to minimize the overall complexity of the two regulatory structures and avoid creating unnecessary burden.

6. Other EPA Rules

In addition to the power sector rules discussed above, the development of SIPs for criteria pollutants (ozone, $PM_{2.5}$, and SO_2) and regional haze may also have implications for existing fossil-fired EGUs.

Regarding ozone, the proposal included a discussion of the June 6, 2013, proposed implementation rule for the 2008 ozone National Ambient Air Quality Standards (NAAQS), addressing the statutory requirements for areas EPA has designated as nonattainment for the 2008 ozone NAAQS. The final implementation rule for the 2008 ozone NAAQS was signed on February 13, 2015, and published on March 6, 2015, with an effective date of April

6, 2015. In general, the 2008 ozone NAAQS implementation rule interprets applicable statutory requirements and provides flexibility to states to minimize administrative burdens associated with developing and implementing plans to meet and maintain the NAAQS. The rule establishes due dates for attainment plans and clarifies attainment dates for each ozone nonattainment area according to its classification based on air quality thresholds, with attainment dates starting in July 2015 through July 2032 depending on an area's classification.

On November 25, 2014, the EPA Administrator signed the proposed rulemaking for the 2015 revisions to the ozone NAAQS. The proposal was published in the Federal Register on December 17, 2014 (79 FR 75234). The Administrator proposed to revise the primary ozone standard to a level in the range of 0.065 to 0.070 ppm and took comment on lower levels including 0.060 ppm and on retaining the current standard of 0.075 ppm. Among other things, the ozone NAAQS proposal also proposed to retain the current indicator, averaging time, and form of the standard and included a proposed secondary ozone NAAQS in the 0.065 to 0.070 ppm range.

The proposal also outlined the key implementation milestones requiring revised SIPs, with due dates starting in October 2018 for infrastructure and interstate transport SIPs, attainment plans due 2020-21, and attainment dates of 2020-37.

The EPA is under a court order to finalize its review of the ozone NAAQS by October 1, 2015.

Some commenters expressed concern with the potential impact proposed revisions to the ozone NAAQS could have on state planning efforts and affected entities' ability to comply with any potentially new requirements associated with a revised ozone NAAQS and those related to the 111(d) emission guidelines. In particular, commenters raised issues with a potentially more stringent ozone standard and the permitting and state planning implications this may create. While there was no discussion of the proposed revisions to the ozone NAAQS in the 111(d) emission guidelines proposal, commenters expressed a desire for the EPA to coordinate promulgation of the final 111(d) emission guidelines (and any other climate regulations) with the potential revision to the ozone standard to provide certainty and flexibility for states and affected sources.

While it is premature to speculate about the outcome of the ozone NAAQS review and how a more stringent ozone NAAQS may impact sources of ozone precursor emissions, including EGUs, we believe the planning and compliance timeframes that would follow from a revised ozone NAAQS and the timeframes we are finalizing today for submittal of the CAA section 111(d) state plans will allow considerable time for coordination by states in the development of their respective plans, as needed. As stated in the proposal, the EPA is prepared to work with states to assist them in coordinating their efforts across these planning processes.

Regarding $PM_{2.5}$ NAAQS implementation, the proposal stated that the EPA was developing a proposed implementation rule to provide guidance to states on the development of SIPs for the 2012 $PM_{2.5}$ NAAQS. The proposed $PM_{2.5}$ SIP requirements rule was signed on March 10, 2015, and published on March 23, 2015 (80 FR 15340). The proposal addresses a number of requirements including attainment plan due dates, attainment dates and attainment date extension criteria for Moderate and Serious nonattainment areas; determination criteria for Reasonably Available Control Measures (RACM) for Moderate areas and Best Available Control Measures (BACM) for Serious areas; plans for demonstrating reasonable further progress and for meeting periodic quantitative milestones; and criteria for reclassifying a Moderate nonattainment area to Serious. The EPA is planning to finalize the $PM_{2.5}$ implementation rule in early 2016.

There are currently only 9 areas designated nonattainment for the 2012 $PM_{2.5}$ NAAQS, with an effective date of April 15, 2015. Since the attainment plans for these areas must be completed and submitted to the EPA in September 2016, we expect that the four states with such areas should have already decided on their approach to implementing the 2012 $PM_{2.5}$ NAAQS when they begin to develop their plans for implementing the 111(d) guidelines, and will be able to coordinate the two.

Related to the SO_2 NAAQS, and as stated in the proposal, the SO_2 NAAQS was revised in June 2010 to protect public health from the short-term effects of SO_2 exposure. In July 2013, the EPA designated 29 areas in 16 states as nonattainment for the SO_2 NAAQS. The EPA based these nonattainment designations on the most recent set of certified air quality monitoring data as well as an assessment of nearby emission sources and weather patterns that contribute to the monitored levels. The date for attainment plans for these areas to be completed and submitted to the EPA was April 2015. As such, we expect states with such areas to have already decided on their approach to implementing the SO_2 NAAQS as they start planning for implementation of the 111(d) guidelines, which should allow for coordination and consideration of SO_2 related air quality measures into their 111(d) planning. The EPA intends to address the designations for all other areas in three separate actions in the future.[1038] These

[1038] The EPA has developed a comprehensive implementation strategy for these future actions that focuses resources on identifying and addressing unhealthy levels of SO_2 in areas where people are most likely to be exposed to violations of the standard. The strategy is available at http://www.epa.gov/airquality/sulfurdioxide/implement.html, and the associated area designations schedule is at http://www.epa.gov/airquality/sulfurdioxide/designations/pdfs/201503Schedule.pdf.

designations must be completed by no later than July 2, 2016, December 31, 2017, and December 31, 2020 with attainment plans due between 2018 and 2022.

Regarding requirements under the regional haze program, several affected EGUs have deadlines in the 2016-2021 timeframe to install controls to comply with the Best Available Retrofit Technology (BART) and reasonable progress requirements of the Regional Haze Rule. Soon after these deadlines, some of the same affected EGUs may be required to reduce their utilization, convert into natural gas-fired facilities, or shut down entirely as a result of state 111(d) plans. Some commenters have expressed concern that for these affected EGUs, specifically those that choose to retire, the capital equipment installed to comply with the Regional Haze Rule would likely become stranded assets.

While the EPA is providing considerable flexibility for states and sources under the final 111(d) emission guidelines, the EPA acknowledges the possibility that some sources could ultimately be faced with the potential for stranded assets as a result of state 111(d) plans. For these sources, however, states have the option of developing BART alternatives that replace control requirements that would otherwise result in stranded assets at a particular EGU with the aggregate emission reductions that will result from retirements, fuel switching, reduced utilization, or lesser controls at multiple EGUs.

In fact, the EPA already has experience working with states to account for these very types of changed circumstances.[1039] The EPA will continue to work with states to explore options for integrating compliance requirements across multiple regulatory programs, as warranted.

The EPA believes that CAA section 111(d) efforts and actions will tend to contribute to overall air quality improvements and thus should be complementary to criteria pollutant and regional haze SIP efforts.

7. Final Rule Flexibilities

As discussed in Section VIII of this preamble, the EPA is providing states flexibility in developing approvable plans under CAA section 111(d), including the ability to impose

[1039] For example, Oregon replaced its BART determination for the Boardman Coal Plant with a new requirement that accounted for a planned shutdown before the EPA took action on the state's SIP submission (76 FR 12661). Washington similarly replaced its BART determination for the TransAlta Centralia Power Plant before the EPA took action on the state's SIP submission (77 FR 72742). Oklahoma submitted a SIP revision with a new BART determination for the AEP/PSO Northeastern Power Station, which included enforceable requirements for reduced utilization and early unit retirements, to replace a FIP that had been promulgated by the EPA (79 FR 12944). Finally, the EPA finalized a BART determination for Unit 3 at the Dave Johnston Power Plant in Wyoming that included two compliance options, one of which included a federally enforceable retirement date and less costly controls.

source-by-source limitations reflecting the BSER performance rates to each affected EGU or to adopt rate-based or mass-based emission performance goals, and to rely on a wide range of CO_2 emission reduction measures, including measures that are not part of the BSER. The EPA is also providing states considerable flexibility with respect to the timeframes for plan development and implementation, with up to 3 years permitted for final plans to be submitted after the GHG emission guidelines are finalized, and up to 15 years for all emission reduction measures to be fully implemented. The EPA is establishing an 8-year interim period over which to achieve the full required reductions to meet the CO_2 performance rates, and this begins in 2022, more than seven years from the June 18, 2014 date of proposal of the rulemaking. The 8-year interim period from 2022 through 2029, is separated into three steps, 2022-2024, 2025-2027, and 2028-2029, each associated with its own interim CO_2 emission performance rates.

In light of these broad flexibilities, we believe that states will have ample opportunity, when developing and implementing their CAA section 111(d) plans, to coordinate their response to this requirement with source and state responses to any obligations that may be applicable to affected EGUs as a result of the MATS, CSAPR, 316(b), SE ELG and CCR rules, all of which are or soon will be final rules. In addition, we believe that states will be able to design CAA section 111(d) plans that use innovative, cost-effective regulatory strategies, that spark investment and innovation across a wide variety of clean energy technologies, and that will help reduce cost and ensure reliability, while also ensuring that all applicable environmental requirements are met.[1040] We also believe that the broad flexibilities in this action will enable states and affected EGUs to build on their longstanding, successful records of complying with multiple CAA, CWA, and other environmental requirements, while assuring an adequate, affordable, and reliable supply of electricity.

XI. Impacts of the Final Action[1041]

A. What are the air impacts?

The EPA anticipates significant emission reductions under the final guidelines for the utility power sector. In the final

[1040] It should be noted that regulatory obligations imposed upon states and sources operate independently under different statutes and sections of statutes; the EPA expects that states and sources will take advantage of available flexibilities as appropriate, but will comply with all relevant legal requirements.

[1041] The impacts presented in this section of the preamble represent an illustrative implementation of the guidelines. As states implement the final guidelines, they have sufficient flexibility to adopt different state-level or regional approaches that may yield different costs, benefits, and environmental impacts. For example, states may use the flexibilities described in these guidelines to find approaches that are more cost-effective for their particular state or choose approaches that shift the balance of co-benefits and impacts to match broader state priorities.

emission guidelines, the EPA has translated the source category-specific CO_2 emission performance rates into equivalent state-level rate-based and mass-based CO_2 goals in order to maximize the range of choices that states will have in developing their plans. Because of the range of choices available to states and the lack of *a priori* knowledge about the specific choices states will make in response to the final goals, the Regulatory Impact Analysis (RIA) for this final action presents two scenarios designed to achieve these goals, which we term the "rate-based" illustrative plan approach and the "mass-based" illustrative plan approach.[1042]

Under the rate-based approach, when compared to 2005, CO_2 emissions are projected to be reduced by approximately 22 percent in 2020, 28 percent in 2025, and 32 percent in 2030. Under the mass-based approach, when compared to 2005, CO_2 emissions are projected to be reduced by approximately 23 percent in 2020, 29 percent in 2025, and 32 percent in 2030. The final guidelines are projected to result in substantial co-

[1042] It is important to note that the differences between the analytical results for the rate-based and mass-based illustrative plan approaches presented in the RIA may not be indicative of likely differences between the approaches if implemented by states and affected EGUs in response to the final guidelines. If one approach performs differently than the other on a given metric during a given time period, this does not imply this will apply in all instances.

benefits through reductions of SO_2, NO_X and $PM_{2.5}$ that will have direct public health benefits by lowering ambient levels of these pollutants and ozone. Tables 15 and 16 show expected CO_2 and other air pollutant emissions in the base case and reductions under the final guidelines for 2020, 2025, and 2030 for the rate-based and mass-based approaches, respectively.

Table 15. Summary of CO_2 and Other Air Pollutant Emission Reductions from the Base Case under Rate-based Illustrative Plan Approach

	CO_2 (millions short tons)	SO_2 (thousand short tons)	NO_X (thousand short tons)
2020 Final Guidelines			
Base Case	2,155	1,311	1,333
Final Guidelines	2,085	1,297	1,282
Emissions Reductions	69	14	50
2025 Final Guidelines			
Base Case	2,165	1,275	1,302
Final Guidelines	1,933	1,097	1,138
Emissions Reductions	232	178	165
2030 Final Guidelines			
Base Case	2,227	1,314	1,293
Final Guidelines	1,812	996	1,011
Emissions Reductions	415	318	282

Source: Integrated Planning Model, 2015.
Note: Emissions may not sum due to rounding.

Table 16. Summary of CO_2 and Other Air Pollutant Emission Reductions from the Base Case under Mass-based Illustrative Plan Approach

	CO_2 (million short tons)	SO_2 (thousand short tons)	NO_X (thousand short tons)
2020 Final Guidelines			
Base Case	2,155	1,311	1,333
Final Guidelines	2,073	1,257	1,272
Emissions Reductions	81	54	60

2025 Final Guidelines			
Base Case	2,165	1,275	1,302
Final Guidelines	1,901	1,090	1,100
Emissions Reductions	265	185	203
2030 Final Guidelines			
Base Case	2,227	1,314	1,293
Final Guidelines	1,814	1,034	1,015
Emissions Reductions	413	280	278

Source: Integrated Planning Model, 2015.
Note: Emissions may not sum due to rounding.

The reductions in Tables 15 and 16 do not account for reductions in hazardous air pollutants (HAPs) that may occur as a result of this rule. For instance, the fine particulate reductions presented above do not reflect all of the reductions in many heavy metal particulates.

B. Endangered Species Act

As explained in the preamble to the proposed rule (79 FR at 34933-934), the EPA has carefully considered the requirements of section 7(a)(2) of the Endangered Species Act (ESA) and applicable ESA regulations, and reviewed relevant ESA case law and guidance, to determine whether consultation with the U.S. Fish and Wildlife Service (FWS) and/or National Marine Fisheries Service (together, the Services) is required by the ESA. The EPA proposed to conclude that the requirements of ESA section 7(a)(2) would not be triggered by promulgation of the rule, and we now finalize that determination.

Section 7(a)(2) of the ESA requires federal agencies, in consultation with one or both of the Services (depending on the species at issue), to ensure that actions they authorize, fund, or carry out are not likely to jeopardize the continued existence of federally listed endangered or threatened species or result in the destruction or adverse modification of designated critical habitat of such species. 16 U.S.C. 1536(a)(2). Under relevant implementing regulations, section 7(a)(2) applies only to actions where there is discretionary federal involvement or control. 50 CFR 402.03. Further, under the regulations consultation is required only for actions that "may affect" listed species or designated critical habitat. 50 CFR section 402.14. Consultation is not required where the action has no effect on such species or habitat. Under this standard, it is the federal agency taking the action that evaluates the action and determines whether consultation is required. *See* 51 FR 19926, 19949 (June 3, 1986). Effects of an action include both the direct and indirect effects that will be added to the environmental baseline. 50 CFR 402.02. Direct effects are the direct or immediate effects of an action on a listed species or its habitat.[1043] Indirect effects are those that

[1043] *See* Endangered Species Consultation Handbook, U.S. Fish & Wildlife Service and National Marine Fisheries Service at 4-25 (March 1998) (providing examples of direct effects: *e.g.*, are "caused by the proposed action and are later in time, but still are reasonably certain to occur." *Id.* To trigger the consultation requirement, there must thus be a causal connection between the federal action, the effect in question, and the listed species, and if the effect is indirect, it must be reasonably certain to occur.

The EPA notes that the projected environmental effects of this rule are positive: reductions in overall GHG emissions, and reductions in PM and ozone-precursor emissions (SO_2 and NO_X). The EPA recognizes that beneficial effects to listed species can, as a general matter, result in a "may affect" determination under the ESA. However, the EPA's assessment that the rule will have an overall net positive environmental effect by virtue of reducing emissions of certain air pollutants does not address whether the rule may affect any listed species or designated critical habitat for ESA section 7(a)(2) purposes and does not constitute any finding of effects for that purpose. The fact that the rule will have overall positive effects on the national and global environment does not mean that the rule may affect any listed species in its habitat or the designated critical habitat of such species within the meaning of ESA section

driving an off road vehicle through the nesting habitat of a listed species of bird and destroying a ground nest; building a housing unit and destroying the habitat of a listed species).

7(a)(2) or the implementing regulations or require ESA consultation. The EPA has considered various types of potential effects in reaching the conclusion that ESA consultation is not required for this rule.

With respect to the projected GHG emission reductions, the EPA considered in detail in the proposal why such reductions do not trigger ESA consultation requirements under section 7(a)(2). As explained in the proposal, in reaching this conclusion the EPA was mindful of significant legal and technical analysis undertaken by FWS and the U.S. Department of the Interior (DOI) in the context of listing the polar bear as a threatened species under the ESA. In that context, in 2008, FWS and DOI expressed the view that the best scientific data available were insufficient to draw a causal connection between GHG emissions and effects on the species in its habitat.[1044] The DOI Solicitor concluded that where the effect at issue is climate change, proposed actions involving GHG emissions cannot pass the "may affect" test of the section 7 regulations and thus are not subject to ESA consultation.

[1044] *See, e.g.*, 73 FR 28212, 28300 (May 15, 2008); Memorandum from David Longly Bernhardt, Solicitor, U.S. Department of the Interior re: ''Guidance on the Applicability of the Endangered Species Act's Consultation Requirements to Proposed Actions Involving the Emission of Greenhouse Gases'' (Oct. 3, 2008).

As described in the proposal, the EPA has also previously considered issues relating to GHG emissions in connection with the requirements of ESA section 7(a)(2) and has supplemented DOI's analysis with additional consideration of GHG modeling tools and data regarding listed species. Although the GHG emission reductions projected for this final rule are large (estimated reductions of about 415 million short tons of CO_2 in 2030 relative to the base case under the rate-based illustrative plan approach– see Table 14 above), the EPA evaluated larger reductions in assessing this same issue in the context of the light duty vehicle GHG emission standards for model years 2012-2016 and 2017-2025. There the agency projected emission reductions over the lifetimes of the model years in question[1045] which are roughly five to six times those projected above and, based on air quality modeling of potential environmental effects, concluded that "EPA knows of no modeling tool which can link these small, time-attenuated changes in global metrics to particular effects on listed species in particular areas. Extrapolating from global metric to local effect with such small numbers, and accounting for further links in a causative chain, remain beyond current modeling capabilities." EPA, *Light Duty Vehicle Greenhouse Gas Standards and Corporate Average Fuel*

[1045] *See* 75 FR at 25438 Table I.C 2-4 (May 7, 2010); 77 FR at 62894 Table III-68 (Oct. 15, 2012).

Economy Standards, Response to Comment Document for Joint Rulemaking at 4-102 (Docket EPA-OAR-HQ-2009-4782). The EPA reached this conclusion after evaluating issues relating to potential improvements relevant to both temperature and oceanographic pH outputs. The EPA's ultimate finding was that "any potential for a specific impact on listed species in their habitats associated with these very small changes in average global temperature and ocean pH is too remote to trigger the threshold for ESA section 7(a)(2)."*Id.* The EPA believes that the same conclusion applies to the present rule. *See, e.g., Ground Zero Center for Non-Violent Action* v. *U.S. Dept. of Navy,* 383 F. 3d 1082, 1091-92 (9th Cir. 2004) (where the likelihood of jeopardy to a species from a federal action is extremely remote, ESA does not require consultation). The EPA's conclusion is entirely consistent with DOI's analysis regarding ESA requirements in the context of federal actions involving GHG emissions.[1046]

[1046] The EPA has received correspondence from a U.S. Senator and a Member of the U.S. House of Representatives noting that the Services have identified several listed species affected by global climate change. *See* Letter from Rob Bishop, Chairman, House Committee on Natural Resources, to Gina McCarthy, Administrator, U.S. Environmental Protection Agency, dated June 11, 2015; Letter from Rob Bishop, Chairman, House Committee on Natural Resources, and James M. Inhofe, Chairman, Senate Committee on Environment and Public Works, to Gina McCarthy, Administrator, U.S. Environmental Protection Agency, dated June 15, 2015. EPA's assessment of ESA requirements in connection

With regard to non-GHG air emissions, the EPA also projects substantial reductions of SO_2 and NO_X as a collateral consequence of this final action. However, CAA section 111(d)(1) standards cannot directly control emissions of criteria pollutants. See CAA section 111(d)(1)(i). Consequently, CAA section 111(d) provides no discretion to adjust the standard based on potential impacts to endangered species of reduced criteria pollutant emissions. Section 7(a)(2) consultation thus is not required with respect to the projected reductions of criteria pollutant emissions. *See* 50 CFR 402.03; *see also, WildEarth Guardians v. U.S. Envt'l Protection Agency,* 759 F.3d 1196, 1207-10 (10th Cir. 2014) (EPA has no duty to consult under section 7(a)(2) of the ESA regarding hazardous air pollutant controls that it did not require – and likely lacked authority to require – in a federal implementation plan for regional haze controls under section 169A of the CAA).

Finally, the EPA has also considered other potential effects of the rule (beyond reductions in air pollutants) and

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with the present rule does not address whether global climate change may, as a general matter, be a relevant consideration in the status of certain listed species. Rather, the requirements of ESA section 7(a)(2) must be considered and applied to the specific action at issue. As explained above, EPA's conclusion that ESA section 7(a)(2) consultation is not required here is premised on the specific facts and circumstances of the present rule and is fully consistent with prior relevant analyses conducted by DOI, FWS, and EPA.

whether any such effects are "caused by" the rule and "reasonably certain to occur" within the meaning of the ESA regulatory definition of the effects of an action. 50 CFR 402.02. As the EPA noted in the proposal, there are substantial questions as to whether any potential for relevant effects results from any element of the rule or would result instead from separate decisions and actions made in connection with the development, implementation, and enforcement of a plan to implement the standards established in the rule. *Cf. American Trucking Assn's* v. *EPA,* 175 F. 3d 1027, 1043-45 (D.C. Cir. 1999), *rev'd on different grounds sub nom., Whitman* v. *American Trucking Assn's,* 531 U.S. 457 (2000) (National Ambient Air Quality Standards have no economic impact, for purposes of Regulatory Flexibility Act, because impacts result from the actions of states through their development, implementation and enforcement of SIPs).[1047] The EPA recognized, for instance, that

[1047] One commenter questioned the EPA's citation to *American Trucking Assn's.* As stated by the commenter, the statute at issue in that case – the Regulatory Flexibility Act (RFA) – is distinguishable from the ESA in that it addresses only direct effects and does not consider indirect effects. The commenter misreads the EPA's citation to this case. The EPA cites this case simply to reference a decision considering the impacts of an EPA action – the revision of a NAAQS under the CAA– that in certain respects provides a useful analogy to the present rule. A NAAQS is implemented through a series of subsequent planning decisions generally taken by states by means of adoption of SIPs. States can choose to impose or avoid the types of impacts at issue in the D.C. Circuit case through their planning questions may exist whether decisions such as increased utilization of solar or wind power could have effects on listed species. The EPA received comments on the proposal asserting that because potential increased reliance on wind or solar power may be an element of building block 3, and because wind and solar facilities may in some cases have effects on listed species, the EPA must consult under the ESA on this aspect of the rule. The EPA is also aware of certain questions regarding potential effects of the rule on the Big Bend Power Station located in Florida, which discharges effluent that provides a warm water refuge for manatees. The Big Bend Power Station and another coal-fired facility located in Florida – the Crystal

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decisions; thus such impacts were not viewed as having been caused – for purposes of the RFA – by the EPA's promulgation of the revised NAAQS in the first instance. The standard setting and implementation mechanisms under section 111(d) are very similar. Under section 111(d), the EPA is required to establish "a procedure similar to that provided by section 7410" – the provision establishing the SIP mechanism for implementing NAAQS. Thus, the D.C. Circuit's discussion provides a useful analogy to the present rule and the various types of potential effects that may be attributable to future implementation planning decisions by states and other entities as they exercise their discretion in determining how to implement the federal guidelines, but not to promulgation of the rule itself. The EPA's citation to this case was not intended to address any comparison of the scope of effects covered by the RFA and the effects cognizable under section 7(a)(2) of the ESA. The EPA is aware that the ESA addresses both direct and indirect effects as defined by the applicable ESA regulations. The discussion supporting the EPA's ESA conclusion expressly acknowledges the relevance of indirect effects to the ESA analysis and explains why such effects are not present here.

River Plant – are, for example, referenced in the June 11, 2015, and June 15, 2015, congressional letters to EPA cited above.

The EPA has carefully considered the comments and the correspondence from Congress as well as the case law and other materials cited in those documents. The EPA does not believe that the effects of potential future changes in the energy sector – including increased reliance on wind or solar power as a result of future potential actions by states or other implementing entities – or any potential alterations in the operations of any particular facility are caused by the current rule or sufficiently certain to occur so as to require ESA consultation on the rule. The EPA appreciates that the ESA regulations call for consultation where actions authorized, funded, or carried out by federal agencies may have indirect effects on listed species or designated critical habitat. However, as noted above, indirect effects must be caused by the action at issue and must be reasonably certain to occur. At this point, there is no reasonable certainty regarding implementation of any planning measures in any location, let alone in any location occupied by a listed species or its designated critical habitat. The EPA cannot predict with reasonable certainty where such measures may take effect or which measures may be adopted. It is not clear, for instance, whether a particular implementation plan will call, if at all, for increased reliance on wind power, as opposed to solar power, or on some other form of low or zero carbon emitting generation. It is also entirely uncertain how a future implementation plan for a particular state might affect, if at all, operations at a specific facility.[1048] The precise steps included in an implementation plan cannot be determined or ordered by this federal action, and they are not sufficiently certain to be attributable to this final rule for ESA purposes. These steps will flow from a series of later in time decisions generally made by other entities – usually states – in their distinct planning processes. These later decisions cannot now be required by the rule, are not caused by the rule, and are not reasonably certain to occur. The EPA also notes that the plans adopted for particular states may themselves provide wide degrees of implementation flexibility, thus further increasing the uncertainty that any species-

[1048] A congressional letter of June 11, 2015, referenced above asserts that EPA's modeling suggests that the Big Bend Power Station and Crystal River Energy Complex in Florida will be prematurely retired as a result of the rule. EPA notes that any such facility-level projections associated with the rule cannot be stated with sufficient certainty to qualify as potential indirect effects under the ESA. These projections are based on numerous assumptions regarding a variety of planning and business decisions yet to be made by the implementing governments (usually states) and facility owners. Given the wide degrees of discretion and flexibility and the numerous options available for such decision making, the potential for such outcomes to be realized as currently projected is at this point too uncertain to qualify as an effect under the ESA.

impacting activity will occur in any particular location, if at all. The Services have explained that section 7(a)(2) was not intended to preclude federal actions based on potential future speculative effects.[1049] These are precisely the types of speculative future activities and effects at issue here.[1050] For this additional reason, the EPA concludes that the rule does not

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[1049] *See* 51 FR at 19933 (describing effects that are "reasonably certain to occur" in the context of consideration of cumulative effects and distinguishing broader consideration that may be appropriate in applying a procedural statute such as the National Environmental Policy Act, as opposed to a substantive provision such as ESA section 7(a)(2) that may prohibit certain federal actions); Endangered Species Consultation Handbook, U.S. Fish & Wildlife Service and National Marine Fisheries Service at 4-30 (March 1998) (in the same context, describing indicators that an activity is reasonably certain to occur as including governmental approvals of the action or indications that such approval is imminent, project sponsors' assurance that the action will proceed, obligation of venture capital, or initiation of contracts; and noting that the more governmental administrative discretion remains to be exercised, the less there is reasonable certainty the action will proceed).

[1050] EPA also notes that some of the future implementing activities may involve federal actions that are subject to ESA consultation, thus providing consideration of any impacts on listed species at the appropriate point when particular activities have become reasonably certain. Several commenters on the proposal specifically noted that such future activities – *e.g.*, development of additional RE facilities such as wind farms – may call for ESA consultation. Further, EPA notes that section 9 of the ESA, which prohibits the take of individuals of most listed species, provides an additional protection for listed species as future implementing activities become reasonably certain.

have effects on listed species that trigger the section 7(a)(2) consultation requirement.[1051]

C. What are the energy impacts?

The final guidelines have important energy market implications. Table 17 presents a variety of important energy

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[1051] The commenters cite certain cases that they assert support consulting under ESA section 7(a)(2). The EPA has considered these cases, each of which is distinguishable from the present rule. By way of example, a commenter cites two cases involving EPA actions: *Defenders of Wildlife v. EPA*, 420 F.3d 946 (9th Cir. 2005), *rev'd*, *National Association of Homebuilders v. Defenders of Wildlife*, 551 U.S. 644 (2007); and *Washington Toxics Coalition v. EPA*, 413 F.3d 1024 (9th Cir. 2005). In *Defenders of Wildlife* (a decision that was reversed by the U.S. Supreme Court), a principal relevant impact of the federal action at issue – the EPA's approval of a state's permitting program under the Clean Water Act – was that following the action, the relevant permitted activities would no longer be subject to consultation under the ESA. By contrast, promulgation of the present rule will result in no change to any ESA requirements applicable to any future activities directed by plans (either state or federal) implementing the rule. The action at issue in *Washington Toxics Coalition* involved the EPA's registration of certain pesticide active ingredients under the Federal Insecticide, Fungicide, and Rodenticide Act. Such actions provide authorization for the sale and distribution of those products, consistent with applicable labelling requirements. The EPA also notes that under the EPA's regulations, registered pesticide labels must, among other things, specify the product ingredients and the methods and sites of product application. 40 CFR 156.10. By contrast, the present rule only sets goals and describes potential pathways to meeting those goals, all of which are subject to future considerations and decisions involved in the implementation of plans (generally by states). The rule neither authorizes, nor directs, any of the future measures to meet the rule's goals. Those activities remain subject to the full range of future decision making addressing which types of measures to implement, what emitting entities will be affected, how much, and when.

market impacts for 2020, 2025, and 2030 under both the rate-based and mass-based illustrative plan approaches.

Table 17. Summary Table of Important Energy Market Impacts for Rate-based and Mass-based Illustrative Plan Approaches (Percent Change from Base Case)

	Rate-Based			Mass-Based		
	2020	**2025**	**2030**	**2020**	**2025**	**2030**
Retail electricity prices	3%	1%	1%	3%	2%	0%
Price of coal at minemouth	-1%	-5%	-4%	-1%	-5%	-3%
Coal production for power sector use	-5%	-14%	-25%	-7%	-17%	-24%
Price of natural gas delivered to power sector	5%	-8%	2%	4%	-3%	-2%
Natural gas use for electricity generation	3%	-1%	-1%	5%	0%	-4%

These figures reflect the EPA's illustrative modeling that presumes policies that lead to generation shifts and growing use of demand-side EE and renewable electricity generation out to 2029. If states make different policy choices, impacts could be different. For instance, if states implement renewable and/or demand-side EE policies on a more aggressive time-frame, impacts on natural gas and electricity prices would likely be less. Implementation of other measures not included in the BSER calculation or compliance modeling, such as nuclear uprates, transmission system improvements, use of energy storage technologies or retrofit CCS, could also mitigate gas price and/or electricity price impacts.

Energy market impacts from the guidelines are discussed more extensively in the RIA found in the docket for this rulemaking.

D. What are the compliance costs?

The compliance costs of this final action are represented in this analysis as the change in electric power generation costs between the base case and the final rule in which states pursue a distinct set of strategies beyond the strategies taken in the base case to meet the terms of the final guidelines. The compliance costs estimates include cost estimates for demand-side EE. The compliance assumptions – and, therefore, the projected compliance costs - set forth in this analysis are illustrative in nature and do not represent the full suite of compliance flexibilities states may ultimately pursue. The illustrative analysis is designed to reflect, to the extent possible, the scope and the nature of the final guidelines. However, there is considerable uncertainty with regards to the precise measures that states will adopt to meet the final requirements, because there are considerable flexibilities afforded to the states in developing their state plans.

The incremental cost is the projected additional cost of complying with the guidelines in the year analyzed and includes the amortized cost of capital investment, needed new capacity, shifts between or amongst various fuels, deployment of demand-side EE programs, and other actions associated with compliance. These important dynamics are discussed in more detail in the RIA in the rulemaking docket.

The EPA estimates the annual incremental compliance cost for the rate-based approach for final emission guidelines to be $2.5 billion in 2020, $1.0 billion in 2025 and $8.4 billion in 2030, including the costs associated with monitoring, reporting, and recordkeeping (MR&R).[1052] The EPA estimates the annual incremental compliance cost for the mass-based approach for final emission guidelines to be $1.4 billion in 2020, $3.0 billion in 2025 and $5.1 billion in 2030, including the costs associated with MR&R.

More detailed cost estimates are available in the RIA included in the rulemaking docket.

E. What are the economic and employment impacts?

The final standards are projected to result in certain changes to power system operation as a compliance with the

[1052] The MR&R costs estimates are $65 million in 2020, $15 million in 2025 and $15 million in 2030 and are assumed to be the same for both rate-based and mass-based illustrative plan approaches.

standards. See Table 16 above for a variety of important energy market impacts for 2020, 2025, and 2030 under both the rate-based and mass-based illustrative plan approaches.

It is important to note that the EPA's modeling does not necessarily account for all of the factors that may influence business decisions regarding future coal-fired capacity. Many power companies already factor a potential financial liability associated with carbon emissions into their long term capacity planning that would further influence business decisions to replace these aging assets with modern, and significantly cleaner, generation.

The compliance modeling done to support the final rule assumes that overall electric demand will decrease as states ramp up programs that result in lower overall demand. Demand-side EE levels are expected to increase such that they achieve about a 7.8 percent reduction on overall electricity demand levels in 2030 under the final guidelines.

Changes in price or demand for electricity, natural gas, and coal can impact markets for goods and services produced by sectors that use these energy inputs in the production process or supply those sectors. Changes in the cost of production may result in changes in prices, quantities produced, and profitability of affected firms. The EPA recognizes that these guidelines provide significant flexibilities and states implementing the guidelines may choose to mitigate impacts to some markets outside the utility power sector. Similarly, demand for new generation or demand-side EE as a result of states implementing the guidelines can result in shifts in production and profitability for firms that supply those goods and services.

Executive Order 13563 directs federal agencies to consider the effect of regulations on job creation and employment. According to the Executive Order, "our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation. It must be based on the best available science." (Executive Order 13563, 2011) Although standard benefit-cost analyses have not typically included a separate analysis of regulation-induced employment impacts, we typically conduct employment analyses. While the economy continues moving toward full-employment, employment impacts are of particular concern and questions may arise about their existence and magnitude.

States have the responsibility and flexibility to implement policies and practices for compliance with the final guidelines. Quantifying the associated employment impacts is complicated by the wide range of approaches that states may use. As such, the EPA's employment analysis includes projected employment impacts associated with illustrative plan approaches for these guidelines for the electric power industry, coal and natural gas production, and demand-side EE activities. These projections are derived, in part, from a detailed model of the utility power sector used for this regulatory analysis, and U.S government data on employment and labor productivity. In the electricity, coal, and natural gas sectors, the EPA estimates that these guidelines could result in a net decrease of approximately 25,000 job-years in 2025 for the final guidelines under the rate-based illustrative plan approach and approximately 26,000 job-years in 2025 under the mass-based approach. For 2030, the estimates of the net decrease in job-years are 31,000 under the rate-based approach and 34,000 under the mass-based approach. The agency is also offering an illustrative calculation of potential employment effects due to demand-side EE programs. Employment impacts from demand-side energy EE programs in 2030 could range from approximately 52,000 to 83,000 jobs under the final guidelines.

By its nature, demand-side EE reduces overall demand for electric power. The EPA recognizes as more efficiency is built into the U.S. power system over time, lower fuel requirements may lead to fewer jobs in the coal and natural gas extraction sectors, as well as in fossil-fuel fired EGU construction and operation than would otherwise have been expected. The EPA also recognizes the fact that, in many cases, employment gains and losses that might be attributable to this rule would be expected to affect different sets of people. Moreover, workers who lose jobs in these sectors may find employment elsewhere just as workers employed in new jobs in these sectors may have been previously employed elsewhere. Therefore, the employment estimates reported in these sectors may include workers previously employed elsewhere. This analysis also does not capture potential economy-wide impacts due to changes in prices (of fuel, electricity, labor, for example) or other factors such as improved labor productivity and reduced health care expenditures resulting from cleaner air. For these reasons, the numbers reported here should not be interpreted as a net national employment impact.

F. What are the benefits of the final goals?

Implementing the final standards will generate benefits by reducing emissions of CO_2 and criteria pollutant precursors, including SO_2, NO_X, and directly-emitted particles. SO_2 and NO_X are precursors to $PM_{2.5}$ (particles smaller than 2.5 microns), and NO_X is a precursor to ozone. The estimated benefits associated with these emission reductions are beyond those achieved by previous EPA rulemakings including the Mercury and Air Toxics Standards rule. The health and welfare benefits from reducing air pollution are considered co-benefits for these standards.

For this rulemaking, we were only able to quantify the climate benefits from reduced emissions of CO_2 and the health co-benefits associated with reduced exposure to $PM_{2.5}$ and ozone. There are many additional benefits which we are not able to quantify, leading to an underestimate of monetized benefits. In summary, we estimate the total combined climate benefits and health co-benefits for the rate-based approach to be $3.5 to $4.6 billion in 2020, $18 to $28 billion in 2025, and $34 to $54 billion in 2030 (3 percent discount rate, 2011$). Total combined climate benefits and health co-benefits for the mass-based approach are estimated to be $5.3 to $8.1 billion in 2020, $19 to $29 billion in 2025, and $32 to $48 billion in 2030 (3 percent discount rate, 2011$). A summary of the emission reductions and monetized benefits estimated for this rule at all discount rates is provided in Tables 15 through 22 of this preamble.

Table 18. Summary of the Monetized Global Climate Benefits for the Final Guidelines (billions of 2011$)[a]

	Discount Rate (Statistic)	**Monetized Climate Benefits**		
YEAR		**2020**	**2025**	**2030**
		Rate-based Approach		
CO_2 Reductions (million short tons)		69	232	415
	5 percent (average SC-CO_2)	$0.80	$3.1	$6.4

	3 percent (average $SC\text{-}CO_2$)	$2.8	$10	$20
	2.5 percent (average $SC\text{-}CO_2$)	$4.1	$15	$29
	3 percent (95th percentile $SC\text{-}CO_2$)	$8.2	$31	$61
Mass-based Approach				
CO_2 Reductions (million short tons)		81	265	413
	5 percent (average $SC\text{-}CO_2$)	$0.94	$3.6	$6.4
	3 percent (average $SC\text{-}CO_2$)	$3.3	$12	$20
	2.5 percent (average $SC\text{-}CO_2$)	$4.9	$17	$29
	3 percent (95th percentile $SC\text{-}CO_2$)	$9.7	$35	$60

[a] Climate benefit estimates reflect impacts from CO_2 emission changes in the analysis years presented in the table and do not account for changes in non-CO_2 GHG emissions. These estimates are based on the global social cost of carbon ($SC\text{-}CO_2$) estimates for the analysis years and are rounded to two significant figures.

Table 19. Summary of the Monetized Health Co-Benefits in the U.S. for the Final Guidelines, Rate-based Approach (billions of 2011$)[a]

Pollutant	National Emission Reductions (thousands of short tons)	Monetized Health Co-benefits (3 percent discount)	Monetized Health Co-benefits (7 percent discount)
Final Guidelines, Rate-based Approach, 2020			
$PM_{2.5}$ precursors [b]			

SO_2	14	\$0.44 to \$0.99	\$0.39 to \$0.89
NO_X	50	\$0.14 to \$0.33	\$0.13 to \$0.30
Ozone precursor [c]			
NO_X (ozone season only)	19	\$0.12 to \$0.52	\$0.12 to \$0.52
Total Monetized Health Co-benefits		\$0.70 to \$1.8	\$0.64 to \$1.7
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		\$3.5 to \$4.6	\$3.5 to \$4.5
Final Guidelines, Rate-based Approach, 2025			
$PM_{2.5}$ precursors [b]			
SO_2	178	\$6.4 to \$14	\$5.7 to \$13
NO_X	165	\$0.56 to \$1.3	\$0.50 to \$1.1
Ozone precursor [c]			
NO_X (ozone season only)	70	\$0.49 to \$2.1	\$0.49 to \$2.1
Total Monetized Health Co-benefits		\$7.4 to \$18	\$6.7 to \$16
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		\$18 to \$28	\$17 to \$26
Final Guidelines, Rate-based Approach, 2030			
$PM_{2.5}$ precursors [b]			
SO_2	318	\$12 to \$28	\$11 to \$25
NO_X	282	\$1.0 to \$2.3	\$0.93 to \$2.1
Ozone precursor [c]			
NO_X (ozone season only)	118	\$0.86 to \$3.7	\$0.86 to \$3.7
Total Monetized Health Co-benefits		\$14 to \$34	\$13 to \$31
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		\$34 to \$54	\$33 to \$51

[a] All estimates are rounded to two significant figures, so estimates may not sum. It is important to note that the

monetized co-benefits do not include reduced health effects from direct exposure to SO_2, direct exposure to NO_2, exposure to mercury, ecosystem effects or visibility impairment. Air pollution health co-benefits are estimated using regional benefit-per-ton estimates for the contiguous U.S.

[b] The monetized $PM_{2.5}$ co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors, such as SO_2 and NO_X. The co-benefits do not include the benefits of reductions in directly emitted $PM_{2.5}$. These additional benefits would increase overall benefits by a few percent based on the analyses conducted for the proposed rule. PM co-benefits are shown as a range reflecting the use of two concentration-response functions, with the lower end of the range based on a function from Krewski et al. (2009) and the upper end based on a function from Lepeule et al. (2012). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[c] The monetized ozone co-benefits reflect the human health benefits associated with reducing exposure to ozone through reductions of NO_X during the ozone season. Ozone co-benefits are shown as a range reflecting the use of several different concentration-response functions, with the lower end of the range based on a function from Bell, et al. (2004) and the upper end based on a function from Levy, et al. (2005). Ozone co-benefits occur in the analysis year, so they are the same for all discount rates.

[d] We estimate climate benefits associated with four different values of a one ton CO_2 reduction (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). Referred to as the social cost of carbon, each value increases over time. For the purposes of this table, we show the benefits associated with the model average at 3 percent discount rate, however we emphasize the importance and value of considering the full range of social cost of carbon values. We provide combined climate and health estimates based on additional discount rates in the RIA.

Table 20. Summary of the Monetized Health Co-Benefits in the U.S. for the Final Guidelines, Mass-based Approach (billions of 2011$)[a]

Pollutant	National Emission Reductions	Monetized Health Co-benefits	Monetized Health Co-benefits

	(thousands of short tons)	(3 percent discount)	(7 percent discount)
Final Guidelines, Mass-based Approach, 2020			
$PM_{2.5}$ precursors [b]			
SO_2	54	\$1.7 to \$3.8	\$1.5 to \$3.4
NO_X	60	\$0.17 to \$0.39	\$0.16 to \$0.36
Ozone precursor [c]			
NO_X (ozone season only)	23	\$0.14 to \$0.61	\$0.14 to \$0.61
Total Monetized Health Co-benefits		\$2.0 to \$4.8	\$1.8 to \$4.4
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		\$5.3 to \$8.1	\$5.1 to \$7.7
Final Guidelines, Mass-based Approach, 2025			
$PM_{2.5}$ precursors [b]			
SO_2	185	\$6.0 to \$13	\$5.4 to \$12
NO_X	203	\$0.58 to \$1.3	\$0.52 to \$1.2
Ozone precursor [c]			
NO_X (ozone season only)	88	\$0.56 to \$2.4	\$0.56 to \$2.4
Total Monetized Health Co-benefits		\$7.1 to \$17	\$6.5 to \$16
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		\$19 to \$29	\$18 to \$27
Final Guidelines, Mass-based Approach, 2030			
$PM_{2.5}$ precursors [b]			
SO_2	280	\$10 to \$23	\$9.0 to \$20
NO_X	278	\$0.87 to \$2.0	\$0.79 to \$1.8
Ozone precursor [c]			
NO_X (ozone season only)	121	\$0.82 to \$3.5	\$0.82 to \$3.5
Total Monetized Health Co-benefits		\$12 to \$28	\$11 to \$26

Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]	$32 to $48	$31 to $46

[a] All estimates are rounded to two significant figures, so estimates may not sum. It is important to note that the monetized co-benefits do not include reduced health effects from direct exposure to SO_2, direct exposure to NO_2, exposure to mercury, ecosystem effects or visibility impairment. Air pollution health co-benefits are estimated using regional benefit-per-ton estimates for the contiguous U.S.
[b] The monetized $PM_{2.5}$ co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors, such as SO_2 and NO_X. The co-benefits do not include the benefits of reductions in directly emitted $PM_{2.5}$. These additional benefits would increase overall benefits by a few percent based on the analyses conducted for the proposed rule. PM co-benefits are shown as a range reflecting the use of two concentration-response functions, with the lower end of the range based on a function from Krewski et al. (2009) and the upper end based on a function from Lepeule et al. (2012). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.
[c] The monetized ozone co-benefits reflect the human health benefits associated with reducing exposure to ozone through reductions of NO_X during the ozone season. Ozone co-benefits are shown as a range reflecting the use of several different concentration-response functions, with the lower end of the range based on a function from Bell, et al. (2004) and the upper end based on a function from Levy, et al. (2005). Ozone co-benefits occur in the analysis year, so they are the same for all discount rates.
[d] We estimate climate benefits associated with four different values of a one ton CO_2 reduction (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). Referred to as the social cost of carbon, each value increases over time. For the purposes of this table, we show the benefits associated with the model average at 3 percent discount rate, however we emphasize the importance and value of considering the full range of social cost of carbon values. We provide combined climate and health estimates based on additional discount rates in the RIA.

The EPA has used the social cost of carbon (SC-CO_2) estimates presented in the *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (May 2013, Revised June 2015)* ("current TSD") to analyze CO_2 climate impacts of this rulemaking.[1053] We refer to these estimates, which were developed by the U.S. government, as "SC-CO_2 estimates." The SC-CO_2 is a metric that estimates the monetary value of impacts associated with marginal changes in CO_2 emissions in a given year. It includes a wide range of anticipated climate impacts, such as net changes in agricultural productivity and human health, property damage from increased flood risk, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning. It is typically used to assess the avoided damages as a result of regulatory actions (i.e.,

[1053] Docket ID EPA-HQ-OAR-2013-0495, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Carbon, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Domestic Policy Council, Environmental Protection Agency, National Economic Council, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (May 2013, Revised July 2015). Available at: http://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf.

benefits of rulemakings that lead to an incremental reduction in cumulative global CO_2 emissions).

The SC-CO_2 estimates used in this analysis were developed over many years, using the best science available, and with input from the public. Specifically, an interagency working group (IWG) that included the EPA and other executive branch agencies and offices used three integrated assessment models (IAMs) to develop the SC-CO_2 estimates and recommended four global values for use in regulatory analyses. The SC-CO_2 estimates were first released in February 2010 and updated in 2013 using new versions of each IAM. The 2010 SC-CO_2 Technical Support Document (2010 TSD)[1054] provides a complete discussion of the methods used to develop these estimates and the current TSD presents and discusses the 2013 update (including two recent minor corrections to the estimates).[1055]

[1054] Docket ID EPA-HQ-OAR-2009-0472-114577, *Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Carbon*, with participation by the Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Environmental Protection Agency, National Economic Council, Office of Energy and Climate Change, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (February 2010). Also available at: http://www.whitehouse.gov/sites/default/files/omb/inforeg/for-agencies/Social-Cost-of-Carbon-for-RIA.pdf.

[1055] The current version of the TSD is available at: https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-

The EPA received numerous comments on the SC-CO_2 estimates as part of this rulemaking. The comments covered a wide range of topics including the technical details of the modeling conducted to develop the SC-CO_2 estimates, the aggregation and presentation of the SC-CO_2 estimates, and the process by which the SC-CO_2 estimates were derived. Many but not all commenters were supportive of the SC-CO_2 and its application to this rulemaking. Commenters also provided constructive recommendations for potential opportunities to improve the SC-CO_2 estimates in future updates. Many of these comments were similar to those that OMB's Office of Information and Regulatory Affairs received in response to a separate request for public comment on the approach used to develop the estimates. After careful evaluation of the full range of comments submitted to OMB, the IWG continues to recommend the use of the SC-CO_2 estimates in regulatory impact analysis.[1056] With the release of the response

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response-to-comments-final-july-2015.pdf, Docket ID EPA-HQ-OAR-2013-0495, *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866*, Interagency Working Group on Social Cost of Carbon, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Domestic Policy Council, Environmental Protection Agency, National Economic Council, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (May 2013, Revised July 2015).

[1056] See https://www.whitehouse.gov/omb/oira/social-cost-of-carbon for additional details, including the OMB Response to Comments and the SC-CO_2 TSDs.

to comments, the IWG announced plans to obtain expert independent advice from the National Academies of Sciences, Engineering, and Medicine (Academies) to ensure that the SC-CO_2 estimates continue to reflect the best available scientific and economic information on climate change. The Academies review will be informed by the public comments received and focus on the technical merits and challenges of potential approaches to improving the SC-CO_2 estimates in future updates. See the EPA Response to Comments document for the complete response to comments received on SC-CO_2 as part of this rulemaking.

Concurrent with OMB's publication of the response to comments on SC-CO_2 and announcement of the Academies process, OMB posted a revised TSD that includes two minor technical corrections to the current estimates. One technical correction addressed an inadvertent omission of climate change damages in the last year of analysis (2300) in one model and the second addressed a minor indexing error in another model. On average the revised SC-CO_2 estimates are one dollar less than the mean SC-CO_2 estimates reported in the November 2013 revision to the May 2013 TSD. The change in the estimates associated with the 95th percentile estimates when using a 3 percent discount rate is slightly larger, as those estimates are heavily influenced by the results from the model that was affected by the indexing error.

The EPA, as a member of the IWG on the SC-CO_2, has carefully examined and evaluated the minor technical corrections in the revised TSD and the public comments submitted to OMB's separate SC-CO_2 comment process. Additionally, the EPA has carefully examined and evaluated all comments received regarding the SC-CO_2 through this rulemaking process. The EPA concurs with the IWG's conclusion that it is reasonable, and scientifically appropriate, to use the current SC-CO_2 estimates for purposes of regulatory impact analysis, including for this proceeding.

The four SC-CO_2 estimates are as follows: $12, $40, $60, and $120 per short ton of CO_2 emissions in the year 2020 (2011$).[1057] The first three values are based on the average SC-CO_2 from the three IAMs, at discount rates of 5, 3, and 2.5 percent, respectively. The SC-CO_2 value at several discount rates are included because the literature shows that the SC-CO_2 is quite sensitive to assumptions about the discount rate, and because no consensus exists on the appropriate rate to use in an intergenerational context (where costs and benefits are incurred by different generations). The fourth value is the 95th

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[1057] The current version of the TSD is available at: https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf. The 2010 and 2013 TSDs present SC-CO_2 in 2007$ per metric ton. The estimates were adjusted to (1) short tons for using conversion factor 0.90718474 and (2) 2011$ using GDP Implicit Price Deflator, http://www.gpo.gov/fdsys/pkg/ECONI-2013-02/pdf/ECONI-2013-02-Pg3.pdf.

percentile of the SC-CO_2 from all three models at a 3 percent discount rate. It is included to represent higher-than-expected impacts from temperature change further out in the tails of the SC-CO_2 distribution (representing less likely, but potentially catastrophic, outcomes).

There are limitations in the estimates of the benefits from the final emission guidelines, including the omission of climate and other CO_2 related benefits that could not be monetized. The 2010 TSD discusses a number of limitations to the SC-CO_2 analysis, including the incomplete way in which the IAMs capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and technological change, uncertainty in the extrapolation of damages to high temperatures, and assumptions regarding risk aversion. Currently, IAMs do not assign value to all of the important impacts of CO_2 recognized in the literature, such as ocean acidification or potential tipping points, for various reasons, including the inherent difficulties in valuing non-market impacts and the fact that the science incorporated into these models understandably lags behind the most recent research. Nonetheless, these estimates and the discussion of their limitations represent the best available information about the social benefits of CO_2 emission reductions to inform the benefit-cost analysis. As previously noted, the IWG plans to seek independent expert advice on technical opportunities to improve the SC-CO_2 estimates from the Academies. The Academies process will help to ensure that the SC-CO_2 estimates used by the federal government continue to reflect the best available science and methodologies. Additional details are provided in the TSDs.

The health co-benefits estimates represent the total monetized human health benefits for populations exposed to reduced $PM_{2.5}$ and ozone resulting from emission reductions from the illustrative compliance strategy for the final standards. Unlike the global SC-CO_2 estimates, the air pollution health co-benefits are estimated for the contiguous U.S. only. We used a "benefit-per-ton" approach to estimate the benefits of this rulemaking. To create the $PM_{2.5}$ benefit-per-ton estimates, we conducted air quality modeling for an illustrative scenario reflecting the proposed standards to convert precursor emissions into changes in ambient $PM_{2.5}$ and ozone concentrations. We then used these air quality modeling results in BenMAP[1058] to calculate average regional benefit-per-ton estimates using the health impact assumptions used in the PM NAAQS RIA[1059] and Ozone NAAQS

[1058] http://www.epa.gov/airquality/benmap/index.html

[1059] U.S. Environmental Protection Agency (U.S. EPA). 2012. *Regulatory Impact Analysis for the Final Revisions to the National Ambient Air Quality Standards for Particulate Matter*. Research Triangle Park, NC: Office of Air Quality Planning and Standards, Health and Environmental Impacts Division. (EPA

RIAs.[1060,1061] The three regions were the Eastern U.S., Western U.S., and California. To calculate the co-benefits for the final standards, we multiplied the regional benefit-per-ton estimates generated from modeling of the proposed standards by the corresponding regional emission reductions for the final standards.[1062] All benefit-per-ton estimates reflect the geographic distribution of the modeled emissions for the proposed standards, which may not exactly match the emission reductions in this final rulemaking, and thus they may not reflect the local variability in population density, meteorology, exposure, baseline health incidence rates, or other local factors for any specific location. More information

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document number EPA-452/R-12-003, December). Available at: <http://www.epa.gov/pm/2012/finalria.pdf>.

[1060] U.S. Environmental Protection Agency (U.S. EPA). 2008b. Final Ozone NAAQS Regulatory Impact Analysis. Research Triangle Park, NC: Office of Air Quality Planning and Standards, Health and Environmental Impacts Division, Air Benefit and Cost Group Research. (EPA document number EPA-452/R-08-003, March). Available at: <http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=194645>.

[1061] U.S. Environmental Protection Agency (U.S. EPA). 2010. Section 3: Re-analysis of the Benefits of Attaining Alternative Ozone Standards to Incorporate Current Methods. Available at: <http://www.epa.gov/ttnecas1/regdata/RIAs/s3-supplemental_analysis-updated_benefits11-5.09.pdf>.

[1062] U.S. Environmental Protection Agency. 2013. *Technical support document: Estimating the benefit per ton of reducing $PM_{2.5}$ precursors from 17 sectors.* Research Triangle Park, NC: Office of Air and Radiation, Office of Air Quality Planning and Standards, January. Available at: <http://www.epa.gov/airquality/benmap/models/Source_Apportionment_BPT_TSD_1_31_13.pdf>.

regarding the derivation of the benefit-per-ton estimates is available in the RIA.

PM benefit-per-ton values are generated using two concentration-response functions, Krewski et al. (2009) [1063] and Lepeule et al. (2012) [1064]. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type. Even though we assume that all fine particles have equivalent health effects, the benefit-per-ton estimates vary between $PM_{2.5}$ precursors depending on the location and magnitude of their impact on $PM_{2.5}$ concentrations, which drive population exposure.

It is important to note that the magnitude of the $PM_{2.5}$ and ozone co-benefits is largely driven by the concentration response functions for premature mortality and the value of a statistical life used to value reductions in premature mortality. For $PM_{2.5}$, we use two key empirical studies, one based

[1063] Krewski D.; M. Jerrett; R. T. Burnett; R. Ma; E. Hughes; Y. Shi, et al. 2009. *Extended Follow-up and Spatial Analysis of the American Cancer Society Study Linking Particulate Air Pollution and Mortality.* Health Effects Institute. (HEI Research Report number 140). Boston, MA: Health Effects Institute.
[1064] Lepeule, J.; F. Laden; D. Dockery; J. Schwartz. 2012. "Chronic Exposure to Fine Particles and Mortality: An Extended Follow-Up of the Harvard Six Cities Study from 1974 to 2009." *Environmental Health Perspective*, 120(7), July, pp. 965-970.

on the American Cancer Society cohort study (Krewski et al, 2009) and one based on the extended Six Cities cohort study (Lepuele et al, 2012). We present the $PM_{2.5}$ co-benefits results as a range based on benefit-per-ton estimates calculated using the concentration-response functions from these two epidemiology studies, but this range does not capture the full range of uncertainty inherent in the co-benefits estimates. In the RIA for this rule, which is available in the docket, we also include $PM_{2.5}$ co-benefits estimates using benefit-per-ton estimates based on expert judgments of the effect of $PM_{2.5}$ on premature mortality (Roman et al., 2008)[1065] as a characterization of uncertainty regarding the $PM_{2.5}$-mortality relationship.

For the ozone co-benefits, we present the results as a range reflecting benefit-per-ton estimates which use several different concentration-response functions for mortality, with the lower end of the range based on a benefit-per-ton estimate using the function from Bell et al. (2004)[1066] and the upper end based on a benefit-per-ton estimate using the function from Levy et al.

[1065] Roman, H., et al. 2008. "Expert Judgment Assessment of the Mortality Impact of Changes in Ambient Fine Particulate Matter in the U.S." *Environmental Science & Technology*, Vol. 42, No. 7, February, pp. 2268 – 2274.

[1066] Bell, M.L., et al. 2004. "Ozone and Short-Term Mortality in 95 U.S. Urban Communities, 1987-2000." *Journal of the American Medical Association,* 292(19), pp. 2372-8.

(2005).[1067] Similar to $PM_{2.5}$, the range of ozone co-benefits does not capture the full range of inherent uncertainty.

In this analysis, in estimating the benefits-per-ton for $PM_{2.5}$ precursors, the EPA assumes that the health impact function for fine particles is without a threshold. This is based on the conclusions of EPA's *Integrated Science Assessment for Particulate Matter*,[1068] which evaluated the substantial body of published scientific literature, reflecting thousands of epidemiology, toxicology, and clinical studies that documents the association between elevated $PM_{2.5}$ concentrations and adverse health effects, including increased premature mortality. This assessment, which was twice reviewed by the EPA's independent Science Advisory Board, concluded that the scientific literature consistently finds that a no-threshold model most adequately portrays the PM-mortality concentration-response relationship.

In general, we are more confident in the magnitude of the risks we estimate from simulated $PM_{2.5}$ concentrations that coincide with the bulk of the observed PM concentrations in the

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[1067] Levy, J.I., S.M. Chemerynski, and J.A. Sarnat. 2005. "Ozone exposure and mortality: an empiric Bayes metaregression analysis." *Epidemiology*. 16(4): p. 458-68.

[1068] U.S. Environmental Protection Agency. 2009. *Integrated Science Assessment for Particulate Matter (Final Report)*. Research Triangle Park, NC: National Center for Environmental Assessment, RTP Division. (EPA document number EPA-600-R-08-139F, December). Available at: http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=216546.

epidemiological studies that are used to estimate the benefits. Likewise, we are less confident in the risk we estimate from simulated $PM_{2.5}$ concentrations that fall below the bulk of the observed data in these studies.

For this analysis, policy-specific air quality data are not available,[1069] and thus, we are unable to estimate the percentage of premature mortality associated with this specific rule that is above the lowest measured $PM_{2.5}$ levels (LML) for the two $PM_{2.5}$ mortality epidemiology studies that form the basis for our analysis. As a surrogate measure of mortality impacts above the LML, we provide the percentage of the population exposed above the lowest measured $PM_{2.5}$ level (LML) in each of the two studies, using the estimates of baseline projected $PM_{2.5}$ from the air quality modeling for the proposed guidelines used to calculate the benefit-per-ton estimates for the EGU sector. Using the Krewski et al. (2009) study, 88 percent of the population is exposed to annual mean $PM_{2.5}$ levels at or above the LML of 5.8 micrograms per cubic meter (μg/m^3). Using the Lepeule et al. (2012) study, 46 percent of the population is exposed above the LML of 8 μg/m^3. It is important to note that baseline exposure is only one parameter in the health impact function, along with baseline incidence rates, population, and change in air quality.

[1069] In addition, site-specific emission reductions will depend upon how states implement the guidelines.

Every benefit analysis examining the potential effects of a change in environmental protection requirements is limited, to some extent, by data gaps, model capabilities (such as geographic coverage) and uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. Despite these uncertainties, we believe the air quality co-benefit analysis for this rule provides a reasonable indication of the expected health benefits of the air pollution emission reductions for the illustrative analysis of the final standards under a set of reasonable assumptions. This analysis does not include the type of detailed uncertainty assessment found in the 2012 $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS) RIA (U.S. EPA, 2012) because we lack the necessary air quality input and monitoring data to conduct a complete benefits assessment. In addition, using a benefit-per-ton approach adds another important source of uncertainty to the benefits estimates. The 2012 $PM_{2.5}$ NAAQS benefits analysis provides an indication of the sensitivity of our results to various assumptions.

We note that the monetized co-benefits estimates shown here do not include several important benefit categories, including exposure to SO_2, NO_X, and hazardous air pollutants (e.g., mercury and hydrogen chloride), as well as ecosystem effects and visibility impairment. Although we do not have sufficient information or modeling available to provide monetized estimates for this rule, we include a qualitative assessment of these unquantified benefits in the RIA for the final guidelines. In addition, in the RIA for the final standards, we did not estimate changes in emissions of directly emitted particles. As a result, quantified $PM_{2.5}$ related benefits are underestimated by a relatively small amount. In the RIA for the proposed guidelines, the benefits from reductions in directly emitted $PM_{2.5}$ were less than 10 percent of total monetized health co-benefits across all scenarios and years.

For more information on the benefits analysis, please refer to the RIA for this rule, which is available in the rulemaking docket.

XII. Statutory and Executive Order Reviews

Additional information about these Statutory and Executive Orders can be found at http://www2.epa.gov/laws-regulations/laws-and-executive-orders.

A. Executive Order 12866: Regulatory Planning and Review, and Executive Order 13563: Improving Regulation and Regulatory Review

This final action is an economically significant regulatory action that was submitted to the OMB for review. Any changes made in response to OMB recommendations have been documented in the docket. The EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis, which is contained in the "Regulatory Impact Analysis for Clean Power Plan Final Rule" (EPA-452/R-15-003, July 2015), is available in the docket and is briefly summarized in section XI of this preamble.

Consistent with Executive Order 12866 and Executive Order 13563, the EPA estimated the costs and benefits for illustrative compliance approaches of implementing the guidelines. The final rule establishes: 1) carbon dioxide (CO_2) emission performance rates for two source categories of existing fossil fuel-fired EGUs, fossil fuel-fired electric utility steam generating units and stationary combustion turbines, and 2) guidelines for the development, submittal and implementation of state plans that implement the CO_2 emission performance rates. Actions taken to comply with the guidelines will also reduce the emissions of directly-emitted $PM_{2.5}$, SO_2 and NO_X. The benefits associated with these $PM_{2.5}$, SO_2 and NO_X reductions are referred to as co-benefits, as these reductions are not the primary objective of this rule.

The EPA has used the social cost of carbon estimates presented in the *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (May 2013, Revised July 2015)* ("current TSD") to analyze CO_2 climate impacts of this rulemaking. We refer to these estimates, which were developed by the U.S. government, as "SC-CO_2 estimates." The SC-CO_2 is an estimate of the monetary value of impacts associated with a marginal change in CO_2 emissions in a given year. The four SC-CO_2 estimates are associated with different discount rates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent), and each increases over time. In this summary, the EPA provides the estimate of climate benefits associated with the SC-CO_2 value deemed to be central in the current TSD: the model average at 3 percent discount rate.

In the final emission guidelines, the EPA has translated the source category-specific CO_2 emission performance rates into equivalent state-level rate-based and mass-based CO_2 goals in order to maximize the range of choices that states will have in developing their plans. Because of the range of choices available to states and the lack of *a priori* knowledge about the specific choices states will make in response to the final goals, the Regulatory Impact Analysis (RIA) for this rule analyzed two implementation scenarios designed to achieve these goals, which we term the "rate-based" illustrative plan approach and the "mass-based" illustrative plan approach.

It is very important to note that the differences between the analytical results for the rate-based and mass-based illustrative plan approaches presented in the RIA may not be indicative of likely differences between the approaches if implemented by states and affected EGUs in response to the final guidelines. Rather, the two sets of analyses are intended to illustrate two different approaches to accomplish the emission performance rates finalized in the Clean Power Plan Final Rule. In other words, if one approach performs differently than the other on a given metric during a given time period, this does not imply this will apply in all instances in all time periods in all places.

The EPA estimates that, in 2020, the final guidelines will yield monetized climate benefits (in 2011$) of approximately $2.8 billion for the rate-based approach and $3.3 billion for the mass-based approach (3 percent model average). For the rate-based approach, the air pollution health co-benefits in 2020 are estimated to be $0.7 billion to $1.8 billion (2011$) for a 3 percent discount rate and $0.64 billion to $1.7 billion (2011$) for a 7 percent discount rate. For the mass-based approach, the air pollution health co-benefits in 2020 are estimated to be $2.0 billion to $4.8 billion (2011$) for a 3 percent discount rate and $1.8 billion to $4.4 billion (2011$) for a 7 percent discount rate. The annual, illustrative compliance costs estimated by IPM and inclusive of demand-side EE program and participant costs and MRR costs in 2020, are approximately \$2.5 billion for the rate-based approach and \$1.4 billion for the mass-based approach (2011\$). The quantified net benefits (the difference between monetized benefits and compliance costs) in 2020 are estimated to range from \$1.0 billion to \$2.1 billion (2011\$) for the rate-based approach and from \$3.9 billion to 6.7 billion (2011\$) for the mass-based approach, using a 3 percent discount rate (model average).

The EPA estimates that, in 2025, the final guidelines will yield monetized climate benefits (in 2011\$) of approximately \$10 billion for the rate-based approach and \$12 billion for the mass-based approach (3 percent model average). For the rate-based approach, the air pollution health co-benefits in 2025 are estimated to be \$7.4 billion to \$18 billion (2011\$) for a 3 percent discount rate and \$6.7 billion to \$16 billion (2011\$) for a 7 percent discount rate. For the mass-based approach, the air pollution health co-benefits in 2025 are estimated to be \$7.1 billion to \$17 billion (2011\$) for a 3 percent discount rate and \$6.5 billion to \$16 billion (2011\$) for a 7 percent discount rate. The annual, illustrative compliance costs estimated by IPM and inclusive of demand-side EE program and participant costs and MRR costs in 2025, are approximately \$1.0 billion for the rate-based approach and \$3.0 billion for the mass-based approach (2011$). The quantified net benefits (the difference between monetized benefits and compliance costs) in 2025 are estimated to range from $17 billion to $27 billion (2011$) for the rate-based approach and $16 billion to $26 billion (2011$) for the mass-based approach, using a 3 percent discount rate (model average).

The EPA estimates that, in 2030, the final guidelines will yield monetized climate benefits (in 2011$) of approximately $20 billion for the rate-based approach and $20 billion for the mass-based approach (3 percent model average). For the rate-based approach, the air pollution health co-benefits in 2030 are estimated to be $14 billion to $34 billion (2011$) for a 3 percent discount rate and $13 billion to $31 billion (2011$) for a 7 percent discount rate. For the mass-based approach, the air pollution health co-benefits in 2030 are estimated to be $12 billion to $28 billion (2011$) for a 3 percent discount rate and $11 billion to $26 billion (2011$) for a 7 percent discount rate. The annual, illustrative compliance costs estimated by IPM and inclusive of demand-side EE program and participant costs and MRR costs in 2030, are approximately $8.4 billion for the rate-based approach and $5.1 billion for the mass-based approach (2011$). The quantified net benefits (the difference between monetized benefits and compliance costs) in 2030 are estimated to range from $26 billion to $45 billion (2011$) for the rate-based approach and from $26 billion to $43 billion (2011$) for the mass-based approach, using a 3 percent discount rate (model average).

Tables 20 and 21 provide the estimates of the climate benefits, health co-benefits, compliance costs and net benefits of the final emission guidelines for rate-based and mass-based illustrative plan approaches, respectively.

Table 21. Summary of the Monetized Benefits, Compliance Costs, and Net Benefits for the Final Guidelines in 2020, 2025 and 2030 Under the Rate-Based Illustrative Plan Approach [Billions of 2011$][a]

	Rate-Based Approach		
	2020	**2025**	**2030**
Climate Benefits[b]			
5% discount rate	$0.80	$3.1	$6.4
3% discount rate	$2.8	$10	$20
2.5% discount rate	$4.1	$15	$29
95th percentile at 3% discount rate	$8.2	$31	$61
	Air Quality Co-benefits Discount Rate		

	3%	7%	3%	7%	3%	7%
Air Quality Health Co-benefits[c]	\$0.70 to \$1.8	\$0.64 to \$1.7	\$7.4 to \$18	\$6.7 to \$16	\$14 to \$34	\$13 to \$31
Compliance Costs[d]	\$2.5		\$1.0		\$8.4	
Net Benefits[e]	\$1.0 to \$2.1	\$1.0 to \$2.0	\$17 to \$27	\$16 to \$25	\$26 to \$45	\$25 to \$43
Non-Monetized Benefits	Non-monetized climate benefits Reductions in exposure to ambient NO_2 and SO_2 Reductions in mercury deposition Ecosystem benefits associated with reductions in emissions of NO_X, SO_2, PM, and mercury Visibility impairment					

[a] All are rounded to two significant figures, so figures may not sum.

[b] The climate benefit estimate in this summary table reflects global impacts from CO_2 emission changes and does not account for changes in non-CO_2 GHG emissions. Also, different discount rates are applied to SC-CO_2 than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SC-CO_2 estimated for a 3 percent discount rate. However, we emphasize the importance and value of considering the full range of SC-CO_2 values. As shown in the RIA, climate benefits are also estimated using the other three SC-CO_2 estimates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95[th] percentile at 3 percent). The SC-CO_2 estimates are year-specific and increase over time.

[c] The air pollution health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of SO_2 and NO_X. The range reflects the use of concentration-response functions from different epidemiology studies. The co-benefits do not include the benefits of reductions in directly emitted $PM_{2.5}$. These additional benefits would increase overall benefits by a few percent based on the analyses conducted for the proposed rule. The reduction in premature fatalities each year

accounts for over 98 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[d] Total costs are approximated by the illustrative compliance costs estimated using the Integrated Planning Model for the final guidelines and a discount rate of approximately 5 percent. This estimate includes monitoring, recordkeeping, and reporting costs and demand-side EE program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global SC-CO_2 at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on additional discount rates.

Table 22. Summary of the Monetized Benefits, Compliance Costs, and Net Benefits for the Final Guidelines in 2020, 2025 and 2030 Under the Mass-Based Illustrative Plan Approach [Billions of 2011$][a]

	Mass-Based Approach		
	2020	**2025**	**2030**
Climate Benefits[b]			
5% discount rate	$0.9	$3.6	$6.4
3% discount rate	$3.3	$12	$20
2.5% discount rate	$4.9	$17	$29
95th percentile at 3%	$9.7	$35	$60

discount rate

	Air Quality Co-benefits Discount Rate					
	3%	7%	3%	7%	3%	7%
Air Quality Health Co-benefits[c]	$2.0 to $4.8	$1.8 to $4.4	$7.1 to $17	$6.5 to $16	$12 to $28	$11 to $26
Compliance Costs[d]	$1.4		$3.0		$5.1	
Net Benefits[e]	$3.9 to $6.7	$3.7 to $6.3	$16 to $26	$15 to $24	$26 to $43	$25 to $40
Non-Monetized Benefits	Non-monetized climate benefits Reductions in exposure to ambient NO_2 and SO_2 Reductions in mercury deposition Ecosystem benefits associated with reductions in emissions of NO_X, SO_2, PM, and mercury Visibility improvement					

[a] All are rounded to two significant figures, so figures may not sum.

[b] The climate benefit estimate in this summary table reflects global impacts from CO_2 emission changes and does not account for changes in non-CO_2 GHG emissions. Also, different discount rates are applied to SC-CO_2 than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SC-CO_2 estimated for a 3 percent discount rate. However, we emphasize the importance and value of considering the full range of SC-CO_2 values. As shown in the RIA, climate benefits are also estimated using the other three SC-CO_2 estimates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). The SC-CO_2 estimates are year-specific and increase over time.

[c] The air pollution health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of SO_2 and

NO_X. The co-benefits do not include the benefits of reductions in directly emitted $PM_{2.5}$. These additional benefits would increase overall benefits by a few percent based on the analyses conducted for the proposed rule. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in premature fatalities each year accounts for over 98 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[d] Total costs are approximated by the illustrative compliance costs estimated using the Integrated Planning Model for the final guidelines and a discount rate of approximately 5 percent. This estimate includes monitoring, recordkeeping, and reporting costs and demand-side EE program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global SC-CO_2 at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on additional discount rates.

There are additional important benefits that the EPA could not monetize. Due to current data and modeling limitations, our estimates of the benefits from reducing CO_2 emissions do not include important impacts like ocean acidification or potential tipping points in natural or managed ecosystems. Unquantified benefits also include climate benefits from reducing emissions of non-CO_2 GHGs (e.g., nitrous oxide and methane) and co-benefits from reducing direct exposure to SO_2, NO_X and hazardous air pollutants (e.g., mercury), as well as from reducing ecosystem effects and visibility impairment. Based upon the foregoing discussion, it remains clear that the benefits of this final action are substantial, and far exceed the costs. Additional details on benefits, costs, and net benefits estimates are provided in this RIA.

B. Paperwork Reduction Act (PRA)

The information collection requirements in this rule have been submitted for approval to OMB under the PRA. The Information Collection Request (ICR) document prepared by the EPA has been assigned the EPA ICR number 2503.02. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

This rule does not directly impose specific requirements on EGUs located in states or areas of Indian country. The rule also does not impose specific requirements on tribal governments that have affected EGUs located in their area of Indian country. For areas of Indian country, the rule establishes CO_2 emission performance goals that could be addressed through either tribal or federal plans. A tribe would have the opportunity under the Tribal Authority Rule (TAR), but not the obligation, to apply to the EPA for Treatment as State (TAS) for purposes of a CAA section 111(d) plan and, if approved by the EPA, to establish a CAA section 111(d) plan for its area of Indian country. To date, no tribe has requested or obtained TAS eligibility for purposes of a CAA section 111(d) plan. For areas of Indian country with affected EGUs where a tribe has not applied for TAS and submitted any needed plan, if the EPA determines that a CAA section 111(d) plan is necessary or appropriate, the EPA would have the responsibility to establish the plans. Because tribes are not required to implement section 111(d) plans and because no tribe has yet sought TAS eligibility for this purpose, this action is not anticipated to impose any information collection burden on tribal governments over the 3-year period covered by this ICR.

This rule does impose specific requirements on state governments with affected EGUs. The information collection requirements are based on the recordkeeping and reporting burden associated with developing, implementing, and enforcing a plan to limit CO_2 emissions from existing sources in the utility power sector. These recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to agency policies set forth in 40 CFR part 2, subpart B.

The annual burden for this collection of information for the states (averaged over the first 3 years following promulgation) is estimated to be a range of 505,000 to 821,000 hours at a total annual labor cost of $35.8 to $58.1 million. The lower bound estimate reflects the assumption that some states already have EE and RE programs in place. The higher bound estimate reflects the overly-conservative assumption that no states have EE and RE programs in place.

The total annual burden for the federal government associated with the state collection of information (averaged over the first 3 years following promulgation) is estimated to be 54,000 hours at a total annual labor cost of $3.00 million. Burden is defined at 5 CFR 1320.3(b).

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the agency will announce that approval in the *Federal Register* and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. This action will not impose any requirements on small entities. Specifically, emission guidelines established under

CAA section 111(d) do not impose any requirements on regulated entities and, thus, will not have a significant economic impact upon a substantial number of small entities. After emission guidelines are promulgated, states establish emission standards on existing sources, and it is those requirements that could potentially impact small entities.

Our analysis here is consistent with the analysis of the analogous situation arising when the EPA establishes NAAQS, which do not impose any requirements on regulated entities. As here, any impact of a NAAQS on small entities would only arise when states take subsequent action to maintain and/or achieve the NAAQS through their SIPs. See American Trucking Assoc. v. EPA, 175 F.3d 1029, 1043-45 (D.C. Cir. 1999) (NAAQS do not have significant impacts upon small entities because NAAQS themselves impose no regulations upon small entities).

Nevertheless, the EPA is aware that there is substantial interest in the rule among small entities and, as detailed in section III.A of the preamble to the proposed carbon pollution emission guidelines for existing EGUs (79 FR 34845-34847; June 18, 2014) and in section II.D of the preamble to the proposed carbon pollution emission guidelines for existing EGUs in Indian Country and U.S. Territories (79 FR 65489; November 4, 2014), has conducted an unprecedented amount of stakeholder outreach. As part of that outreach, agency officials participated in many meetings with individual utilities and electric utility associations, as well as industry leaders and trade association representatives from various industries. While formulating the provisions of the rule, the EPA considered the input provided over the course of the stakeholder outreach as well as the input provided in the many public comments.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The emission guidelines do not impose any direct compliance requirements on EGUs located in states or areas of Indian country. As explained in section XII.B above, the rule also does not impose specific requirements on tribal governments that have affected EGUs located in their area of Indian country. The rule does impose specific requirements on state governments that have affected EGUs. Specifically, states are required to develop plans to implement the guidelines under CAA section 111(d) for affected EGUs. The burden for states to develop CAA section 111(d) plans in the 3-year period following promulgation of the rule was estimated and is listed in section XII.B above, but this burden is estimated to be below $100 million in any one year. Thus, this rule is not subject to the requirements of section 202 or section 205 of the UMRA.

This rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. Specifically, the state governments to which rule requirements apply are not considered small governments.

In light of the interest among governmental entities, the EPA conducted outreach with national organizations representing state and local elected officials and tribal governmental entities while formulating the provisions of this rule. Sections III.A and XI.F of the preamble to the proposed carbon pollution emission guidelines for existing EGUs (79 FR 34845-34847; June 18, 2014) and sections II.D and VI.F of the preamble to the proposed carbon pollution emission guidelines for existing EGUs in areas of Indian Country and U.S. Territories (79 FR 65489; November 4, 2014) describes the extensive stakeholder outreach the EPA has conducted on setting emission guidelines for existing EGUs. The EPA considered the input provided over the course of the stakeholder outreach as well as the input provided in the many public comments when developing the provisions of these emission guidelines.

E. Executive Order 13132: Federalism

The EPA has concluded that this action may have federalism implications, pursuant to agency policy for implementing the Order, because it imposes substantial direct compliance costs on state or local governments, and the federal government will not provide the funds necessary to pay those costs. As discussed in the Supporting Statement found in the docket for this rulemaking, the development of state plans will entail many hours of staff time to develop and coordinate programs for compliance with the rule, as well as time to work with state legislatures as appropriate, to develop a plan submittal. Consistent with this determination, the EPA provides the following federalism summary impact statement.

The EPA consulted with state and local officials early in the process of developing the proposed action to permit them to have meaningful and timely input into its development. As described in the Federalism discussion in the preamble to the proposed standards of performance for GHG emissions from new EGUs (79 FR 1501; January 8, 2014), the EPA consulted with state and local officials in the process of developing the proposed standards for newly constructed EGUs. This outreach addressed planned actions for new, reconstructed, modified and existing sources. The EPA invited the following 10 national organizations representing state and local elected officials to a meeting on April 12, 2011, in Washington DC: (1) National Governors Association; (2) National Conference of State Legislatures, (3) Council of State Governments, (4) National League of Cities, (5) U.S. Conference of Mayors, (6) National Association of Counties,

(7) International City/County Management Association, (8) National Association of Towns and Townships, (9) County Executives of America, and (10) Environmental Council of States. The National Association of Clean Air Agencies also participated. On February 26, 2014, the EPA re-engaged with those governmental entities to provide a pre-proposal update on the emission guidelines for existing EGUs and emission standards for modified and reconstructed EGUs. In addition, as described in section III.A of the preamble to the proposed carbon pollution emission guidelines for existing EGUs (79 FR 34845-34847; June 18, 2014), extensive stakeholder outreach conducted by the EPA allowed state leaders, including governors, state attorneys general, environmental commissioners, energy officers, public utility commissioners, and air directors, opportunities to engage with EPA officials and provide input regarding reducing carbon pollution from power plants.

In the spirit of Executive Order 13132, and consistent with the EPA’s policy to promote communications between the EPA and state and local governments, the EPA specifically solicited comment on the proposed action from state and local officials. The EPA received comments from over 400 entities representing state and local governments.

Several themes emerged from state and local government comments. Commenters raised concerns with the building blocks that comprise the best system of emission reduction (BSER), including the stringency of the building blocks, and the timing of achieving interim CO_2 levels. They also identified the potential for electric system reliability issues and stranded assets due to the proposed timeframe for plan submittals and CO_2 emission reductions. In addition, states commented on state plan development and implementation topics, including state plan approaches, early actions, trading programs, interstate crediting for RE, and EPA guidance and outreach.

Commenters identified overarching concerns regarding the stringency of the CO_2 goals and the timeframe for achieving reductions that encompassed the building blocks, the BSER, and associated timing for achievement of interim CO_2 levels. State commenters, in particular, identified changes to the stringency of the building blocks, concerns with the timeframe over which reductions must be achieved, and concerns with the approaches and measures used for the BSER. For the final rule, in response to stakeholder comments, the EPA has made refinements to the building blocks, the period of time over which measures are deployed, and the stringency of emission limitations that those measures can achieve in a practical and reasonable cost way. The final BSER reflects those refinements.

To many commenters, the proposal’s 2020 compliance date, together with the stringency of the interim CO_2 goal, bore significant reliability implications. In this final rule, the agency is addressing those concerns via adjustments to the compliance timeframe (an 8-year interim period that begins in 2022) and to the approach for meeting interim CO_2 emission performance rates (a glide path separated into three steps, 2022-2024, 2025-2027, and 2028-2029), as well as a more gradual phase in of the emission reduction expectations. These adjustments provide more time for planning, consultation and decision making in the formulation of state plans and in EGUs' choices of compliance strategies. The final rule also retains flexibilities presented in the proposal and offers additional opportunities, including opportunities for trading within and between states, and other multi-state compliance approaches that will further support electric system reliability. The EPA is also requiring each state to demonstrate in its final state that it has considered electric system reliability issues in developing its plan - and is providing the time to do so. Even with this foundation of flexibility in place, these final guidelines further provide states with the option of proposing amendments to approved plans in the event that unanticipated and significant reliability challenges arise.

Commenters provided compelling information indicating that it will take longer than the agency initially anticipated to for states to complete the tasks necessary to finalize a state plan, including administrative and potential legislative processes. Recognizing this, as well as the urgent need for actions to reduce GHG emissions, the EPA is requiring states to make an initial submittal by September 6, 2016, and is allowing states two additional years to submit a final plan, if justified (to be submitted by September 6, 2018).

States commented on state plan development and implementation topics that included state plan approaches, early actions being taken into account, trading programs being allowed, interstate crediting for RE being allowed, and guidance and outreach being provided by the EPA. For the state plan approaches, commenters expressed concerns with the proposed "portfolio approach" for state plans, including concerns with enforceability of requirements, and identified a "state commitment approach" with backstop measures as an option for state plans. In this final rule, in response to stakeholder comments on the portfolio approach and alternative approaches, the EPA is finalizing a "state measures" approach that includes a requirement for the inclusion of backstop measures.

State commenters supported providing incentives for states and utilities to deploy CO_2-reducing investments, such as RE and demand-side EE measures, as early as possible. The EPA recognizes the value of such early actions, and in this final rule is establishing the CEIP to provide opportunities for investment in RE and demand-side EE projects that deliver results in 2020 and/or 2021.

Many state commenters supported the use of mass-based and rate-based emission trading programs in state plans, including interstate emission trading programs. The EPA also received a number of comments from states and stakeholders about the value of EPA support in developing and/or administering tracking systems to support state administration of rate-based and mass-based emission trading programs. In this final rule, states may use trading or averaging approaches and technologies or strategies that are not explicitly mentioned in any of the three building blocks as part of their overall plans, as long as they achieve the required emission reductions from affected fossil-fuel-fired EGUs. In addition, in response to concerns from states and power companies that the need for up-front interstate cooperation in developing multi-state plans could inhibit the development of interstate programs that could lower cost, the final rule provides additional options to allow individual EGUs to use creditable out-of-state reductions to achieve required CO_2 reductions, without the need for up-front interstate agreements. The EPA is committed to working with states to provide support for tracking of emissions and allowances or credits, to help implement multi-state trading or averaging approaches.

In their comments, many states identified the need for the

EPA to provide guidance, including guidance on RE and EE emission measurement and verification (EM&V), and to maintain regular contact/forums with states throughout the implementation process. To provide state and local governments and other stakeholders with an understanding of the rule requirements, and to provide efficiencies where possible and reduce the cost and administrative burden, the EPA will continue outreach throughout the plan development and submittal process. Outreach will include opportunities for states to participate in briefings, teleconferences, and meetings about the final rule. The EPA's 10 regional offices will continue to be the entry point for states and tribes to ask technical and policy questions. The agency will host (or partner with appropriate groups to co-host) a number of webinars about various components of the final rule during the first two months after the final rule is issued. The EPA will use information from this outreach process to inform the training and other tools that will be of most use to the states and tribes that are implementing the final rule. The EPA expects to issue guidance on specific topics, including evaluation, measurement and verification (EM&V) for RE and demand-side EE, state-community engagement, and resources and financial assistance for RE and demand-side EE. As guidance documents, tools, templates and other resources become available, the EPA, in consultation with the U.S. Department of

Energy and other federal agencies, will continue to make these resources available via a dedicated website.

A list of the state and local government commenters has been provided to OMB and has been placed in the docket for this rulemaking. In addition, the detailed response to comments from these entities is contained in the EPA's response to comments document on this final rulemaking, which has also been placed in the docket for this rulemaking.

As required by section 8(a) of Executive Order 13132, the EPA included a certification from its Federalism Official stating that the EPA had met the Executive Order's requirements in a meaningful and timely manner when it sent the draft of this final action to OMB for review pursuant to Executive Order 12866. A copy of the certification is included in the public version of the official record for this final action.

F. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

This action has tribal implications. However, it will neither impose substantial direct compliance costs on federally recognized tribal governments, nor preempt tribal law. Tribes are not required to develop or adopt CAA programs, but they may apply to the EPA for treatment in a manner similar to states (TAS) and, if approved, do so. As a result, tribes are not required to develop plans to implement the guidelines under CAA section 111(d) for affected EGUs in their areas of Indian country. To the extent that a tribal government seeks and attains TAS status for that purpose, these emission guidelines would require that planning requirements be met and emission management implementation plans be executed by the tribes. The EPA notes that this rule does not directly impose specific requirements on affected EGUs, including those located in areas of Indian country, but provides guidance to any tribe approved by the EPA to address CO_2 emissions from EGUs subject to section 111(d) of the CAA. The EPA also notes that none of the affected EGUs are owned or operated by tribal governments.

As described in sections III.A and XI.F of the preamble to the proposed carbon pollution emission guidelines for existing EGUs (79 FR 34845-34847; June 18, 2014) and sections II.D and VI.F of the preamble to the proposed carbon pollution emission guidelines for existing EGUs in Indian Country and U.S. Territories (79 FR 65489; November 4, 2014), the rule was developed after extensive and vigorous outreach to tribal governments. These tribes expressed varied points of view. Some tribes raised concerns about the impacts of the regulations on EGUs located in their areas of Indian country and the subsequent impact on jobs and revenue for their tribes. Other tribes expressed concern about the impact the regulations would have on the cost of water covered under treaty to their communities as a result of increased costs to the EGU that provide energy to transport the water to the tribes. Other tribes raised concerns about the impacts of climate change on their communities, resources, ways of life and hunting and treaty rights. The tribes were also interested in the scope of the guidelines being considered by the agency (e.g., over what time period, relationship to state and multi-state plans) and how tribes will participate in these planning activities.

The EPA consulted with tribal officials under the EPA Policy on Consultation and Coordination with Indian Tribes early in the process of developing this action to permit them to have meaningful and timely input into its development. A summary of that consultation follows.

Prior to issuing the supplemental proposal on November 4, 2014, the EPA consulted with tribes as follows. The EPA held a consultation with the Ute Tribe, the Crow Nation, and the Mandan, Hidatsa, Arikara (MHA) Nation on July 18, 2014. On August 22, 2014, the EPA held a consultation with the Fort Mojave Tribe. On September 15, 2014, the EPA held a consultation with the Navajo Nation. The Navajo Nation sent a letter to the EPA on September 18, 2014, summarizing the information presented at the consultation and the Navajo Nation’s position on the supplemental proposal. One issue raised by tribal officials was the potential impacts of the June 18, 2014 proposal and the supplemental proposal on tribes with budgets that are dependent on revenue from coal mines and power plants, as well as employment at the mines and power plants. The tribes noted the high unemployment rates and lack of access to basic services on their lands. Tribal officials also asked whether the rules will have any impact on a tribe's ability to seek TAS. Tribal officials also expressed interest in agency actions with regard to facilitating power plant compliance with regulatory requirements. The Navajo Nation made the following recommendations in their letter of September 18, 2014: the Navajo Nation supports a mass-based CO_2 emission standard based on the highest historical CO_2 emissions since 1996; the Navajo Nation requests that the EPA grant the Navajo Nation carbon credits and that the Navajo Nation retains ownership and control of such credits; building block 2 is not appropriate for the Navajo Nation because there are no NGCC plants located on the Navajo Nation; building block 3 is not appropriate for the Navajo Nation because the Navajo people already receive virtually all of their electricity from carbon-free sources (mostly hydroelectric power) and their use of electricity is negligible compared to the generation at the power plants; building block 4 is not appropriate for the Navajo Nation because of the inadequate access to electricity, and the goal should allow for an increase in energy consumption on the Navajo

Nation; the supplemental proposal should consider the useful life of the power plants located on the Navajo Nation; and the supplemental proposal should clarify that RE projects located within the Navajo Nation that provide electricity outside the Navajo Nation should be counted toward meeting the relevant state's RE goals under the Clean Power Plan.

After issuing the supplemental proposal, the EPA held additional consultation with tribes. On November 18, 2014, the EPA held consultations with the following tribes: Fort McDowell Yavapai Nation, Fort Mojave Tribe, Hopi Tribe, Navajo Nation, and Ak-Chin Indian Community. A consultation with the Ute Indian Tribe of the Uintah and Ouray Reservation was held on December 16, 2014 and with the Gila River Indian Community on January 15, 2015. The Navajo Nation reiterated the concerns raised during the previous consultation. Several tribes also again indicated that they wanted to ensure they would be included in the development of any tribal or federal plans for areas of Indian country. The Fort Mojave Tribe and the Navajo Nation expressed concern with using data from 2012 as the basis for the goal for their areas of Indian country; in their view, that year was not representative for the affected EGU. On April 28, 2015, the EPA held an additional consultation with the Navajo Nation. The issues raised by the Navajo Nation during the consultation included whether the EPA has the authority to set less stringent standards on a case-by-case basis, and a suggested "parity glide path" that would account and adjust for the very low electricity usage by the Navajo Nation and promote Navajo Nation economic growth and demand. Furthermore, on July 7, 2015 the EPA conducted an additional consultation with the Navajo Nation. One of the goals of the consultation was for the new government of the Navajo Nation to deepen their understanding of the rulemaking. The questions raised by the nation had to do with goal setting and carbon credits, the timing of the rulemaking, and the proposed federal plan. Additionally, on July 14, 2015 the EPA conducted an additional consultation with the Fort Mojave Tribe. The Fort Mojave tribes expressed concerns that 2012 is not a representative year, that natural gas-fired combined cycle power plants should be treated differently from coal-fired power plants, and that the proposed goal for Fort Mojave was not appropriate. Additionally, they also expressed interest in being engaged in the federal plan process. Responses to these comments and others received are available in the Response to Comment Document that is in the docket for this rulemaking. As required by section 7(a), the EPA's Tribal Consultation Official has certified that the requirements of the executive order have been met in a meaningful and timely manner. A copy of the certification is included in the docket for this action.

G. Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks

This action is subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because it is an economically significant regulatory action as defined by Executive Order 12866, and the EPA believes that the environmental health or safety risk addressed by this action has a disproportionate effect on children. Accordingly, the agency has evaluated the environmental health and welfare effects of climate change on children.

CO_2 is a potent GHG that contributes to climate change and is emitted in significant quantities by fossil fuel-fired power plants. The EPA believes that the CO_2 emission reductions resulting from implementation of these final guidelines, as well as substantial ozone and $PM_{2.5}$ emission reductions as a co-benefit, will further improve children's health.

The assessment literature cited in the EPA's 2009 Endangerment Finding concluded that certain populations and lifestages, including children, the elderly, and the poor, are most vulnerable to climate-related health effects. The assessment literature since 2009 strengthens these conclusions by providing more detailed findings regarding these groups' vulnerabilities and the projected impacts they may experience.

These assessments describe how children's unique physiological and developmental factors contribute to making them particularly vulnerable to climate change. Impacts to children are expected from heat waves, air pollution, infectious and waterborne illnesses, and mental health effects resulting from extreme weather events. In addition, children are among those especially susceptible to most allergic diseases, as well as health effects associated with heat waves, storms, and floods. Additional health concerns may arise in low income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity within households.

More detailed information on the impacts of climate change to human health and welfare is provided in section II.A of this preamble.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action, which is a significant regulatory action under EO 12866, is likely to have a significant effect on the supply, distribution, or use of energy. The EPA has prepared a Statement of Energy Effects for this action as follows. We estimate a 1 to 2 percent change in retail electricity prices on average across the contiguous U.S. in 2025, and a 22 to 23 percent reduction in coal-fired electricity generation as a result of this rule. The

EPA projects that utility power sector delivered natural gas prices will increase by up to 2.5 percent in 2030. For more information on the estimated energy effects, please refer to the economic impact analysis for this proposal. The analysis is available in the RIA, which is in the public docket.

I. National Technology Transfer and Advancement Act (NTTAA)

This rulemaking does not involve technical standards.

J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629; February 16, 1994) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the U.S. The EPA defines environmental justice as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. The EPA has this goal for all communities and persons across this Nation. It will be achieved when everyone enjoys the same degree of protection from environmental and health hazards and equal access to the decision-making process to have a healthy environment in which to live, learn, and work.

Leading up to this rulemaking the EPA summarized the public health and welfare effects of GHG emissions in its 2009 Endangerment Finding. See, section VIII.A of this preamble where the EPA summarizes the public health and welfare impacts from GHG emissions that were detailed in the 2009 Endangerment Finding under CAA section 202(a)(1).[1070] As part of the Endangerment Finding, the Administrator considered climate change risks to minority populations and low-income populations, finding that certain parts of the population may be especially vulnerable based on their characteristics or circumstances. Populations that were found to be particularly vulnerable to climate change risks include the poor, the elderly, the very young, those already in poor health, the disabled, those living alone, and/or indigenous populations dependent on one or a few resources. See sections XII.F and XII.G, above, where the EPA discusses Consultation and Coordination with Tribal Governments and Protection of Children. The Administrator placed weight on

[1070] "Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act," 74 FR 66496 (Dec. 15, 2009) ("Endangerment Finding").

the fact that certain groups, including children, the elderly, and the poor, are most vulnerable to climate-related health effects.

The record for the 2009 Endangerment Finding summarizes the strong scientific evidence in the major assessment reports by the U.S. Global Change Research Program (USGCRP), the Intergovernmental Panel on Climate Change (IPCC), and the National Research Council (NRC) of the National Academies that the potential impacts of climate change raise environmental justice issues. These reports concluded that poor communities can be especially vulnerable to climate change impacts because they tend to have more limited adaptive capacities and are more dependent on climate-sensitive resources such as local water and food supplies. In addition, Native American tribal communities possess unique vulnerabilities to climate change, particularly those impacted by degradation of natural and cultural resources within established reservation boundaries and threats to traditional subsistence lifestyles. Tribal communities whose health, economic well-being, and cultural traditions that depend upon the natural environment will likely be affected by the degradation of ecosystem goods and services associated with climate change. The 2009 Endangerment Finding record also specifically noted that Southwest native cultures are especially vulnerable to water quality and availability impacts. Native

Alaskan communities are already experiencing disruptive impacts, including coastal erosion and shifts in the range or abundance of wild species crucial to their livelihoods and well-being.

The most recent assessments continue to strengthen scientific understanding of climate change risks to minority populations and low-income populations in the U.S.[1071] The new assessment literature provides more detailed findings regarding these populations' vulnerabilities and projected impacts they may experience. In addition, the most recent assessment reports provide new information on how some communities of color (more specifically, populations defined jointly by ethnic/racial characteristics and geographic location) may be uniquely

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[1071] Melillo, Jerry M., Terese (T.C.) Richmond, and Gary W. Yohe, Eds., 2014: *Climate Change Impacts in the United States: The Third National Climate Assessment.* U.S. Global Change Research Program, 841 pp.
IPCC, 2014: *Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects.* Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, 1132 pp.

IPCC, 2014: *Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part B: Regional Aspects*. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Barros, V.R., C.B. Field, D.J. Dokken, M.D. Mastrandrea, K.J. Mach, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, 688 pp.

vulnerable to climate change health impacts in the U.S. These reports find that certain climate change related impacts—including heat waves, degraded air quality, and extreme weather events—have disproportionate effects on low-income populations and some communities of color, raising environmental justice concerns. Existing health disparities and other inequities in these communities increase their vulnerability to the health effects of climate change. In addition, assessment reports also find that climate change poses particular threats to health, well-being, and ways of life of indigenous peoples in the U.S.

As the scientific literature presented above and as the 2009 Endangerment Finding illustrates, low income populations and some communities of color are especially vulnerable to the health and other adverse impacts of climate change. The EPA believes that communities will benefit from this final rulemaking because this action directly addresses the impacts of climate change by limiting GHG emissions through the establishment of CO_2 emission guidelines for existing affected fossil fuel-fired EGUs.

In addition to reducing CO_2 emissions, the guidelines finalized in this rulemaking would reduce other emissions from affected EGUs that reduce generation due to higher adoption of EE and RE. These emission reductions will include SO_2 and NOx, which form ambient $PM_{2.5}$ and ozone in the atmosphere, and hazardous air pollutants (HAP), such as mercury and hydrochloric acid. In the final rule revising the annual $PM_{2.5}$ NAAQS,[1072] the EPA identified low-income populations as being a vulnerable population for experiencing adverse health effects related to PM exposures. Low-income populations have been generally found to have a higher prevalence of pre-existing diseases, limited access to medical treatment, and increased nutritional deficiencies, which can increase this population's susceptibility to PM-related effects.[1073] In areas where this rulemaking reduces exposure to $PM_{2.5}$, ozone, and methylmercury, low-income populations will also benefit from such emissions reductions. The RIA for this rulemaking, included in the docket for this rulemaking, provides additional information regarding the health and ecosystem effects associated with these emission reductions.

Additionally, as outlined in the community and environmental justice considerations section IX of this preamble, the EPA has taken a number of actions to help ensure that this action will not have potential disproportionately high

[1072] "National Ambient Air Quality Standards for Particulate Matter, Final Rule," 78 FR 3086 (Jan. 15, 2013).
[1073] U.S. Environmental Protection Agency (U.S. EPA). 2009. *Integrated Science Assessment for Particulate Matter (Final Report)*. EPA-600-R-08-139F. National Center for Environmental Assessment – RTP Division. December. Available on the Internet at <http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=216546>.

and adverse human health or environmental effects on overburdened communities. The EPA consulted its May 2015, *Guidance on Considering Environmental Justice During the Development of Regulatory Actions*, when determining what actions to take.[1074] As described in the community and environmental justice considerations section of this preamble the EPA also conducted a proximity analysis, which is available in the docket of this rulemaking and is discussed in section IX. Additionally, as outlined in sections I and IX of this preamble, the EPA has engaged with communities throughout this rulemaking and has devised a robust outreach strategy for continual engagement throughout the implementation phase of this rulemaking.

K. Congressional Review Act (CRA)

This final action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is a "major rule" as defined by 5 U.S.C. 804(2).

XIII. Statutory Authority

The statutory authority for this action is provided by sections 111, 301, 302, and 307(d)(1)(C) of the CAA as amended

[1074] Guidance on Considering Environmental Justice During the Development of Regulatory Actions. http://epa.gov/environmentaljustice/resources/policy/considering-ej-in-rulemaking-guide-final.pdf. May 2015.

(42 U.S.C. 7411, 7601, 7602, 7607(d)(1)(C)). This action is also subject to section 307(d) of the CAA (42 U.S.C. 7607(d)).

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: ___________________.

____
Gina McCarthy,
Administrator.

For the reasons stated in the preamble, title 40, chapter I, part 60 of the Code of the Federal Regulations is amended as follows:

PART 60--STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

1. The authority citation for Part 60 continues to read as follows:

Authority: 42 U.S.C. 7401 et seq.

2. Add subpart UUUU to read as follows:

Subpart--UUUU Emission Guidelines for Greenhouse Gas Emissions and Compliance Times for Electric Utility Generating Units

Sec.

Introduction

State and Multi-State Plan Requirements

guidelines to the EPA?

Definitions

Introduction

§60.5700 What is the purpose of this subpart?

This subpart establishes emission guidelines and approval criteria for State or multi-State plans that establish emission standards limiting greenhouse gas (GHG) emissions from an affected steam generating unit, integrated gasification combined cycle (IGCC), or stationary combustion turbine. An affected steam generating unit, IGCC, or stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected EGU. These emission guidelines are developed in accordance with sections 111(d) of the Clean Air Act and subpart B of this part. To the extent any requirement of this subpart is inconsistent with the requirements of subparts A or B of this part, the requirements of this subpart will apply.

§60.5705 Which pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases. The emission guidelines for greenhouse gases established in this subpart are expressed as carbon dioxide (CO_2) emission performance rates and equivalent statewide CO_2 emission goals.

(b) PSD and Title V Thresholds for Greenhouse Gases.

(1) For the purposes of §51.166(b)(49)(ii), with respect to GHG emissions from facilities, the "pollutant that is subject to the standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in §51.166(b)(48) and in any State Implementation Plan (SIP) approved by the EPA that is interpreted to incorporate, or specifically incorporates, §51.166(b)(48) of this chapter.

(2) For the purposes of §52.21(b)(50)(ii), with respect to GHG emissions from facilities regulated in the plan, the "pollutant that is subject to the standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in §52.21(b)(49) of this chapter.

(3) For the purposes of §70.2 of this chapter, with respect to greenhouse gas emissions from facilities regulated in the

plan, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in §70.2 of this chapter.

(4) For the purposes of §71.2, with respect to greenhouse gas emissions from facilities regulated in the plan, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in §71.2 of this chapter.

§60.5710 Am I affected by this subpart?

If you are the Governor of a State in the contiguous United States with one or more affected EGUs that commenced construction on or before January 8, 2014, you must submit a State or multi-State plan to the U.S. Environmental Protection Agency (EPA) that implements the emission guidelines contained in this subpart. If you are the Governor of a State in the contiguous United States with no affected EGUs for which construction commenced on or before January 8, 2014, in your State, you must submit a negative declaration letter in place of the State plan.

§60.5715 What is the review and approval process for my plan?

The EPA will review your plan according to §60.27 except that under §60.27(b) the Administrator will have 12 months after the date the final plan or plan revision (as allowed under §60.5795) is submitted, to approve or disapprove such plan or revision or each portion thereof. If you submit an initial submittal under §60.5765(a) in lieu of a final plan submittal the EPA will follow the procedure in §60.5765(b).

§60.5720 What if I do not submit a plan or my plan is not approvable?

(a) If you do not submit an approvable plan the EPA will develop a Federal plan for your State according to §60.27 except that under §60.27(d) the EPA will have one year to promulgate a Federal plan for your State from the date EPA finds you failed to submit a plan or EPA disapproves your plan. The Federal plan will implement the emission guidelines contained in this subpart. Owners and operators of affected EGUs not covered by an approved plan must comply with a Federal plan implemented by the EPA for the State.

(b) After a Federal plan has been implemented in your State, it will be withdrawn when your State submits, and the EPA approves, a final plan.

§60.5725 In lieu of a State plan submittal, are there other acceptable option(s) for a State to meet its CAA section 111(d) obligations?

A State may meet its CAA section 111(d) obligations only by submitting a final State or multi-State plan submittal or a negative declaration letter (if applicable).

§60.5730 Is there an approval process for a negative declaration letter?

No. The EPA has no formal review process for negative declaration letters. Once your negative declaration letter has been received, the EPA will place a copy in the public docket and publish a notice in the FEDERAL REGISTER. If, at a later date, an affected EGU for which construction commenced on or before January 8, 2014 is found in your State, you will have been found to have failed to submit a final plan as required, and a Federal plan implementing the emission guidelines contained in this subpart will apply to that affected EGU until you submit, and the EPA approves, a final State plan.

§60.5735 What authorities will not be delegated to State, local, or tribal agencies?

The authorities that will not be delegated to State, local, or tribal agencies are specified in paragraphs (a) and (b) of this section.

(a) Approval of alternatives, not already approved by this subpart, to the CO_2 emission performance rates in Table 1 to this subpart established under §60.5855.

(b) Approval of alternatives, not already approved by this subpart, to the CO_2 emissions goals in Tables 2, 3 and 4 to this subpart established under §60.5855.

§60.5736 Will the EPA impose any sanctions?

The EPA will not withhold any existing federal funds from a State on account of a State's failure to submit, implement, or enforce an approvable plan or plan revision, or to meet any other requirements under this subpart or subpart B of this part.

§60.5737 What is the Clean Energy Incentive Program and how do I participate?

(a) This subpart establishes the Clean Energy Incentive Program (CEIP). Participation in this program is optional. The program enables States to award early action emission rate credits (ERCs) and allowances to eligible renewable energy (RE) or demand-side energy efficiency (EE) projects that generate megawatt hours (MWh) or reduce end-use energy demand during 2020 and 2021. Eligible projects are those that:

(1) Are located in or benefit a state that has submitted a final state plan that includes requirements establishing its participation in the CEIP; and

(2) Commence construction in the case of RE, or commence operation in the case of demand-side EE, following the submission of a final state plan to the EPA, or after September

6, 2018 for a state that chooses not to submit a final state plan by that date; and

(3) Generate metered MWh from any type of wind or solar resources; or

(4) Result in quantified and verified electricity savings (MWh) through demand-side EE implemented in low-income communities.

(b) The EPA will award matching ERCs or allowances to States that award early action ERCs or allowances, up to a limit equivalent to 300 million tons of CO_2 emissions. The awards will be executed as follows:

(1) For RE projects that generate metered MWh from wind or solar resources: for every two MWh generated, the project will receive one early action ERC (or the equivalent number of allowances) from the state, and the EPA will provide one matching ERC (or the equivalent number of allowances) to the state to award to the project.

(2) For EE projects implemented in low-income communities: for every two MWh in end-use demand savings achieved, the project will receive two early action ERCs (or the equivalent number of allowances), and the EPA will provide two matching ERCs (or the equivalent number of allowances) to the state to award to the project.

(c) You may participate in this program by including in your State plan a mechanism that enables issuance of early action ERCs or allowances by the State to parties effectuating reductions in the calendar years 2020 and 2021 in a manner that would have no impact on the emission performance of affected EGUs required to meet rate-based or mass-based emission standards during the performance periods. This mechanism is not required to account for matching ERCs or allowances that may be issued to the State by the EPA.

(d) If you are submitting an initial submittal by September 6, 2016, you must include a non-binding statement of intent to participate in the program. If you are submitting a final plan by September 6, 2016, your State plan must either include requirements establishing the necessary infrastructure to implement such a program and authorizing its affected EGUs to use early action allowances or ERCs as appropriate, or you must include a non-binding statement of intent as part of its supporting documentation and revise your plan to include the appropriate requirements at a later date.

(e) Your final State plan, or plan revision if applicable, must require that projects eligible to be awarded under this program be evaluated, monitored, verified, and issued per applicable requirements of the State plan approved by the EPA as meeting §60.5805 through §60.5835.

State and Multi-State Plan Requirements

§60.5740 What must I include in my federally enforceable State or multi State plan?

(a) You must include the components described in paragraphs (a)(1) through (5) of this section in your plan submittal. The final plan must meet the requirements and include the information required under §60.5745.

(1) Identification of affected EGUs. Consistent with §60.25(a), you must identify the affected EGUs covered by your plan and all affected EGUs in your State that meet the applicability criteria in §60.5845. In addition, you must include an inventory of CO_2 emissions from the affected EGUs during the most recent calendar year for which data is available prior to the submission of the plan.

(2) Emission standards. You must include an identification of all emission standards for each affected EGU according to §60.5775, compliance periods for each emission standard according to §60.5770, and a demonstration that the emission standards, when taken together, achieve the applicable CO_2 emission performance rates or CO_2 emission goals described in §60.5855. Allowance systems are an acceptable form of emission standards under this subpart.

(i) Your plan does not need to include corrective measures specified in paragraph (a)(2)(ii) of this section if your plan:

(A) Imposes emission standards on all affected EGUs that, assuming full compliance by all affected EGUs, mathematically assure achievement of the CO_2 emission performance rates in the plan for each plan period;

(B) Imposes emission standards on all affected EGUS that, assuming full compliance by all affected EGUs, mathematically assure achievement of the CO_2 emission goals; or

(C) Imposes emission standards on all affected EGUs that, assuming full compliance by all affected EGUs, in conjunction with applicable requirements under state law for EGUs subject to subpart TTTT of this subpart, assuming the applicable requirements under state law are met by all EGUs subject to subpart TTTT of this subpart, achieve the applicable mass-based CO_2 emission goals plus new source CO_2 emission complement allowed for in §60.5790(b)(5).

(ii) If your plan does not meet the requirements of (a)(2)(i) of this section, your plan must include the requirement for corrective measures to be implemented if triggered. Upon triggering corrective measures, if you do not already have them included in your approved State plan, you must submit corrective measures to EPA for approval as a plan revision per the requirements of §60.5785(c). These corrective measures must ensure that the interim period and final period CO_2 emission performance rates or CO_2 emission goals are achieved by your affected EGUs, as applicable, and must achieve additional emission reductions to offset any emission performance shortfall. Your plan must include the requirement that corrective measures be triggered and implemented according to paragraphs (a)(2)(ii)(A) through (H) of this section.

(A) Your plan must include a trigger for an exceedance of an interim step 1 or interim step 2 CO_2 emission performance rate or CO_2 emission goal by 10 percent or greater, either on average or cumulatively (if applicable).

(B) Your plan must include a trigger for an exceedance of an interim step 1 goal or interim step 2 goal of 10 percent or greater based on either reported CO_2 emissions with applied plus or minus adjustments for net CO_2 allowances "imports" or "exports" (if applicable), or based on the adjusted CO_2 emission rate (if applicable).

(C) Your plan must include a trigger for a failure to meet an interim period goal based on reported CO_2 emissions with applied plus or minus adjustments for net CO_2 allowances "imports" or "exports" (if applicable), or based on the adjusted CO_2 emission rate (if applicable).

(D) Your plan must include a trigger for a failure to meet the interim period or any final reporting period CO_2 emission performance rate or CO_2 emission goal, either on average or cumulatively (if applicable).

(E) Your plan must include a trigger for a failure to meet any final reporting period goal based on reported CO_2 emissions with applied plus or minus adjustments for net CO_2 allowances "imports" or "exports" (if applicable).

(F) Your plan must include a trigger for a failure to meet the interim period CO_2 emission performance rate or CO_2 emission goal based on the adjusted CO_2 emission rate (if applicable).

(G) Your plan must include a trigger for a failure to meet any final reporting period CO_2 emission performance rate or CO_2 emission goal based on the adjusted CO_2 emission rate (if applicable).

(H) A net import adjustment represents the CO_2 emissions (in tons) equal to the number of net imported CO_2 allowances. This adjustment is added to reported CO_2 emissions. Under this adjustment, such allowances must be issued by a state with an emission budget trading program that only applies to affected EGUs (or affected EGUs plus EGUs covered by subpart TTTT of this part as applicable). A net export adjustment represents the CO_2 emissions (in tons) equal to the number of net exported CO_2 allowances. This adjustment is subtracted from reported CO_2 emissions.

(iii) If your plan relies upon State measures, in addition to or in lieu of emission standards on your affected EGUs, then the final State plan must include the information in paragraph (a)(3) of this section and the submittal must include the information listed in §60.5745(a)(6).

(iv) If your plan requires emission standards in addition to relying upon State measures, then you must demonstrate that the emission standards and State measures are, when taken together, results in the achievement of to meet the applicable mass-based CO_2 emission goal described in §60.5855 by your State's affected EGUs.

(3) State measures backstop. If your plan relies upon State measures, you must submit, as part of the plan, a federally enforceable backstop that includes emission standards for affected EGUs that will be put into place, if there is a triggering event listed in paragraph (a)(3)(i) of this section, within 18 months of the due date of the report required in paragraph (b) of §60.5870(c). The emission standards on the affected EGUs as part of the backstop must be able to meet either the CO_2 emission performance rates or mass-based or rate-based CO_2 emission goal for your State during the interim and final periods. You must either submit, along with the backstop emission standards, provisions to adjust the emission standards to make up for the prior emission performance shortfall, such that no modification of the emission standards is necessary in order to address the emission performance shortfall, or you must submit, as part of the final plan, backstop emission standards

that assure affected EGUs would achieve your State's CO_2 emission performance rates or emission goals during the interim and final periods, and then later submit appropriate revisions to the backstop emission standards adjusting for the shortfall through the State plan revision process described in §60.5785. The backstop must also include the requirements in paragraphs (a)(3)(i) through (iii).

(i) A trigger for the backstop to go into effect upon:

(A) A failure to meet a programmatic milestone;

(B) An exceedance of 10 percent or greater of an interim step 1 goal or interim step 2 goal based on reported CO_2 emissions, with applied plus or minus adjustments for net CO_2 allowances "imports" or "exports" (if applicable);

(C) A failure to meet the interim period goal based on reported CO_2 emissions, with applied plus or minus adjustments for net CO_2 allowances "imports" or "exports" (if applicable); or

(D) A failure to meet any final reporting period goal based on reported CO_2 emissions, with applied plus or minus adjustments for net CO_2 allowances "imports" or "exports" (if applicable).

(ii) You may include in your plan any additional triggers so long as they do not reduce the stringency of the triggers required under paragraph (a)(3)(i) of this section.

(iii) A schedule for implementation of the backstop once triggered, and you must identify all necessary State administrative and technical procedures for implementing the backstop.

(4) Identification of applicable monitoring, reporting, and recordkeeping requirements for each affected EGU. You must include in your plan all applicable monitoring, reporting and recordkeeping requirements for each affected EGU and the requirements must be consistent with or no less stringent than the requirements specified in §60.5860.

(5) State reporting. You must include in your plan a description of the process, contents, and schedule for State reporting to the EPA about plan implementation and progress including information required under §60.5870.

(i) You must include in your plan a requirement for a report to be submitted by July 1, 2021, that demonstrates that the State has met, or is on track to meet, the programmatic milestone steps indicated in the timeline required in §60.5770.

(b) You must follow the requirements of subpart B of this part and demonstrate that they were met in your State plan. However, the provisions of §60.24(f) shall not apply.

§60.5745 What must I include in my final plan submittal?

(a) In addition to the components of the plan listed in §60.5740, a final plan submittal to the EPA must include the information in paragraphs (a)(1) through (13) of this section. This information must be submitted to the EPA as part of your final plan submittal but will not be codified as part of the federally enforceable plan upon approval by EPA.

(1) You must include a description of your plan approach and the geographic scope of the plan (i.e., State or multi-State, geographic boundaries related to the plan elements), including, if applicable, identification of multi-State plan participants.

(2) You must identify CO_2 emission performance rates or equivalent statewide CO_2 emission goals that your affected EGUs will achieve. If the geographic scope of your plan is a single State, then you must identify CO_2 emission performance rates or emission goals according to §60.5855. If your plan includes multiple States and you elect to set CO_2 emission performance goals, you must identify CO_2 emission goals calculated according to §60.5750.

(i) You must specify in the plan submittal the CO_2 emission performance rates or emission goals that affected EGUs will meet for the interim period, each interim step, and the final period (including each final reporting period) pursuant to §60.5770.

(3) You must include a demonstration that the affected EGUs covered by the plan are projected to achieve the CO_2 emission performance rates or CO_2 emission goals described in §60.5855.

(4) You must include a demonstration that each affected EGU's emission standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable according to §60.5775.

(5) If your plan includes emission standards on your affected EGUs sufficient to meet either the CO_2 emission performance rates or CO_2 emision goals, you must include in your plan submittal the information in paragraphs (a)(5)(i) through (v) of this section as applicable.

(i) If your plan applies separate rate-based CO_2 emission standards for affected EGUs (in lbs CO_2/MWh) that are equal to or lower than the CO_2 emission performance rates listed in Table 1 of this subpart, then no additional demonstration is required beyond inclusion of the emission standards in the plan.

(ii) If a plan applies rate-based emission standards to individual affected EGUs at a lbs CO_2/MWh rate that differs from the CO_2 emission performance rates in Table 1 of this subpart or the State's rate-based CO_2 emission goal in Table 2 of this subpart, then a further demonstration is required that the application of the CO_2 emission standards will achieve the CO_2 emission performance rates or State rate-based CO_2 goal. You must demonstrate through a projection that the adjusted weighted average CO_2 emission rate of affected EGUs, when weighted by generation (in MWh), will be equal to or less than the CO_2 emission performance rates or the rate-based CO_2 emission goal.

This projection must address the interim period and the final period. The projection in the plan submittal must include the information listed in (a)(5)(v) and in addition the following:

(A) An analysis of the change in generation of affected EGUs given the compliance costs and incentives under the application of different emission rate standards across affected EGUs in a State;

(B) A projection showing how generation is expected to shift between affected EGUs and across affected EGUs and non-affected EGUs over time;

(C) Assumptions regarding the availability and anticipated use of the MWh of electricity generation or electricity savings from eligible resources that can be issued ERCs;

(D) The specific calculation (or assumption) of how eligible resource MWh of electricity generation or savings are being used in the projection to adjust the reported CO_2 emission rate of affected EGUs;

(E) If a state plan provides for the ability of renewable energy resources located in states with mass-based plans to be issued ERCs, consideration in the projection that such resources must meet geographic eligibility requirements, based on power purchase agreements or related documentation; and

(F) Any other applicable assumptions used in the projection.

(iii) If a plan establishes mass-based emission standards for affected EGUs that cumulatively do not exceed the State's EPA-specified mass CO_2 emission goal then no additional demonstration is required beyond inclusion of the emission standards in the plan.

(iv) If a plan applies mass-based emission standards to individual affected EGUs that do not meet the requirements of paragraph (a)(5)(iii) you must include a demonstration that your mass-based emission program will be designed such that compliance by affected EGUs would achieve the State mass-based CO_2 emission goals. This demonstration includes the information listed in paragraph (a)(5)(v) and emission budgets for affected EGUs during the interim period and final periods that are equal to or lower than the applicable State mass-based CO_2 goals specified in Table 3 of this subpart.

(v) Your plan demonstration to be included in your plan submittal, if applicable, must include the information listed in (a)(5)(v)(A) through (M) of this section.

(A) A summary of each affected EGU's anticipated future operation characteristics, including:

(1) Annual generation;

(2) CO_2 emissions;

(3) Fuel use, fuel prices (when applicable), fuel carbon content;

(4) Fixed and variable operations and maintenance costs (when applicable);

(5) Heat rates; and

(6) Electric generation capacity and capacity factors.

(B) An identification of any planned new electric generating capacity.

(C) Analytic treatment of the potential for building unplanned new electric generating capacity.

(D) A timeline for implementation of EGU-specific actions (if applicable).

(E) All wholesale electricity prices.

(F) A geographic representation appropriate for capturing impacts and/or changes in electric system.

(G) A time period of analysis, which must extend through at least 2031.

(H) An anticipated electricity demand forecast (MWh load and MW peak demand) at the State or regional level, including the source and basis for these estimates, and, if appropriate, justification and documentation of underlying assumptions that inform the development of the demand forecast (e.g., annual economic and demand growth rate or population growth rate).

(I) A demonstration that each emission standard included in your plan meets the requirements of §60.5775.

(J) Any ERC or emission allowance prices, when applicable.

(K) An identification of State-enforceable measures with electricity savings and RE generation, in MWh, expected for individual and collective measures and any assumptions related to the quantification of the MWh, as applicable.

(L) An identification of planning reserve margins.

(M) Any other applicable assumptions used in the projection.

(6) If your plan relies upon State measures, in addition to or in lieu of the emission standards required by paragraph §60.5740(a)(2), the final State plan submittal must include the information under paragraphs (a)(5)(iv) and (a)(6)(i) through (v) of this section.

(i) You must include a description of all the State measures the State will rely upon to achieve the applicable CO_2 emission goals required under §60.5855(e), the projected impacts of the State measures over time, the applicable State laws or regulations related to such measures, and identification of parties or entities implementing such State measures.

(ii) You must include the schedule and milestones for the implementation of the State measures. If the State measures in your plan submittal rely upon measures that do not have a direct effect on the emissions measured at an affected EGU's stack, you must also demonstrate how the minimum emission, monitoring and verification (EM&V) requirements listed under §60.5795 that apply to those programs and projects will be met.

(iii) You must demonstrate that federally enforceable emission standards for affected EGUs in conjunction with any State measures relied upon for your plan, are sufficient to achieve the mass-based CO_2 emission goal for the interim period, each interim step in that interim period, the final period, and each final reporting period. In addition, you must demonstrate that each emission standard included in your plan meets the requirements of §60.5775 and each State measure included in your plan submittal meets the requirements of §60.5780.

(iv) You must include a CO_2 performance projection of your State measures that shows how the measures will achieve the future CO_2 performance at affected EGUs. Elements of this projection must include the following for the interim period and the final period:

(A) A baseline demand and supply forecast as well as the underlying assumptions and data sources of each forecast;

(B) The magnitude of energy and emission impacts from all measures included in the plan and applicable assumptions;

(C) An explanation of the tools and emission quantification approaches used in the projection; and

(D) Underlying emission quantification assumptions.

(v) A State must demonstrate that the combined State-enforceable measures, in conjunction with any federally enforceable CO_2 emission standards for affected EGUs, if included, will result in the achievement by the affected EGUs of the State's mass-based CO_2 emission goals for the interim period, interim step, and final reporting periods. In addition, you must demonstrate that each State measure included in your plan submittal meets the requirements of §60.5780.

(7) Your plan submittal must include a demonstration that the reliability of the electrical grid has been considered.

(8) Your plan submittal must include a timeline with all the programmatic milestone steps the State intends to take between the time of the State plan submittal and January 1, 2022 to ensure the plan is effective as of January 1, 2022.

(9) Your plan submittal must adequately demonstrate that your State has the legal authority (e.g., through regulations or legislation) and funding to implement and enforce each component of the State plan submittal, including federally enforceable emission standards for affected EGUs or State measures as applicable.

(10) Your State plan submittal must demonstrate that each interim step goal required under §60.5855(c), will be met and include in its supporting documentation a description of the

analytic process, tools, methods, and assumptions used to make this demonstration.

(11) Your plan submittal must include certification that a hearing required under §60.23(c)(1) on the State plan was held, a list of witnesses and their organizational affiliations, if any, appearing at the hearing, and a brief written summary of each presentation or written submission pursuant to the requirements of §60.23(f).

(12) Your plan submittal must include documentation of any conducted community outreach and community involvement, including engagement with vulnerable communities.

(13) Your plan submittal must include supporting material for your plan including:

(i) Materials demonstrating the State's legal authority to carry out each component of its plan, including emissions standards or State measures;

(ii) Materials supporting that the CO_2 emission performance rates or CO_2 emission goals will be achieved by affected EGUs identified under the plan, according to paragraph (a)(3) of this section;

(iii) Materials supporting any calculations for CO_2 emission goals calculated according to §60.5855, if applicable; and

(iv) Any other materials necessary to support evaluation of the plan by the EPA.

(b) You must submit your final plan to the EPA electronically according to §60.5875.

§60.5750 Can I work with other States to develop a multi-State plan?

A multi-State plan must include all the required elements for a plan specified in §60.5740(a). A multi-State plan must meet the requirements of paragraphs (a) and (b) of this section.

(a) The multi-State plan must demonstrate that all affected EGUs in all participating States will meet the CO_2 emission performance rates listed in Table 1 of this subpart or an equivalent CO_2 emission goal according to paragraphs (a)(1) or (2) of this section. States may only follow the procedures in (a)(1) or (2) if they have functionally equivalent requirements meeting §60.5775 and §60.5790 included in their plans.

(1) For States electing to demonstrate performance with a CO_2 emission rate-based goal, the CO_2 emission goals identified in the plan according to §60.5855 will be an adjusted weighted (by net energy output) average lbs CO_2/MWh emission rate to be achieved by all affected EGUs in the multi-State area during the plan periods; or

(2) For States electing to demonstrate performance with a CO_2 emission mass-based goal, the CO_2 emission goals identified in the multi-State plan according to §60.5855 will be total CO_2 emissions by all affected EGUs in the multi-State area during

the plan periods.

(b) Options for submitting a multi-State plan include the following:

(1) States participating in a multi-State plan may submit one multi-State plan submittal on behalf of all participating States. The joint submittal must be signed electronically, according to §60.5875, by authorized officials for each of the States participating in the multi-State plan. In this instance, the joint submittal will have the same legal effect as an individual submittal for each participating State. The joint submittal must address plan components that apply jointly for all participating States and components that apply for each individual State in the multi-State plan, including necessary State legal authority to implement the plan, such as State regulations and statutes.

(2) States participating in a multi-State plan may submit a single plan submittal, signed by authorized officials from each participating State, which addresses common plan elements. Each participating States must, in addition, provide individual plan submittals that address State-specific elements of the multi-State plan.

(3) States participating in a multi-State plan may separately make individual submittals that address all elements of the multi-State plan. The plan submittals must be materially

consistent for all common plan elements that apply to all participating States, and also must address individual State-specific aspects of the multi-State plan. Each individual State plan submittal must address all required plan components in §60.5740.

(c) A State may elect to participate in more than one multi-State plan. If a State elects to participate in more than one multi-State plan then you must identify in the State plan submittal required under §60.5745, the subset of affected EGUs that are subject to the specific multi-State plan or your State's individual plan. An affected EGU can only be subject to one plan.

(d) A State may elect to allow its affected EGUs to interact with affected EGUs in other States through mass-based trading programs or a rate-based trading program without entering into a formal multi-State plan allowed for under this section, so long as such programs are part of an EPA-approved state plan.

(1) For States that elect to do mass-based trading under this option the State must indicate in its plan that its emission budget trading program will be administered using an EPA-approved (or EPA-administered) emission and allowance tracking system.

(2) For States that elect to use a rate-based trading

program which allows the affected EGUs to use ERCs from other State rate-based trading programs, the plan must require affected EGUs within their State to comply with emission standards equal to the sub-category CO_2 emission performance rates in Table 1 of this subpart.

§60.5760 What are the timing requirements for submitting my plan?

(a) You must submit a final plan with the information required under §60.5745 by September 6, 2016, unless you are submitting an initial submittal, allowed under §60.5765, in lieu of a final State plan submittal, according to paragraphs (b) of this section.

(b) For States seeking a two year extension for a final plan submittal, you must include the information in §60.5765(a) in an initial submittal by September 6, 2016, to receive an extension to submit your final State plan submittal by September 6, 2018.

(c) You must submit all information required under paragraphs (a) and (b) of this section according to the electronic reporting requirements in §60.5875.

§60.5765 What must I include in an initial submittal if requesting an extension for a final plan submittal?

(a) You must sufficiently demonstrate that your State is able to undertake steps and processes necessary to timely submit a final plan by the extended date of September 6, 2018, by addressing the following required components in an initial submittal by September 6, 2016, if requesting an extension for a final plan submittal:

(1) An identification of final plan approach or approaches under consideration and description of progress made to date on the final plan components;

(2) An appropriate explanation of why the State requires additional time to submit a final plan by September 6, 2018; and

(3) Demonstration or description of opportunity for public comment on the initial submittal and meaningful engagement with stakeholders, including vulnerable communities, during the time in preparation of the initial submittal and the plans for engagement during development of the final plan.

(b) You must submit an initial submittal allowed in paragraph (a) of this section, information required under paragraph (c) of this section (only if a State elects to submit an initial submittal to request an extension for a final plan submittal), and a final State plan submittal according to §60.5870. If a State submits an initial submittal, an extension for a final State plan submittal is considered granted and a final State plan submittal is due according to §60.5760(b) unless a State is notified within 90 days of the EPA receiving the initial submittal that the EPA finds the initial submittal does not meet the requirements listed in paragraph (a) of this section and the State has failed to submit the final plan required by September 6, 2016.

(c) If an extension for submission of a final plan has been granted, you must submit a progress report by September 6, 2017. The 2017 report must include the following:

(1) A summary of the status of each component of the final plan, including an update from the 2016 initial submittal and a list of which final plan components are not complete.

(2) A commitment to a plan approach (e.g., single or multi-State, rate-based or mass-based emission performance level, rate-based or mass-based emission standards), including draft or proposed legislation and/or regulations.

(3) An updated comprehensive roadmap with a schedule and milestones for completing the final plan, including any updates to community engagement undertaken and planned.

§60.5770 What schedules, performance periods, and compliance periods must I include in my plan?

(a) The affected EGUs covered by your plan must meet the CO_2 emission requirements required under §60.5855 for the interim period, interim steps, and the final reporting periods according to paragraph (b) of this section. You must also include in your plan compliance periods for each affected EGU regulated under the plan according to paragraphs (c) and (d) of this section.

(b) Your plan must require your affected EGUs to achieve each CO_2 emission performance rate or CO_2 emission goal, as applicable, required under §60.5855 over the periods according to paragraphs (b)(1) through (3) of this section.

(1) The interim period.

(2) Each interim step.

(3) Each final reporting period.

(c) The emission standards for affected EGUs regulated under the plan must include the following compliance periods:

(1) For the interim period, affected EGUs must have emission standards that have compliance periods that are no longer than each interim step and are imposed for the entirety of the interim step either alone or in combination.

(2) For the final period, EGUs must have emission standards that have compliance periods that are no longer than each final reporting period and are imposed for the entirety of the final reporting period either alone or in combination.

(3) Compliance periods for each interim step and each final reporting period may take forms shorter than specified in this regulation, provided the schedules of compliance collectively end on the same schedule as each interim step and final reporting period.

(d) If your plan relies upon State measures in lieu of or in addition to emission standards for affected EGUs regulated under the plan, then the period for achievement of each State measure must be identical to the compliance periods for affected EGUs listed in paragraphs (c)(1) through (3) of this section.

§60.5775 What emission standards must I include in my plan?

(a) Emission standard(s) for affected EGUs under your plan must be quantifiable, verifiable, non-duplicative, permanent, and enforceable with respect to each affected EGU. The plan must include the methods by which each emission standard meets each of the following requirements in paragraphs (b) through (f) of this section.

(b) An affected EGU's emission standard is quantifiable if it can be reliably measured in a manner that can be replicated.

(c) An affected EGU's emission standard is verifiable if adequate monitoring, recordkeeping and reporting requirements are in place to enable the State and the Administrator to independently evaluate, measure, and verify compliance with the emission standard.

(d) An affected EGU's emission standard is non-duplicative with respect to a State plan if it is not already incorporated as an emission standard in another State plan unless incorporated in multi-State plan.

(e) An affected EGU's emission standard is permanent if the emission standard must be met for each compliance period, or unless it is replaced by another emission standard in an approved plan revision, or the State demonstrates in an approvable plan revision that the emission reductions from the emission standard are no longer necessary for the State to meet its State level of performance.

(f) An affected EGU's emission standard is enforceable if:

(1) A technically accurate limitation or requirement and the time period for the limitation or requirement are specified;

(2) Compliance requirements are clearly defined;

(3) The affected EGUs responsible for compliance and liable for violations can be identified;

(4) Each compliance activity or measure is enforceable as a practical matter; and

(5) The Administrator, the State, and third parties maintain the ability to enforce against violations (including if an affected EGU does not meet its emission standard based on its emissions, its allowances if it is subject to a mass-based emission standard, or its ERCs if it is subject to a rate-based emission standard) and secure appropriate corrective actions, in the case of the Administrator pursuant to CAA sections 113(a)-(h), in the case of a State, pursuant to its plan, State law or CAA section 304, as applicable, and in the case of third parties, pursuant to CAA section 304.

§60.5780 What State measures may I rely upon in support of my plan?

You may rely upon State measures in support of your plan that are not emission standard(s) on affected EGUs, provided those State measures meet the requirements in paragraph (a) of this section.

(a) Each State measure is quantifiable, verifiable, non-duplicative, permanent, and enforceable with respect to each affected entity (entities other than affected EGUs with no federally enforceable obligations under a State plan), and your plan supporting materials include the methods by which each State measure meets each of the following requirements in paragraphs (1) through (5) of this subpart.

(1) A State measure is quantifiable with respect to an affected entity if it can be reliably measured in a manner that can be replicated.

(2) A State measure is verifiable with respect to an affected entity if adequate monitoring, recordkeeping and reporting requirements are in place to enable the State to independently evaluate, measure, and verify compliance with the State measure.

(3) A State measure is non-duplicative with respect to an affected entity if it is not already incorporated as a State measure or an emission standard in another State plan or State plan supporting material unless incorporated in multi-State plan.

(4) A State measure is permanent with respect to an affected entity if the State measure must be met for at least each compliance period, or unless it is replaced by another State measure in an approved plan revision, or the State demonstrates in an approved plan revision that the emission reductions from the State measure are no longer necessary for the State's affected EGUs to meet its CO_2 emission performance rates.

(5) A State measure is enforceable against an affected entity if:

(i) A technically accurate limitation or requirement and the time period for the limitation or requirement are specified;

(ii) Compliance requirements are clearly defined;

(iii) The affected entities responsible for compliance and liable for violations can be identified;

(iv) Each compliance activity or measure is enforceable as a practical matter; and

(v) The State maintains the ability to enforce violations and secure appropriate corrective actions.

§60.5785 What is the procedure for revising my plan?

(a) Plans can be revised only with approval by the Administrator. The Administrator will approve a plan revision if it is satisfactory with respect to the applicable requirements of this subpart and any applicable requirements of subpart B of this part, including the requirement in §60.5745(a)(3) to demonstrate achievement of the CO_2 emission performance rates in §60.5855. If one (or more) of the elements of the plan set in §60.5740 require revision with respect to achieving the CO_2 emission performance rates in §60.5855, a request must be submitted to the Administrator indicating the proposed revisions to the plan to ensure the CO_2 emission performance rates are met. In addition, the following provisions in (b) through (d) may apply.

(b) You may submit revisions to a plan to adjust CO_2 emission goals under the following instances:

(1) Addressing the addition of an affected EGU required to be included in a plan under §60.5740(a)(1).

(2) Addressing EGUs that become subject to subpart TTTT of this part and are no longer considered affected EGUs for incorporation in a plan.

(c) If your State is required to submit a notification according to section §60.5870(d) indicating a triggering of corrective measures as described in §60.5740(a)(2)(i) and your plan does not already include corrective measures to be implemented if triggered, you must revise your State plan to include corrective measures to be implemented. The corrective measures must ensure achievement of the CO_2 emission performance rates or State CO_2 emission goal. Additionally, the corrective measures must achieve additional emission reductions to offset any emission performance shortfall relative to the overall interim period or final period CO_2 emission performance rate or State CO_2 emission goal. The State plan revision submission must explain how the corrective measures both make up for the shortfall and address the State plan deficiency that caused the shortfall. The State must submit the revised plan and explanation to the EPA within 24 months after submitting the State report required in section §60.5870(a) indicating the exceedance in lieu of the requirements of §60.28(a). The State must implement corrective measures within 6 months of the EPA's approval of a plan revision adding them. The shortfall must be made up as expeditiously as practicable.

(d) If your plan relies upon State measures, your State triggers the backstop under §60.5740(a)(3)(i), and your State measures plan backstop does not include a mechanism to make up the shortfall, you must revise your backstop emission standards to make up the shortfall. The shortfall must be made up as expeditiously as practicable.

(e) Reliability Safety Valve

(1) In order to trigger a reliability safety valve, you must notify the EPA within 48 hours of an unforeseen, emergency situation that threatens reliability, such that your State will need a short-term modification of emission standards under a

State plan for a specified affected EGU or EGUs. The EPA will consider the notification in §60.5870(g)(1) to be an approved short-term modification to the State plan without needing to go through the full State plan revision process if the State provides a second notification to the EPA within seven days of the first notification. The short-term modification under a reliability safety valve allows modification to emission standards under the State plan for an affected EGU or EGUs for an initial period of up to 90 days. During that period of time, the EGU or EGUs will need to comply with the modified emission standards identified in the initial notification required under §60.5870(g)(1) or amended in the second notification required under §60.5870(g)(2). For the duration of the up to 90-day short-term modification, the emissions of the affected EGU or EGUs that exceed their obligations under the approved State plan will not be counted against the State's CO_2 emission performance rate or goal. The EPA reserves the right to review any such notification required under §60.5870(g), and, in the event that the EPA finds such notification is improper, the EPA may disallow the short-term modification and affected EGUs must continue to operate under the approved State plan emission standards. As described more fully below in §60.5870(g)(3), at least seven days before the end of the initial 90-day reliability safety valve period, the State must notify the appropriate EPA regional office whether the reliability concern has been addressed and the EGU or EGUs can resume meeting the original emission standards established in the State plan prior to the short-term modification or whether a serious, ongoing reliability issue necessitates the EGU or EGUs emitting beyond the amount allowed under the State plan.

(2) Plan revisions submitted pursuant to §60.5870(g)(3) must meet the requirements for State plan revisions under §60.5785(a).

§60.5790 What must I do to meet my plan obligations?

(a) To meet your plan obligations, you must demonstrate that your affected EGUs are complying with their emission standards as specified in §60.5740, and you must demonstrate that the emission standards on affected EGUs in conjunction with any State measures are resulting in achievement of the CO_2 emission performance rates or statewide CO_2 emission goals using the procedures in paragraphs (b) through (d) of this section. If your plan requires the use of allowances for your affected EGUs to comply with their emission standards, you must follow the requirements under paragraph (b) of this section and §60.5830. If your plan requires the use of ERCs for your affected EGUs to comply with their emission standards, you must follow the requirements under paragraphs (c) and (d) of this section and §§60.5795 through 60.5805.

(b) If you submit a plan that sets a mass-based emission trading program for your affected EGUs, the State plan must include emission standards and requirements that specify the allowance system, related compliance requirements and mechanisms, and the emission budget as appropriate. These requirements must include those listed in paragraphs (b)(1) through (5).

(1) CO_2 emission monitoring, reporting, and recordkeeping requirements for affected EGUs.

(2) Requirements for State allocation of allowances consistent with §60.5815.

(3) Requirements for tracking of allowances, from issuance through submission for compliance, consistent with §60.5820.

(4) The process for affected EGUs to demonstrate compliance (allowance "true-up" with reported CO_2 emissions) consistent with §60.5825.

(5) Requirements that address increased emissions from new sources, beyond the emissions expected from new sources if existing EGUs were given standards of performance in the form of the subcategory-specific emission performance rates. You may meet this requirement by requiring one of the options under paragraphs (b)(5)(i) through (iii).

(i) You may include, as part of your plan's supporting documentation, requirements enforceable as a matter of State law regulating emissions from existing affected EGUs and emissions from EGUs covered by subpart TTTT of this part under the mass-based CO_2 goal plus new source CO_2 emission complement applicable to your State in Table 4 of this subpart. If you choose this option, the term "mass-based CO_2 goal plus new source CO_2 emission complement" shall apply rather than "CO_2 mass based goal" and the term "CO_2 emission goal" shall include "mass-based CO_2 goal plus new source CO_2 emission complement" in these emission guidelines.

(ii) You may include requirements in your State plan for emission budget allowance allocation methods that align incentives to generate to existing or new sources;

(iii) You may submit an approvable equivalent method which requires affected EGUs to meet the mass-based CO_2 emission goal. The EPA will evaluate the approvability of such an alternative method on a case by case basis.

(c) If you submit a plan that sets rate-based emission standards on your affected EGUs, to meet the requirements of §60.5775, you must follow the requirements in paragraphs (c)(1) through (4).

(1) You must require the owner or operator of each affected EGU covered by your plan to calculate an adjusted CO_2 emission rate to demonstrate compliance with its emission standard by factoring stack emissions and any ERCs into the following

equation:

$$CO_2 emission\ rate = \frac{\sum M_{CO2}}{\sum MWh_{op} + \sum MWh_{ERC}}$$

Where:

CO_2 emission rate = An affected EGU's calculated CO_2 emission rate that will be used to determine compliance with the applicable CO_2 emission standard.

M_{CO2} = Measured CO_2 mass in units of pounds (lbs) summed over the compliance period for an affected EGU.

MWh_{op} = Total net energy output over the compliance period for an affected EGU in units of MWh.

MWh_{ERC} = ERC replacement generation for an affected EGU in units of MWh (ERCs are denominated in whole integers as specified in paragraph (d) of this section).

(2) Your plan must specify that an ERC qualifies for the compliance demonstration specified in paragraph (c)(1) of this section if the ERC meets the requirements of paragraphs (c)(2)(i) through (iv).

(i) An ERC must have a unique serial number.

(ii) An ERC must represent one MWh of actual energy generated or saved with zero associated CO_2 emissions.

(iii) An ERC must only be issued to an eligible resource that meets the requirements of §60.5795 or to an affected EGU that meets the requirements of §60.5800 and must only be issued by a State or its State agent through an EPA-approved ERC tracking system that meets the requirements of §60.5810, or by the EPA through an EPA-administered tracking system; and

(iv) An ERC must be surrendered and retired only once for purpose of compliance with this regulation through an EPA-approved ERC tracking system that meets the requirements of §60.5810, or by the EPA through an EPA-administered tracking system.

(3) Your plan must specify that an ERC does not qualify for the compliance demonstration specified in paragraph (c)(1) of this section if it does not meet the requirements of paragraph (c)(2) of this section or if any State has used that same ERC for purposes of demonstrating achievement of its State measures. The plan must additionally include provisions that address requirements for revocation or adjustment that apply if an ERC issued by the State is subsequently found to have been improperly issued.

(4) Your plan must include provisions either allowing for or restricting banking of ERCs between compliance periods for affected EGUs, and provisions not allowing any borrowing of any

ERCs from future compliance periods by affected EGUs or eligible resources.

(d) If you want an affected EGU subject to a rate-based emission standard (whether under an emission standards plan or as a part of the federally enforceable backstop in a State measures plan) to be able to use ERCs issued pursuant to your State measures to demonstrate compliance with its emission standard, to meet the requirements of §60.5775, such ERCs must meet the requirements of paragraphs (c) of this section.

Emission Rate Credit Requirements

§60.5795 What affected EGUs qualify for generation of ERCs?

(a) For issuance of ERCs to affected EGUs, the plan must specify the accounting method and process for ERC issuance. For plans that require that affected EGUs meet a rate-based CO_2 emission goal, where all affected EGUs have identical emission standards, you must specify the accounting method listed in paragraph (a)(1) of this section for generating ERCs. For plans that require affected EGUs to meet the CO_2 emission performance rates or CO_2 emission goals where affected EGUs have emission standards that are not equal for all affected EGUs, you must specify the accounting methods listed in paragraphs (a)(1) and (2) of this section for generating ERCs.

(1) You must include the calculation method for determining the number of ERCs, denominated in MWh, that may be issued to an

affected EGU that is in compliance with its emission standard, based on the difference between its emission standard and its CO_2 emission rate for the compliance period; and

(2) You must include the calculation method for determining the number of ERCs, denominated in MWh, that may be issued to affected EGUs that meet the definition of a stationary combustion turbine based on the displaced emissions from affected EGUs not meeting the definition of a stationary combustion turbine, resulting from the difference between its annualized net energy output in MWh for the calendar year(s) in the compliance period and its net energy output in MWh for the 2012 calendar year (January 1, 2012, through December 31, 2012).

(b) Any ERCs generated through the method described as required by paragraph (a)(2) must not be used by any affected EGUs other than steam generating units or IGCCs to demonstrate compliance as prescribed under §60.5790(c)(1).

(c) Any states in a multi-State plan that requires the use of ERCs for affected EGUs to comply with their emission standards must have functionally equivalent requirements pursuant to paragraphs (a)(1) and (2) of this section for generating ERCs.

§60.5800 What other resources qualify for issuance of ERCs?

(a) ERCs may only be issued for generation or savings produced on or after January 1, 2022, to an eligible resource that meets each of the requirements in paragraphs (a)(1) through (4) of this section.

(1) Resources qualifying for eligibility only include resources that increased new installed electrical generation nameplate capacity, or new electrical savings measures installed or implemented on or after January 1, 2013. If a resource had a nameplate capacity uprate, ERCs may be issued only for the difference in generation between the uprated nameplate capacity and its nameplate capacity prior to the uprate. ERCs must not be issued for generation for an uprate that followed a derate that occurred on or after January 1, 2013. A resource that is relicensed or receives a license extension is considered existing capacity and is not an eligible resource, unless it receives a capacity uprate as a result of the relicensing process that is reflected in its relicensed permit. In such a case, only the difference in nameplate capacity between its relicensed permit and its prior permit is eligible to be issued ERCs.

(2) The resource must be connected to, and deliver energy to or save electricity on, the electric grid in the contiguous United States.

(3) The resource is located in either:

(i) A State whose affected EGUs are subject to rate-based emission standards pursuant to this regulation; or

(ii) A State with mass-based emission standards, and the resource can demonstrate (e.g., through a power purchase agreement or contract for delivery) that the electricity generated is delivered with the intention to meet load in a State with affected EGUs which are subject to rate-based emission standards pursuant to this regulation, and was treated as a generation resource used to serve regional load that included the State whose affected EGUs are subject to rate-based emission standards. In this situation the only type of eligible resource in the State with mass-based emission standards is renewable generating technologies listed in (a)(4)(i) of this section.

(4) The resource falls into one of the following categories of resources:

(i) Renewable electric generating technologies using one of the following renewable energy resources: wind, solar, geothermal, hydro, wave, tidal;

(ii) Qualified biomass;

(iii) Waste-to-energy (biogenic portion only);

(iv) Nuclear power;

(v) A non-affected combined heat and power unit, including waste heat power;

(vi) A demand-side EE or demand-side management measure that saves electricity and is calculated on the basis of quantified ex post savings, not "projected" or "claimed" savings; or

(vii) A category identified in a State plan and approved by the EPA to generate ERCs.

(b) Any resource that does not meet the requirements of this subpart or an approved State plan cannot be issued ERCs for use by an affected EGU with its compliance demonstration required under §60.5790(c).

(c) ERCs may not be issued to any of the following:

(1) New, modified, or reconstructed EGUs that are subject to subpart TTTT of this part, except combined heat and power (CHP) units that meet the requirements of a CHP unit under paragraph (a);

(2) EGUs that do not meet the applicability requirements of §§60.5845 and 60.5850, except CHP units that meet the requirements of a CHP unit under paragraph (a);

(3) Measures that reduce CO_2 emissions outside the electric power sector, including GHG offset projects representing emission reductions that occur in the forestry and agriculture sectors, direct air capture, and crediting of CO_2 emission reductions that occur in the transportation sector as a result of vehicle electrification; and

(4) Any measure not approved by the EPA for issuance of ERCs in connection with a specific State plan.

(d) You must include the appropriate requirements in paragraphs (d)(1) through (3) for an applicable eligible resource in your plan.

(1) If qualified biomass is an eligible resource, the plan must include a description of why the proposed feedstocks or feedstock categories should qualify as an approach for controlling increases of CO_2 levels in the atmosphere as well as the proposed valuation of biogenic CO_2 emissions. In addition, for sustainably-derived agricultural and forest biomass feedstocks, the state plan must adequately demonstrate that such feedstocks appropriately control increases of CO_2 levels in the atmosphere and methods for adequately monitoring and verifying these feedstock sources and related sustainability practices. For all qualified biomass feedstocks, plans must specify how biogenic CO_2 emissions will be monitored and reported, and identify specific EM&V, tracking and auditing approaches.

(2) If waste-to-energy is an eligible resource, the plan must assess both their capacity to strengthen existing or implement new waste reduction, reuse, recycling and composting programs, and measures to minimize any potential negative impacts of waste-to-energy operations on such programs. Additionally the plan must include a method for determining the proportion of total MWh generation from a waste-to-energy facility that is eligible for use in adjusting a CO_2 emission

rate (i.e., that which is generated from biogenic materials).

(3) If carbon capture and utilization (CCU) is an eligible resource in a plan, the plan must include analysis supporting how the proposed qualifying CCU technology results in CO_2 emission mitigation from affected EGUs and provide monitoring, reporting, and verification requirements to demonstrate the reductions.

(e) States and areas of Indian country that do not have any affected EGUs, and other countries, may provide ERCs to adjust CO_2 emissions provided they are connected to the contiguous U.S. grid and meet the other requirements for eligibility and eligible resources included in this section.

§60.5805 What is the process for the issuance of ERCs?

If your plan uses ERCs your plan must include the process and requirements for issuance of ERCs to affected EGUs and eligible resources set forth in paragraphs (a) through (f) of this section.

(a) Eligibility application. Your plan must require that, to receive ERCs, the owner or operator must submit an eligibility application to you that demonstrates that the requirements of your State plan as approved by the EPA as meeting §60.5792 (for an affected EGU) or §60.5800 (for an eligible resource) are met, and, in the case of an eligible resource, includes at a minimum:

(1) Documentation that the eligibility application has only been submitted to you, or pursuant to an EPA-approved multi-State collaborative approach;

(2) An EM&V plan that meets the requirements of the State plan as approved by the EPA as meeting §60.5795; and

(3) A verification report from an independent verifier that verifies the eligibility of the eligible resource to be issued an ERC and that the EM&V plan meets the requirements of the State plan as approved by the EPA of meeting §60.5795.

(b) Registration of eligible resources. Your plan must require that any affected EGU or eligible resource register with an ERC tracking system that meets the requirements of §60.5810 prior to the issuance, and your plan must specify that you will only register an affected EGU or eligible resource after you approve its eligibility application and determine that the requirements of paragraph (a) of this section are met.

(c) M&V reports. For an eligible resource registered pursuant to paragraph (b) above, your plan must require that, prior to issuance of ERCs by you, the owner or operator must submit the following:

(1) An M&V report that meets the requirements of your State plan as approved by the EPA as meeting §60.5835; and

(2) A verification report from an independent verifier that verifies that the requirements of the M&V report are met.

(e) Issuance of ERCs. Your plan must specify your procedure for issuance of ERCs based on your review of an M&V report and verification report, and must require that ERCs be issued only on the basis of energy actually generated or saved, and that only one ERC is issued for each verified MWh.

(f) Tracking system. Your plan must require that ERCs may only be issued through an ERC tracking system approved as part of the State plan.

(g) Error Adjustment. Your plan must include a mechanism to adjust the number of ERCs issued if any are issued based on error (clerical, formula input error, etc.).

(h) Qualification status of an eligible resource. Your plan must include a mechanism to temporarily or permanently revoke the qualification status of an eligible resource, such that it can no longer be issued ERCs for at least the duration that it does not meet the requirements for being issued ERCs in your State plan.

(i) Qualification status of an independent verifier.

(1) Eligibility. To be an independent verifier, a person must be approved by the State as:

(A) An independent verifier, as defined by this regulation; and

(B) Eligible to verify EM&V plans and/or M&V reports per the requirements of the approved State plan as meeting §§60.5830 and 60.5835 respectively.

(2) Revocation of qualification. Your plan must include a mechanism to temporarily or permanently revoke the qualification status of an independent verifier, such that it can no longer verify EM&V plans or M&V reports for at least the duration of the period it does not meet the requirements of your State plan.

§60.5810 What applicable requirements are there for an ERC tracking system?

(a) Your plan must include provisions for an ERC tracking system, if applicable, that meets the following requirements:

(1) It electronically records the issuance of ERCs, transfers of ERCs among accounts, surrender of ERCs by affected EGUs as part of a compliance demonstration, and retirement or cancellation of ERCs; and

(2) It documents and provides electronic, internet-based public access to all information that supports the eligibility of eligible resources and issuance of ERCs and functionality to generate reports based on such information, which must include, for each ERC, an eligibility application, EM&V plan, M&V reports, and independent verifier verification reports.

(b) If approved in a State plan, an ERC tracking system may provide for transfers of ERCs to/from another ERC tracking system approved in a State plan, or provide for transfers of ERCs to/from an EPA-administered ERC tracking system used to administer a federal plan.

Mass Allocation Requirements

§60.5815 What are the requirements for State allocation of allowances in a mass-based program?

(a) For a mass-based trading program, a State plan must include requirements for CO_2 allowance allocations according to paragraphs (b) through (f) of this section.

(b) Provisions for allocation of allowances for each compliance period for each affected EGU prior to the beginning of the compliance period.

(c) Provisions for allocation of set-aside allowance, if applicable, must be established to ensure that the eligible resources must meet the same requirements for the ERC eligible resource requirements of §60.5800, and the State must include eligibility application and verification provisions equivalent to those for ERCs in §60.5805 and EM&V plan and M&V report provisions that meet the requirements of §60.5830 and §60.5835.

(d) Provisions for adjusting allocations if the affected EGUs or eligible resources are incorrectly allocated CO_2 allowances.

(e) Provisions allowing for or restricting banking of allowances between compliance periods for affected EGUs.

(f) Provisions not allowing any borrowing of emissions from future compliance periods by affected EGUs.

§60.5820 What are my allowance tracking requirements?

(a) Your plan must include provisions for an allowance tracking system, if applicable, that meets the following requirements:

(1) It electronically records the issuance of allowances, transfers of allowances among accounts, surrender of allowances by affected EGUs as part of a compliance demonstration, and retirement of allowances; and

(2) It documents and provides electronic, internet-based public access to all information that supports the eligibility of eligible resources and issuance of set aside allowances and functionality to generate reports based on such information, which must include, for each set aside allowance, an eligibility application, EM&V plan, M&V reports, and independent verifier verification reports.

(b) If approved in a State plan, an allowance tracking system may provide for transfers of allowances to/from another ERC tracking system approved in a State plan, or provide for transfers of allowances to/from an EPA-administered allowance tracking system used to administer a federal plan.

§60.5825 What is the process for affected EGUs to demonstrate compliance in a mass-based program?

(a) A plan must require affected EGUs owners and operators to demonstrate compliance with emission standards in a mass based program by holding an amount not less than the tons of total CO_2 emissions for such compliance period from all affected EGUs at the facility in the account for the affected EGU's emissions in the allowance tracking system required under 60.5820 during the applicable compliance period.

(b) In a mass-based trading program a plan may allow multiple affected EGUs co-located at the same facility to demonstrate that they are meeting the applicable emission standards on a facility-wide basis by the owner or operator holding enough allowances to cover all the affected EGUs at the facility.

(1) If there are not enough allowances to cover the facility's affected EGUs' emissions then there must be provisions for determining the compliance status of each affected EGU located at that facility.

Evaluation Measurement and Verification Plans and Monitoring and Verification Reports

§60.5830 What are the requirements for EM&V plans for eligible resources?

(a) If your plan requires your affected EGUs to meet their emission standards in accordance with §60.5790, your plan must include requirements that any EM&V plan that is submitted in accordance with the requirements of §60.5805, in support of the issuance of an ERC or set-aside allowance that can be used in accordance with §60.5790, must meet the EM&V criteria approved as part of your State plan.

(b) Your plan must require each EM&V plan to include identification of the eligible resource and its applicable approved eligibility application.

(c) Your plan must require that an EM&V plan must contain specific criteria, as applicable to the specific eligible resource. For example, for RE resources, requirements discussing how the generation data will be physically measured on a continuous basis using a revenue-quality meter.

(1) For demand-side EE, your State plan must require that each EM&V plan quantify and verify electricity savings on a retrospective (ex-post) basis using industry best-practice EM&V protocols and methods that yield accurate and reliable measurements of electricity savings. Your plan must also require each EM&V plan to include an assessment of the independent factors that influence the electricity savings, the expected life of the savings (in years), and a baseline that represents what would have happened in the absence of the demand-side EE activity. Additionally, your plan must require that each EM&V plan include a demonstration of how the industry best-practices protocol and methods were applied to the specific activity, project, measure, or program covered in the EM&V plan, and include an explanation of why these protocols or methods were

selected.

(d) For EM&V plans to be acceptable, eligible resources must clearly demonstrate how all such best-practice approaches will be applied for the purposes of quantifying and verifying MWh results. Subsequent reporting of demand-side EE savings values must demonstrate and explain how the EM&V plan was followed.

§60.5835 What are the requirements for M&V reports for eligible resources?

(a) If your plan requires your affected EGUs to meet their emission standards in accordance with §60.5790, your plan must include requirements that any M&V report that is submitted in accordance with the requirements of §60.5805, in support of the issuance of an ERC or set-aside allocation that can be used in accordance with §60.5790, must meet the requirements of this section.

(b) Your plan must require that each M&V report include the following:

(1) For the first M&V report submitted, documentation that the energy-generating resources, energy-saving measures, or practices were installed or implemented consistent with the description in the approved eligibility application required in §60.5805(a).

(2) Each M&V report submitted must include the following:

(i) Identification of the time period covered by the M&V report;

(ii) A description of how relevant quantification methods, protocols, guidelines, and guidance specified in the EM&V plan were applied during the reporting period to generate the quantified MWh of generation or MWh of energy savings;

(iii) Documentation (including data) of the energy generation and/or energy savings from any activity, project, measure, resource, or program addressed in the EM&V report, quantified and verified in MWh for the period covered by the M&V report, in accordance with its EM&V plan, and based on ex-post energy generation or savings; and

(iv) Documentation of any change in the energy generation or savings capability of the eligible resource from the description of the resource in the approved eligibility application during the period covered by the M&V report and the date on which the change occurred, and/or demonstration that the eligible resource continued to meet the requirements of §60.5800.

Applicability of Plans to Affected EGUs

§60.5840 Does this subpart directly affect EGU owners or operators in my State?

(a) This subpart does not directly affect EGU owners or operators in your State. However, affected EGU owners or operators must comply with the plan that a State or States develop to implement the emission guidelines contained in this subpart.

(b) If a State does not submit, or EPA disapproves, a final plan or initial submittal to implement and enforce the emission guidelines contained in this subpart by September 6, 2016, the EPA will implement and enforce a Federal plan, as provided in §60.5720, to ensure that each affected EGU within the State that commenced construction on or before January 8, 2014 complies with all the provisions of this subpart.

§60.5845 What affected EGUs must I address in my State plan?

(a) The EGUs that must be addressed by your plan are any affected steam generating unit, IGCC, or stationary combustion turbine that commenced construction on or before January 8, 2014.

(b) An affected EGU is a steam generating unit, IGCC, or stationary combustion turbine that meets the relevant applicability conditions specified in paragraph (b)(1) through (3) of this section except as provided in §60.5850.

(1) Serves a generator connected to a utility power distribution system with a nameplate capacity of 25 MW-net or greater (i.e., capable of selling greater than 25 MW of electricity);

(2) Has a base load rating (i.e., design heat input capacity) greater than 260 GJ/hr (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel); and

(3) Stationary combustion turbines that meet the definition of either a combined cycle or combined heat and power combustion turbine.

§60.5850 What EGUs are excluded from being affected EGUs?

(a) EGUs that are excluded from being affected EGUs are:

(1) EGUs that are subject to subpart TTTT of this part as a result of commencing construction after the subpart TTTT applicability date; and those subject to subpart TTTT of this part as a result of commencing modification or reconstruction;

(2) Steam generating units and IGCC units that are currently and always have been subject to a federally enforceable permit limiting annual net-electric sales to one-third or less of its potential electric output, or 219,000 MWh or less;

(3) Non-fossil units (i.e., units that are capable of combusting 50 percent or more non-fossil fuel) that have always historically limited the use of fossil fuels to 10 percent or less of the annual capacity factor or are subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor.

(4) Stationary combustion turbines not capable of combusting natural gas (e.g., not connected to a natural gas pipeline)

(5) EGUs that are combined heat and power units that have always historically limited, or are subject to a federally enforceable permit currently limiting and always historically limiting, annual net-electric sales to a utility distribution system to the design efficiency times the potential electric output or 219,000 MWh (whichever is greater), or less;

(6) EGUs that serve a generator along with other steam generating unit(s), IGCC(s), or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less;

(7) EGUs that are a municipal waste combustor unit that is subject to subpart Eb of this part; and

(8) EGUs that are a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part.

§60.5855 What are the CO_2 emission performance rates for affected EGUs?

(a) You must require, in your plan, emission standards on affected EGUs to meet the CO_2 emission performance rates listed in Table 1 of this subpart except as provided in paragraph (b) of this section. In addition, you must set CO_2 emission performance rates for the interim steps, according to paragraph (a)(1) of this section.

(1) You must set CO_2 emission performance rates for your affected EGUs to meet during the interim step periods on average and as applicable for the two subcategories of affected EGUs.

(b) You may elect to require your affected EGUs to meet emission standards that differ from the CO_2 emission performance rates listed in Table 1 of this subpart, provided that you demonstrate that the affected EGUs in your State will collectively meet their CO_2 emission performance rate by achieving statewide emission goals that are equivalent and no less stringent than the CO_2 emission performance rates listed in Table 1, and provided that your equivalent statewide CO_2 emission goals take one of the following forms:

(1) Average statewide rate-based CO_2 emission goals listed in Table 2 of this subpart, except as provided in paragraphs (c) and (d); or

(2) Cumulative statewide mass-based CO_2 emission goals listed in Table 3 of this subpart, except as provided in paragraphs (c) and (d).

(c) If your plan incorporates CO_2 emission goals listed in paragraphs (b)(1) or (2) of this section you must develop your own interim step goals and final reporting period goal for your affected EGUs to meet either on average or cumulatively.

Additionally the following applies if you elect to develop your own goals:

(1) The interim period and interim steps CO_2 emission goals must be in the same form, either both rate (in units of pounds per net MWh) or both mass (in tons); and

(2) You must set interim step goals that will either on average or cumulatively meet the State's interim period goal, as applicable to a rate-based or mass-based goal.

(d) Your plan's interim period and final period CO_2 emission goals incorporated pursuant to paragraph (b)(1) or (2) of this section, may be changed in the plan only according to situations listed in paragraphs (d)(1) through (3) of this section. If a situation requires a plan revision, you must follow the procedures in §60.5785 to submit a plan revision.

(1) If your plan implements CO_2 emission goals, you may submit a plan or plan revision, allowed in §60.5785, to make corrections to them, as a result of changes in the inventory of affected EGUs; and

(2) You may address EGUs that become subject to subpart TTTT of this part and are no longer considered affected EGUs for incorporation in a plan.

(3) If you elect to require your affected EGUs to meet emission standards or State measures, in addition to or in lieu of emission standards, to meet mass-based CO_2 emission goals in

your plan, you may elect to incorporate the mass emissions from EGUs that are subject to subpart TTTT of this part that are considered new affected EGUs under subpart TTTT of this part.

(e) If your plan submittal requires your affected EGUs to meet State measures in addition to or in lieu of emission standards, you must only use the mass-based goals allowed for in paragraph (b)(2) of this section to demonstrate that your affected EGUs are meeting the required emissions performance.

(f) Nothing in this subpart precludes an affected EGU from complying with its emission standard or you from meeting your State measures.

§60.5860 What applicable monitoring, recordkeeping, and reporting requirements do I need to include in my plan for affected EGUs?

(a) Your plan must include monitoring for affected EGUs that is no less stringent than what is described in (a)(1) through (8) of this section.

(1) The owner or operator of an affected EGU (or group of affected EGUs that share a monitored common stack) that is required to meet rate-based or mass-based emission standards must prepare a monitoring plan in accordance with the applicable provisions in §75.53(g) and (h) of this chapter, unless such a plan is already in place under another program that requires CO_2

mass emissions to be monitored and reported according to part 75 of this chapter.

(2) For rate-based emission standards, each compliance period shall include only "valid operating hours" in the compliance period, i.e., full or partial unit (or stack) operating hours for which:

(i) "Valid data" (as defined in §60.5880) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (lbs). For the purposes of this subpart, substitute data recorded under part 75 of this chapter are not considered to be valid data; and

(ii) The corresponding hourly net energy output value is also valid data (Note: for operating hours with no useful output, zero is considered to be a valid value).

(3) For rate-based emission standards, the owner or operator of an affected EGU must measure and report the hourly CO_2 mass emissions (lbs) from each affected unit using the procedures in paragraphs (a)(3)(i) through (vi) of this section, except as otherwise provided in paragraph (a)(4) of this section.

(i) The owner or operator of an affected EGU must install, certify, operate, maintain, and calibrate a CO_2 continuous emissions monitoring system (CEMS) to directly measure and record CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere and an exhaust gas flow rate monitoring system according to §75.10(a)(3)(i) of this chapter. However, when an O_2 monitor is used this way, it only quantifies the combustion CO_2; therefore, if the EGU is equipped with emission controls that produce non-combustion CO_2 (e.g., from sorbent injection), this additional CO_2 must be accounted for, in accordance with section 3 of appendix G to part 75 of this chapter. As an alternative to direct measurement of CO_2 concentration, provided that the affected EGU does not use carbon separation (e.g., carbon capture and storage), the owner or operator of an affected EGU may use data from a certified oxygen (O_2) monitor to calculate hourly average CO_2 concentrations, in accordance with §75.10(a)(3)(iii) of this chapter. If CO_2 concentration is measured on a dry basis, the owner or operator of the affected EGU must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to §75.11(b) of this chapter. Alternatively, the owner or operator of an affected EGU may either use an appropriate fuel-specific default moisture value from §75.11(b) or submit a petition to the Administrator under §75.66 of this chapter for a site-specific default moisture value.

(ii) For each "valid operating hour" (as defined in paragraph (a)(2) of this section), calculate the hourly CO_2 mass emission rate (tons/hr), either from Equation F-11 in Appendix F to part 75 of this chapter (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of Appendix F to part 75 of this chapter (if CO_2 concentration is measured on a dry basis).

(iii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in §72.2 of this chapter), to convert it to tons of CO_2. Multiply the result by 2,000 lbs/ton to convert it to lbs.

(iv) The hourly CO_2 tons/hr values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under §75.57(e) of this chapter and must be reported electronically under §75.64(a)(6), if required by a plan. The owner or operator must use these data, or equivalent data, to calculate the hourly CO_2 mass emissions.

(v) Sum all of the hourly CO_2 mass emissions values from paragraph (a)(3)(ii) of this section over the entire compliance period.

(vi) For each continuous monitoring system used to determine the CO_2 mass emissions from an affected EGU, the monitoring system must meet the applicable certification and quality assurance procedures in §75.20 of this chapter and Appendices A and B to part 75 of this chapter.

(4) The owner or operator of an affected EGU that

exclusively combusts liquid fuel and/or gaseous fuel may, as an alternative to complying with paragraph (a)(3) of this section, determine the hourly CO_2 mass emissions according to paragraphs (a)(4)(i) through (a)(4)(vi) of this section.

(i) Implement the applicable procedures in appendix D to part 75 of this chapter to determine hourly EGU heat input rates (MMBtu/hr), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted. The fuel flow meter(s) used to measure the hourly fuel flow rates must meet the applicable certification and quality-assurance requirements in sections 2.1.5 and 2.1.6 of appendix D to part 75 (except for qualifying commercial billing meters). The fuel GCV must be determined in accordance with section 2.2 or 2.3 of appendix D, as applicable.

(ii) For each measured hourly heat input rate, use Equation G-4 in Appendix G to part 75 of this chapter to calculate the hourly CO_2 mass emission rate (tons/hr).

(iii) For each “valid operating hour” (as defined in paragraph (a)(2) of this section), multiply the hourly tons/hr CO_2 mass emission rate from paragraph (a)(4)(ii) of this section by the EGU or stack operating time in hours (as defined in §72.2 of this chapter), to convert it to tons of CO_2. Then, multiply the result by 2,000 lbs/ton to convert it to lbs.

(iv) The hourly CO_2 tons/hr values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under §75.57(e) of this chapter and must be reported electronically under §75.64(a)(6), if required by a plan. You must use these data, or equivalent data, to calculate the hourly CO_2 mass emissions.

(v) Sum all of the hourly CO_2 mass emissions values (lb) from paragraph (a)(4)(iii) of this section over the entire compliance period.

(vi) The owner or operator of an affected EGU may determine site-specific carbon-based F-factors (F_c) using Equation F-7b in section 3.3.6 of appendix F to part 75 of this chapter, and may use these F_c values in the emissions calculations instead of using the default F_c values in the Equation G-4 nomenclature.

(5) For both rate-based and mass-based standards, the owner or operator of an affected EGU (or group of affected units that share a monitored common stack) must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record on an hourly basis net electric output. Measurements must be performed using 0.2 accuracy class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20. Further, the owner or operator of an affected EGU that is a combined heat and power facility must install, calibrate, maintain and operate equipment to continuously measure and record on an hourly basis useful

thermal output and, if applicable, mechanical output, which are used with net electric output to determine net energy output. The owner or operator must use the following procedures to calculate net energy output, as appropriate for the type of affected EGU(s).

(i) Determine P_{net} the hourly net energy output in MWh. For rate-based standards, perform this calculation only for valid operating hours (as defined in paragraph (a)(2) of this section). For mass-based standards, perform this calculation for all unit (or stack) operating hours, i.e., full or partial hours in which any fuel is combusted.

(ii) If there is no net electrical output, but there is mechanical or useful thermal output, either for a particular valid operating hour (for rate-based applications), or for a particular operating hour (for mass-based applications), the owner or operator of the affected EGU must still determine the net energy output for that hour.

(iii) For rate-based applications, if there is no (i.e., zero) gross electrical, mechanical, or useful thermal output for a particular valid operating hour, that hour must be used in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(iv) Calculate P_{net} for your affected EGU (or group of affected EGUs that share a monitored common stack) using the following equation. All terms in the equation must be expressed in units of MWh. To convert each hourly net energy output value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

$$P_{net} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_{A}}{\text{TDF}} + [(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}]$$

Where:

P_{net} = Net energy output of your affected EGU for each valid operating hour (as defined in 60.5860(a)(2)) in MWh.

$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

$(Pe)_{A}$ = Electric energy used for any auxiliary loads in MWh.

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to SATP conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(v) of this section in MWh.

$(Pt)_{HR}$ = Non-steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least on an annual basis 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and 20.0 percent of the total net energy output consist of useful thermal output on a 12-operating month rolling average basis, or 1.0 for all other affected EGUs.

(v) If applicable to your affected EGU (for example, for combined heat and power), you must calculate $(Pt)_{PS}$ using the following equation:

$$(Pt)_{PS} = \frac{Q_m \times H}{CF}$$

Where:

Q_m = Measured steam flow in kilograms (kg) (or pounds (lbs)) for the operating hour.

H = Enthalpy of the steam at measured temperature and pressure (relative to SATP conditions or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb).

CF = Conversion factor of 3.6×10^9 J/MWh or 3.413×10^6 Btu/MWh.

(v) For rate-based standards, sum all of the values of P_{net} for the valid operating hours (as defined in paragraph (a)(2) of this section), over the entire compliance period. Then, divide the total CO_2 mass emissions for the valid operating hours from paragraph (a)(3)(v) or (a)(4)(v) of this section, as applicable, by the sum of the P_{net} values for the valid operating hours plus any ERC replacement generation (as shown in §60.5790(c)), to determine the CO_2 emissions rate (lb/net MWh) for the compliance period.

(vi) For mass-based standards, sum all of the values of P_{net} for all operating hours, over the entire compliance period.

(6) In accordance with §60.13(g), if two or more affected EGUs implementing the continuous emissions monitoring provisions in paragraph (a)(2) of this section share a common exhaust gas stack and are subject to the same emissions standard, the owner or operator may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If an owner or operator of an affected EGU chooses this option, the hourly net electric output for the common stack must be the sum of the hourly net electric output of the individual affected EGUs and the operating time must be expressed as "stack operating hours" (as defined in §72.2 of this chapter).

(7) In accordance with §60.13(g), if the exhaust gases from an affected EGU implementing the continuous emissions monitoring provisions in paragraph (a)(2) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), the hourly CO_2 mass emissions and the "stack operating time" (as defined in §72.2 of this chapter) at each stack or duct must be monitored separately. In this

case, the owner or operator of an affected EGU must determine compliance with an applicable emissions standard by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the net energy output for the affected EGU.

(8) Consistent with §60.5775 or §60.5780, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly net energy output to the individual affected EGUs according to the fraction of the total steam load contributed by each EGU. Alternatively, if the EGUs are identical, you may apportion the combined hourly net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU.

(b) For mass-based standards, the owner or operator of an affected EGU must determine the CO_2 mass emissions (tons) for the compliance period as follows:

(1) For each operating hour, calculate the hourly CO_2 mass (tons) according to paragraph (a)(3) or (a)(4) of this section, except that a complete data record is required, i.e., CO_2 mass emissions must be reported for each operating hour. Therefore, substitute data values recorded under part 75 of this chapter for CO_2 concentration, stack gas flow rate, stack gas moisture content, fuel flow rate and/or GCV shall be used in the calculations; and

(2) Sum all of the hourly CO_2 mass emissions values over the entire compliance period.

(3) The owner or operator of an affected EGU must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record on an hourly basis net electric output. Measurements must be performed using 0.2 accuracy class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20. Further, the owner or operator of an affected EGU that is a combined heat and power facility must install, calibrate, maintain and operate equipment to continuously measure and record on an hourly basis useful thermal output and, if applicable, mechanical output, which are used with net electric output to determine net energy output (P_{net}). The owner or operator must calculate net energy output according to paragraphs (a)(5)(i)(A) and (B) of this section.

(c) Your plan must require the owner or operator of each affected EGU covered by your plan to maintain the records, as described in (b)(1) through (2) of this subpart, for at least 5 years following the date of each compliance period, occurrence, measurement, maintenance, corrective action, report, or record.

(1) The owner or operator of an affected EGU must maintain each record on site for at least 2 years after the date of each compliance period, compliance true-up period, occurrence,

measurement, maintenance, corrective action, report, or record, whichever is latest, according to §60.7. The owner or operator of an affected EGU may maintain the records off site and electronically for the remaining year(s).

(2) The owner or operator of an affected EGU must keep all of the following records:

(i) All documents, data files, and calculations and methods used to demonstrate compliance with an affected EGU's emission standard under §60.5775.

(ii) Copies of all reports submitted to the State under paragraph (c) of this section.

(iii) Data that are required to be recorded by 40 CFR Part 75 Subpart F.

(iv) Data with respect to any ERCs generated by the affected EGU or used by the affected EGU in its compliance demonstration including the information in paragraphs (c)(2)(iv)(A) and (B) of this section.

(A) All documents related to any ERCs used in a compliance demonstration, including each eligibility application, EM&V plan, M&V report, and independent verifier verification report associated with the issuance of each specific ERC.

(B) All records and reports relating to the surrender and retirement of ERCs for compliance with this regulation, including the date each individual ERC with a unique serial identification number was surrendered and/or retired.

(d) Your plan must require the owner or operator of an affected EGU covered by your plan to include in a report submitted to you at the end of each compliance period the information in paragraphs (d)(1) through (5) of this section.

(1) Owners or operators of an affected EGU must include in the report all hourly CO_2, for each affected EGU (or group of affected EGUs that share a monitored common stack).

(2) For rate-based standards, each report must include:

(i) The hourly CO_2 mass emission rate values (tons/hr) and unit (or stack) operating times, (as monitored and reported according to part 75 of this chapter), for each valid operating hour in the compliance period;

(ii) The net electric output and the net energy output (P_{net}) values for each valid operating hour in the compliance period;

(iii) The calculated CO_2 mass emissions (lb) for each valid operating hour in the compliance period;

(iv) The sum of the hourly net energy output values and the sum of the hourly CO_2 mass emissions values, for all of the valid operating hours in the compliance period;

(v) ERC replacement generation (if any), properly justified (see paragraph (c)(5) of this section); and

(vi) The calculated CO_2 mass emission rate for the compliance period (lbs/net MWh).

(3) For mass-based standards, each report must include:

(i) The hourly CO_2 mass emission rate value (tons/hr) and unit (or stack) operating time, as monitored and reported according to part 75 of this chapter, for each unit or stack operating hour in the compliance period;

(ii) The calculated CO_2 mass emissions (tons) for each unit or stack operating hour in the compliance period;

(iii) The sum of the CO_2 mass emissions (tons) for all of the unit or stack operating hours in the compliance period;

(iv) The net electric output and the net energy output (P_{net}) values for each unit or stack operating hour in the compliance period; and

(v) The sum of the hourly net energy output values for all of the unit or stack operating hours in the compliance period.

(vi) Notwithstanding the requirements in paragraphs (c)(3)(i) through (c)(3)(iii) of this section, if the compliance period is a discrete number of calendar years (e.g., one year, three years), in lieu of reporting the information specified in those paragraphs, the owner or operator may report:

(A) The cumulative annual CO_2 mass emissions (tons) for each year of the compliance period, derived from the electronic emissions report for the fourth calendar quarter of that year, submitted to EPA under §75.64(a) of this chapter; and

(B) The sum of the cumulative annual CO_2 mass emissions values from paragraph (c)(3)(v)(A) of this section, if the compliance period includes multiple years.

(4) For each affected EGU's compliance period, the report must also include the applicable emission standard and demonstration that it met the emission standard. An owner or operator must also include in the report the affected EGU's calculated emission performance as a CO_2 emission rate or cumulative mass in units of the emission standard required in §§60.5790(b) through (d) and 60.5855, as applicable.

(5) If the owner or operator of an affected EGU is complying with an emission standard by using ERCs, they must include in the report a list of all unique ERC serial numbers that were retired in the compliance period, and, for each ERC, the date an ERC was surrendered and retired and eligible resource identification information sufficient to demonstrates that it meets the requirements of §60.5800 and qualifies to be issued ERCs (including location, type of qualifying generation or savings, date commenced generating or saving, and date of generation or savings for which the ERC was issued).

(6) If the owner or operator of an affected EGU is complying with an emission standard or State measures by using

allowances, they must include in the report a list of all unique allowance serial numbers that were retired in the compliance period, and, for each allowance, the date an allowance was surrendered and retired and if the allowance was a set-aside allowance the eligible resource identification information sufficient to demonstrate that it meets the requirements of §60.5815(c) and qualifies to be issued set-aside allowances (including location, type of qualifying generation or savings, date commenced generating or saving, and date of generation or savings for which the allowance was issued).

(e) The owner or operator of an affected EGU must follow any additional requirements for monitoring, recordkeeping and reporting in a plan that are required under §60.5785, if applicable.

(f) If an affected EGU captures CO_2 to meet the applicable emission limit, owners and operator must report in accordance with the requirements of 40 CFR Part 98 Subpart PP and either:

(1) Report in accordance with the requirements of 40 CFR Part 98 subpart RR, if injection occurs on-site, or

(2) Transfer the captured CO_2 to an EGU or facility that reports in accordance with the requirements of 40 CFR Part 98 subpart RR, if injection occurs off-site.

(3) Transfer the captured CO_2 to a facility that has received an innovative technology waiver from EPA pursuant to paragraph (g) of this section.

(g) Any person may request the Administrator to issue a waiver of the requirement that captured CO_2 from an affected EGU be transferred to a facility reporting under 40 CFR Part 98 subpart RR. To receive a waiver, the applicant must demonstrate to the Administrator that its technology will store captured CO_2 as effectively as geologic sequestration, and that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare, or safety. In making this determination, the Administrator shall consider (among other factors) operating history of the technology, whether the technology will increase emissions or other releases of any pollutant other than CO_2, and permanence of the CO_2 storage. The Administrator may test the system itself, or require the applicant to perform any tests considered by the Administrator to be necessary to show the technology's effectiveness, safety, and ability to store captured CO_2 without release. The Administrator may grant conditional approval of a technology, the approval conditioned on monitoring and reporting of operations. The Administrator may also withdraw approval of the waiver on evidence of releases of CO_2 or other pollutants. The Administrator will provide notice to the public of any application under this provision, and provide public notice of any proposed action on a petition before the Administrator takes final action.

Recordkeeping and Reporting Requirements

§60.5865 What are my recordkeeping requirements?

(a) You must keep records of all information relied upon in support of any demonstration of plan components, plan requirements, supporting documentation, and the status of meeting the plan requirements defined in the plan for each interim step and the interim period. After 2029, States must keep records of all information relied upon in support of any continued demonstration that the final emissions goals are being achieved.

(b) You must keep records of all data submitted by the owner or operator of each affected EGU that is used to determine compliance with each affected EGU emissions standard or requirements in an approved State plan, consistent with the affected EGU requirements listed in §60.5860.

(c) If your State has a requirement for all hourly CO_2 emissions and net generation information to be used to calculate compliance with an annual emissions standard or State measure for affected EGUs, any information that is submitted by the owners or operators of affected EGUs to the EPA electronically pursuant to requirements in Part 75 meets the recordkeeping requirement of this section and you are not required to keep records of information that would be in duplicate of paragraph (b) of this section.

(d) You must keep records at a minimum for 10 years, for the interim period, and 5 years, for the final period, from the date the record is used to determine compliance with an emissions standard, plan requirement, CO_2 emission performance rate or CO_2 emissions goal. Each record must be in a form suitable and readily available for expeditious review.

§60.5870 What are my reporting and notification requirements?

(a) In lieu of the annual report required under §60.25(e) and (f) of this part, you must report the information in paragraphs (b) through (f) of this section.

(b) You must submit a report covering each interim step within the interim period and each of the final 2-calendar year periods due no later than July 1 of the year following the end of the period. The interim period reporting starts with a reporting covering interim step 1 due no later than July 1, 2025. The final period reports start with a biennual report covering the first final reporting period (which is due by July 1, 2032), a 2-calendar year average of emissions or cumulative sum of emissions used to determine compliance with the final CO_2 emission performance rate or CO_2 emission goal (as applicable).

The report must include the information in paragraphs (b)(1) through (4) of this paragraph.

(1) The report must include the emissions performance achieved by all affected EGUs during the reporting period, consistent with the plan approach according to §60.5745(a), and identification of whether each affected EGU is in compliance with its emission standard and whether the collective of all affected EGUs covered by the State are on schedule to meet the applicable CO_2 emission performance rate or emission goal during the performance periods and compliance periods, as specified in the plan.

(2) The report must include a comparison of the CO_2 emission performance rate or CO_2 emission goal identified in the State plan for the applicable interim step period versus the actual average, cumulative, or adjusted CO_2 emission performance (as applicable) achieved by all affected EGUs.

(i) For interim step 3, you do not need to include a comparison between the applicable interim step 3 CO_2 emission performance rate or emission goal; you must only submit the average, cumulative or adjusted CO_2 emission performance (as applicable) of your affected EGUs during that period in units of your applicable CO_2 emission performance rate or emission goal.

(3) The report must include all other required information, as specified in your State plan according to §60.5740(a)(5).

(4) The report must include a program review that your State has conducted that addresses all aspects of the administration of the state plan and overall program, including State evaluations and regulatory decisions regarding eligibility applications for ERC resources and M&V reports (and associated EM&V activities), and State issuance of ERCs. The program review must assess whether the program is being administered properly in accordance with the approved plan, that reported annual MWh of generation and savings from qualified ERC resources are being properly quantified, verified, and reported in accordance with approved EM&V plans, and that appropriate records are being maintained. The program review must also address determination of the eligibility of verifiers by the State and the conduct of verifiers, including the quality of verifier reviews.

(c) If your plan relies upon State measures, in lieu of or in addition to emission standards, then you must submit an annual report to the EPA in addition to the reports required under paragraph (b) of this section for the interim period. In the final period, you must submit biennual reports consistent with those required under paragraph (b) of this section. The annual reports in the interim period must be submitted no later than July 1 following the end of each calendar year starting with the annual year 2022 (January 1, 2022 to December 31, 2022). The annual and biennual reports must include the information in paragraphs (c)(1) and (2) of this section.

(1) You must include in your report the status of implementation of federally enforceable emission standards (if applicable) and State measures.

(2) You must include information regarding the status of the periodic programmatic milestones to show progress in program implementation. The programmatic milestones with specific dates for achievement must be consistent with the State measures included in the State plan submittal.

(d) If your plan includes the requirement for emission standards on your affected EGUs, then you must submit a notification in the report required under paragraph (b) of this section to the EPA if your affected EGUs trigger corrective measures as described in §60.5740(a)(2)(i). If corrective measures are required you must follow the requirements in 60.5785 for revising your plan to implement the corrective measures.

(e) If your plan relies upon State measures, in lieu of or in addition to emission standards, than you must submit a notification as required under paragraphs (e)(1) and (2) of this section.

(1) You must submit a notification in the report required under paragraph (c) of this section to the EPA if at the end of

the calendar year your State did not meet a programmatic milestone included in your plan submittal. This notification must detail the implementation of the backstop required in your plan to be fully in place within 18 months of the due date of the report required in paragraph (b) of this section. In addition, the notification must describe the steps taken by the State to inform the affected EGUs in its State that the backstop has been triggered.

(2) You must submit a notification in the report required under paragraph (b) of this section to the EPA if you trigger the backstop as described in §60.5740(a)(3)(i). This notification must detail the steps that will be taken by you to implement the backstop so that it is fully in place within 18 months of the due date of the report required in paragraph (b) of this section. In addition, the notification must describe the steps taken by the State to inform the affected EGUs that the backstop has been triggered.

(f) You must include in your 2029 report (which is due by July 1, 2030) the calculation of average emissions, cumulative sum of emissions, or adjusted emissions (as applicable) over the interim period and a comparison of those values to your interim CO_2 emission performance rate or emission goal. The calculated value must be in units consistent with the approach you set in your plan for the interim period.

(g) The notifications listed in paragraphs (g)(1) through (3) of this section are required for the reliability safety valve allowed in §60.5785(e).

(1) As required under §60.5785(e), you must submit an initial notification to the appropriate EPA regional office within 48 hours of an unforeseen, emergency situation. The initial notification must:

(i) Include a full description, to the extent that it is known, of the emergency situation that is being addressed;

(ii) Identify the affected EGU or EGUs that are required to run to assure reliability; and

(iii) Specify the modified emission standards at which the identified EGU or EGUs will operate.

(2) Within 7 days of the initial notification in §60.5870(g)(1), the State must submit a second notification to the appropriate EPA regional office that documents the initial notification. If the State fails to submit this documentation on a timely basis, the EPA will notify the State, which must then notify the affected EGU(s) that they must operate or resume operations under the original approved State plan emissions standards. This notification must include the following:

(i) A full description of the reliability concern and why an unforeseen, emergency situation that threatens reliability requires the affected EGU or EGUs to operate under modified emission standards from those originally required in the State plan including discussion of why the flexibilities provided under the state's plan are insufficient to address the concern;

(ii) A description of how the State is coordinating or will coordinate with relevant reliability coordinators and planning authorities to alleviate the problem in an expedited manner;

(iii) An indication of the maximum time that the State anticipates the affected EGU or EGUs will need to operate in a manner inconsistent with its or their obligations under the State's approved plan;

(iv) A written concurrence from the relevant reliability coordinator and/or planning authority confirming the existence of the imminent reliability threat and supporting the temporary modification request or an explanation of why this kind of concurrence cannot be provided;

(v) The modified emission standards or levels that the affected EGU or EGU will be operating at for the remainder of the 90-day period if it has changed from the initial notification; and

(vi) Information regarding any system-wide or other analysis of the reliability concern conducted by the relevant planning authority, if any.

(3) At least 7 days before the end of the 90-day reliability safety valve period, the State must notify the

appropriate EPA regional office that either:

(i) The reliability concern has been addressed and the affected EGU or EGUs can resume meeting the original emissions standards in the State plan approved prior to the short-term modification; or

(ii) There still is a serious, ongoing reliability issue that necessitates the EGU or EGUs to emit beyond the amount allowed under the State plan. In this case, the State must provide a notification to the EPA that it will be submitting a State plan revision according to paragraph §60.5785(a) of this section to address the reliability issue. The notification must provide the date by which a revised State plan will be submitted to EPA and documentation of the ongoing emergency with a written concurrence from the relevant reliability coordinator and/or planning authority confirming the continuing urgent need for the EGU or EGUs to operate beyond the requirements of the State plan and that there is no other reasonable way of addressing the ongoing reliability emergency but for the EGU or EGUs to operate under an alternative emission standard than originally approved under the State plan. After the initial 90-day period, any excess emissions beyond what is authorized in the original approved State plan will count against the State's overall CO_2 emission goal or emission performance rate for affected EGUs.

§60.5875 How do I submit information required by these Emission

Guidelines to the EPA?

(a) You must submit to the EPA the information required by these emission guidelines following the procedures in paragraphs (b) through (e) of this section.

(b) All negative declarations, State plan submittals, supporting materials that are part of a State plan submittal, any plan revisions, and all State reports required to be submitted to the EPA by the State plan must be reported through EPA's State Plan Electronic Collection System (SPeCS). SPeCS is a web accessible electronic system is accessed at the EPA's Central Data Exchange (CDX) (http://www.epa.gov/cdx/). States who claim that a State plan submittal or supporting documentation includes confidential business information (CBI) must submit that information on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: State and Local Programs Group, MD C539-01, 4930 Old Page Rd., Durham, NC 27703.

(c) Only a submittal by the Governor or the Governor's designee by an electronic submission through SPeCS shall be considered an official submittal to the EPA under this subpart. If the Governor wishes to designate another responsible official the authority to submit a State plan, the EPA must be notified via letter from the Governor prior to the September 6, 2016, deadline for plan submittal so that they have the ability to submit the initial or final plan submittal in the SPeCS. If the Governor has previously delegated authority to make CAA submittals on the Governor's behalf, a State may submit documentation of the delegation in lieu of a letter from the Governor. The letter or documentation must identify the designee to whom authority is being designated and must include the name and contact information for the designee and also identify the State plan preparers who will need access to SPeCS. A State may also submit the names of the State plan preparers via a separate letter prior to the designation letter from the Governor in order to expedite the State plan administrative process. Required contact information for the designee and preparers includes the person's title, organization and email address.

(d) The submission of the information by the authorized official must be in a non-editable format. In addition to the non-editable version all plan components designated as federally enforceable must also be submitted in an editable version. Following initial plan approval, States must provide the EPA with an editable copy of any submitted revision to existing approved federally enforceable plan components, including State plan backstop measures. The editable copy of any such submitted plan revision must indicate the changes made at the State level, if any, to the existing approved federally enforceable plan components, using a mechanism such as redline/strikethrough. These changes are not part of the State plan until formal approval by EPA.

(e) You must provide the EPA with non-editable and editable copies of any submitted revision to existing approved federally enforceable plan components, including State plan backstop measures. The editable copy of any such submitted plan revision must indicate the changes made at the State level, if any, to the existing approved federally enforceable plan components, using a mechanism such as redline/strikethrough. These changes are not part of the State plan until formal approval by EPA.

Definitions

§60.5880 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subparts A (General Provisions) and B of this part.

Adjusted CO_2 emission rate means the reported CO_2 emission rate of an affected EGU, adjusted as described in §60.5790(c)(1) to reflect any ERCs used by an affected EGU to demonstrate compliance with its CO_2 emission standards.

Affected electric generating unit or *Affected EGU* means a steam generating unit, integrated gasification combined cycle (IGCC), or stationary combustion turbine that meets the relevant applicability conditions in section §60.5845.

Allowance means an authorization for each specified unit of actual CO_2 emitted from an affected EGU or a facility during a specified period.

Allowance system means a control program under which the owner or operator of each affected EGU is required to hold an authorization for each specified unit of CO_2 emitted from that facility during a specified period and which limits the total amount of such authorizations available to be held for CO_2 for a specified period and allows the transfer of such authorizations not used to meet the authorization-holding requirement.

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady-state basis, as determined by the physical design and characteristics of the EGU at ISO conditions. For a stationary combustion turbine, *base load rating* includes the heat input from duct burners.

Biomass means biologically based material that is living or dead (e.g., trees, crops, grasses, tree litter, roots) above and below ground, and available on a renewable or recurring basis. Materials that are biologically based include non-fossilized, biodegradable organic material originating from modern or contemporarily grown plants, animals, or microorganisms (including plants, products, byproducts and residues from agriculture, forestry, and related activities and industries, as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material).

CO_2 emission goal means a statewide rate-based CO_2 emission goal or mass-based CO_2 emission goal specified in §60.5855.

Combined cycle unit means an electric generating unit that uses a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit to generate additional electricity.

Combined heat and power unit or *CHP unit, (*also known as "cogeneration") means an electric generating unit that uses a steam-generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy source.

Common practice baseline or CPB means a baseline derived based on a default technology or condition that would have been in place at the time of implementation of an EE measure in the absence of the EE measure (for example, the standard or market-average or pre-existing equipment that a typical consumer/building owner would have continued to use or would have installed at the time of project implementation in a given circumstance, such as a given building type, EE program type or delivery mechanism, and geographic region).

Compliance period means a discrete time period for an affected EGU to comply with either an emission standard or State measure. Compliance periods for affected EGUs required in plans must meet the requirements of §60.5770.

Control area operator means an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas and contributing to frequency regulation of the interconnection.

Demand-side energy efficiency means an installed piece of equipment or system, a modification of existing equipment or system, or a strategy intended to affect consumer electricity-use behavior, that results in a reduction in electricity use (in MWh) at an end-use facility, premises, or equipment connected to the electricity grid.

Derate means a decrease in the available capacity of an electric generating unit, due to a system or equipment modification or to discounting a portion of a generating unit's capacity for planning purposes.

Design efficiency means the rated overall net efficiency (e.g., electric plus thermal output) on a higher heating value basis of the EGU at the base load rating and ISO conditions.

Eligible resource means a resource that meets the requirements of §60.5800(a).

Emission Rate Credit or ERC means a tradable compliance instrument that meets the requirements of §60.5790(c).

EM&V plan means a plan that meets the requirements of §60.5830.

ERC tracking system means a system for the issuance, surrender and retirement of ERCs that meets the requirements of §60.5810.

Essential generating characteristics means any characteristic that affects the eligibility of an eligible resource for generating ERCs pursuant to this regulation, including the type of resource.

Existing State program, requirement, or measure means, in the context of a State plan, a regulation, requirement, program, or measure administered by a State, utility, or other entity that is currently established.

Final period means the period that begins on January 1, 2030, and continues thereafter. The final period is comprised of final reporting periods, each of which may be no longer than two calendar years (with a calendar year beginning on January 1 and ending on December 31).

Final reporting period means an increment of plan performance within the final period, with each final reporting period being no longer than two calendar years (with a calendar year beginning on January 1 and ending on December 31), with the first final reporting period in the final period beginning on January 1, 2030, and ending no later than December 31, 2031.

Fossil fuel means natural gas (as defined in subpart TTTT of this part), petroleum (as defined in subpart TTTT of this part), coal (as defined in subpart TTTT of this part), and any form of solid fuel (as defined in subpart TTTT of this part), liquid fuel (as defined in subpart TTTT of this part), or gaseous fuel (as defined in subpart TTTT of this part) derived from such material for the purpose of creating useful heat.

Heat recovery steam generating unit (HRSG) means a unit in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

Independent verifier means a person (including any company, any corporate parent or subsidiary, any contractors or subcontractors, and the actual person) who has the appropriate technical and other qualifications to provide verification reports. The independent verifier must not have, or have had, any direct or indirect financial or other interest in the subject of its verification report or ERCs that could impact their impartiality in performing verification services.

Integrated gasification combined cycle facility or *IGCC facility* means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas plus any integrated equipment that provides electricity or useful thermal output to either the affected facility or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the unit during operation.

Interim period means the period of eight calendar years from January 1, 2022, to December 31, 2029. The interim period is composed of at least three interim steps, interim step 1, interim step 2, and interim step 3, and may be composed of more than three interim steps at your discretion, provided your first and second interim steps and no single interim step is longer than three calendar years each (with a calendar year beginning on January 1 and ending on December 31), and your last interim step is no longer than two calendar years (with a calendar year beginning on January 1 and ending on December 31).

Interim step means an increment of plan performance within the interim period. You must have at least three interim steps within the interim period. You may have more than three interim steps at your discretion, provided your first and second interim steps and no single interim step is longer than three calendar years each (with a calendar year beginning on January 1 and ending on December 31), and your last interim step is no longer than two calendar years (with a calendar year beginning on January 1 and ending on December 31).

Interim step 1 means the period of three calendar years from January 1, 2022, to December 31, 2024.

Interim step 2 means the period of three calendar years from January 1, 2025, to December 31, 2027.

Interim step 3 means the period of two calendar years from January 1, 2028, to December 31, 2029.

ISO conditions means 288 Kelvin (15° C), 60 percent relative humidity and 101.3 kilopascals pressure.

M&V report means a report that meets the requirements of §60.5835].

Mechanical output means the useful mechanical energy that is not used to operate the affected facility, generate electricity and/or thermal output, or to enhance the performance of the affected facility. Mechanical energy measured in horsepower hour must be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Nameplate capacity means, starting from the initial installation, the maximum rated output of a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer is capable of producing on a steady-state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the equipment, starting from the completion of any subsequent physical change resulting in an increase in the maximum electrical generating output that the equipment is capable of producing on a steady-state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount (in MWe, rounded to the nearest tenth) as of such completion as specified by the person conducting the physical change.

Natural gas means a fluid mixture of hydrocarbons (e.g., methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous State under ISO conditions. In addition, natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Finally, natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Net allowance export/import means a net transfer of CO_2 allowances during an interim step, the interim period, or final reporting period which represents the net number of CO_2 allowances (issued by a respective State) that are transferred from the compliance accounts of affected EGUs in that state to the compliance accounts of affected EGUs in another State. This net transfer is determined based on compliance account holdings at the end of the plan performance period. Compliance account holdings, as used here, refer to the number of CO_2 allowances surrendered for compliance during a plan performance period, as well as any remaining CO_2 allowances held in a compliance account as of the end of a plan performance period.

Net-electric output means the amount of gross generation the generator(s) produce (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (i.e., auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (e.g., the point of sale).

Net energy output means:

(1) The net electric or mechanical output from the affected facility, plus 100 percent of the useful thermal output measured relative to SATP conditions that is not used to generate additional electric or mechanical output or to enhance the performance of the unit (e.g., steam delivered to an industrial process for a heating application).

(2) For combined heat and power facilities where at least 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating month rolling average basis, the net electric or mechanical output from the affected EGU divided by 0.95, plus 100 percent of the useful thermal output; (e.g., steam delivered to an industrial process for a heating application).

Qualified biomass means a biomass feedstock that is demonstrated as a method to control increases of CO_2 levels in the atmosphere.

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25° C, 77 °F)) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

State agent means an entity acting on behalf of the State, with the legal authority of the State.

State measures means measures that the State adopts and implements as a matter of State law. Such measures are enforceable only per State law, and are not included in and codified as part of the federally enforceable State plan.

Stationary combustion turbine means all equipment, including but not limited to the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emissions control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, heat recovery system or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. If a stationary combustion turbine burns any solid fuel directly it is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected facility or auxiliary equipment.

Uprate means an increase in available electric generating unit power capacity due to a system or equipment modification.

Useful thermal output means the thermal energy made available for use in any heating application (e.g., steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the affected EGU, to directly enhance the performance of the affected EGU (e.g., economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the affected EGU. Useful thermal output for affected EGU(s) with no condensate return (or other thermal energy input to the affected EGU(s)) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected EGU(s) with meaningful energy in the condensate return (or other thermal energy input to the affected EGU) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter. For CEMS, the initial certification requirements in §75.20 of this chapter and appendix A to part 75 of this chapter must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to part 75 of this chapter must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to part 75 of this chapter apply. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to part 75 of this chapter must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to part 75 of this chapter apply (except for qualifying commercial billing meters).

Waste-to-Energy means a process or unit (e.g., solid waste incineration unit) that recovers energy from the conversion or combustion of waste stream materials, such as municipal solid waste, to generate electricity and/or heat.

Table 1 to Subpart UUUU of Part 60—CO_2 Emission Performance Rates

(Pounds of CO_2 per Net MWh)

Affected EGU	Interim Rate	Final Rate
Steam generating unit or integrated gasification combined cycle (IGCC)	1,534	1,305
Stationary combustion turbine	832	771

Table 2 to Subpart UUUU of Part 60—Statewide Rate-based CO_2 Emission Goals (Pounds of CO_2 per Net MWh)

State	Interim Emission Goal	Final Emission Goal
Alabama	1,157	1,018
Arizona	1,173	1,031
Arkansas	1,304	1,130
California	907	828
Colorado	1,362	1,174
Connecticut	852	786
Delaware	1,023	916
Florida	1,026	919
Georgia	1,198	1,049
Idaho	832	771
Illinois	1,456	1,245
Indiana	1,451	1,242
Iowa	1,505	1,283
Kansas	1,519	1,293
Kentucky	1,509	1,286
Lands of the Fort Mojave Tribe	832	771
Lands of the Navajo Nation	1,534	1,305
Lands of the Uintah and Ouray Reservation	1,534	1,305
Louisiana	1,293	1,121
Maine	842	779

Maryland	1,510	1,287
Massachusetts	902	824
Michigan	1,355	1,169
Minnesota	1,414	1,213
Mississippi	1,061	945
Missouri	1,490	1,272
Montana	1,534	1,305
Nebraska	1,522	1,296
Nevada	942	855
New Hampshire	947	858
New Jersey	885	812
New Mexico	1,325	1,146
New York	1,025	918
North Carolina	1,311	1,136
North Dakota	1,534	1,305
Ohio	1,383	1,190
Oklahoma	1,223	1,068
Oregon	964	871
Pennsylvania	1,258	1,095
Rhode Island	832	771
South Carolina	1,338	1,156
South Dakota	1,352	1,167
Tennessee	1,411	1,211
Texas	1,188	1,042
Utah	1,368	1,179
Virginia	1,047	934
Washington	1,111	983
West Virginia	1,534	1,305
Wisconsin	1,364	1,176
Wyoming	1,526	1,299

Table 3 to Subpart UUUU of Part 60—Statewide Mass-based CO_2 Emission Goals (Short Tons of CO_2)

State	**Interim Emission Goal (2022-2029)**	**Final Emission Goals (2 year blocks starting with 2030-2031)**
Alabama	497,682,304	113,760,948
Arizona	264,495,976	60,341,500
Arkansas	269,466,064	60,645,264
California	408,216,600	96,820,240

Colorado	267,103,064	59,800,794
Connecticut	57,902,920	13,883,046
Delaware	40,502,952	9,423,650
Florida	903,877,832	210,189,408
Georgia	407,408,672	92,693,692
Idaho	12,401,136	2,985,712
Illinois	598,407,008	132,954,314
Indiana	684,936,520	152,227,670
Iowa	226,035,288	50,036,272
Kansas	198,874,664	43,981,652
Kentucky	570,502,416	126,252,242
Lands of the Fort Mojave Tribe	4,888,824	1,177,038
Lands of the Navajo Nation	196,462,344	43,401,174
Lands of the Uintah and Ouray Reservation	20,491,560	4,526,862
Louisiana	314,482,512	70,854,046
Maine	17,265,472	4,147,884
Maryland	129,675,168	28,695,256
Massachusetts	101,981,416	24,209,494
Michigan	424,457,200	95,088,128
Minnesota	203,468,736	45,356,736
Missouri	500,555,464	110,925,768
Mississippi	218,706,504	50,608,674
Montana	102,330,640	22,606,214
Nebraska	165,292,128	36,545,478
Nevada	114,752,736	27,047,168
New Hampshire	33,947,936	7,995,158
New Jersey	139,411,048	33,199,490
New Mexico	110,524,488	24,825,204
New York	268,762,632	62,514,858
North Carolina	455,888,200	102,532,468
North Dakota	189,062,568	41,766,464
Ohio	660,212,104	147,539,612
Oklahoma	356,882,656	80,976,398
Oregon	69,145,312	16,237,308
Pennsylvania	794,646,616	179,644,616
Rhode Island	29,259,080	7,044,450
South Carolina	231,756,984	51,997,936
South Dakota	31,591,600	7,078,962
Tennessee	254,278,880	56,696,792
Texas	1,664,726,728	379,177,684

Utah	212,531,040	47,556,386
Virginia	236,640,576	54,866,222
Washington	93,437,656	21,478,344
West Virginia	464,664,712	102,650,684
Wisconsin	250,066,848	55,973,976
Wyoming	286,240,416	63,268,824

Table 4 to Subpart UUUU of Part 60— Statewide Mass-based CO_2 Goals plus New Source CO_2 Emission Complement (Short Tons of CO_2)

State	Interim Emission Goal (2022-2029)	Final Emission Goals (2 year blocks starting with 2030-2031)
Alabama	504,534,496	115,272,348
Arizona	275,895,952	64,760,392
Arkansas	272,756,576	61,371,058
California	430,988,824	105,647,270
Colorado	277,022,392	63,645,748
Connecticut	58,986,192	14,121,986
Delaware	41,133,688	9,562,772
Florida	917,904,040	213,283,190
Georgia	412,826,944	93,888,808
Idaho	13,155,256	3,278,026
Illinois	604,953,792	134,398,348
Indiana	692,451,256	153,885,208
Iowa	228,426,760	50,563,762
Kansas	200,960,120	44,441,644
Kentucky	576,522,048	127,580,002
Lands of the Fort Mojave Tribe	5,186,112	1,292,276
Lands of the Navajo Nation	202,938,832	45,911,608
Lands of the Uintah and Ouray Reservation	21,167,080	4,788,708
Louisiana	318,356,976	71,708,642
Maine	17,592,128	4,219,936
Maryland	131,042,600	28,996,872
Massachusetts	103,782,424	24,606,744
Michigan	429,446,408	96,188,604
Minnesota	205,761,008	45,862,346

Mississippi	221,990,024	51,332,926
Missouri	505,904,560	112,105,626
Montana	105,704,024	23,913,816
Nebraska	167,021,320	36,926,888
Nevada	120,916,064	29,436,214
New Hampshire	34,519,280	8,121,182
New Jersey	141,919,248	33,752,728
New Mexico	114,741,592	26,459,850
New York	272,940,440	63,436,364
North Carolina	461,424,928	103,753,712
North Dakota	191,025,152	42,199,354
Ohio	667,812,080	149,215,950
Oklahoma	361,531,056	82,001,704
Oregon	72,774,608	17,644,106
Pennsylvania	804,705,296	181,863,274
Rhode Island	29,819,360	7,168,032
South Carolina	234,516,064	52,606,510
South Dakota	31,963,696	7,161,036
Tennessee	257,149,584	57,329,988
Texas	1,707,356,792	396,210,498
Utah	220,386,616	50,601,386
Virginia	240,240,880	55,660,348
Washington	97,691,736	23,127,324
West Virginia	469,488,232	103,714,614
Wisconsin	252,985,576	56,617,764
Wyoming	295,724,848	66,945,204

The White House

Office of the Press Secretary

For Immediate Release March 28, 2017

Presidential Executive Order on Promoting Energy Independence and Economic Growth

EXECUTIVE ORDER

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PROMOTING ENERGY INDEPENDENCE AND ECONOMIC GROWTH

By the authority vested in me as President by the Constitution and the laws of the United States of America, it is hereby ordered as follows:

Section 1. Policy. (a) It is in the national interest to promote clean and safe development of our Nation's vast energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production, constrain economic growth, and prevent job creation. Moreover, the prudent development of these natural resources is essential to ensuring the Nation's geopolitical security.

(b) It is further in the national interest to ensure that the Nation's electricity is affordable, reliable, safe, secure, and clean, and that it can be produced from coal, natural gas, nuclear material, flowing water, and other domestic sources, including renewable sources.

(c) Accordingly, it is the policy of the United States that executive departments and agencies (agencies) immediately review existing regulations that potentially burden the development or use of domestically produced energy resources and appropriately suspend, revise, or rescind those that unduly burden the development of domestic energy resources beyond the degree necessary to protect the public interest or otherwise comply with the law.

(d) It further is the policy of the United States that, to the extent permitted by law, all agencies should take appropriate actions to promote clean air and clean water for the American people, while also respecting the proper roles of the Congress and the States concerning these matters in our constitutional republic.

(e) It is also the policy of the United States that necessary and appropriate environmental regulations comply with the law, are of greater benefit than cost, when permissible, achieve environmental improvements for the American people, and are developed through transparent processes that employ the best available peer-reviewed science and economics.

Sec. 2. Immediate Review of All Agency Actions that Potentially Burden the Safe, Efficient Development of Domestic Energy Resources. (a) The heads of agencies shall review all existing regulations, orders, guidance documents, policies, and any other similar agency actions (collectively, agency actions) that potentially burden the development or use of domestically produced energy resources, with particular attention to oil, natural gas, coal, and nuclear energy resources. Such review shall not include agency actions that are mandated by law, necessary for the public interest, and consistent with the policy set forth in section 1 of this order.

(b) For purposes of this order, "burden" means to unnecessarily obstruct, delay, curtail, or otherwise impose significant costs on the siting, permitting, production, utilization, transmission, or delivery of energy resources.

(c) Within 45 days of the date of this order, the head of each agency with agency actions described in subsection (a) of this section shall develop and submit to the Director of the Office of Management and Budget (OMB Director) a plan to carry out the review required by subsection (a) of this section. The plans shall also be sent to the Vice President, the Assistant to the President for Economic Policy, the Assistant to the President for Domestic Policy, and the Chair of the Council on Environmental Quality. The head of any agency who determines that such agency does not have agency actions described in subsection (a) of this section shall submit to the OMB Director a written statement to that effect and, absent a determination by the OMB Director that such agency does have agency actions described in subsection (a) of this section, shall have no further responsibilities under this section.

(d) Within 120 days of the date of this order, the head of each agency shall submit a draft final report detailing the agency actions described in subsection (a) of this section to the Vice President, the OMB Director, the Assistant to the President for Economic Policy, the Assistant to the President for Domestic Policy, and the Chair of the Council on Environmental Quality. The report shall include specific recommendations that, to the extent permitted by law, could alleviate or eliminate aspects of agency actions that burden domestic energy production.

(e) The report shall be finalized within 180 days of the date of this order, unless the OMB Director, in consultation with the other officials who receive the draft final reports, extends that deadline.

(f) The OMB Director, in consultation with the Assistant to the President for Economic Policy, shall be responsible for coordinating the recommended actions included in the agency final reports within the Executive Office of the President.

(g) With respect to any agency action for which specific recommendations are made in a final report pursuant to subsection (e) of this section, the head of the relevant agency shall, as soon as practicable, suspend, revise, or rescind, or publish for notice and comment proposed rules suspending, revising, or rescinding, those actions, as appropriate and consistent with law. Agencies shall endeavor to coordinate such regulatory reforms with their activities undertaken in compliance with Executive Order 13771 of January 30, 2017 (Reducing Regulation and Controlling Regulatory Costs).

Sec. 3. Rescission of Certain Energy and Climate-Related Presidential and Regulatory Actions. (a) The following Presidential actions are hereby revoked:

(i) Executive Order 13653 of November 1, 2013 (Preparing the United States for the Impacts of Climate Change);

(ii) The Presidential Memorandum of June 25, 2013 (Power Sector Carbon Pollution Standards);

(iii) The Presidential Memorandum of November 3, 2015 (Mitigating Impacts on Natural Resources from Development and Encouraging Related Private Investment); and

(iv) The Presidential Memorandum of September 21, 2016 (Climate Change and National Security).

(b) The following reports shall be rescinded:

(i) The Report of the Executive Office of the President of June 2013 (The President's Climate Action Plan); and

(ii) The Report of the Executive Office of the President of March 2014 (Climate Action Plan Strategy to Reduce Methane Emissions).

(c) The Council on Environmental Quality shall rescind its final guidance entitled "Final Guidance for Federal Departments and Agencies on Consideration of Greenhouse Gas Emissions and the Effects of Climate Change in National Environmental Policy Act Reviews," which is referred to in "Notice of Availability," 81 Fed. Reg. 51866 (August 5, 2016).

(d) The heads of all agencies shall identify existing agency actions related to or arising from the Presidential actions listed in subsection (a) of this section, the reports listed in subsection (b) of this section, or the final guidance listed in subsection (c) of this section. Each agency shall, as soon as practicable, suspend, revise, or rescind, or publish for notice and comment proposed rules suspending, revising, or rescinding any such actions, as appropriate and consistent with law and with the policies set forth in section 1 of this order.

Sec. 4. Review of the Environmental Protection Agency's "Clean Power Plan" and Related Rules and Agency Actions. (a) The Administrator of the Environmental Protection Agency (Administrator) shall immediately take all steps necessary to review the final rules set forth in subsections (b)(i) and (b)(ii) of this section, and any rules and guidance issued pursuant to them, for consistency with the policy set forth in section 1 of this order and, if appropriate, shall, as soon as practicable, suspend, revise, or rescind the guidance, or publish for notice and comment proposed rules suspending, revising, or rescinding those rules. In addition, the Administrator shall immediately take all steps necessary to review the proposed rule set forth in subsection (b)(iii) of this section, and, if appropriate, shall, as soon as practicable, determine whether to revise or withdraw the proposed rule.

(b) This section applies to the following final or proposed rules:

(i) The final rule entitled "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," 80 Fed. Reg. 64661 (October 23, 2015) (Clean Power Plan);

(ii) The final rule entitled "Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units," 80 Fed. Reg. 64509 (October 23, 2015); and

(iii) The proposed rule entitled "Federal Plan Requirements for Greenhouse Gas Emissions From Electric Utility Generating Units Constructed on or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulations; Proposed Rule," 80 Fed. Reg. 64966 (October 23, 2015).

(c) The Administrator shall review and, if appropriate, as soon as practicable, take lawful action to suspend, revise, or rescind, as appropriate and consistent with law, the "Legal Memorandum Accompanying Clean Power Plan for Certain Issues," which was published in conjunction with the Clean Power Plan.

(d) The Administrator shall promptly notify the Attorney General of any actions taken by the Administrator pursuant to this order related to the rules identified in subsection (b) of this section so that the Attorney General may, as appropriate, provide notice of this order and any such action to any court with jurisdiction over pending litigation related to those rules, and may, in his discretion, request that the court stay the litigation or otherwise delay further litigation, or seek other appropriate relief consistent with this order, pending the completion of the administrative actions described in subsection (a) of this section.

Sec. 5. Review of Estimates of the Social Cost of Carbon, Nitrous Oxide, and Methane for Regulatory Impact Analysis. (a) In order to ensure sound regulatory decision making, it is essential that agencies use estimates of costs and benefits in their regulatory analyses that are based on the best available science and economics.

(b) The Interagency Working Group on Social Cost of Greenhouse Gases (IWG), which was convened by the Council of Economic Advisers and the OMB Director, shall be disbanded, and the following documents issued by the IWG shall be withdrawn as no longer representative of governmental policy:

(i) Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (February 2010);

(ii) Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis (May 2013);

(iii) Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis (November 2013);

(iv) Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis (July 2015);

(v) Addendum to the Technical Support Document for Social Cost of Carbon: Application of the Methodology to Estimate the Social Cost of Methane and the Social Cost of Nitrous Oxide (August 2016); and

(vi) Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis (August 2016).

(c) Effective immediately, when monetizing the value of changes in greenhouse gas emissions resulting from regulations, including with respect to the consideration of domestic versus international impacts and the consideration of appropriate discount rates, agencies shall ensure, to the extent permitted by law, that any such estimates are consistent with the guidance contained in OMB Circular A-4 of September 17, 2003 (Regulatory Analysis), which was issued after peer review and public comment and has been widely accepted for more than a decade as embodying the best practices for conducting regulatory cost-benefit analysis.

Sec. 6. Federal Land Coal Leasing Moratorium. The Secretary of the Interior shall take all steps necessary and appropriate to amend or withdraw Secretary's Order 3338 dated January 15, 2016 (Discretionary Programmatic Environmental Impact Statement (PEIS) to Modernize the Federal Coal Program), and to lift any and all moratoria on Federal land coal leasing activities related to Order 3338. The Secretary shall commence Federal coal leasing activities consistent with all applicable laws and regulations.

Sec. 7. Review of Regulations Related to United States Oil and Gas Development. (a) The Administrator shall review the final rule entitled "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources," 81 Fed. Reg. 35824 (June 3, 2016), and any rules and guidance issued pursuant to it, for consistency with the policy set forth in section 1 of this order and, if appropriate, shall, as soon as practicable, suspend, revise, or rescind the guidance, or publish for notice and comment proposed rules suspending, revising, or rescinding those rules.

(b) The Secretary of the Interior shall review the following final rules, and any rules and guidance issued pursuant to them, for consistency with the policy set forth in section 1 of this order and, if appropriate, shall, as soon as practicable, suspend, revise, or rescind the guidance, or publish for notice and comment proposed rules suspending, revising, or rescinding those rules:

(i) The final rule entitled "Oil and Gas; Hydraulic Fracturing on Federal and Indian Lands," 80 Fed. Reg. 16128 (March 26, 2015);

(ii) The final rule entitled "General Provisions and Non-Federal Oil and Gas Rights," 81 Fed. Reg. 77972 (November 4, 2016);

(iii) The final rule entitled "Management of Non Federal Oil and Gas Rights," 81 Fed. Reg. 79948 (November 14, 2016); and

(iv) The final rule entitled "Waste Prevention, Production Subject to Royalties, and Resource Conservation," 81 Fed. Reg. 83008 (November 18, 2016).

(c) The Administrator or the Secretary of the Interior, as applicable, shall promptly notify the Attorney General of any actions taken by them related to the rules identified in subsections (a) and (b) of this section so that the Attorney General may, as appropriate, provide notice of this order and any such action to any court with jurisdiction over pending litigation related to those rules, and may, in his discretion, request that the court stay the litigation or otherwise delay further litigation, or seek other appropriate relief consistent with this order, until the completion of the administrative actions described in subsections (a) and (b) of this section.

Sec. 8. General Provisions. (a) Nothing in this order shall be construed to impair or otherwise affect:

(i) the authority granted by law to an executive department or agency, or the head thereof; or

(ii) the functions of the Director of the Office of Management and Budget relating to budgetary, administrative, or legislative proposals.

(b) This order shall be implemented consistent with applicable law and subject to the availability of appropriations.

(c) This order is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or in equity by any party against the United States, its departments, agencies, or entities, its officers, employees, or agents, or any other person.

DONALD J. TRUMP

THE WHITE HOUSE,
March 28, 2017.

E&E NEWS

The Clean Power Plan faces attacks by the Trump administration and a long and complicated legal fight

President Trump's White House victory significantly dimmed the outlook for U.S. EPA's Clean Power Plan. Trump will try to unravel the rule along with other environmental regulations that he deems burdensome.

He has directed EPA to review or rescind the rule, which will take time and face lawsuits from environmental groups. The Trump administration also could try to rewrite a finding that CO2 is a dangerous air pollutant. That would face substantial legal hurdles.

Implementation of the Clean Power Plan has been on hold since the Supreme Court in February 2016 froze the rule until legal battles were resolved. More than half of states and numerous industry groups are challenging the regulation. Dozens of lawyers faced off in the U.S. Court of Appeals for the District of Columbia Circuit in oral arguments in September 2016. If the court issues a decision, parties on the losing side may appeal to the Supreme Court. The court in late April agreed to put the case on hold for 60 days, until the end of June – partially granting a Trump administration request to freeze proceedings indefinitely. Now the judges are considering arguments from both sides on whether to put a long-term hold on the case or simply close it.

The Clean Power Plan case has seen several plot twists. The D.C. Circuit in May 2016 decided to bypass review by a panel of three judges and hear the case en banc -- with the full court. In February 2016, the Supreme Court blocked EPA from implementing the rule after the D.C. Circuit had declined to issue a stay. For many, that signaled doom. But then Justice Antonin Scalia died, leaving an opening on the bench. Scalia had cast the pivotal vote by which the Supreme Court decided 5-4 to halt the Clean Power Plan, giving critics reason to believe justices would torpedo the rule along those same lines.

Litigation Timeline

The Clean Power Plan has been in and out of federal court since before it was even finalized. Lawsuits challenging the final rule are now consolidated at the D.C. Circuit and may ultimately land at the Supreme Court. In the meantime, the rule remains frozen, and state compliance deadlines are no longer certain.

JUNE 2014

U.S. EPA releases draft Clean Power Plan.

2014 - 2015

Industry and states file suit in D.C. Circuit to block draft rule. Court rejects early challenges as premature.

AUGUST 2015

EPA announces final rule. (States would have been required to submit initial plans in 2016 and final plans in 2018. The compliance period would have begun in 2022 and ramped up through 2030.)

OCTOBER 2015

Clean Power Plan is published in *Federal Register*.

LATE 2015 - EARLY 2016

States and industry sue and ask for stay. D.C. Circuit declines to stay rule.

FEBRUARY 2016

U.S. Supreme Court grants stay, pending D.C. Circuit litigation.

SEPTEMBER 2016

D.C. Circuit hears oral arguments en banc, bypassing planned review by a three-judge panel.

2016 - 2018 (PRE-STAY)

State plans due.

EARLY 2017

D.C. Circuit expected to issue decision. Losing side may appeal to the Supreme Court.

2017

White House begins process to unravel rule.

2017

President Trump directed the Justice Department to ask the court to forego or postpone consideration of the Clean Power Plan.

MAY 2017

Court freezes litigation for 60 days, until the end of June.

For questions or comments about E&E's Power Plan Hub or related stories, please email **PowerPlanHub@eenews.net**.

CLEAN POWER PLAN
IN THE COURTS

- **Overview & Litigation Timeline**
- **D.C. Circuit Oral Argument Tipsheet**
- **Battle Lines**
- **Lawyers to Watch**
- **Legal Documents**
- **States at a Glance**

The essential news for energy & environment professionals

2016 Gas Outlook

Natural Gas Supply, Demand, Capacity and Prices in the Pacific Northwest

Projections through October 2026

This report, compiled by the Northwest Gas Association (NWGA) and its members, provides a consensus industry perspective of the Pacific Northwest's current and projected natural gas supply, demand, prices and delivery capabilities through 2026. The Pacific Northwest in this case includes British Columbia (BC) and the U.S. states of Washington, Oregon and Idaho. Additional information, including white papers on specific natural gas topics, can be found at www.nwga.org.

NWGA
NORTHWEST GAS ASSOCIATION

What's New

The golden age of natural gas continues and appears to be gaining longevity. This means consumers could continue to enjoy low prices and ample supply for decades.

Yet, as the good news about natural gas endures, the market is causing many to scratch their heads. Not much has changed…but everything is different. Despite historic low prices and dropping rig counts, North American production actually increased in 2015 and supply has remained plentiful. On the demand side, consumers are enjoying the resulting cost savings, but demand growth from all sectors has been slower than anticipated – a trend we also noted last year. While there are explanations for these incongruities, the general take-away is this: We have lots of affordable natural gas and will for the foreseeable future. Perhaps the biggest difference today is the imperative we have to make the case that natural gas is a foundation fuel, an energy, economic and environmental solution. The question is, are we fully capitalizing on the potential benefits of this abundant, low-cost, clean-burning resource, given readily available technology to do so? For instance, opportunities for the direct use of natural gas in homes and businesses remain and transportation uses have barely been tapped.

Not much has changed . . . but everything is different

Natural gas has historically been and will continue to be a bargain among energy resources. According to the U.S. Energy Information Administration (EIA), natural gas averaged more than $4/Dekatherm (Dth)[1] from 1981-2000 in real dollars ($2015); was well under $3/Dth in 2015 and is projected to reach $5/Dth by 2025 and remain there through 2040.[2] Weather driven price volatility may occur, however, especially if large loads materialize in the region. That is why it remains important for providers to have access to and make use of a variety of tools to prudently manage their natural gas purchases.

In the Pacific Northwest, according to the EIA, natural gas utility customers saw the cost of the commodity portion of their bills drop by almost 50 percent in 2015 over what they would have paid in 2008. Yet demand growth in most sectors is tepid at best, despite a decent uptick in the region's economy.

Also, 2015 saw our region burn more natural gas than ever before to generate electricity, largely due to a very

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[1] A Dth is a measure of energy content representing one million British Thermal Units (Btu). A Mcf is a volumetric measure representing 1,000 cubic ft. While the energy content of a Mcf varies according to a variety of factors, it is roughly equivalent to a Dth (typically 0.95 to 1.05 Dth per Mcf). We use volumetric measures (thousand, million and billion cubic feet; Mcf, MMcf, Bcf) interchangeably with energy measures (dekatherm, thousand dekatherm, million dekatherm; Dth, MDth, MMDth).

[2] EIA, *Natural Gas Spot and Futures Prices,* July, 2016; EIA, *2016 Annual Energy Outlook,* July, 2016

warm and dry water year. Gas for generation remains the only sector showing material growth. Regional electric utilities continue to add gas-fired generation to their portfolios out of a recognition that gas plants provide an immediate, cost-effective means to reduce greenhouse gas (GHG) emissions;[3] deliver an on-demand supply to support variable renewable resources such as wind and solar; and build reliable, affordable base load assets when they become necessary. For instance, construction of a 440-megawatt (MW) Portland General Electric (PGE) natural gas base load plant is under way in Boardman, OR, joining a flexible dispatch 220-MW plant that went online in 2014. Others may be planned as coal-fired generation is retired in the region.

In the industrial sector, large natural gas users are still considering locating or expanding in the Northwest, including an LNG export facility in Coos Bay, OR and methanol refineries proposed in Clatskanie, OR, and the Port of Kalama, WA. But industrial demand growth in 2015 was nearly nonexistent. Unless and until these plans are finalized, we project almost no additional growth in regional industrial loads.

While there will be ample natural gas to serve whatever demand emerges, one question is whether there will be enough capacity to move the supply from where its produced to where it is needed. The seas are calm right now, but an inflection point could happen if some combination of LNG export, methanol and new gas-fired power generation loads emerge. This Outlook examines the potential affect that new large loads could have on regional infrastructure capacity.

We have updated data in this 2016 Outlook, but most key conclusions are similar to last year. Most of the trends identified in the 2015 Outlook continue to be relevant. Where appropriate, revised analyses and updated tables/graphics provide details of what's new.

[3] Natural gas emits about 50% less carbon dioxide as coal when burned in power plants and 25% less than gasoline or diesel when used for vehicle fuel. http://www.eia.gov/tools/faqs/faq.cfm?id=73&t=11

Regional Economic Outlook

The U.S. and Canada continue to grow despite headwinds created by low energy prices and sputtering growth outside of North America. That being said, growth in both countries is far from booming. An increasing number of forecasters in the public and private sectors see U.S. GDP growth in the low 2% range for 2016 and 2017. In Canada, growth is forecasted to come in under 2% in 2016 and slightly above 2% in 2017.

Overall Inflation in both countries is expected to be below 2% in 2016, and then rising to around 2% by 2017. Beyond 2017, both market-based and professional forecasts see inflation near the 2% targets of the Federal Reserve (the Fed) and the Bank of Canada (BOC). Broadly speaking, the U.S. and Canada are slipping into a prolonged "two-two" growth pattern — that is, annual 2% growth in both output and prices.

Moderate national growth, weak external growth, and subdued inflation pressures will keep the Fed and BOC cautious about the timing of any future interest rate increases. This, along with low oil prices, will help keep the dollar strong relative to the loonie.

However, diverging from the U.S., Canada's new government will embark on an expansionary fiscal policy in 2016. This will provide benefits on both sides of the border. Unfortunately, given America's somewhat eccentric political environment, U.S. fiscal policy will remain sidelined for the current election cycle.

In the U.S. Pacific Northwest (PNW), Idaho, Oregon and Washington continue to outperform the U.S., thanks to continued strong growth in the major metropolitan areas. However, the PNW's smaller metropolitan areas are also showing relatively strong growth. Leading indicators produced by the Federal Reserve Bank of Philadelphia suggest the PNW will continue to outperform the U.S. through the rest of this year. Specifically, PNW employment growth will likely exceed U.S. growth in 2016, with U.S. growth expected to be just under 2%. Excluding manufacturing, employment growth will continue to be broad-based in terms of sector.

Like the U.S. PNW, British Columbia (BC) also continues to outperform Canada's national economy — in 1Q 2016, BC employment growth was 3% compared to 0.7% nationally. Growth is centered in the Vancouver and Victoria metropolitan areas with strength in both the goods and service sectors. In 2016, Canadian forecasters see BC's employment growth to be nearly twice the expected national level of less than 1%.

External risks to the U.S. and Canadian economies are weak growth and political instability outside of North America. Of particular concern is slower growth in China and Brazil, and repercussions of the U.K.'s recent decision to exit from the European Union. In this context, another sharp drop in global energy prices would hit investment spending in both countries. More regionally, BC's housing market continues to defy expectations in terms of price appreciation. Of particular concern is the Vancouver housing market. A sharp housing contraction would be a significant drag on BC growth.

– Grant D. Forsyth, Chief Economist, Avista Corp.

Sources: Bank of Canada, Bank of Montreal, B.C. Stats, Bloomberg.com, Canada Department of Finance, CIBC, Canada Mortgage and Housing Corporation, CBC, Scotiabank, Statistics Canada, RBC, T.D. Economics, The Economist, U.S. Bureau of Labor Statistics, U.S. Federal Reserve.

2016 GAS OUTLOOK – Supply

Key Conclusions

- North America's abundant natural gas resource, made available by accessing shale rock formations deep underground, continues to transform the energy landscape. (See Figure S1.)
- Enhanced production technologies continue to safely, responsibly and more cost-effectively deliver results that exceed expectations, despite lower natural gas and oil prices, declining rig counts, reallocation of capital, and stronger regulation.
- Pacific Northwest natural gas consumers benefit from their proximity to the prolific Western Canadian Sedimentary Basin (WCSB) and U.S. Rocky Mountain (Rockies) natural gas-producing regions.

Summary

In 2015, the Potential Gas Committee (PGC) released an updated estimate of Total Potential Natural Gas Resource in the U.S. The estimate of 2,515 trillion cubic feet (Tcf) was the largest in its half-century history of issuing this biennial report. The 2014 estimate exceeded the 2012 assessment by more than 5 percent, clearly documenting the ongoing benefits from the geological feat of shale gas mining. In 2015, shale gas production represented 53 percent of U.S. dry gas production, up from 10 percent in 2007.[4]

In Canada, "ultimate potential" and conventional natural gas resources are estimated at 1,087 Tcf, of which nearly 80 percent (855 Tcf), is found in the WCSB.[5]

FIGURE S1. North American Shale Formations

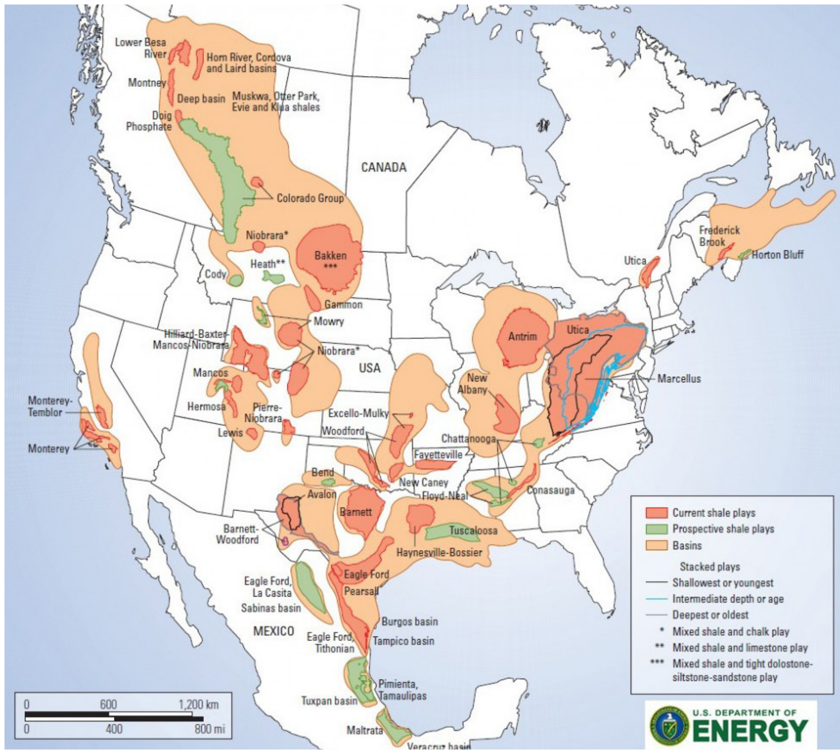
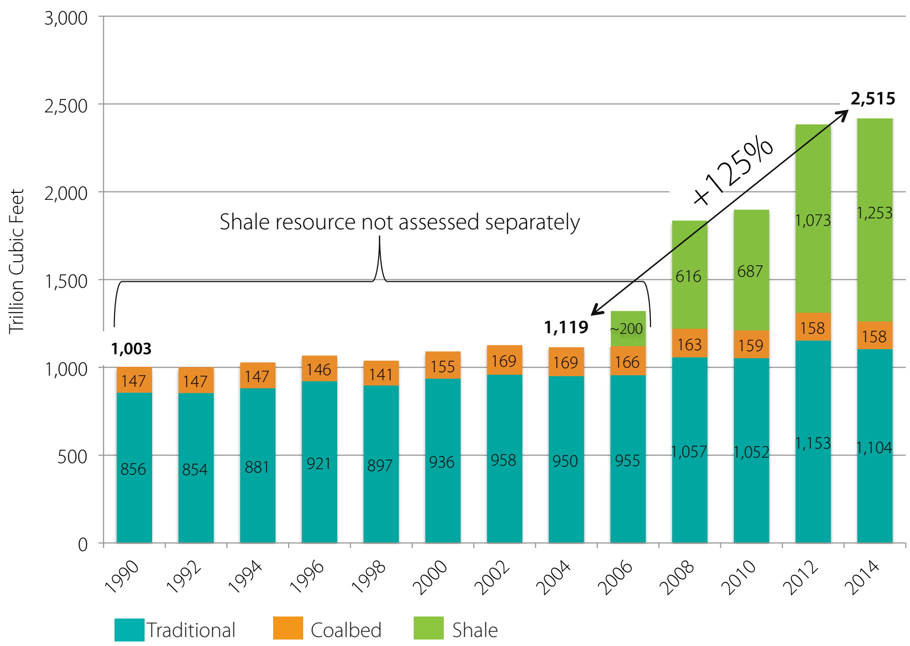


FIGURE S2. PGC Estimate of Total Potential Resources



[4] *The Growth of U.S. Natural Gas*, EIA presentation, June 15, 2015. http://www.eia.gov/conference/2015/pdf/presentations/staub.pdf

[5] *Canada's Energy Future 2016: Energy Supply and Demand Projections to 2040, Chapter 6,* NEB, January, 2016.

The U.S. and Russia have long been the largest producers of natural gas in the world, with the U.S. most often chasing Russia for bragging rights as Number 1. In recent years, Russian production appears to be on the wane while U.S production volumes are mind-boggling. According to the EIA and Statistics Canada, total North American marketable production averaged a record high of 99.5 Bcf/day in February, 2016. Average North American production for the year in 2015 was 93.4 Bcf/d, an increase of 4.3 Bcf/d or almost 5 percent over 2014.[6]

These production increases occurred in spite of a sharp drop in active drilling rigs. According to Baker Hughes' North America Rig Count, there was an average of 1,840 natural gas drilling rigs operating in the U.S. and Canada in September 2008. (This excludes oil rigs; the primary distinction between the two rig types is the targeted resource, however both produce natural gas.) In September 2015, there was an average of 308 natural gas rigs operating in the U.S. and Canada. That number had declined to 131 natural gas rigs as of the week of July 8, 2016.

In its July 2016 Short Term Energy Outlook, the EIA expects that natural gas production will increase 1 percent in 2016 and by 2.4 percent in 2017. Over the longer term, the EIA forecasts production to increase more than 50 percent by 2040.[7] As a result, the U.S. is expected to switch from a modest importer to a net exporter of natural gas in 2017.

What's going on here? Drilling technologies continue to advance at a dizzying pace, enabling producers to cost-effectively squeeze out more molecules of gas from every well. For example, producers in the Haynesville Shale play were recently successful in implementing "supersizing" techniques – extending the lateral portion of a well by thousands more feet.[8] Besides boosting volume and efficiency, which allows producers to realize profits even in a low price environment, this technology reduces the need to build more wellheads and further minimizes the industry's environmental footprint. Simply put, there's plenty of innovation going on beneath the surface.

FIGURE S3. Natural Gas Production by Country

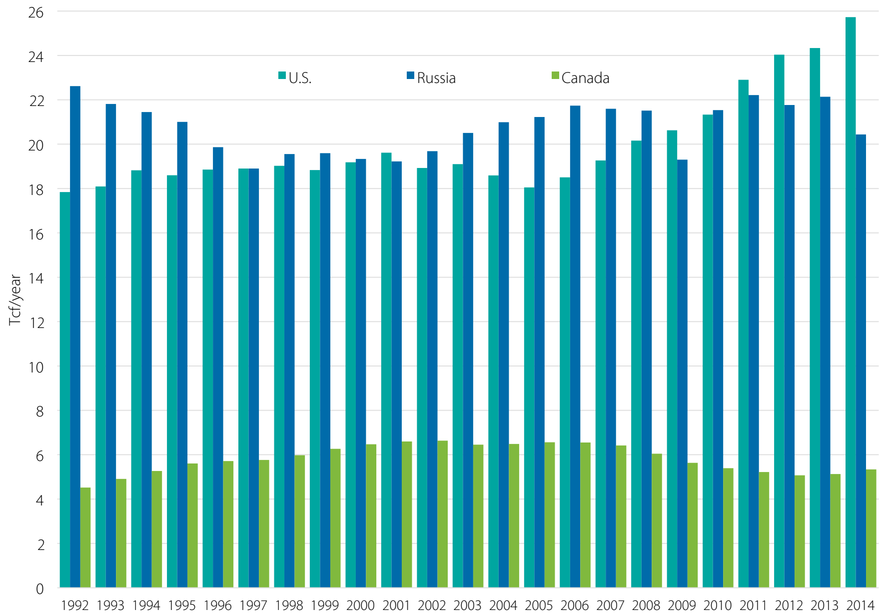
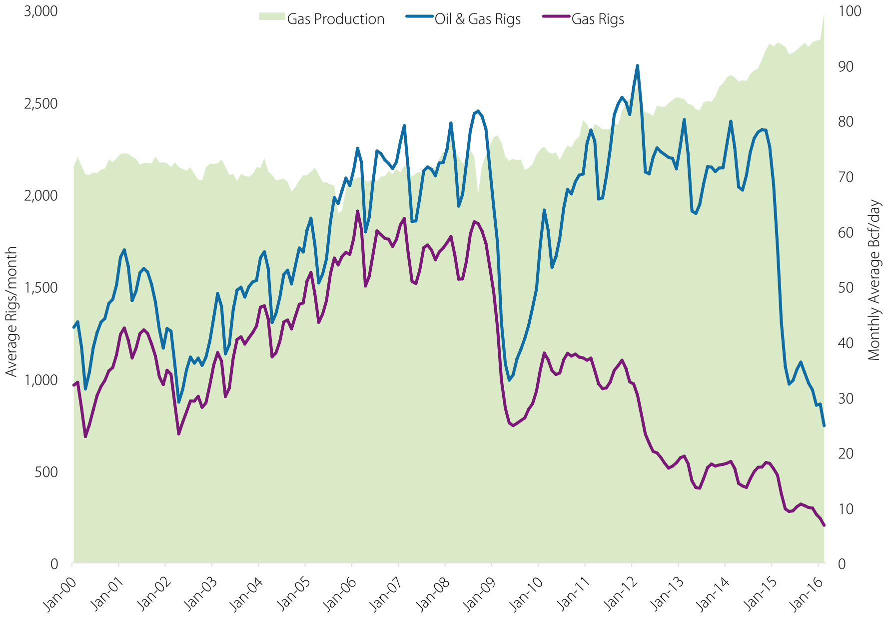


FIGURE S4. Increase in Natural Gas Production Despite Decline in Rigs (U.S. and Canada)



Source: U.S. EIA, Statistics Canada and Baker Hughes, Inc.

6 EIA, *Marketed Natural Gas Production; StatCan, Tables 131-0001/0004 – Supply and Disposition of Natural Gas*
7 EIA *2016 Annual Energy Outlook*, July 2016
8 *Modern Gas Drilling is Likely to Ensure Low Prices for Years*, Wall Street Journal, Sept. 2, 2015.

The Pacific Northwest is served by two prolific sources of supply: the WCSB and the U.S. Rockies, predominately, Colorado, Utah and Wyoming. Together these regions produced an average of 24.3 Bcf/d in 2015,[9] or more than 30 percent of North America's total natural gas supply. Production from these two areas is projected to approach a combined 30 Bcf/d by 2025.[10]

Northwest consumers benefit from access to different supply basins because shippers are able to flow from the regions that offer the best value at the time. Figure S5 is not a complete picture as it documents flows on one of the two pipelines serving the region, but it is nonetheless representative. For instance, in 2007 more than half the gas delivered to Northwest Pipeline shippers was sourced from the Rockies. The share of Canadian gas serving the Northwest has increased over the last several years as the price differential between Rockies and Canadian gas has widened, due in part to the growth in northern BC production.

Supply Variables

Key issues identified in prior Outlooks as having the potential to affect natural gas supplies are still relevant. They include:

- Development of new or improved well-completion technologies and techniques.
- The effect of the current low natural gas and oil prices environment on future production.
- The potential impact environmental concerns may have on natural gas production and pipeline expansions.
- Adequate access to gas supply, e.g., pipeline expansions and their timing.
- Local and national legislation or regulations affecting production/extraction processes.

FIGURE S5. Supply Diversity

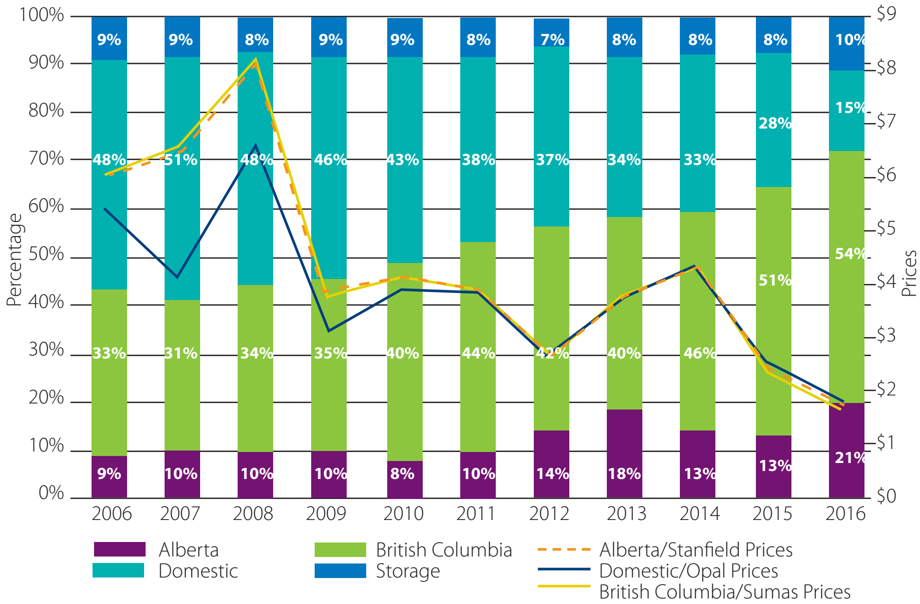


FIGURE S6. Supply Regions Serving the Pacific Northwest

[9] Statistics Canada, Table 131-0001 – *Supply and Disposition of Natural Gas, 2016; EIA, Natural Gas Gross Withdrawals and Production by State (CO, UT, WY)*, 2015

[10] NEB, *Canada's Energy Future 2016:* http://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016/index-eng.html - WCSB, January 2016; EIA, *2016 AEO Lower 48 Natural Gas Production and Prices by Supply Region (Table 61) – Dakotas/Rocky Mountain Region*, July 2016

Responsible Gas Production

The arrival of new and abundant natural gas supplies has changed the nation's energy picture. It also has brought new attention to gas production methods. Fracking – an abbreviation for hydraulic fracturing – is now a common term in our country's energy debate.

In fact, hydraulic fracturing isn't new: oil and gas developers have been using it for more than 60 years. Hydraulic fracturing uses water, sand and small amounts of chemicals to break open solid rock, releasing trapped fuels. According to the U.S. Department of Energy (DOE), more than 2 million wells have been hydraulically fractured to date and about 95 percent of new wells drilled today are fractured.

So, why are we only hearing about it now?

In the last 10 years, engineers learned how to combine hydraulic fracturing with another time-tested construction practice: horizontal drilling. Conventional drilling uses fracturing along the length of a vertical well. Now it's possible to send fracturing equipment horizontally along a shale deposit, releasing natural gas in larger volumes than ever before.

The combination of these technologies has helped the U.S. become the world's largest natural gas producer.

As with any industrial process, gas producers experienced a learning curve in terms of environmental protection. But as the industry and regulators have learned more about these processes, drillers are continually improving their operations. Some areas of interest are:

- **Water use.** Increasingly, gas producers are recycling the water they use to fracture rock. Some are starting with non-potable water, and the industry is studying ways to eliminate water entirely from the fracturing process.
- **Groundwater.** Groundwater protection is one of the highest priorities of drilling engineers. Without proper well casings, drilling fluids and natural gas can leak into the groundwater. That's why the American Petroleum Institute has established detailed standards for well casings, and state regulators closely inspect well construction. It's important to note that hydraulic fracturing itself has not been associated with groundwater contamination.
- **Disposal.** The industry and regulators have established practices to prevent spills from water emerging from wells and to protect municipal water treatment facilities.
- **Methane.** The industry has been working hard to reduce methane emissions from gas production. A recent U.S. Environmental Protection Agency (EPA) study found that total methane emissions from gas production are 38 percent lower than they were in 2005 – although gas production grew by 26 percent during that time.
- **Earthquakes.** Increased gas production has been associated with new earthquake activity. The technology exists to help well developers avoid earthquakes and government oversight is increasingly helpful. For instance, BC has robust regulations concerning seismic activity related to well-drilling and completion. Additionally, the industry has backed new regulations in gas-producing states to reduce earthquake potential, and a new working group through the Interstate Oil & Gas Compact Commission and the Ground Water Protection Council is now focusing on this issue.

The rapid growth of gas production has spurred regulators and academics to learn more about the environmental impact of gas development. NWGA looks forward to emerging information and continued cooperation between the natural gas industry and state and federal regulators.

– Sources: *FracFocus, Energy In Depth, U.S. Department of Energy*

2016 GAS OUTLOOK – Prices

Key Conclusions

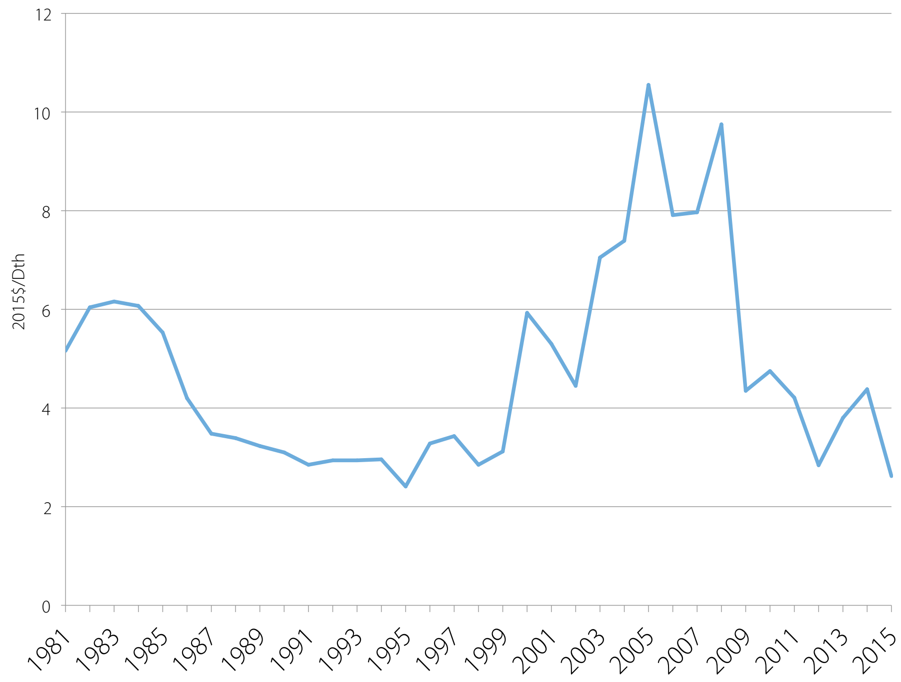
1. Spot prices and futures contracts for natural gas continue to reflect the sustained growth of North American natural gas production.
   - Northwest consumers continue to benefit from low natural gas prices, with forecasts below Henry Hub for the foreseeable future.
2. Long-term price forecasts are sharply lower than those made prior to the advent of shale.
3. Natural gas remains a price-competitive transportation fuel.

Summary

According to EIA historical data, the spot price of natural gas averaged $4.40/Dth from 1981 to 2000 when adjusted for inflation ($2015). The average spot price was $2.62/Dth in 2015 and is currently (as of July) $2.36/Dth in 2016, 46 percent lower than the 2014 average of $4.37/Dth. Monthly Henry Hub spot prices are forecast to remain at or below $3/Dth until 2017.[11] Residential and commercial natural gas customers in the Northwest saved almost $2 billion in 2014 compared to what they would have paid in 2007 (adjusted for inflation).[12] These prices demonstrate a continuing surplus of natural gas supply across North America due mostly to the unprecedented production from shale formations noted earlier.

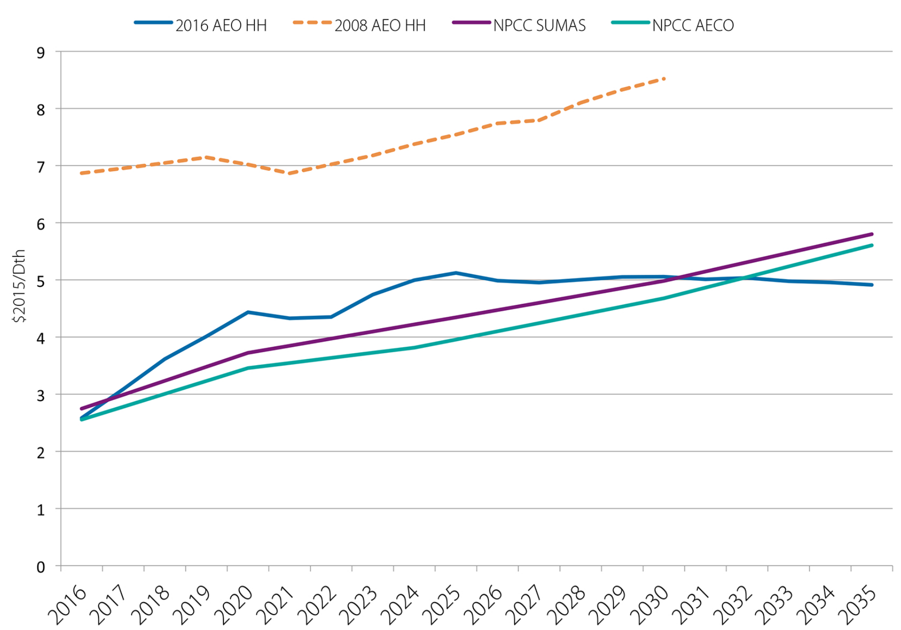
Analysts continue to be bullish on the ability of the U.S. and Canada to develop and deliver low-priced natural gas for years to come, notwithstanding periodic weather related volatility and spikes during periods of high demand. That means consumers can expect to enjoy good economic value from natural gas for years to come. In fact, Henry Hub prices are not expected to rise much above $5/Dth ($2015) through 2040[13] and the long range outlook is sharply lower than it was prior to the advent of shale gas. (Figure P2). Furthermore, Northwest supply sources typically trade at a discount to North American benchmarks like the Henry Hub. The Northwest Power and Conservation Council corroborates this concept in its Fuel Price Forecast for the 7th Power Plan (Figure P2).

FIGURE P1. Historic Natural Gas Prices



Source: U.S. EIA, *Natural Gas Prices (Wellhead)*

FIGURE P2. Natural Gas Spot Price Forecast Comparisons



[11] EIA, *Short-Term Energy Outlook*, July 2016.

[12] EIA for ID, OR & WA, *Number of Gas Consumers, Gas Consumption by End Us, Res/Comm Price*. Statistics Canada for BC, *Table 129-0003, Number of Res/Comm Consumers; Res/Comm revenues*

[13] *EIA, 2016 Annual Energy Outlook*

Despite the recent sharp drop in oil prices, natural gas has maintained a roughly 3:1 price advantage over oil on a Btu basis. The differential has been as much as 8:1 (Figure P3). And natural gas is expected to become even more price competitive with diesel and gasoline as a transportation fuel into the future (Figure P4).

Price Variables

NWGA members are tracking a number of market dynamics that could influence natural gas prices going forward:

1. North American economic growth.
2. Pace of natural gas adoption for generation, industrial and transportation uses.
3. Future costs and/or permitting constraints resulting from new energy policies, environmental legislation and regulation.
4. Effect of new and improved production technologies.
5. Effect of infrastructure constraints on regional pricing.
6. Benefits and costs of North American natural gas (such as LNG) exports to premium overseas markets.

FIGURE P3. Natural Gas/Crude Oil Comparison

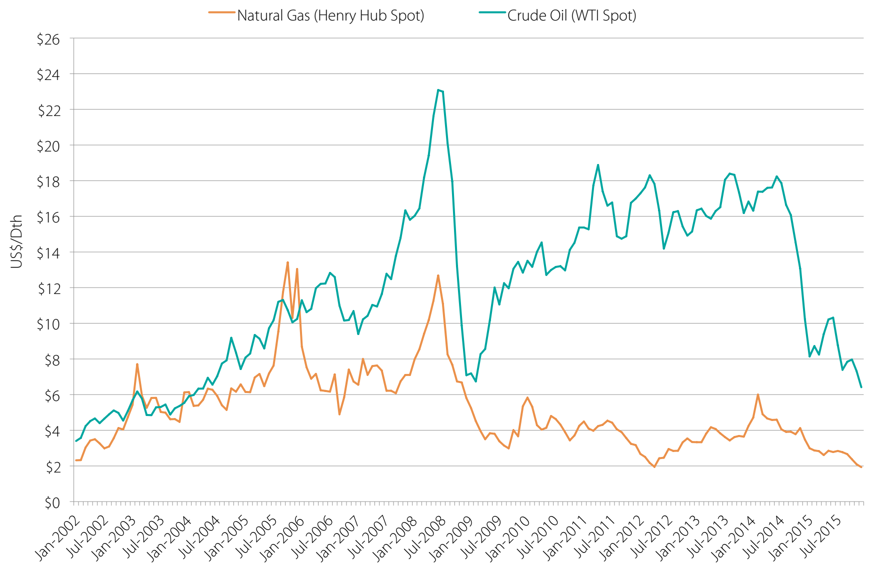
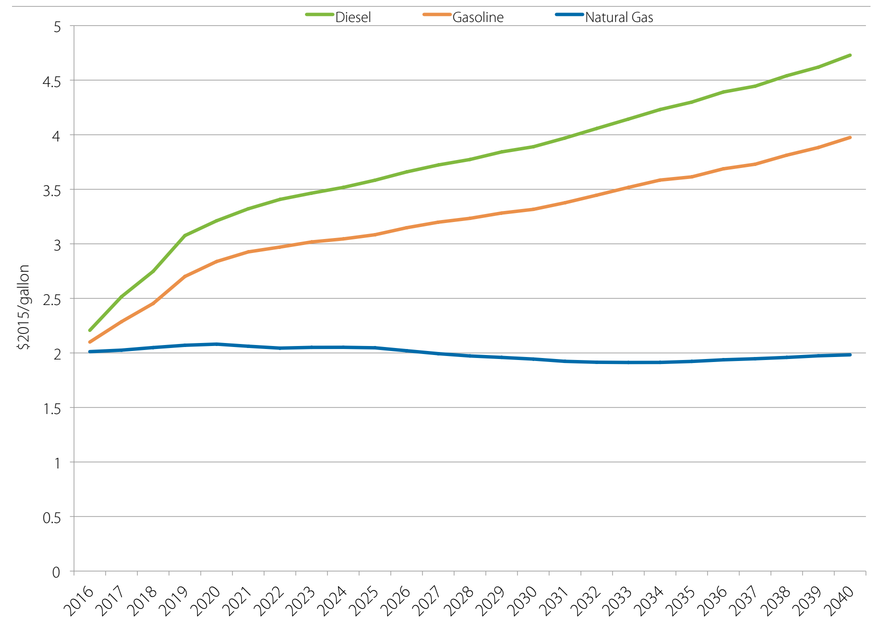


FIGURE P4. EIA Transportation Fuel Price Forecast, 2016 AEO Early Release



Oil Price Volatility

The downward trend in global oil prices that began in 2014 continued through the 2015-16 winter with a precipitous drop to under $30 a barrel – a 70 percent decline in 18 months and the lowest since 2003.

Persistent oversupply, made worse in January by Iran's increase in production following the removal of U.S. sanctions, combined with economic stagnation in Europe and economic slowing in China, created the perfect storm to make crude oil prices plummet. Drivers have certainly benefited at the pump, while producing companies and state/provinces dependent on oil revenues find themselves squeezed. Chevron, Royal Dutch Shell and BP have all announced layoffs; Alaska, Alberta, North Dakota and Texas are among those grappling with significant budgetary challenges.

The EIA predicts a decline in non-OPEC production globally in 2016, mainly due to American and Russian reductions, but increases in OPEC production, mainly from Iran. Still, it expects global oil inventory to continue to rise in the short term and prices to recover only slowly. According to the EIA's July 2016 Short-Term Energy Outlook, Brent oil prices (a global benchmark) are forecast to average $44 a barrel in 2016 and average $52 a barrel in 2017, presuming a slight uptick in demand and reduction in the supply glut. Nevertheless, industry analysts think it could be years before oil returns to $90 or $100 a barrel, the price that has been the norm over the last decade.

What do oil prices have to do with natural gas?Depressed oil prices cause companies to cut investments in production. Natural gas production is also affected since it is often associated with oil production. While natural gas volumes are expected to continue rising, the trend is for slower growth over the next few years (see Supply Section). Another impact is on natural gas as a transportation fuel. As noted in this section, the differential between natural gas and diesel/gasoline is expected to hold up and grow over time. Nevertheless, the precipitous decline in oil prices chilled the transition to natural gas as payback periods for investing in new and more expensive equipment lengthened.

2016 GAS OUTLOOK – Demand

Key Conclusions

1. Growth rates in the Pacific Northwest over this forecast period are a little lower than the 2015 Outlook.
2. A number of variables could significantly affect demand during the forecast period. This Outlook explores two plausible scenarios: some natural gas replacement of regional coal-fired generation along with accelerated industrial and transportation loads; and significant demand growth from LNG exports and major petrochemical developments.

Summary

Moderate economic growth in the Pacific Northwest is not translating into natural gas demand growth in the region. In fact, at 0.8 percent growth per year, we are projecting the slowest rate of growth since we began publishing the Outlook in 2004 (Table D1). This translates to cumulative growth of about 62 million Dth over the 10-year forecast horizon.

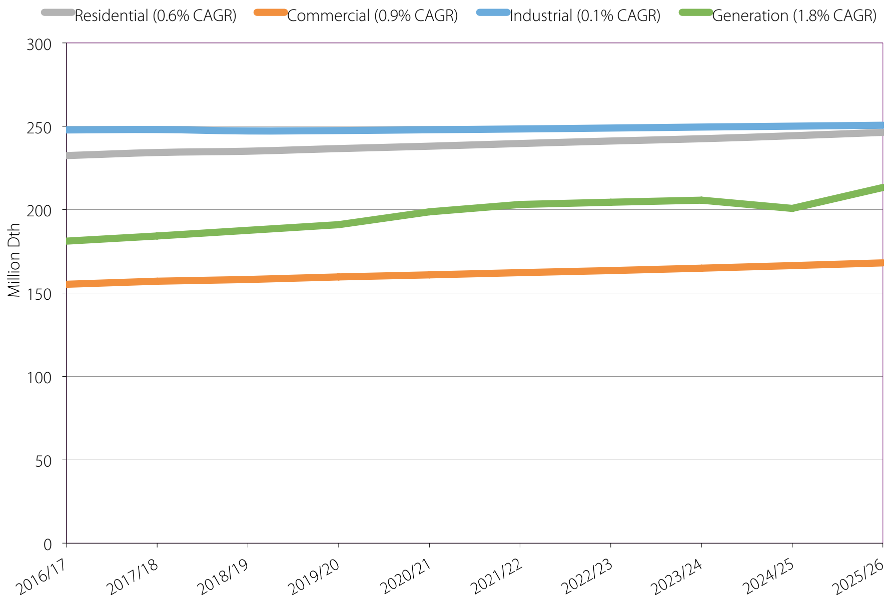
Figure D1 depicts forecasted natural gas load growth by economic sector. Core market (residential, commercial) demand is characterized by modest growth, as new customer additions are partly offset by declining use per customer of natural gas due to tighter building standards and more efficient appliances.

The "Great Recession" cost the region more than 20 percent of its industrial gas load between 2007 and 2012, although industry remains the largest user (Figure D2). Overall, there is almost no organic industrial demand growth throughout the forecast horizon (0.1 percent), reflecting both efficiency gains and a stable manufacturing sector. Proposals to add new industrial loads in the region continue to advance but associated volumes are not accounted for in the expected, low or high forecasts. Instead, we examine the potential impacts of these projects through a separate, accelerated demand scenario at the end of this section.

TABLE D1. Projected Regional Demand Growth through 2026

	Low		Expected		High	
	Annual Rate	Cumulative	Annual Rate	Cumulative	Annual Rate	Cumulative
Total	**0.4%**	**3.4%**	**0.8%**	**7.0%**	**1.0%**	**11.0%**
Residential	0.4%	3.7%	0.6%	5.6%	1.1%	9.1%
Commercial	0.5%	4.7%	0.9%	7.6%	1.4%	11.4%
Industrial	-0.3%	-2.6%	0.1%	1.1%	0.5%	4.2%
Generation	1.1%	9.2%	1.8%	15.1%	1.3%	11.0%

FIGURE D1. Projected Load Growth by Sector Through 2026



New gas-fired generation demand continues to account for the majority of forecast load growth in the region, though at a slower pace than in years past. While demand for natural gas to fuel generation is projected to grow year over year, this year's Outlook documents a downward adjustment in gas-fired generation demand of about 17 percent compared to the 2015 Outlook. We attribute this adjustment primarily to improved modeling that more accurately depicts the likely utilization of gas-fired generation plants in the region.

Public policy and regulatory initiatives in Washington and Oregon have compelled the pending closure of two coal-fired generation facilities in the region: TransAlta's Centralia units and the Boardman plant operated by PGE. In addition, a recent court settlement mandates the closure of Colstrip Units 1 and 2 in Montana by 2022. Although no commercial agreements have yet been executed, we expect that some portion of the output of these plants will be replaced with gas-fired generation. Therefore, we include a simple expanded generation demand scenario at the end of this section.

Demand Composition – Regional natural gas loads are more sensitive to weather variations today than when gas was first delivered to the region. Currently, variable weather-sensitive loads make up more than two-thirds of the region's natural gas use (Figure D3). Consequently, the region's infrastructure is being utilized differently today than when it was first built. Then, less than 50 percent of the region's annual load was subject to weather patterns.

System Planning – Planning standards are designed to meet demand on the coldest day likely to occur in a gas utility's service territory. While each company approaches this forecasting requirement a little differently, "peak" or "design" days are typically based on actual 24-hour average temperatures recorded at representative locations. A comparison of the NWGA member company weather design standards can be found in Appendix B. Peak day loads are 2.7 percent lower on average than the 2015 forecast (Figure D4).

FIGURE D2. Historic Demand by Sector

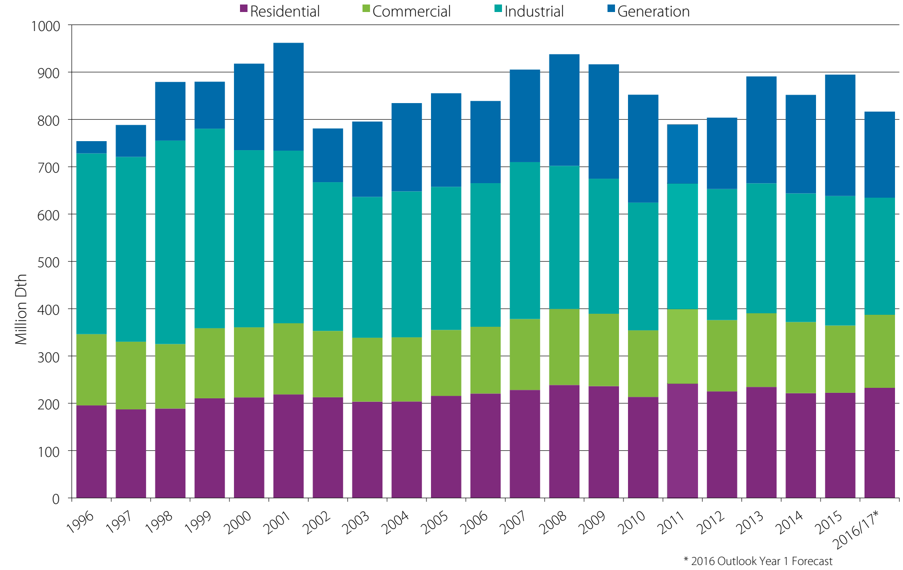


FIGURE D3. Demand Composition

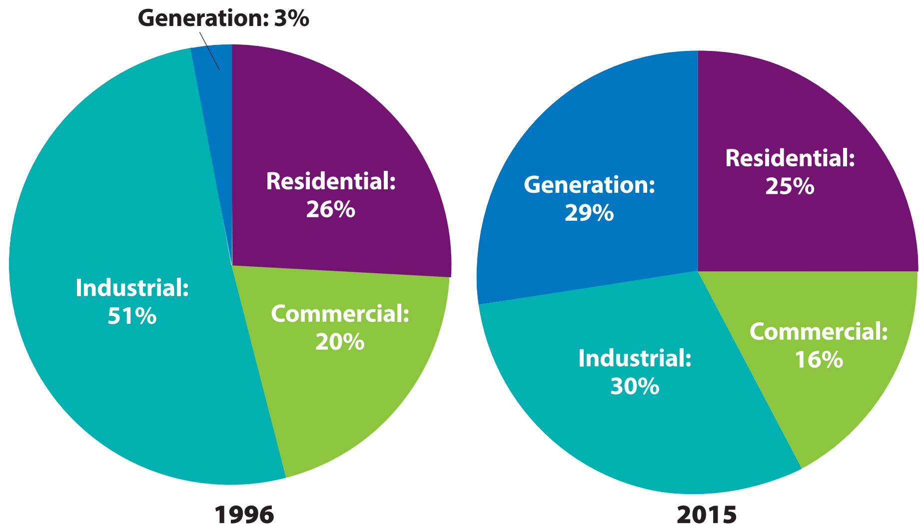
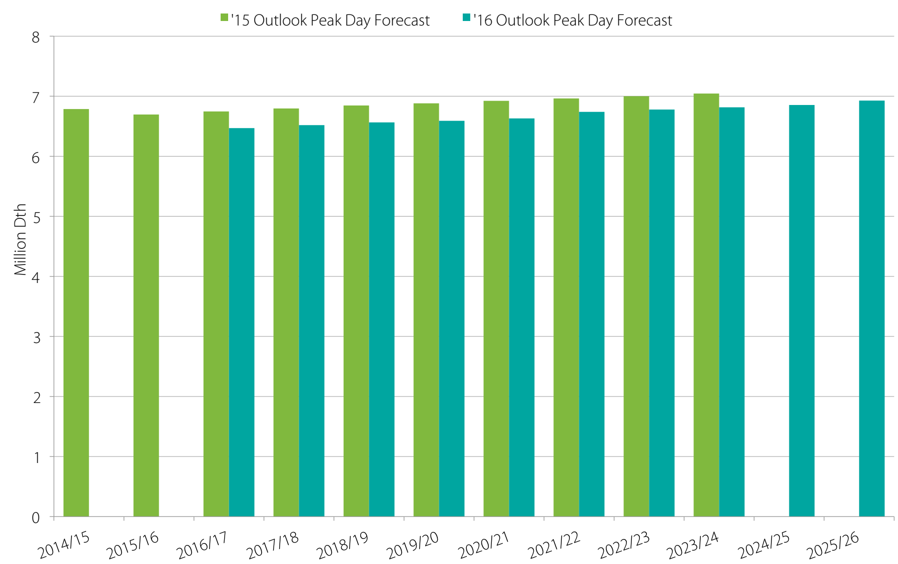


FIGURE D4. 2015-16 Peak Day Forecast Comparison



Clean and Efficient: Benefits of Direct Use of Natural Gas

For many years, energy agencies have alerted Americans to the importance of energy efficiency. A variety of tags and certifications, backed by financial incentives, encourage us to understand our equipment buying options. We know that it makes sense to spend a little more on a product so that we can save money and energy throughout its useful life.

These efforts continue to reduce per capita energy use for both natural gas and electric customers. And the more energy we save, the lower our impact on the environment.

But focusing on product efficiency only reveals half the story. To get the whole picture, it's important to look at what's called the full fuel cycle. That means understanding how much energy is retained – or lost – from the energy's source until its final use in your water heater, oven or home heating system.

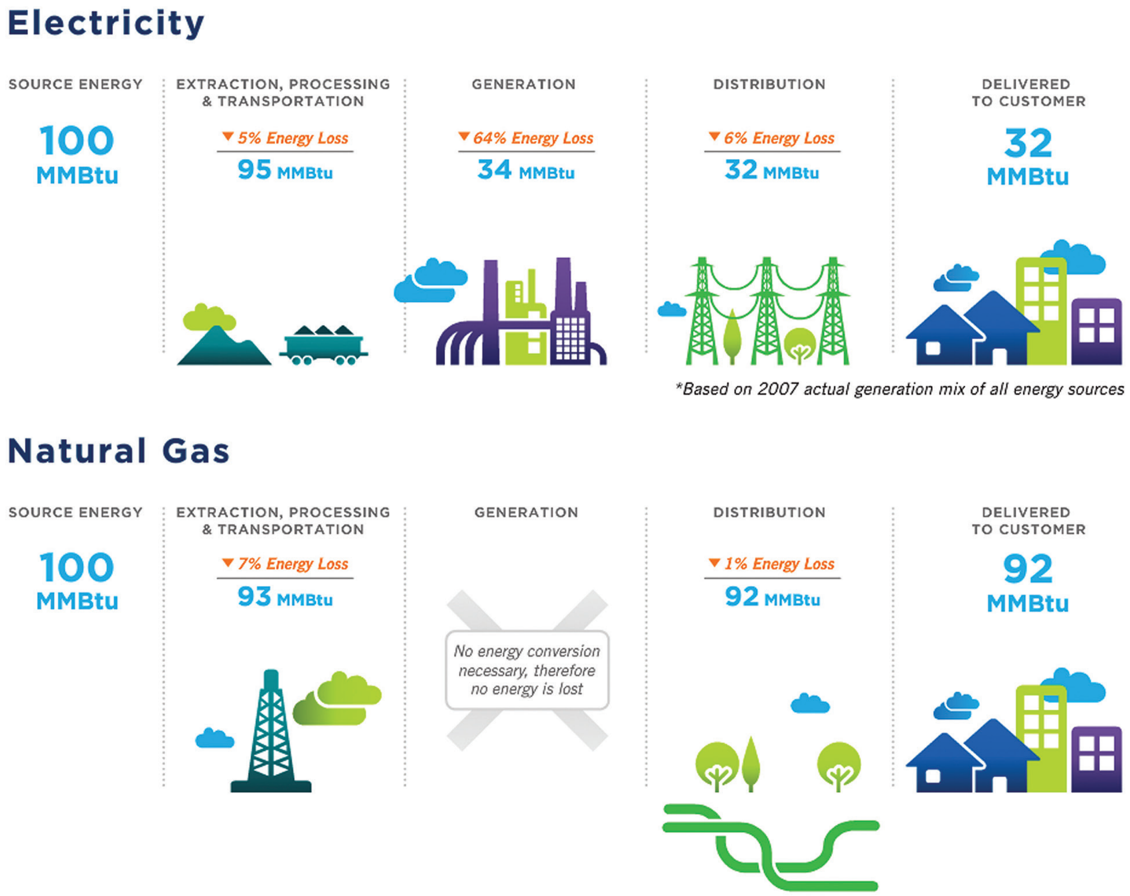
And with the full fuel cycle in mind, direct use of natural gas comes out a winner in the energy efficiency race. For instance, by the time you turn on your electric appliance, up to 68 percent of the energy value from the original fuel has been lost. So the full fuel cycle efficiency is about 32 percent. The full fuel cycle efficiency of a natural gas appliance is about 92 percent – a substantial difference.

Here's how it works:

1. Even with advances in renewable power, most electricity in the U.S. is generated by either coal or natural gas.
2. We lose some of the energy benefits of those fuels as they are transported to the power plant.
3. The major energy loss occurs during generation itself when potentially useful energy is lost in the form of heat as the fuel is burned to crank an engine or turn a turbine.
4. Finally, we lose more energy over the electric transmission lines. So for every 100 MMBtu of fuel that leaves the mine or well, only 32 MMBtu is left to power our electrical appliances.

These fuel choices have important environmental implications. On average, the house fueled by natural gas is responsible for about one third fewer greenhouse gas emissions than a comparable all-electric home (*American Gas Association, Dispatching Direct Use: Achieving GHG Reductions with Natural Gas in Homes and Businesses,* Nov 2015). Furthermore, the more fuel we waste, the more we need to produce and transport – processes that also affect the environment.

We are approaching a future when a combination of wind, solar, wave energy and usable storage will reduce our reliance on fossil fuels. Until then, one of the most effective ways we have to save energy and reduce carbon emissions today is to use natural gas directly in our homes, businesses, and vehicles wherever gas is available. We have the ability to maximize these benefits using today's technologies.



Possible Regional Demand Scenarios

We have developed two scenarios to explore the impact that plausible but currently unaddressed growth could have on regional demand and capacity utilization. They include a coal replacement scenario and an accelerated industrial growth scenario.

NOTE: These scenarios are created wholly by the NWGA. In developing them, we accessed public information and tested whether our assumptions were reasonable with a number of regional stakeholders. They are solely intended to illustrate a possible future outcome. To our knowledge, neither scenario reflects any actual negotiations or commercial agreements, nascent or otherwise, except as can be found publicly.

SCENARIO 1: Coal Replacement

In response to policy and regulatory requirements, PGE agreed to cease coal-fueled generation at the Boardman plant in 2020. Likewise, TransAlta will phase out its Centralia plant, closing Unit 1 by 2020 and Unit 2 by 2025.

Depending on market conditions, TransAlta intends to replace its coal-fired facility with a clean-burning natural gas plant as part of a planned Centralia 3. Per TransAlta: "The Centralia 3 project develops replacement power for the current 1,340-MW capacity Centralia coal-fired plant…[t]he proposed new natural gas plant is assumed initially as a roughly one-for-one replacement of Centralia's 670-MW coal-fired Unit 1."[14] Similarly PGE, while keenly focused on developing renewable fuel alternatives to replace as much of the 550-MW capacity of the Boardman plant as possible, has not dismissed the possibility that natural gas may play some role in its new generation portfolio.

In addition, Grays Harbor Energy (GHE) sought and received approval from Washington's Energy Facility Site Evaluation Council (EFSEC) to add 650 MW of gas-fired generating capacity to its existing 650-MW facility (construction period of up to 22 months to begin no later than December, 2020).[15]

This scenario assumes 800 MW of new combined-cycle gas combustion turbine (CCCT) generation above our expected case forecast (which already accounts for the new PGE Carty plant). Six hundred (600) MW will be added to Western Washington loads in 2019-20 replacing TransAlta and 200 MW to Eastern Oregon loads in 2020-21 replacing a portion of Boardman. Further assumptions include current turbine technology with a heat rate of 7,000 Btu/kilowatt-hour[16] operated 75 percent of the time (utilization rate). Under this scenario, 300 MW of generation equals an annual gas load of 13.8 MMDth and a daily load of 37,800 Dth.

SCENARIO 2: Accelerated Industrial Demand

A number of industrial projects have been proposed for the region. We classify them into two types of industrial load: general and large load projects.

The general category includes a number of proposed local projects like Woodfibre LNG near Squamish, BC, FortisBC's Tilbury LNG expansion, Puget Sound Energy's Tacoma LNG, as well as some generic U.S. and Canadian industrial loads not otherwise accounted for in the Outlook forecast. For the general category of prospective load, NWGA adjusted the base case industrial load by adding 35,000 Dth/day starting in the 2017-18 heating year, 200,000 Dth/day in 2019-20 and another 200,000 Dth/day in 2021-22.

We are using the methanol plants being proposed for the region by Northwest Innovation Works (NWIW) as a scalable proxy for the large load scenario. Together, the two proposed NWIW methanol plants are expected to consume about 550,000 Dth/day of natural gas. The methanol plants are proposed for two locations in the region. The Port Westward site is not expected to require as much on-site generation as Kalama, which explains the differential in projected loads shown below. The plants' expected load and service dates are:

Methanol Plant	Expected Load	In-Service
Kalama, WA	300,000 Dth/day	2020-21
Clatskanie, OR	250,000 Dth/day	2023

The average daily load for the entire region in 2015 was almost 2.5 million Dth (more during the winter months, less during the summer). If fully built out as proposed, the two methanol plants will consume almost one quarter of the region's current average daily load.

[14] www.transalta.com/us/2011/12/growth-2/
[15] EFSEC, *Amendment 5 to Grays Harbor Energy Center Site Certification Agreement*, Dec. 21, 2010
[16] A heat rate of 7,000 is representative of the newest CCCT generating units operating in the region (e.g., Port Westward, Mint Farm, etc.).

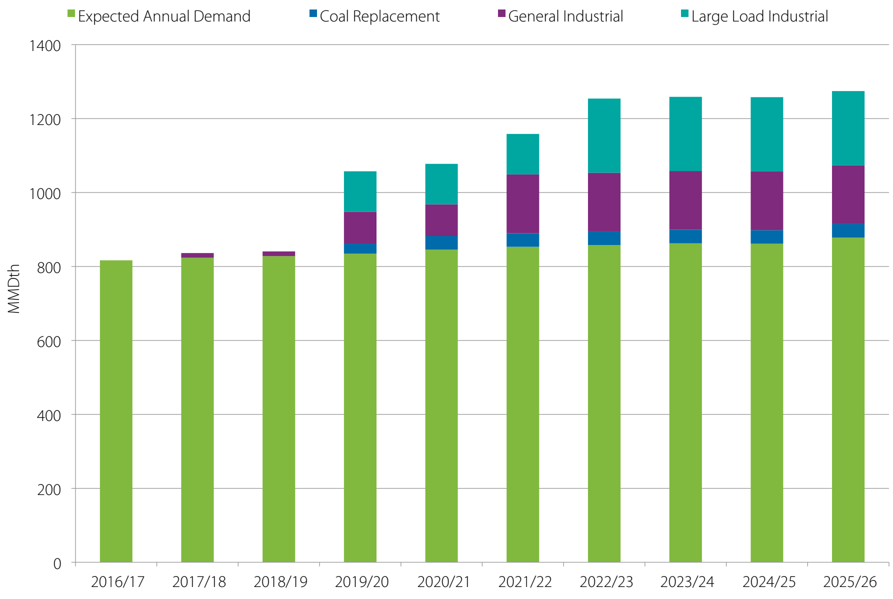
Combined Results – If both scenarios were fully realized, the total annual demand in the last year of the forecast would include an additional 396 MMDth per year over the base case, for a total of almost 1,300 MMDth; an increase of about 45 percent. The overall annual growth rate would increase from 0.8 percent to 5.1 percent. As discussed in more detail in the following section, these results suggest an accelerated need for additional capacity in the region.

Demand Variables

The demand for natural gas in the region is changing and NWGA members continue to watch a number of demand drivers that have yet to be quantified, including:

1. The magnitude and nature of the use of natural gas for generating electricity.
2. The possibility of new significant industrial loads (including exports).
3. The regional growth potential for natural gas as a transportation fuel.
4. The adequacy of natural gas infrastructure to support regional growth opportunities.
5. The impact of future energy policies and plans on demand, particularly GHG legislation. (See sidebar on page 16.)

FIGURE D5. Growth Scenarios



A Closer Look: Regional Policies/Plans that Could Impact Demand

Climate Policy Initiatives

Throughout the Northwest, there are several initiatives being considered to cut carbon emissions. Here are some of the proposals we are closely tracking:

In Oregon, two energy bills were considered during an interim legislative session in spring 2016. The first, a Clean Air and Coal Transition Plan (HB4036, later inserted into SB1547), requires the state's major electric utilities to forego coal-fired generation by 2030 and serve half of customers' demand with renewables by 2040. A collaborative effort by utilities and environmentalists, the bill was meant to fend off a similar measure poised to appear on the November ballot. Despite concerns raised by the state's Public Utility Commission about its actual effectiveness reducing carbon and shifting of costs and risks to ratepayers, the bill was passed. One possible implication of the new law could be an increase in the amount of gas-fired generation serving the region, both as a base-load resource and as a reliable backup to support intermittent renewable generation.

The other Oregon bill, intended to enforce the state's earlier adopted climate goals to reduce carbon emissions 75 percent below 1990 levels by 2050, called for the state to establish a cap-and-trade system with phased carbon emissions limits. It died in committee.

In Washington state, the legislature considered a number of carbon limiting proposals, all of which ultimately died. In response to the Legislature's lack of action in this regard, Gov. Jay Inslee directed the Department of Ecology to develop and implement a binding carbon cap. The highly controversial rule would establish a cap on emissions of the state's largest stationary sources (e.g., factories, power plants, oil refineries) that provide the gasoline used in the state and region, and the more than 1 million households and businesses that use natural gas. The rule is currently under development and expected to go into effect in January of 2017.

In addition, Washington voters will decide this fall whether to levy a carbon tax on themselves. Initiative 732 proposes to start the tax at $15 per ton of carbon, escalating to a cap of $100 per ton over 40 years. (If successful, this would be the first carbon tax enacted by a U.S. state.)

In BC, a diverse Climate Leadership Team is leading the task to update the province's 2008 GHG reduction plan. Climate Action Plan 2.0 seeks to expand the use of carbon pricing and identify new programs to achieve provincial GHG targets (33 percent reduction from 2007 emission levels by 2020 and 80 percent reduction by 2050).

How these initiatives affect our member utilities, their customers, and overall demand is uncertain. Do they raise rates and/or provide disincentives for large-scale industry to locate or expand here? Do they effectively reduce GHG or, in the case of renewables, drive the need for more gas-fired generation plants for backup? Of key importance to us is that our industry and customers are treated fairly.

Northwest Power Plan

In February 2016, the Northwest Power and Conservation Council (NPCC or Council) adopted its seventh Northwest Power Plan, which addresses the many variables affecting the region's power network and provides guidance on which resources can help ensure a reliable and economical regional power system for the next 20 years.

According to the Plan, the Council expects energy efficiency improvements and deployment of "demand response resources" (such as technology that enables voluntary curtailment of power usage, with price incentives) to provide the most economically sound means for meeting the region's electricity needs through 2035. Then, increased use of existing natural gas-fired generation and new gas-fired units are the most cost-effective resources, the plan says.

The Plan also states that natural gas generation is the lowest cost option for reducing regional carbon emissions. Even without additional carbon control policies, the Council's modeling found that the mix of aggressive efficiency standards, expanded gas-fired generation and planned coal plant retirements would reduce power system carbon emissions nearly 40 percent by 2035, achieving the carbon emission limits set out in the U.S. Environmental Protection Agency's Clean Power Plan (currently in limbo due to court action).

While the Plan encourages investment in renewables, it favors research and development of "more consistent output" resources such as ocean wave and geothermal sources (and methods of storing energy) over expansion of "variable output" renewables such as wind and solar beyond that already mandated. However, the NPCC acknowledges the costs of utility-scale wind and solar generation are becoming more cost-competitive and will continue to play a role in the resource mix, as long as gas-fired generation is present to provide backup and winter-peaking capacity.

In an email provided to *The Oregonian* in December 2015, Tom Eckman, director of NPCC's power division, summarized the council's approach: "We (are) evaluating policies that would reduce carbon emissions at the lowest cost, not how to increase the use of renewable resources… The best policy option involves the use of multiple tactics, which include retiring coal plants and substituting lower carbon-emitting gas, then building renewables only to the extent needed."

The plan can be accessed at http://www.nwcouncil.org/energy/powerplan/7/draftplan/.

2016 GAS OUTLOOK – Capacity

Key Conclusions

- The existing system of natural gas pipelines and storage facilities has reliably served the load requirements of the Pacific Northwest for decades and is sufficient to meet today's needs, though recent cold weather events have approached system limits.
- Additional capacity is likely to be required within the forecast horizon to serve growing demand for natural gas, particularly on a peak design day. Additional generation demand and industrial loads materially above the expected case will amplify and accelerate the need for incremental capacity required to serve the region.
- The timing, location and type of future capacity expansions or additions, whether pipelines or storage, and use of existing infrastructure, will depend on the changing nature of regional natural gas demand. For example, if large industrial loads expand or locate here, the resulting change in daily baseload demand will alter how current and new pipeline systems are used, while also making gas flows more consistent on a year-round basis compared to a largely winter-peaking profile of most systems.

Summary

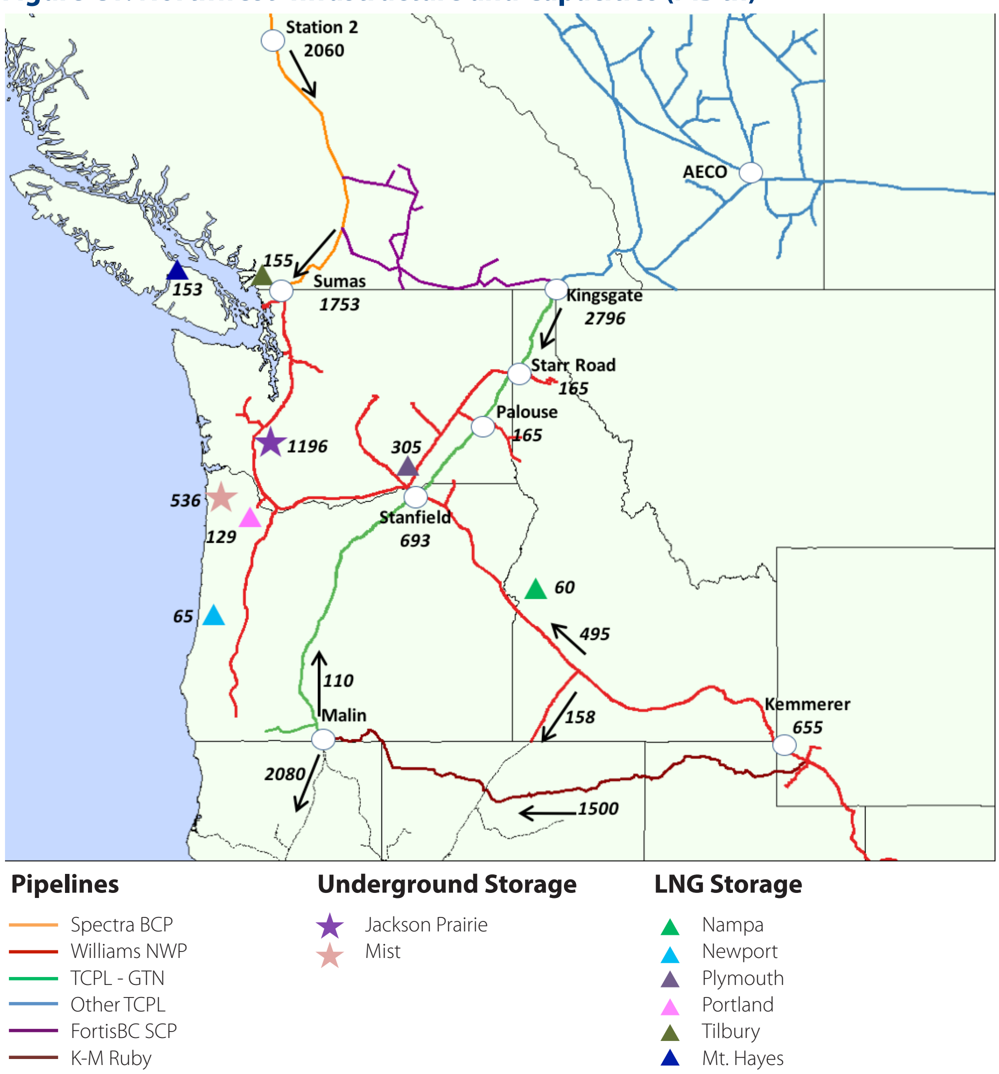
The Pacific Northwest's 48,000-mile network of transmission and distribution pipelines safely and reliably serves 3.2 million natural gas homes and businesses. The pipelines that transport natural gas from production areas in Alberta, BC, and the U.S. Rockies can deliver more than 4 MMDth/day to the region.

TABLE C1. Regional Storage Facilities

Facility	Owner	Type	Capacity* (MDth)	Max Withdrawal** (MDth/day)
Jackson Prairie, WA	Avista, PSE, NW Pipeline	Underground	25,448	1,196
Mist, OR	NW Natural	Underground	16,572	536
	Underground Subtotal		**42,020**	**1,732**
Plymouth, WA	NW Pipeline	Peak (LNG)	2,388	305
Tilbury, BC	FortisBC Energy	Peak (LNG)	591	155
Mt. Hayes, BC	FortisBC Energy	Peak (LNG)	1,530	153
Portland, OR	NW Natural	Peak (LNG)	644	129
Newport, OR	Intermountain Gas	Peak (LNG)	980	65
Nampa, ID	Intermountain Gas	Peak (LNG)	588	60
Swarr Station, WA	PSE	Peak (LNG)***	130	30
Gig Harbor, WA	PSE	Peak (LNG)	13	3
	Peak Storage Subtotal		**6,864**	**900**
Total Storage			**48,884**	**2,632**

*Working gas capacity; gas that can be used to serve the market
** Start of season or full rate; underground storage withdrawal rates decline as working gas volumes decline.
*** LPG: Liquid Propane Gas and Air mixture.

Figure C1. Northwest Infrastructure and Capacities (MDth)



Peak Day Capabilities – Because natural gas utilities are obligated to serve their customers at all times, even during the coldest weather conditions, they design their systems to accommodate extreme, but plausible, conditions called peak or design days (see Appendix B for a comparison of NWGA member company weather design standards). Figure C2 aggregates the projected design day volumes of NWGA gas utility members and plots them against available capacity. Under the expected and high demand cases, peak day loads could stress the system, approaching or exceeding the region's infrastructure capacity within the forecast horizon.

The probability of design days occurring on every distribution system across the entire region on the same day ("coincidental peak day") is small. However, the possibility of very cold weather occurring simultaneously along the I-5 Corridor is reasonably high. Figure C3 plots projected design day volumes along the I-5 Corridor against the pipeline and storage resources available to serve the area. The expected and high demand cases along the I-5 Corridor approach system capabilities within the forecast horizon.

FIGURE C2. Region-wide Peak Day Resource/Demand Balance[17]

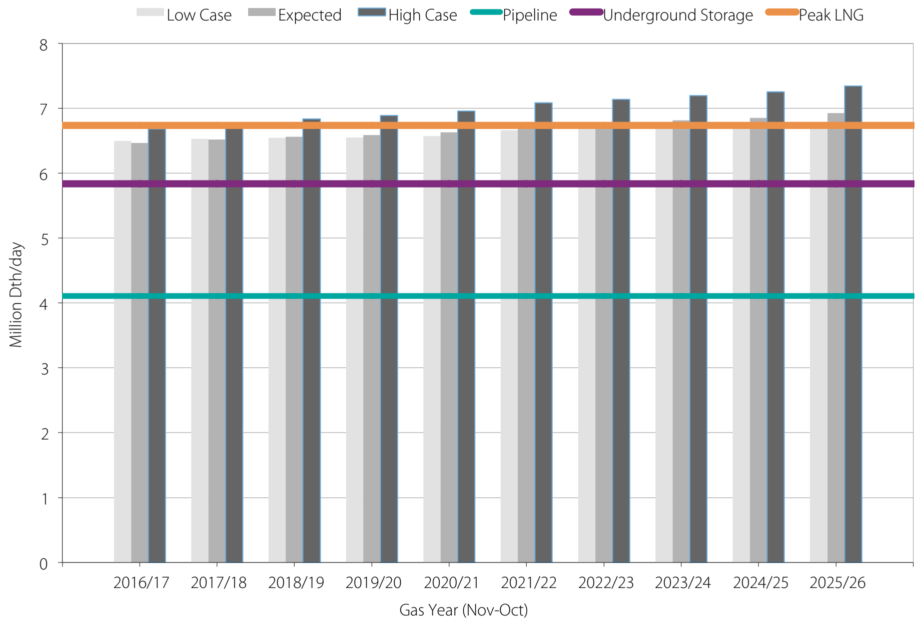
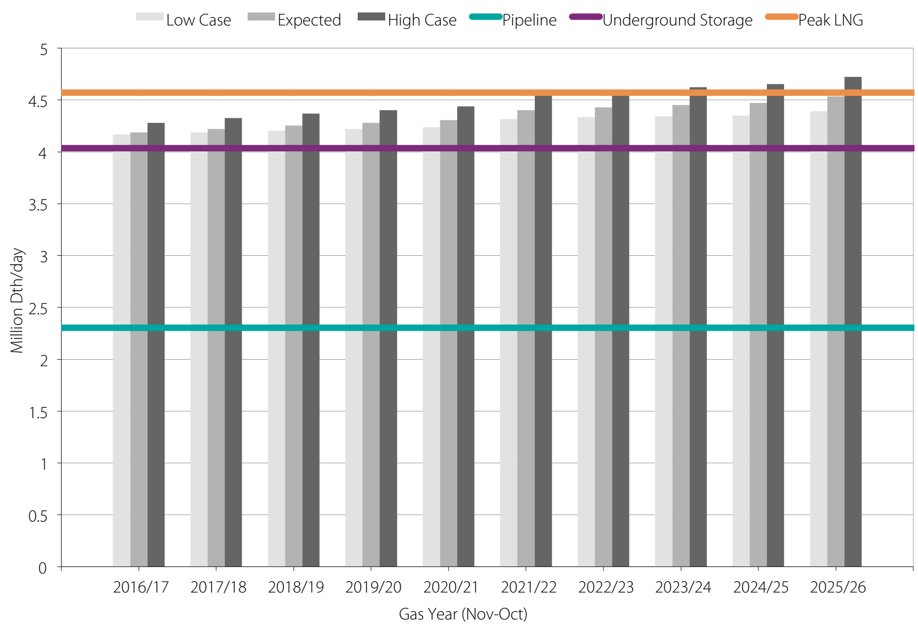


FIGURE C3. I-5 Peak Day Resource/Demand Balance[17]



[17] Figures C2 and C3 assumptions include: a design weather day occurs simultaneously across the depicted region; existing infrastructure will deliver 100 percent of its capability; and gas will not flow to customers without firm pipeline transportation contracts (e.g., industrial users or electricity generators with alternate fuels).

Accelerated Demand Scenario – Regional capacity has served the Northwest's needs under severe circumstances, including the winter of 2013-14. That same winter, however, demonstrated that demand approached the system's capacity on cold weather days. The clear lesson is that the region's delivery infrastructure may require augmentation to accommodate growth. This is especially true if load growth exceeds expected levels. For instance, it's worth keeping an eye on the increased use of natural gas in place of coal and/or to support increased intermittent renewable generation.

Two potential scenarios are outlined in the Demand Section of this report, including accelerated industrial demand and coal-fired generation replacement. Figure C4 includes the projected incremental loads from these scenarios plotted against the resources available to serve the region. Quicker deployment of new capacity will be required to serve the region if these scenarios are realized.

Analyses such as these help send signals to the market of an impending need for additional capacity. Market participants weigh the probability of disruptions against the costs of various infrastructure options to make decisions about what is needed and when. In response to these market signals, projects are typically proposed to serve future delivery capacity needs. Several Infrastructure expansions have been proposed in the Pacific Northwest (Figure C5).

However, reductions in projected demand, a slow economic recovery and the new reality of a vast North American supply of natural gas have all combined to change the nature of projects now being considered within the region (see Appendix D). Today's market for regional infrastructure capacity has evolved from valuing diversity to equally valuing reliability; from providing market access for imported LNG to accessing the Asian LNG export markets; from serving a rapidly growing core market to serving potential industrial and electric generation demand growth; and from once-diminishing Canadian supplies to the need to find new markets for abundant supplies.

FIGURE C4. Accelerated Demand Peak Day Resource/Demand Balance[18]

FIGURE C5. Proposed Natural Gas Infrastructure Projects

[18] Figure C4 assumes that the entire load generated by the accelerated demand scenario will require, and contract for, firm transportation and/or storage capacity. In fact, potential shippers have options including less costly interruptible service contracts that can be curtailed as necessary by the capacity operator.

Still, it is only a matter of time before new capacity within the region will be required. If major industrial loads increase, for example, the region will require infrastructure expansions that provide both diversity and reliability of gas supply for the new base load. The location of new large natural gas loads may drive gas supply sourcing decisions, which will in turn determine the nature and location of capacity enhancements.

Capacity Variables

NWGA members continuously monitor a number of dynamics to ensure that regional natural gas consumers have the gas they need when and where they need it, including:

1. When, where and how much natural gas the region will require to generate electricity, meet peak load, and balance variable renewable resource generation.
2. Whether, when and where large industrial and/or LNG export loads proposed for the region materialize.
3. The impact of the legal, regulatory environment, as well as environmental and community groups, on the ability to build new or expand existing infrastructure in a timely manner to meet future needs. Projects take three to five years to develop, making foresight imperative.

Appendices

Appendix A: Data Tables

Table A1. Maximum Capacity (Bcf/d)

SUPPLY	2016/2017	2017/2018	2018/2019	2019/2020	2020/2021	2021/2022	2022/2023	2023/2024	2024/2025	2025/2026
Pipeline Interconnects	**4,105,153**	**4,105,153**	**4,105,153**	**4,105,153**	**4,105,153**	**4,105,153**	**4,105,153**	**4,105,153**	**4,105,153**	**4,105,153**
WCSB via TCPL/GTN	1,626,888	1,626,888	1,626,888	1,626,888	1,626,888	1,626,888	1,626,888	1,626,888	1,626,888	1,626,888
Stanfield (NWP from GTN)	692,920	692,920	692,920	692,920	692,920	692,920	692,920	692,920	692,920	692,920
Starr Rd (NWP from GTN)	165,000	165,000	165,000	165,000	165,000	165,000	165,000	165,000	165,000	165,000
Palouse (NWP from GTN)	70,459	70,459	70,459	70,459	70,459	70,459	70,459	70,459	70,459	70,459
GTN Direct Connects	511,568	511,568	511,568	511,568	511,568	511,568	511,568	511,568	511,568	511,568
Kingsgate/Yahk BC Interior from TCPL	186,941	186,941	186,941	186,941	186,941	186,941	186,941	186,941	186,941	186,941
Rockies via NWP	495,000	495,000	495,000	495,000	495,000	495,000	495,000	495,000	495,000	495,000
NWP north from NWP south	655,000	655,000	655,000	655,000	655,000	655,000	655,000	655,000	655,000	655,000
Max Demand on Reno Lateral	(160,000)	(160,000)	(160,000)	(160,000)	(160,000)	(160,000)	(160,000)	(160,000)	(160,000)	(160,000)
WCSB via SET	1,983,265	1,983,265	1,983,265	1,983,265	1,983,265	1,983,265	1,983,265	1,983,265	1,983,265	1,983,265
T-South to Huntingdon	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060
T-South to BC Interior (including Kingsvale)	230,205	230,205	230,205	230,205	230,205	230,205	230,205	230,205	230,205	230,205
Storage	**2,627,058**	**2,627,058**	**2,627,058**	**2,627,058**	**2,627,058**	**2,627,058**	**2,627,058**	**2,627,058**	**2,627,058**	**2,627,058**
Jackson Prairie (NWP from JP)	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000
Mist Storage (NWN)	530,450	530,450	530,450	530,450	530,450	530,450	5530,450	530,450	530,450	530,450
Plymouth (NWP from LNG)	305,300	305,300	305,300	305,300	305,300	305,300	305,300	305,300	305,300	305,300
Newport LNG (NWN)	65,300	65,300	65,300	65,300	65,300	65,300	65,300	65,300	65,300	65,300
Portland LNG (NWN)	129,000	129,000	129,000	129,000	129,000	129,000	129,000	129,000	129,000	129,000
Nampa LNG (IGC)	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000
Gig Harbor Satellite LNG (PSE)	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500
Swarr Stn Propane (PSE)	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000
Tilbury LNG (FortisBC)	155,466	155,466	155,466	155,466	155,466	155,466	155,466	155,466	155,466	155,466
Mount Hayes LNG (FortisBC)	153,042	153,042	153,042	153,042	153,042	153,042	153,042	153,042	153,042	153,042
Total Available Supply	**6,732.211**	**6,732.211**	**6,732.211**	**6,732.211**	**6,732.211**	**6,732.211**	**6,732.211**	**6,732.211**	**6,732.211**	**6,732.211**

Appendix A2: Annual Demand Forecast (Dth) – Expected Case

Region/Sector	2016/2017	2017/2018	2018/2019	2019/2020	2020/2021	2021/2022	2022/2023	2023/2024	2024/2025	2025/2026
BC Lower Mainland & Van. Island	**137,762,481**	**137,558,977**	**137,275,317**	**137,257,211**	**137,292,668**	**137,366,036**	**140,030,588**	**140,421,388**	**140,946,117**	**141,667,383**
Residential	51,240,183	50,768,969	50,301,553	49,833,441	49,364,717	48,895,993	48,427,269	47,958,545	47,489,820	47,021,096
Commercial	41,462,038	41,659,552	41,863,845	42,063,946	42,262,101	42,460,255	42,658,410	42,856,565	43,054,720	43,252,874
Industrial	31,222,134	31,254,417	31,271,793	31,521,697	31,827,725	32,133,749	32,439,775	32,745,798	33,051,820	33,357,846
Power Generation	13,838,126	13,876,039	13,838,126	13,838,126	13,838,126	13,876,039	13,838,126	13,838,126	13,838,126	13,876,039
W. Washington	**245,681,514**	**247,022,738**	**249,882,022**	**252,652,390**	**259,182,666**	**262,770,929**	**263,572,006**	**265,292,771**	**262,865,224**	**275,634,134**
Residential	75,466,203	76,538,000	77,247,603	77,858,985	78,626,609	79,605,346	80,266,652	80,651,021	81,657,384	82,871,588
Commercial	47,173,343	48,101,378	48,627,565	49,128,974	49,634,311	50,171,133	50,493,850	50,885,494	51,590,578	52,255,145
Industrial	72,240,680	72,193,833	72,128,127	72,026,028	71,871,434	71,693,186	71,583,821	71,506,691	71,375,394	71,261,850
Power Generation	50,801,288	50,189,527	51,878,726	53,638,403	59,050,311	61,301,265	61,227,683	62,249,565	58,241,868	69,245,551
W. Oregon	**120,509,283**	**121,233,149**	**121,993,348**	**122,835,659**	**123,653,652**	**124,476,461**	**125,324,705**	**126,181,471**	**127,013,537**	**127,843,641**
Residential	38,042,099	38,603,862	39,256,055	39,913,322	40,562,085	41,214,027	41,879,785	42,544,223	43,185,884	43,820,999
Commercial	24,306,758	24,463,542	24,566,146	24,745,632	24,908,665	25,073,117	25,249,113	25,434,879	25,619,209	25,808,095
Industrial	42,660,426	42,665,745	42,671,148	42,676,705	42,682,902	42,689,317	42,695,807	42,702,369	42,708,444	42,714,547
Power Generation	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000
BC Interior	**57,701,788**	**57,868,925**	**56,996,460**	**56,977,917**	**57,212,233**	**57,446,549**	**57,680,865**	**57,915,181**	**58,149,497**	**58,383,813**
Residential	17,389,639	17,528,302	17,675,297	17,816,356	17,954,033	18,091,710	18,229,386	18,367,063	18,504,740	18,642,417
Commercial	11,218,830	11,409,882	11,602,063	11,793,340	11,984,132	12,174,925	12,365,717	12,556,509	12,747,301	12,938,094
Industrial	29,093,318	28,930,741	27,719,100	27,368,221	27,274,068	27,179,914	27,085,761	26,991,608	26,897,455	26,803,302
Power Generation	-	-	-	-	-	-	-	-	-	-
E. Washington & N. Idaho	**75,745,474**	**76,763,183**	**77,659,041**	**78,420,957**	**79,086,223**	**79,658,048**	**80,495,433**	**81,337,544**	**81,763,129**	**82,506,111**
Residential	20,468,649	20,694,999	20,893,765	21,174,728	21,230,424	21,256,322	21,430,390	21,718,093	21,878,941	22,061,081
Commercial	14,211,425	14,364,109	14,522,757	14,749,431	14,829,486	14,907,519	15,065,366	15,299,147	15,433,548	15,591,117
Industrial	32,393,832	32,653,655	32,918,342	33,193,043	33,447,831	33,707,230	33,971,614	34,243,064	34,510,345	34,784,881
Power Generation	8,671,568	9,050,420	9,324,176	9,303,755	9,578,482	9,786,977	10,028,062	10,077,240	9,940,294	10,069,031
E. Oregon & Medford	**102,855,636**	**106,305,834**	**108,058,890**	**109,930,255**	**112,123,668**	**114,168,627**	**115,596,562**	**116,097,788**	**115,478,742**	**116,987,090**
Residential	7,510,846	7,608,319	7,706,384	7,840,791	7,897,140	7,963,062	8,059,612	8,196,582	8,270,981	8,366,674
Commercial	5,445,311	5,509,793	5,578,096	5,670,832	5,713,614	5,765,783	5,833,489	5,926,519	5,981,159	6,051,078
Industrial	10,065,035	10,110,119	10,154,649	10,201,076	10,250,481	10,303,095	10,356,129	10,411,264	10,459,559	10,509,923
Power Generation	79,834,443	83,077,602	84,619,762	86,217,556	88,262,433	90,136,686	91,347,332	91,563,423	90,767,043	92,059,415
S. Idaho	**76,411,517**	**76,857,144**	**76,192,500**	**76,639,590**	**77,090,694**	**77,555,753**	**78,024,758**	**78,496,556**	**78,973,355**	**79,454,217**
Residential	22,325,749	22,549,006	21,985,281	22,205,134	22,427,185	22,651,457	22,877,971	23,106,751	23,337,819	23,571,197
Commercial	11,452,281	11,566,804	11,364,385	11,478,029	11,592,809	11,708,737	11,825,825	11,944,083	12,063,524	12,184,159
Industrial	30,133,488	30,241,334	30,342,834	30,456,427	30,570,699	30,695,559	30,820,962	30,945,721	31,072,013	31,198,861
Power Generation	12,500,000	12,500,000	12,500,000	12,500,000	12,500,000	12,500,000	12,500,000	12,500,000	12,500,000	12,500,000
Expected PNW Annual Demand	**816,667,693**	**823,609,949**	**828,057,578**	**834,713,978**	**845,641,804**	**853,442,402**	**858,057,907**	**862,720,344**	**861,677,970**	**878,316,862**
Residential	232,443,367	234,291,456	235,065,937	236,642,756	238,062,194	239,677,915	241,171,066	242,542,277	244,325,569	246,355,053
Commercial	155,269,988	157,075,061	158,124,856	159,630,185	160,925,118	162,261,470	163,491,769	164,903,197	166,490,039	168,080,561
Industrial	247,808,912	248,049,844	247,205,994	247,443,197	247,925,140	248,402,050	248,953,869	249,546,515	250,075,030	250,631,210
Power Generation	181,145,426	184,193,588	187,660,791	190,997,841	198,729,352	203,100,967	204,441,203	205,728,354	200,787,332	213,250,037

Appendix A3: Annual Demand Forecast (Dth) – High Case

Region/Sector	2016/2017	2017/2018	2018/2019	2019/2020	2020/2021	2021/2022	2022/2023	2023/2024	2024/2025	2025/2026
BC Lower Mainland & Van. Island	**138,676,436**	**138,807,600**	**138,861,611**	**139,193,097**	**139,586,480**	**140,024,826**	**140,394,452**	**140,809,143**	**141,231,048**	**141,698,127**
Residential	51,265,052	50,803,009	50,344,815	49,886,000	49,426,640	48,967,342	48,508,106	48,048,933	47,589,823	47,130,775
Commercial	41,820,742	42,152,310	42,492,744	42,830,897	43,169,052	43,509,197	43,851,342	44,195,498	44,541,675	44,889,885
Industrial	31,752,516	31,976,241	32,185,926	32,638,075	33,152,662	33,672,248	34,196,877	34,726,585	35,261,423	35,801,428
Power Generation	13,838,126	13,876,039	13,838,126	13,838,126	13,838,126	13,876,039	13,838,126	13,838,126	13,838,126	13,876,039
W. Washington	**282,501,016**	**281,210,620**	**282,507,142**	**270,497,977**	**271,878,105**	**279,911,715**	**284,680,210**	**285,387,569**	**285,074,634**	**301,109,664**
Residential	79,651,392	81,081,001	82,241,640	83,007,105	84,600,544	85,984,098	87,313,378	88,369,328	89,443,033	91,008,293
Commercial	49,710,107	50,806,491	51,546,949	52,144,062	53,168,971	53,893,720	54,647,867	55,476,999	56,236,016	57,088,259
Industrial	76,314,833	76,297,895	76,270,776	76,171,680	76,098,925	75,930,175	75,893,716	75,869,879	75,688,053	75,593,192
Power Generation	76,824,684	73,025,231	72,447,777	59,175,130	58,009,665	64,103,721	66,825,249	65,671,362	63,707,531	77,419,920
W. Oregon	**120,835,003**	**122,096,678**	**123,518,302**	**124,884,906**	**126,234,255**	**127,609,263**	**128,994,047**	**130,388,347**	**131,768,281**	**133,148,841**
Residential	38,232,793	39,053,206	40,027,441	40,865,181	41,696,147	42,540,082	43,385,951	44,227,543	45,050,830	45,865,564
Commercial	24,439,401	24,688,289	24,942,463	25,276,835	25,599,322	25,933,114	26,273,940	26,627,347	26,984,289	27,349,414
Industrial	42,662,810	42,855,183	43,048,398	43,242,890	43,438,786	43,636,067	43,834,156	44,033,457	44,233,162	44,433,863
Power Generation	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000
BC Interior	**58,364,634**	**58,771,136**	**58,108,062**	**58,319,824**	**58,792,534**	**59,267,143**	**59,743,658**	**60,222,084**	**60,702,428**	**61,184,696**
Residential	17,436,749	17,593,366	17,758,650	17,918,272	18,074,794	18,231,611	18,388,724	18,546,132	18,703,837	18,861,839
Commercial	11,341,305	11,580,578	11,822,734	12,065,715	12,309,955	12,555,955	12,803,726	13,053,278	13,304,622	13,557,768
Industrial	29,586,580	29,597,191	28,526,678	28,335,836	28,407,785	28,479,577	28,551,209	28,622,674	28,693,969	28,765,089
Power Generation	-	-	-	-	-	-	-	-	-	-
E. Washington & N. Idaho	**80,566,702**	**81,735,974**	**82,492,958**	**83,298,729**	**84,575,058**	**86,131,461**	**87,495,784**	**88,777,737**	**89,313,282**	**90,271,048**
Residential	21,158,639	21,434,221	21,713,181	22,092,034	22,283,231	22,574,819	22,870,220	23,271,202	23,562,244	23,879,166
Commercial	14,892,855	15,111,967	15,333,944	15,625,342	15,786,190	16,016,781	16,250,279	16,557,484	16,778,718	17,026,132
Industrial	33,353,725	33,628,818	33,907,801	34,197,299	34,466,544	34,742,532	35,021,557	35,308,062	35,590,449	35,880,432
Power Generation	11,161,483	11,560,968	11,538,032	11,384,055	12,039,092	12,797,328	13,353,727	13,640,989	13,381,871	13,485,318
E. Oregon & Medford	**122,088,680**	**128,184,075**	**129,155,421**	**131,863,033**	**136,474,284**	**142,177,182**	**145,180,608**	**146,863,408**	**147,921,622**	**149,721,060**
Residential	7,849,667	7,969,387	8,089,995	8,248,115	8,333,658	8,456,746	8,580,529	8,744,036	8,848,783	8,976,469
Commercial	5,699,032	5,781,320	5,864,851	5,972,546	6,032,144	6,115,364	6,199,469	6,309,057	6,382,424	6,472,183
Industrial	10,411,848	10,459,645	10,506,229	10,556,335	10,608,027	10,663,289	10,719,550	10,777,575	10,828,658	10,881,937
Power Generation	98,128,133	103,973,723	104,694,347	107,086,036	111,500,455	116,941,782	119,681,059	121,032,740	121,861,757	123,390,472
S. Idaho	**77,842,888**	**80,645,538**	**82,657,929**	**84,511,354**	**85,006,750**	**85,501,110**	**85,999,788**	**86,501,632**	**87,008,858**	**87,548,520**
Residential	23,131,154	24,177,313	24,335,698	25,311,518	25,564,633	25,820,279	26,078,482	26,339,267	26,602,659	26,868,686
Commercial	11,867,349	12,404,363	12,580,820	13,083,462	13,214,297	13,346,440	13,479,904	13,614,703	13,750,850	13,888,359
Industrial	30,344,385	31,563,862	33,241,411	33,616,374	33,727,820	33,834,391	33,941,401	34,047,662	34,155,348	34,291,475
Power Generation	12,500,000	12,500,000	12,500,000	12,500,000	12,500,000	12,500,000	12,500,000	12,500,000	12,500,000	12,500,000
PNW Annual Demand - Base	**880,875,359**	**891,451,620**	**897,301,425**	**892,568,920**	**902,547,465**	**920,622,700**	**932,488,546**	**938,949,920**	**943,020,153**	**964,681,956**
Residential	238,725,447	242,111,504	244,511,419	247,328,225	249,979,647	252,574,979	255,125,390	257,546,442	259,801,209	262,590,792
Commercial	159,770,790	162,525,319	164,584,505	166,998,859	169,279,930	171,370,571	173,506,528	175,834,367	177,978,595	180,271,999
Industrial	254,426,697	256,378,835	257,687,219	258,758,489	259,900,550	260,958,279	262,158,467	263,385,895	264,451,063	265,647,416
Power Generation	227,952,426	230,435,962	230,518,281	219,483,347	223,387,337	235,718,871	241,698,161	242,183,217	240,789,285	256,171,749

Appendix A4: Annual Demand Forecast (Dth) – Low Case

Region/Sector	2016/2017	2017/2018	2018/2019	2019/2020	2020/2021	2021/2022	2022/2023	2023/2024	2024/2025	2025/2026
BC Lower Mainland & Van. Island	**135,826,604**	**134,934,352**	**133,966,999**	**133,253,267**	**132,588,364**	**131,959,310**	**131,252,461**	**130,581,641**	**129,909,023**	**129,272,612**
Residential	50,961,232	50,391,597	49,827,801	49,265,372	48,704,389	48,145,453	47,588,557	47,033,697	46,480,865	45,930,057
Commercial	40,848,163	40,819,299	40,795,317	40,765,630	40,732,455	40,697,705	40,661,406	40,623,581	40,584,256	40,543,455
Industrial	30,179,083	29,847,417	29,505,755	29,384,139	29,313,394	29,240,113	29,164,372	29,086,237	29,005,776	28,923,061
Power Generation	13,838,126	13,876,039	13,838,126	13,838,126	13,838,126	13,876,039	13,838,126	13,838,126	13,838,126	13,876,039
W. Washington	**247,908,333**	**246,392,805**	**246,986,452**	**249,598,947**	**254,052,345**	**252,469,918**	**256,872,919**	**250,626,536**	**250,609,432**	**270,777,689**
Residential	72,405,066	73,625,772	74,408,822	75,226,299	76,091,849	77,023,326	77,697,521	77,990,903	78,755,221	79,766,282
Commercial	45,170,295	46,183,374	46,755,216	47,373,266	47,883,360	48,426,085	48,746,772	49,049,854	49,647,292	50,213,307
Industrial	69,082,037	69,080,243	69,043,497	68,966,316	68,813,494	68,646,293	68,553,796	68,468,810	68,292,440	68,183,317
Power Generation	61,250,934	57,503,415	56,778,916	58,033,067	61,263,642	58,374,214	61,874,830	55,116,969	53,914,478	72,614,782
W. Oregon	**120,244,029**	**120,412,609**	**120,521,540**	**120,854,235**	**121,174,194**	**121,512,807**	**121,846,780**	**122,199,352**	**122,521,474**	**122,841,718**
Residential	37,890,368	38,209,861	38,551,815	39,040,569	39,530,444	40,035,246	40,534,968	41,042,561	41,524,649	42,002,919
Commercial	24,193,669	24,224,499	24,172,038	24,195,619	24,203,586	24,214,289	24,224,320	24,244,251	24,258,743	24,274,245
Industrial	42,659,992	42,478,249	42,297,686	42,118,047	41,940,163	41,763,272	41,587,492	41,412,540	41,238,082	41,064,555
Power Generation	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000
BC Interior	**56,408,810**	**56,123,144**	**54,863,065**	**54,423,229**	**54,227,579**	**54,035,244**	**53,846,163**	**53,660,275**	**53,477,523**	**53,297,847**
Residential	17,248,818	17,334,193	17,427,117	17,513,504	17,595,895	17,677,633	17,758,722	17,839,166	17,918,968	17,998,130
Commercial	11,036,757	11,157,363	11,277,222	11,394,370	11,509,239	11,622,320	11,733,630	11,843,185	11,951,003	12,057,101
Industrial	28,123,235	27,631,588	26,158,726	25,515,355	25,122,445	24,735,291	24,353,811	23,977,924	23,607,552	23,242,616
Power Generation	-	-	-	-	-	-	-	-	-	-
E. Washington & N. Idaho	**72,981,845**	**74,776,538**	**75,338,142**	**76,929,654**	**77,171,760**	**78,465,359**	**79,273,734**	**79,744,071**	**79,830,878**	**80,232,390**
Residential	19,539,363	19,578,926	19,592,451	19,732,072	19,713,569	19,750,590	19,759,564	19,945,197	19,982,122	20,038,114
Commercial	13,726,893	13,802,889	13,865,564	14,009,918	14,043,229	14,119,863	14,182,040	14,355,000	14,422,902	14,512,161
Industrial	31,459,110	31,709,507	31,963,413	32,227,530	32,473,153	32,724,259	32,978,018	33,239,326	33,497,171	33,762,100
Power Generation	8,256,479	9,685,217	9,916,715	10,960,134	10,941,809	11,870,647	12,354,112	12,204,548	11,928,683	11,920,014
E. Oregon & Medford	**84,029,028**	**87,562,059**	**90,763,380**	**93,693,091**	**86,649,698**	**84,504,706**	**85,759,445**	**86,099,493**	**85,985,884**	**88,068,607**
Residential	7,192,591	7,259,109	7,320,487	7,423,306	7,463,091	7,529,517	7,590,073	7,703,952	7,754,051	7,824,183
Commercial	5,254,807	5,306,373	5,355,892	5,431,016	5,463,388	5,513,398	5,561,208	5,640,471	5,681,853	5,737,641
Industrial	9,720,567	9,762,907	9,805,300	9,848,076	9,895,265	9,945,534	9,995,347	10,047,636	10,093,358	10,141,083
Power Generation	61,861,064	65,233,670	68,281,701	70,990,693	63,827,954	61,516,256	62,612,817	62,707,434	62,456,622	64,365,701
S. Idaho	**74,350,865**	**73,940,592**	**72,753,784**	**72,723,962**	**73,048,070**	**73,372,777**	**73,700,703**	**74,030,861**	**74,365,153**	**74,815,332**
Residential	22,089,017	22,023,487	21,225,865	21,202,652	21,414,679	21,628,825	21,845,114	22,063,565	22,284,200	22,507,042
Commercial	11,330,948	11,296,522	10,971,408	10,960,035	11,069,635	11,180,332	11,292,135	11,405,056	11,519,107	11,634,298
Industrial	28,430,900	28,120,583	28,056,511	28,061,275	28,063,756	28,063,620	28,063,454	28,062,240	28,061,846	28,173,992
Power Generation	12,500,000	12,500,000	12,500,000	12,500,000	12,500,000	12,500,000	12,500,000	12,500,000	12,500,000	12,500,000
PNW Annual Demand - Base	**791,749,515**	**794,142,100**	**795,193,361**	**801,476,386**	**798,912,010**	**796,320,121**	**802,552,204**	**796,942,229**	**796,699,367**	**819,306,196**
Residential	227,326,456	228,422,945	228,354,358	229,403,775	230,513,916	231,790,590	232,774,520	233,619,040	234,700,077	236,066,727
Commercial	151,561,532	152,790,319	153,192,656	154,129,854	154,904,892	155,773,992	156,401,510	157,161,398	158,065,156	158,972,208
Industrial	239,654,924	238,630,494	236,830,889	236,120,738	235,621,670	235,118,383	234,696,289	234,294,714	233,796,225	233,490,724
Power Generation	173,206,603	174,298,342	176,815,457	181,822,020	177,871,531	173,637,156	178,679,884	171,867,077	170,137,909	190,776,537

Appendix A5: Peak Day Demand/Supply Balance (Dth/day) – Expected Case

Region/Sector	2016 / 2017	2017 / 2018	2018 / 2019	2019 / 2020	2020 / 2021	2021 / 2022	2022 / 2023	2023 / 2024	2024 / 2025	2025 / 2026
BC Lower Main & Van. Island (I-5 Corridor)	**1,194,196**	**1,191,368**	**1,188,588**	**1,186,716**	**1,185,048**	**1,183,381**	**1,181,713**	**1,180,046**	**1,178,378**	**1,176,711**
Residential	557,517	552,430	547,385	542,333	537,276	532,218	527,160	522,103	517,045	511,988
Commercial	451,124	453,230	455,406	457,543	459,662	461,780	463,898	466,016	468,134	470,252
Industrial	147,642	147,795	147,884	148,926	150,198	151,470	152,742	154,014	155,286	156,557
Power Generation	37,913	37,913	37,913	37,913	37,913	37,913	37,913	37,913	37,913	37,913
W. Washington (I-5 Corridor)	**1,974,070**	**2,000,175**	**2,024,694**	**2,039,995**	**2,054,398**	**2,137,721**	**2,156,094**	**2,168,477**	**2,179,254**	**2,230,402**
Residential	843,072	858,606	874,608	884,291	893,628	904,966	916,593	923,745	930,840	946,765
Commercial	354,521	361,493	369,581	374,934	379,827	385,784	392,267	397,279	400,920	406,999
Industrial	182,035	182,222	182,650	182,915	183,087	183,314	183,577	183,796	183,838	183,961
Power Generation	594,442	597,855	597,855	597,855	597,855	663,657	663,657	663,657	663,657	692,676
W. Oregon (I-5 Corridor)	**1,018,293**	**1,028,962**	**1,041,235**	**1,054,072**	**1,066,971**	**1,079,743**	**1,092,002**	**1,104,121**	**1,115,601**	**1,126,706**
Residential	590,587	598,676	609,283	619,272	629,324	639,302	648,916	658,337	667,243	675,837
Commercial	306,089	308,669	310,335	313,183	316,030	318,824	321,469	324,167	326,743	329,254
Industrial	51,617	51,617	51,617	51,617	51,617	51,617	51,616	51,616	51,616	51,616
Power Generation	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000
BC Interior	**416,287**	**419,872**	**420,658**	**423,753**	**427,515**	**431,277**	**435,039**	**438,801**	**442,563**	**446,325**
Residential	198,559	200,142	201,820	203,431	205,003	206,575	208,147	209,719	211,291	212,863
Commercial	134,121	136,578	139,055	141,516	143,969	146,422	148,874	151,327	153,780	156,233
Industrial	83,608	83,153	79,783	78,806	78,544	78,281	78,018	77,755	77,492	77,230
Power Generation	-	-	-	-	-	-	-	-	-	-
E. Washington & N. Idaho	**614,519**	**616,784**	**621,623**	**626,122**	**630,663**	**634,362**	**635,506**	**639,747**	**643,411**	**647,076**
Residential	231,176	232,153	234,685	236,788	238,913	240,491	240,415	242,326	243,860	245,397
Commercial	152,426	153,169	154,895	156,707	158,534	160,069	160,718	162,450	163,998	165,549
Industrial	98,883	99,427	100,007	100,592	101,181	101,767	102,338	102,937	103,518	104,095
Power Generation	132,035	132,035	132,035	132,035	132,035	132,035	132,035	132,035	132,035	132,035
E. Oregon & Medford (Non I-5 Supply)	**696,156**	**697,763**	**699,888**	**702,018**	**704,242**	**706,288**	**707,812**	**709,986**	**712,024**	**714,057**
Residential	92,206	93,066	94,277	95,481	96,719	97,836	98,597	99,787	100,879	101,960
Commercial	56,076	56,586	57,262	57,947	58,692	59,379	59,900	60,639	61,340	62,045
Industrial	41,159	41,396	41,635	41,875	42,116	42,359	42,601	42,846	43,091	43,338
Power Generation	506,714	506,714	506,714	506,714	506,714	506,714	506,714	506,714	506,714	506,714
S. Idaho	**554,858**	**563,227**	**566,864**	**557,765**	**561,314**	**565,934**	**569,940**	**573,985**	**582,198**	**586,366**
Residential	352,491	360,830	364,438	355,327	358,881	362,469	366,094	369,755	377,187	380,959
Commercial	36,973	37,003	37,032	37,043	37,040	38,071	38,451	38,836	39,617	40,013
Industrial	114,267	114,267	114,267	114,267	114,267	114,267	114,267	114,267	114,267	114,267
Power Generation	51,127	51,127	51,127	51,127	51,127	51,127	51,127	51,127	51,127	51,127
Total Design (Peak) Day Demand	**6,468,378**	**6,518,151**	**6,563,550**	**6,590,441**	**6,630,151**	**6,738,706**	**6,778,106**	**6,815,163**	**6,853,430**	**6,927,643**
Total Supply	**6,732,211**	**6,732,211**	**6,732,211**	**6,732,211**	**6,732,211**	**6,732,211**	**6,732,211**	**6,732,211**	**6,732,211**	**6,732,211**
Supply Surplus/(Shortfall)	**263,833**	**214,060**	**168,661**	**141,770**	**102,060**	**(6,495)**	**(45,895)**	**(82,952)**	**(121,219)**	**(195,432)**

Appendix A6: Expected I-5 Corridor Peak Day Demand/Supply Balance (Dth/day)

Demand (Region/Sector)	2016/2017	2017/2018	2018/2019	2019/2020	2020/2021	2021/2022	2022/2023	2023/2024	2024/2025	2025/2026
BC Lower Main & Van. Island (I-5 Corridor)	**1,194,196**	**1,191,368**	**1,188,588**	**1,186,716**	**1,185,048**	**1,183,381**	**1,181,713**	**1,180,046**	**1,178,378**	**1,176,711**
Residential	557,517	552,430	547,385	542,333	537,276	532,218	527,160	522,103	517,045	511,988
Commercial (Firm Sales & Transport)	451,124	453,230	455,406	457,543	459,662	461,780	463,898	466,016	468,134	470,252
Industrial (Firm Sales & Transport)	147,642	147,795	147,884	148,926	150,198	151,470	152,742	154,014	155,286	156,557
Power Generation	37,913	37,913	37,913	37,913	37,913	37,913	37,913	37,913	37,913	37,913
W. Washington (I-5 Corridor)	**1,974,070**	**2,000,175**	**2,024,694**	**2,039,995**	**2,054,398**	**2,137,721**	**2,156,094**	**2,168,477**	**2,179,254**	**2,230,402**
Residential	843,072	858,606	874,608	884,291	893,628	904,966	916,593	923,745	930,840	946,765
Commercial (Firm Sales & Transport)	354,521	361,493	369,581	374,934	379,827	385,784	392,267	397,279	400,920	406,999
Industrial (Firm Sales & Transport)	182,035	182,222	182,650	182,915	183,087	183,314	183,577	183,796	183,838	183,961
Power Generation	594,442	597,855	597,855	597,855	597,855	663,657	663,657	663,657	663,657	692,676
W. Oregon (I-5 Corridor)	**1,018,293**	**1,028,962**	**1,041,235**	**1,054,072**	**1,066,971**	**1,079,743**	**1,092,002**	**1,104,121**	**1,115,601**	**1,126,706**
Residential	590,587	598,676	609,283	619,272	629,324	639,302	648,916	658,337	667,243	675,837
Commercial (Firm Sales & Transport)	306,089	308,669	310,335	313,183	316,030	318,824	321,469	324,167	326,743	329,254
Industrial (Firm Sales & Transport)	51,617	51,617	51,617	51,617	51,617	51,617	51,616	51,616	51,616	51,616
Power Generation	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000
Total Peak (Design) Day Demand	**4,186,558**	**4,220,505**	**4,254,517**	**4,280,783**	**4,306,417**	**4,400,844**	**4,429,809**	**4,452,644**	**4,473,234**	**4,533,819**
SUPPLY										
Pipeline Interconnects	**2,304,060**	**2,304,060**	**2,304,060**	**2,304,060**	**2,304,060**	**2,304,060**	**2,304,060**	**2,304,060**	**2,304,060**	**2,304,060**
Max north flow on NWP @ Gorge	**551,000**	**551,000**	**551,000**	**551,000**	**551,000**	**551,000**	**551,000**	**551,000**	**551,000**	**551,000**
Huntingdon/Sumas	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**
T-South to Huntingdon	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060
Underground Storage	**1,726,450**	**1,726,450**	**1,726,450**	**1,726,450**	**1,726,450**	**1,726,450**	**1,726,450**	**1,726,450**	**1,726,450**	**1,726,450**
Jackson Prairie (NWP from JP)	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000
Mist Storage (NWN)	530,450	530,450	530,450	530,450	530,450	530,450	530,450	530,450	530,450	530,450
Peak LNG	**535,308**	**535,308**	**535,308**	**535,308**	**535,308**	**535,308**	**535,308**	**535,308**	**535,308**	**535,308**
Newport LNG (NWN)	65,300	65,300	65,300	65,300	65,300	65,300	65,300	65,300	65,300	65,300
Portland LNG (NWN)	129,000	129,000	129,000	129,000	129,000	129,000	129,000	129,000	129,000	129,000
Gig Harbor Satellite LNG (PSE)	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500
Swarr Stn Propane (PSE)	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000
Tilbury LNG (TGI)	155,466	155,466	155,466	155,466	155,466	155,466	155,466	155,466	155,466	155,466
Mount Hayes LNG	153,042	153,042	153,042	153,042	153,042	153,042	153,042	153,042	153,042	153,042
Total Supply	**4,565,818**	**4,565,818**	**4,565,818**	**4,565,818**	**4,565,818**	**4,565,818**	**4,565,818**	**4,565,818**	**4,565,818**	**4,565,818**
Supply Surplus/(Shortfall)	379,260	345,313	311,301	285,035	259,401	164,974	136,009	113,174	92,584	31,999

Appendix A7: Accelerated Annual Demand

	2016/2017	2017/2018	2018/2019	2019/2020	2020/2021	2021/2022	2022/2023	2023/2024	2024/2025	2025/2026
Expected Annual Demand (Table A2)	**816,667,693**	**823,609,949**	**828,057,578**	**834,713,978**	**845,641,804**	**853,442,402**	**858,057,907**	**862,720,344**	**861,677,970**	**878,316,862**
Coal Replacement	0	0	0	27,600,000	36,800,000	36,800,000	36,800,000	36,800,000	36,800,000	36,800,000
General Industrial	0	12,775,000	12,775,000	85,775,000	85,775,000	158,775,000	158,775,000	158,775,000	158,775,000	158,775,000
Large Load Industrial	0	0	0	109,500,000	109,500,000	109,500,000	200,750,000	200,750,000	200,750,000	200,750,000
Total	**816,667,693**	**836,384,949**	**840,832,578**	**1,057,588,978**	**1,077,716,804**	**1,158,517,402**	**1,254,382,907**	**1,259,045,344**	**1,258,002,970**	**1,274,641,862**

Appendix A8: Accelerated Peak Day Demand

REGION-WIDE ACCELERATED PEAK DAY DEMAND	2016/2017	2017/2018	2018/2019	2019/2020	2020/2021	2021/2022	2022/2023	2023/2024	2024/2025	2025/2026
Expected Peak Day (Table A5)	6,468,378	6,518,151	6,563,550	6,590,441	6,630,151	6,738,706	6,778,106	6,815,163	6,853,430	6,927,643
Coal Replacement	0	0	0	75,616	100,822	100,822	100,822	100,822	100,822	100,822
General	0	35,000	35,000	235,000	235,000	435,000	435,000	435,000	435,000	435,000
Large Load	0	0	0	300,000	300,000	300,000	550,000	550,000	550,000	550,000
TOTAL ACCELERATED PEAK DAY DEMAND	**6,468,378**	**6,553,151**	**6,598,550**	**7,201,057**	**7,265,973**	**7,574,528**	**7,863,928**	**7,900,985**	**7,939,252**	**8,013,465**
REGION-WIDE MAXIMUM SUPPLY (Table A1)										
Pipeline	4,105,153	4,105,153	4,105,153	4,105,153	4,105,153	4,105,153	4,105,153	4,105,153	4,105,153	4,105,153
Storage	1,726,450	1,726,450	1,726,450	1,726,450	1,726,450	1,726,450	1,726,450	1,726,450	1,726,450	1,726,450
Peak	900,608	900,608	900,608	900,608	900,608	900,608	900,608	900,608	900,608	900,608
TOTAL REGIONAL SUPPLY	**6,732,211**	**6,732,211**	**6,732,211**	**6,732,211**	**6,732,211**	**6,732,211**	**6,732,211**	**6,732,211**	**6,732,211**	**6,732,211**
SUPPLY SURPLUS/SHORTFALL	**263,833**	**179,060**	**133,660**	**(468,846)**	**(533,762)**	**(842,317)**	**(1,131,717)**	**(1,168,774)**	**(1,207,041)**	**(1,281,254)**

Appendix B: IRP Characteristics

Company	Region/Area	Customer Classes	Forecast Period	Econometrics	Economic Source
Avista	2 Divisions (WA/ID, OR); 4 Service Territories (WA/ID, Roseburg/ Medford, Klamath Falls, La Grande); 8 demand areas according to available pipeline capacity	Residential, commercial, industrial, core interruptible.	20 years	Separate forecast for customers and use per customer. Key drivers: Population growth, service area residential permitting; U.S., California, and service area employment growth; average household size; U.S. industrial production; U.S. GDP growth; non-weather seasonal factors; and real natural production; and real natural gas prices. Normal weather is based on a 20-year moving average.	IHS Global Insight; Bureau of Labor Statistics; U.S. Census; Bureau of Economic Analysis; NOAA; University of Oregon Economic Indicator; Construction Monitor; U.S. Federal Reserve; The Economist; Wall Street Journal; IMF; World Bank; Bloomberg; Blue Chip Consensus, Washington Office of Financial Management
Cascade	CNGC will forecast at its city gates starting with 2016 IRP. 6 regions; West, Central and East for market share; by county for economic forecasting.	Residential, commercial, Industrial, core interruptible.	20 years	Customer Counts: Population growth, economical employment rates, weather, natural gas price and other regional economic market intelligence	Woods & Poole, FHLMC, Federal Reserve, Schneider Electric, Wood Mackenzie and other regional economic market intelligence.
Fortis	4 service regions: Lower Mainland; Vancouver Island; Northern Interior; Southern Interior.	Residential; commercial; industrial.	20 years	Forecasts based on third party housing starts forecast and market capture. New dwellings, commercial floor space and industrial plant capacity added based on account growth rates. Anticipated 'natural' efficiency improvements incorporated in both existing buildings and new construction. Anticipated changes in the saturation and gas shares for specific end-uses also included. Recent uptick in industrial consumption assumed to continue for the short-term, then level off.	Conference Board of Canada, user surveys (industrial customers)
IntGas	6 regions (includes an "all other" category); West, Central, and East for market share rates; by county for economic forecasting.	Residential, commercial, and industrial (potato processors, other food processors, chemical and fertilizer, manufacturers, institutions, and all other).	5 years	Customer growth forecast: New residential construction customers, # of residential customers who convert to natgas fr/ an alt fuel, and number of small commercial customers (assuming a new household = a new dwelling needed). The annual change in households by county x IGC's market penetration rate in that region = the additional residential anticipated % of conversion customers relative to new construction customers in those locales = # of expected res. conversion customers + residential new construction #s = total expected additional residential customers across the periods, by county.	Church 2016 Forecast; NOAA.
NW Natural	12 Regions based on topology of the gas distribution system	Residential existing, new construction single family, new construction multi-family and residential conversion; commercial existing, new construction and conversions; industrial firm sales; firm transport; interruptible sales.	20 years	Customer growth by region and category. Recent usage data for customer base use + heat use behavior response to historic weather and gas rates.	Oregon Office of Economic Analysis; Northwest Power & Conservation Council; Woods & Poole.
Pacific Power	By state (California, Oregon, Washington, Idaho, Utah, and Wyoming) which is allocated to 37"bubbles," including 10 load bubbles	Residential, commercial, industrial, irrigation, and Public Street and Highway Lighting.	20 years, but IRP discussion focuses on first 10 years.	Forecast by state and customer class. Key drivers: New technologies/end use, demographics, employment, income, weather, DSM, and energy efficiency mandates.	PacifiCorp's 2014 DSM potential study, conducted by Applied Energy Group.
Portland General	Single contiguous service area.	2017-2050 (20 years required).	2017-2050 (20 years required)	Precarious economic conditions, demographic trends such as in-migration and life expectancy, a business environment that favors future growth; Oregon's position as a magnet state, the presence of prominent industry leaders, continued gains in productivity, and emerging sectors sustaining and creating new growth; and the high tech sector.	Oregon Office of Economic Analysis economic forecast and Energy Information Administration.
Puget Sound Energy	Single contiguous service area.	Firm: residential, commercial, industrial, large volume commercial, large volume industrial. Interruptible: commercial and industrial.	20 years	Regional and national economic growth, demographic changes, weather, prices, seasonality, housing starts, and demand side management (DSM) for customer growth and use per customer forecasts; Stochastic approach for developing Low and High growth scenarios.	Moody's Analytics US Macroeconomic Forecast, PSE's regional and economic forecasts, US Bureau of Economic Analysis, US Bureau of Census, Washington State
Questar	Utah and Wyoming (Idaho rolled into Utah).	Residential by state; small commercial by state; large commercial, industrial, and electric generation gas demand all together; firm customer and transportation. All rate classes are forecasted by state, but non-GS (all but residential and small commercial) is only presented system-wide in the IRP document.	11 years for demand forecast; 21 years for SendOut model	Population, personal income, housing starts, and unemployment rate are used in forecasting by state.	University of Utah (Bureau of Economic & Business Research); UT Governor's Office of Planning and Budget; U.S. EIA, U.S. Census Bureau, HIS Global Insight.

Company	Scenarios Developed	Price Forec ast	Weather Design
Avista	An Average Case, Expected Case, Expected Case with Low Price, High Growth with Low Price, Low Growth with High Price, and an Alternate Weather Standard.	Wood Mackenzie – first four years modified to include Nymex forward prices	Coldest day on record, historic peak, and average weather data for each demand region.
Cascade	Low, Medium, High, High Growth with Low Price, Low Growth with High Price, Moderate CO2 costs, High CO2 costs.	A blend of public and private sources (EIA 20 yr, Bentek 5yr, Wood Mackenzie, NYMEX strips, Texas Comptroller)– based onCascade's general portfolio mix	System-weighted 56 HDD, based on coldest day in past 30 years.
Fortis	Reference Case, High and Low (driven by customer addition forecasts); scenarios by region.	Henry Hub forecasts using GLJ, Wood Mackenzie and US EIA along with NYMEX futures.	1-in-20-year day determined through extreme value analysis based on weather data from the last 60 years; result may vary from the actual coldest day in last 20 years.
IntGas	Low, base and high combined with other variables to yield 18 demand scenarios.	NYMEX & 2 proprietary five year forecasts	81 HDD weighted by customers in each district; several distinct laterals and areas of interest are assigned unique HDDs.
NW Natural	High Customer Growth; Low Customer Growth; Carbon Prices; Regional Pipeline Availability.	IHS CERA	Most extreme weather last 30 years (Feb 3, 1989).
Pacific Power	2015 IRP studied 34 core cases, including 3 different regional haze approaches, incorporated draft EPA 111(d) alternatives and additional CO2 taxes. 15 sensitivities focusing on low, high, and 1-in-20 load growth; low/high DG penetration; two types of storage addition; 1-in-20 load growth, low and high DG penetration, as well as two types of storage additions; solar cost sensitivities; two transmission sensitivities; PTC extension; Class 3 DSM; east/west balancing areas	Third-party proprietary data & forecasting services. Low, medium, and high Henry Hub natural gas prices and CO2 prices determined/used in IPM® and AURORAxmp® models. IPM® simulates North American system resulting in plant retirements and renewable resource builds. IPM® results are input in the AURORAxmp® model, which simulates the Western Interconnection and produces unique price projections for the cases analyzed in the 2015 IRP.	1-in-20 weather occurrence included in alternative load forecast to determine resource type and timing impacts.
Portland General	Reference (likely) case, high load and low load, assuming normal weather. 26 portfolios represent either a single resource or a mix of resources. Assess and test total expected portfolio costs using 21 futures.	Wood Mackenzie for natural gas prices long-term fundamental forecast from 2021 through 2035 for long-term Henry Hub price and basis differentials to Sumas, AECO, and other WECC (for electric) supply hubs. PGE extrapolates from the fundamentals forecast for dates after 2035.	Expected normal weather w/50% probability–PGE's reserve cover ~ 80% of a 1-in-5 weather event. Historically winter peaking but summer demand growing; PGE's system will shift to summer peaking by the end of the decade
Puget Sound Energy	Base, Low, High, Base + Low Gas Price, Base + High Gas Price, Base + Very High Gas Price, Base + No CO2, Base + High CO2, Base + Low Demand, Base + High Demand.	Prices for 2016 through 2019 represent 3-month average forward marks. Beyond 2019, natural gas forward prices represent the long-term forecast per Wood Mackenzie. Also generated Low, High & Very High gas prices using Wood Mackenzie forecasts.CO2 prices are based on Northwest Power & Conservation Council's estimated California CO2 prices under the California Global Warming Solutions Act of 2006	52 HDD daily average.
Questar	Stochastic modeling yielding mean, median and base cases; normal weather case also reported to inform quarterly variance reporting and pass through cases.	Means and standard deviations associated with historical data from 9 area price indices; average of 2 price forecasts including PIRA (19 months) and IHS CERA (252 months) as basis for stochastic modeling inputs.	1-in-20-year weather occurrence: 70 HDD at SLC coincident across service territory.

Appendix C: Regional Resource Deficiencies and Preferred Resource Options

Company	IRP File Date	Jurisdiction	Year of Peak Day Deficiency	Preferred Supply Resources Selected
Avista	August 29, 2014	Idaho; Oregon; Washington	No deficiency in planning horizon	N/A
Cascade	July 17, 2015	Oregon; Washington	2013 (OR), 2021 (WA)	Realign delivery rights; incremental GTN, NWP and other upstream pipeline capacity; incremental storage capacity.
FortisBC	March 25, 2014	British Columbia	2017 – Interior Transmission System; 2026 – Coastal Transmission System. To be reassessed in 2017 IRP.	Pipeline looping or LNG storage.
IntGas	January, 2015	Idaho	No deficiency within 5-year planning horizon	N/A
NW Natural	August 29, 2016	Oregon; Washington	2020	Mist Recall; North Mist Expansion; Additional Pipeline Capacity (specific pipeline dependent on scenario).
Puget Sound Energy	November 30, 2015	Washington	2017	Swarr propane air facility upgrade, PSE LNG, Mist Storage and pipeline expansions including the NWP Sumas Express, the Spectra T-South West coast expansion and the NWP N-MAX/ Trail West Cross Cascade expansion.

Developing a sufficient and efficient regional delivery system can be achieved by looking at the total needs of the region, the resources available, and future resource options. While current analysis shows sufficient resources to serve regional demand, they may not fully capture potential demand, both in magnitude and timing, or the future availability of existing resources.

Due to risks inherent in the forecasting process, changing needs and uses for natural gas, limited existing resources, and the lengthy permitting and construction time frames required to bring new resources on line, it is imperative to comprehensively assess regional resource adequacy and future resource needs.

NWGA member utilities strive to understand the planning issues, competitive environment and resource requirements for others in the region because of the region's reliance on a common infrastructure to serve both electricity and natural gas demand. Preparing a plan in isolation of these external considerations could mask potential resource utilization constraints, ignore operational synergies, discount project economies of scale, and result in over-reliance on existing resources.

For example, LDCs may plan to rely upon existing unsubscribed or under-utilized pipeline capacity to meet a future deficit. That same capacity may be relied upon by electric utilities that need gas for power generation sooner than the LDC. In this case, the LDCs' preferred resource would not be available. Therefore, evaluating who needs what, when and where can highlight potential problems and hone in on regional solutions.

This table summarizes the identified deficiencies and preferred supply resource portfolios of the NWGA member utilities from their most recently filed IRPs. It is apparent from the data in the table that near-term deficiencies can be handled with existing resources. Longer-term deficiencies are likely to be met with some combination of currently unsubscribed capacity, future capacity expansions and additional on-system storage including satellite LNG. There are several planning cycles in which to evaluate resource options for deficits far out into the future.

What has not been fully incorporated, however, are the resources regional electricity generators plan to access to meet growing and increasingly variable generation demand. The Outlook has captured future gas-fired generation loads to the extent they are planned, known and available. However, it is difficult to project how and when those resources will be required. The NWGA will continue working with the Pacific Northwest Utilities Conference Committee (trade association of regional electric utilities) to plan accordingly.

Appendix D: Proposed Regional Natural Gas Infrastructure Project Descriptions

Today's market for regional infrastructure capacity has evolved from valuing diversity to equally valuing reliability; from providing market access for imported LNG to accessing the Asian LNG export markets. It is only a matter of time before new capacity within the region will be required. Figure C5 on page 19 in the Capacity Section illustrates active regional infrastructure proposals, which include:

Spectra T-South Expansions: Spectra Energy continues to evaluate expansion of its T-South system to provide incremental delivery options for growing Western Canada gas supply to markets in the Pacific Northwest. All expansions on T-South would require pipeline looping and compression and can be brought into service between 2018-2020.

FortisBC Southern Crossing Expansion: FortisBC's existing Southern Crossing pipeline system enables bidirectional gas flow between Spectra's T-South system at Kingsvale, BC and TransCanada's BC system just upstream from the interconnection with GTN at Kingsgate, ID. The proposed expansion involves a 150 kilometre pipeline looping project on the segment between Kingsvale and Oliver BC and would facilitate access to an additional 300-400 MMcf/d of bi-directional capacity. This expansion would provide for greater market access to Station 2 supply by moving gas west to east or moving Alberta-sourced gas east to west to serve several new large industrial projects proposed for the BC Lower Mainland and the I-5 corridor.

Northwest Pipeline (NWP) Sumas Express: Williams NWP continues to assess the regional benefits of expanding its system along the I-5 corridor from Sumas, WA to the market areas in WA and OR. NWP believes that expanding in its existing corridor is both economical and permittable and can be accomplished in a scalable manner to meet anticipated regional growth. Depending on the size of the ultimate market needs, NWP can meet demand growth through adding additional loop and compression at its existing compressor stations in the corridor.

Gas Transmission Northwest (GTN) Trail West/N-MAX: Project sponsors TransCanada GTN is working with NW Natural and NWP to develop Trail West in conjunction with an expansion of the existing NWP system. The Trail West project would consist of a 106-mile, 30-inch diameter pipeline that would run from GTN's mainline in central Oregon to a NW Natural/NWP hub near Molalla — enhancing delivery capacity to the I-5 Corridor. Trail West's initial design capacity is 500 MMcf/d, expandable to 1,000 MMcf/d. It would be linked to the N-MAX project on the NWP system to deliver gas to other markets along the I-5 corridor. This integrated project is projected to be in service during the fourth quarter of 2021.

Veresen/NWP Pacific Connector Gas Pipeline Project (PCGP): The PCGP is a 232-mile 36-inch diameter pipeline extending from Malin to Coos Bay, OR. Veresen, Inc. and Williams NWP are proposing PCGP to serve the Jordan Cove LNG export terminal, as well as potential regional markets between Malin and Coos Bay. PCGP includes 41,000 horsepower of compression to be installed near Malin yielding a total project design capacity of 1.06 Bcf/d. PCGP will provide access to supplies from Western Canada and the U.S. Rockies via interconnections with GTN and the Ruby Pipeline. Williams NWP will operate PCGP.

About the NWGA:

The NWGA is a bi-national trade organization of the Pacific Northwest natural gas industry. Its mission is to promote natural gas as a cornerstone of the region's energy, economic and environmental foundation. The NWGA produces timely and regionally relevant information relating to natural gas; shapes and communicates the industry's perspective, and engages in policy analysis and advocacy. NWGA members serve more than three million consumers in communities throughout Idaho, Oregon, Washington and British Columbia.

Avista Utilities
www.avistacorp.com

Cascade Natural Gas Corp.
www.cngc.com

FortisBC Energy
www.fortisbc.com

Intermountain Gas Co.
www.intgas.com

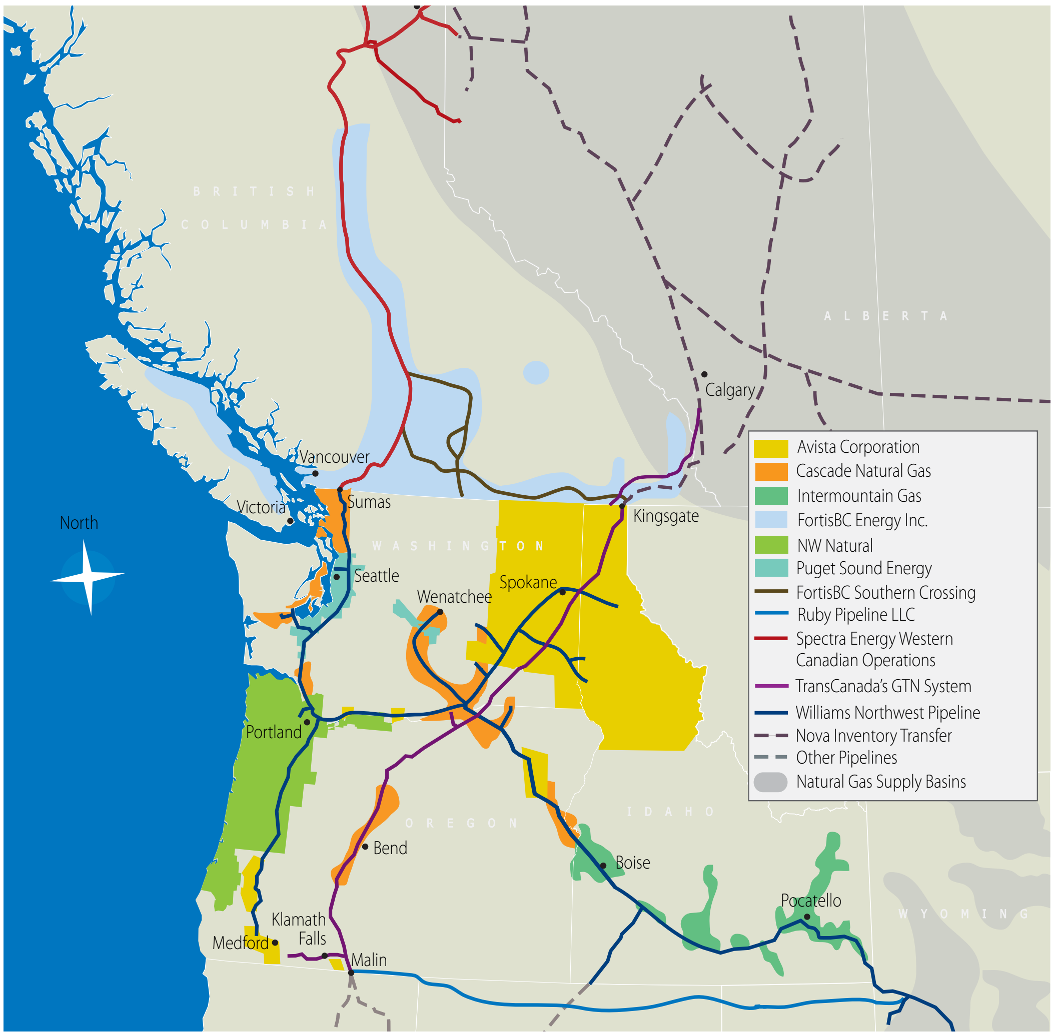
NW Natural
www.nwnatural.com

Puget Sound Energy
www.pse.com

Spectra Energy – BC Pipeline
www.spectraenergy.com

TransCanada – GTN System
http://tcplus.com/GTN

Williams – NW Pipeline
www.northwest.williams.com



NWGA
NORTHWEST GAS ASSOCIATION

1914 Willamette Falls Dr. #260
West Linn, OR 97068
503-344-6637
www.nwga.org @nwgas

Choosing natural gas

Natural gas offers valuable benefits for your home or business's budget and comfort. If you switch your home's space or water heating from electricity to natural gas, you may qualify for up to **$3,550 in fuel conversion rebates**.

Benefits of natural gas

- Convenience »

  Natural gas furnaces distribute heat more evenly than electric heating. Natural gas water heaters heat up to 40 percent faster than electric models. Natural gas ranges cook food faster with better heat control. And natural gas dryers produce less static cling. Plus, you'll never have the hassle of wood with a natural gas fireplace.

- Comfort »

  Natural gas heating delivers air faster and warmer than heat produced by other electric heating equipment. A natural gas fireplace can warm a room much faster than a wood-burning fireplace.

- Savings »

  Natural gas costs less than electricity, heating oil or propane when used to heat your space or water. Electricity can cost up to twice as much.

- Environmentally-friendly »

  In most applications, natural gas produces less chemical emissions and particulates which can cause acid rain or smog. And the majority of natural gas for domestic use is produced in the U.S. and Canada.

- Energy-efficient »

  Direct use of natural gas for space and/or water heating is twice as efficient as using natural gas to produce electricity and transmitting it to a home. And with the use of energy-efficient gas appliances, even greater efficiency is achieved.

- Versatility »

  Natural gas can not only heat your sparce, but it can be used for water heating, clothes drying, cooking, and fireplaces. It can also be used outdoors for barbecuing, gas lighting, and even to heat your swimming pool or hot tub.

- Reliability »

  Natural gas service is piped directly to your home or business site and is always there when you need it. You'll never have to worry about running out of fuel, and many gas appliances will operate during a power outage.

- Value-added »

  Adding natural gas service to your home or business, along with high-efficiency gas appliances, will pay dividends down the road. From a resale standpoint, homes with natural gas offer more appeal to prospective buyers.

- Safety »

  Natural gas is one of the world's safest energy sources. It's lighter than air, nontoxic, odorless and colorless in its natural state. Mercaptan, a harmless odorant, is added to create a clearly detectable scent.

Simple steps to switching to natural gas

1. Determine natural gas availability and costs »
Start by confirming that natural gas is available for your home or business. Please fill out this inquiry request and we will respond within 2-3 business days or call PSE's Customer Construction Services at 1-888-321-7779 (Monday through Friday, 7 a.m. to 5 p.m.). We can let you know availability and costs, if any, within two to four business days.

2. Select a contractor for estimates »
PSE can help you find a pre-screened, qualified independent contractor. They will inform you of your high efficiency equipment options and provide a free on-site estimate based on your needs. And you can be assured that it will be installed professionally and in compliance with your local codes.

3. Check for energy efficiency rebates, incentives and financial assistance »
Be sure to check out PSE's energy-efficiency rebates to help save you more money. If you are switching from PSE electricity to natural gas at your home, you may qualify for up to $3,550 in fuel conversion rebates. Additionally, you may qualify for competitive financing for your equipment and installation costs. A PSE Energy Advisor can assist you with all of this information.

4. Submit a Natural Gas Service Contract »
Once we confirm that natural gas is available for your home or business, you will receive/complete a Gas Service Agreement which will provide PSE useful information such as your intended natural gas use and meter location.

5. Schedule your meter and equipment installation »
A PSE representative will contact you to discuss details about your natural gas service installation, such as access requirements and permitting. An installation date can then be scheduled according to your needs and scope of work. Once your natural gas meter is installed, you can work with your contractor to schedule installation of your high-efficiency equipment and/or appliances.

6. Activate your natural gas service »
As soon as your natural gas equipment is properly installed, simply contact PSE to activate your service. In most cases, your contractor can contact us on your behalf.

Questions about switching to natural gas?

Once you know natural gas is available for your home or business, call a PSE Energy Advisor at 1-800-562-1482, Monday through Friday, 8 a.m. to 5 p.m., for more information about PSE's energy-efficiency rebates, efficient equipment options, energy cost savings estimates, financing referrals and PSE's Contractor Alliance Network.

Cost comparisons

Compare costs between natural gas and other heating fuels.

Financing options

In some cases, adding natural gas service is considered an energy-efficiency upgrade and can qualify for low-interest loans or federal tax credits. For more information, visit the website below or contact a PSE Energy Advisor.

- ENERGY STAR® (tax credits)

Ask an Energy Advisor

Phone
1-800-562-1482

Email
EnergyAdvisor@pse.com

Web
Contact form

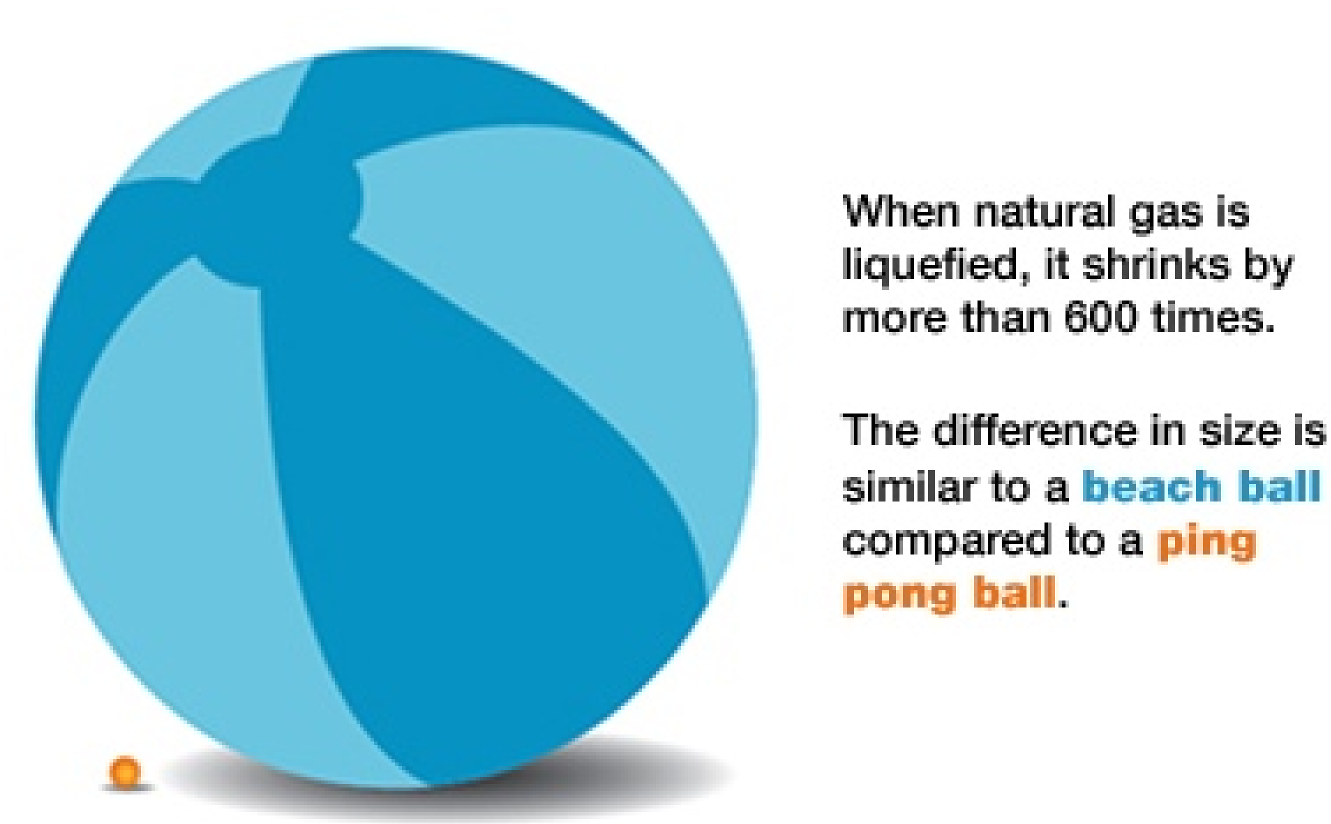
Find a contractor

Featured content

Natural gas conversion rebate

Natural gas safety

LNG is simply the liquid form of the natural gas used in millions of homes and vehicles.



Project Summary

Puget Sound Energy (PSE), Washington’s oldest energy utility, has begun construction of a $310 million Liquefied Natural Gas (LNG) facility at the Port of Tacoma. It will provide a clean and cost-effective gas supply resource for PSE's natural gas customers and a cleaner fuel alternative for maritime vessels owned by TOTE and other local employers. The project is expected to be completed and fully operational by late 2019.

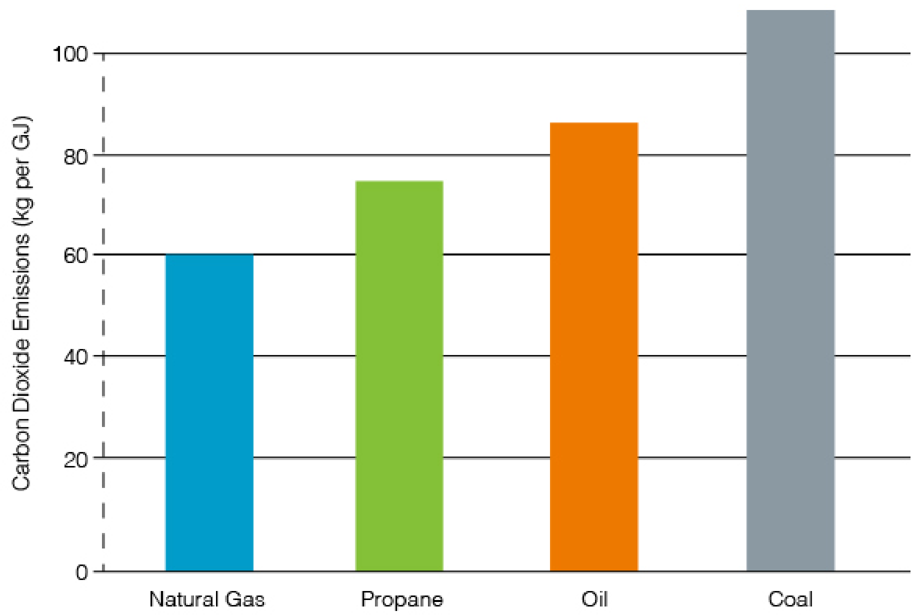
Local

PSE's LNG facility will serve our domestic natural gas customers and provide fuel for ships traveling between Tacoma and Alaska.

Safe

PSE has operated an LNG facility in Gig Harbor for more than a decade. The Tacoma facility will be operated in the same responsible way and built in accordance with the strictest federal guidelines.

LNG is simply the liquid form of the natural gas used in millions of homes and vehicles. When cooled, natural gas is reduced to a liquid that is one six-hundredth the volume, making it easier to store and transport. It is not explosive or flammable in its liquid state. When warmed, it returns to its gaseous state, and the same safe handling procedures are used as with natural gas. More than 100 LNG production, storage and fueling facilities currently operate in the United States.



Clean

Historically, many maritime vessels have used polluting bunker fuel or diesel. That's all changing. Switching from diesel to LNG reduces greenhouse gases more than 30 percent and dramatically reduces dangerous particulate emissions. This helps improve air quality and reduce health risks, and will help local employers like TOTE comply with new, stricter low-sulfur emission standards. Use of LNG also greatly minimizes the potential for harmful fuel spills that could damage the waters of Commencement Bay and Puget Sound.

BC NDP Digital Team | July 26, 2017

Read Premier John Horgan's mandate letters to the new BC NDP government ministers

SHARE SHARE

Every new Premier delivers a mandate letter to the incoming Ministers and Ministers of State serving in their cabinet.

Premier John Horgan's government is no different. This week many of the 22 new Ministers and Ministers of State received their mandate letters from Premier Horgan.

Like the BC NDP platform and its three commitments, Premier Horgan's goals and expected outcomes are largely focused on improving the lives of everyday British Columbians. As he says in each letter: "It has never been more important for new leadership that works for ordinary people, not just those at the top."

In addition to their core responsibilities, all Ministers are expected to ensure members of the B.C. Green caucus are appropriately consulted on major policy issues, budgets, legislation and other matters as outlined in our agreement. After all, he continues, "British Columbians expect our government to work together to advance the public good. That means seeking out, fostering, and advancing good ideas regardless of which side of the house they come from."

Here are the highlights from the Mandate letters released yesterday:

1. The Honourable Melanie Mark, Minister of Advanced Education, Skills and Training

Key priorities for her Ministry include:

- Provide greater access to adult basic education and English-language learning programs by eliminating fees.
- Reduce the financial burden on students by eliminating interest on B.C. government student loans and establish a $1,000 completion grant program to provide debt relief to B.C. graduates.
- Encourage excellence in B.C.'s graduateschool programs by introducing a new graduate student scholarship fund.
- Work with the Minister of Education to support co-op, apprenticeship and work-experience programs for high school and undergraduate students.
- Work with the Minister of Transportation and Infrastructure to implement effective apprenticeship ratios on government-funded

infrastructure projects, and increase participation of equity-seeking groups in the skilled workforce.

Read the full letter:

BRITISH COLUMBIA

July 18, 2017

Honourable Melanie Mark
Minister of Advanced Education, Skills and Training
Parliament Buildings
Victoria, British Columbia V8V 1X4

Dear Minister Mark:

Congratulations on your new appointment as Minister of Advanced Education, Skills and Training.

It has never been more important for new leadership that works for ordinary people, not just those at the top.

It is your job to deliver that leadership in your ministry.

Our government made three key commitments to British Columbians.

Our first commitment is to make life more affordable. Too many families were left behind for too long by the previous government. They are counting on you to do your part to make their lives easier.

Our second commitment is to deliver the services that people count on. Together, we can ensure that children get access to the quality public education they need to succeed, that families can get timely medical attention, and that our senior citizens are able to live their final years with dignity.

These and other government services touch the lives of British Columbians every day. It is your job as minister to work within your budget to deliver quality services that are available and effective.

Our third key commitment is to build a strong, sustainable, innovative economy that works for everyone

2. The Honourable Lana Popham, Minister of Agriculture

Key priorities for her Ministry include:

- Revitalize the Agriculture Land Reserve and the Agricultural Land Commission.
- Establish Grow B.C. to help young farmers access land, and support fruit and nut growers and processors to expand local food production.
- Initiate Feed B.C. to increase the use of B.C.-grown and processed foods in hospitals, schools, and other government facilities.
- Bring back an enhanced Buy B.C. marketing program to help local producers market their products,and work with local producers to expand market access in the rest of Canada and abroad.

Read the full letter:

BRITISH
COLUMBIA

July 18, 2017

Honourable Lana Popham
Minister of Agriculture
Parliament Buildings
Victoria, British Columbia V8V 1X4

Dear Minister Popham:

Congratulations on your new appointment as Minister of Agriculture.

It has never been more important for new leadership that works for ordinary people, not just those at the top.

It is your job to deliver that leadership in your ministry.

Our government made three key commitments to British Columbians.

Our first commitment is to make life more affordable. Too many families were left behind for too long by the previous government. They are counting on you to do your part to make their lives easier.

Our second commitment is to deliver the services that people count on. Together, we can ensure that children get access to the quality public education they need to succeed, that families can get timely medical attention, and that our senior citizens are able to live their final years with dignity.

These and other government services touch the lives of British Columbians every day. It is your job as minister to work within your budget to deliver quality services that are available and effective.

Our third key commitment is to build a strong, sustainable, innovative economy that works for everyone

3. The Honourable David Eby, Attorney General

Key priorities for the Attorney General include:

- Introduce legislation to reform campaign finance laws to ban political contributions by corporations and unions, and set limits on individual contributions.
- Introduce legislation to hold a province-wide referendum on proportional representation in the fall of 2018.
- Introduce legislation to reform lobbying in BC.
- Re-establish the Human Rights Commission.
- Increase the number of court sheriffs, expand the use of duty counsel and increase staffing of the Court Services Branch to address court delays.
- Improve and support legal aid, including First Nations legal services, dispute resolution services for families and expanded poverty law services to increase access to justice.
- Conduct a comprehensive operating review of ICBC.

Read the full letter:

BRITISH COLUMBIA

July 18, 2017

Honourable David Eby
Attorney General
Parliament Buildings
Victoria, British Columbia V8V 1X4

Dear Attorney General Eby:

Congratulations on your new appointment as Attorney General.

It has never been more important for new leadership that works for ordinary people, not just those at the top.

It is your job to deliver that leadership in your ministry.

Our government made three key commitments to British Columbians.

Our first commitment is to make life more affordable. Too many families were left behind for too long by the previous government. They are counting on you to do your part to make their lives easier.

Our second commitment is to deliver the services that people count on. Together, we can ensure that children get access to the quality public education they need to succeed, that families can get timely medical attention, and that our senior citizens are able to live their final years with dignity.

These and other government services touch the lives of British Columbians every day. It is your job as minister to work within your budget to deliver quality services that are available and effective.

Our third key commitment is to build a strong, sustainable, innovative economy that works for everyone

4. The Honourable Katrine Conroy, Minister of Children and Family Development

Key priorities for her Ministry include:

- Enhancing and improving child-protection services to ensure that all children grow up in safe andnurturing environments.
- Investing in child protection to hire additional social workers and staff to support social workers, and toimplement incentives to attract social workers to rural and underserved regions.
- Working to implement the recommendations from Grand Chief Ed John’s report and provide better supports to keep Aboriginal children at home and out of care.

Read the full letter:

BRITISH
COLUMBIA

July 18, 2017

Honourable Katrine Conroy
Minister of Children and Family Development
Parliament Buildings
Victoria, British Columbia V8V 1X4

Dear Minister Conroy:

Congratulations on your new appointment as Minister of Children and Family Development.

It has never been more important for new leadership that works for ordinary people, not just those at the top.

It is your job to deliver that leadership in your ministry.

Our government made three key commitments to British Columbians.

Our first commitment is to make life more affordable. Too many families were left behind for too long by the previous government. They are counting on you to do your part to make their lives easier.

Our second commitment is to deliver the services that people count on. Together, we can ensure that children get access to the quality public education they need to succeed, that families can get timely medical attention, and that our senior citizens are able to live their final years with dignity.

These and other government services touch the lives of British Columbians every day. It is your job as minister to work within your budget to deliver quality services that are available and effective.

Our third key commitment is to build a strong, sustainable, innovative economy that works for everyone

5. The Honourable Katrina Chen, Minister of State for Childcare

Key priorities for her Ministry of State include:

- Work with all levels of government, child-care providers, the private and not-for-profit sectors to implement a universal child-care plan that provides affordable, accessible and high-quality care and early learning to every child whose family wants or needs it, starting with infant/toddler programs before gradually expanding.
- Provide additional investments in the Early Childhood Educator workforce through training, education and fair wages to enhance and ensure quality.
- Accelerate the creation of new child-care spaces in communities across the province as part of building a Better BC.

Read the full letter:

BRITISH
COLUMBIA

July 18, 2017

Honourable Katrina Chen
Minister of State for Child Care
Parliament Buildings
Victoria, British Columbia V8V 1X4

Dear Minister Chen:

Congratulations on your new appointment as Minister of State for Child Care.

It has never been more important for new leadership that works for ordinary people, not just those at the top.

It is your job to deliver that leadership in your ministry.

Our government made three key commitments to British Columbians.

Our first commitment is to make life more affordable. Too many families were left behind for too long by the previous government. They are counting on you to do your part to make their lives easier.

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These and other government services touch the lives of British Columbians every day. It is your job as minister to work within your budget to deliver quality services that are available and effective.

Our third key commitment is to build a strong, sustainable, innovative economy that works for everyone

6. The Honourable Jinny Sims, Minister of Citizens' Services

Key priorities for her Ministry include:

- Instituting a cap on the value and the length of government IT contracts to save money, increaseinnovation, improve competition and help our technology sector grow.
- Ensuring government IT and software development procurement work better for companies that hirelocally and have a local supply chain.
- Improving access to information rules to provide greater public accountability.

Read the full letter:

BRITISH COLUMBIA

July 18, 2017

Honourable Jinny Sims
Minister of Citizens' Services
Parliament Buildings
Victoria, British Columbia V8V 1X4

Dear Minister Sims:

Congratulations on your new appointment as Minister of Citizens' Services.

It has never been more important for new leadership that works for ordinary people, not just those at the top.

It is your job to deliver that leadership in your ministry.

Our government made three key commitments to British Columbians.

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Our third key commitment is to build a strong, sustainable, innovative economy that works for everyone

7. The Honourable Rob Fleming, Minister of Education

Key priorities for his Ministry include:

- Fast-track enhancement to K-12 education funding.
- Review the funding formula to develop a stable and sustainable model for the K-12 education system.
- Provide additional annual funding to ensure students have the school supplies they need to succeed.
- Create an ongoing capital fund for school playgrounds.
- Make schools safer by accelerating the seismic upgrade program.
- Work in partnership to build and upgrade schools in every region of the province.
- Implement the new First Nations history curriculum, develop full-course offerings in Aboriginal languages and implement the educational Calls to Action from the Truth and Reconciliation Commission.

Read the full letter:

BRITISH COLUMBIA

July 18, 2017

Honourable Rob Fleming
Minister of Education
Parliament Buildings
Victoria, British Columbia V8V 1X4

Dear Minister Fleming:

Congratulations on your new appointment as Minister of Education.

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Our third key commitment is to build a strong, sustainable, innovative economy that works for everyone

8. The Honourable Michelle Mungall, Minister of Energy, Mines and Petroleum Resources

Key priorities for this Ministry include:

- Create a roadmap for the future of B.C. energy that will drive innovation, expand energy-efficiency and conservation programs, generate new energy responsibly and sustainably, and create lasting good jobs across the province.
- Reinvigorate the Innovative Clean Energy fund to boost investments in groundbreaking new energy technologies and climate change solutions.
- Freeze B.C. Hydro rates while conducting a comprehensive review of the Crown corporation.
- Immediately refer the Site C dam construction project to the B.C. Utilities Commission on the question of economic viability and consequences to British Columbians in the context of the currentsupply and demand conditions prevailing in the B.C. market.

Read the full letter:

BRITISH
COLUMBIA

July 18, 2017

Honourable Michelle Mungall
Minister of Energy, Mines, and Petroleum Resources
Parliament Buildings
Victoria, British Columbia V8V 1X4

Dear Minister Mungall:

Congratulations on your new appointment as Minister of Energy, Mines, and Petroleum Resources.

It has never been more important for new leadership that works for ordinary people, not just those at the top.

It is your job to deliver that leadership in your ministry.

Our government made three key commitments to British Columbians.

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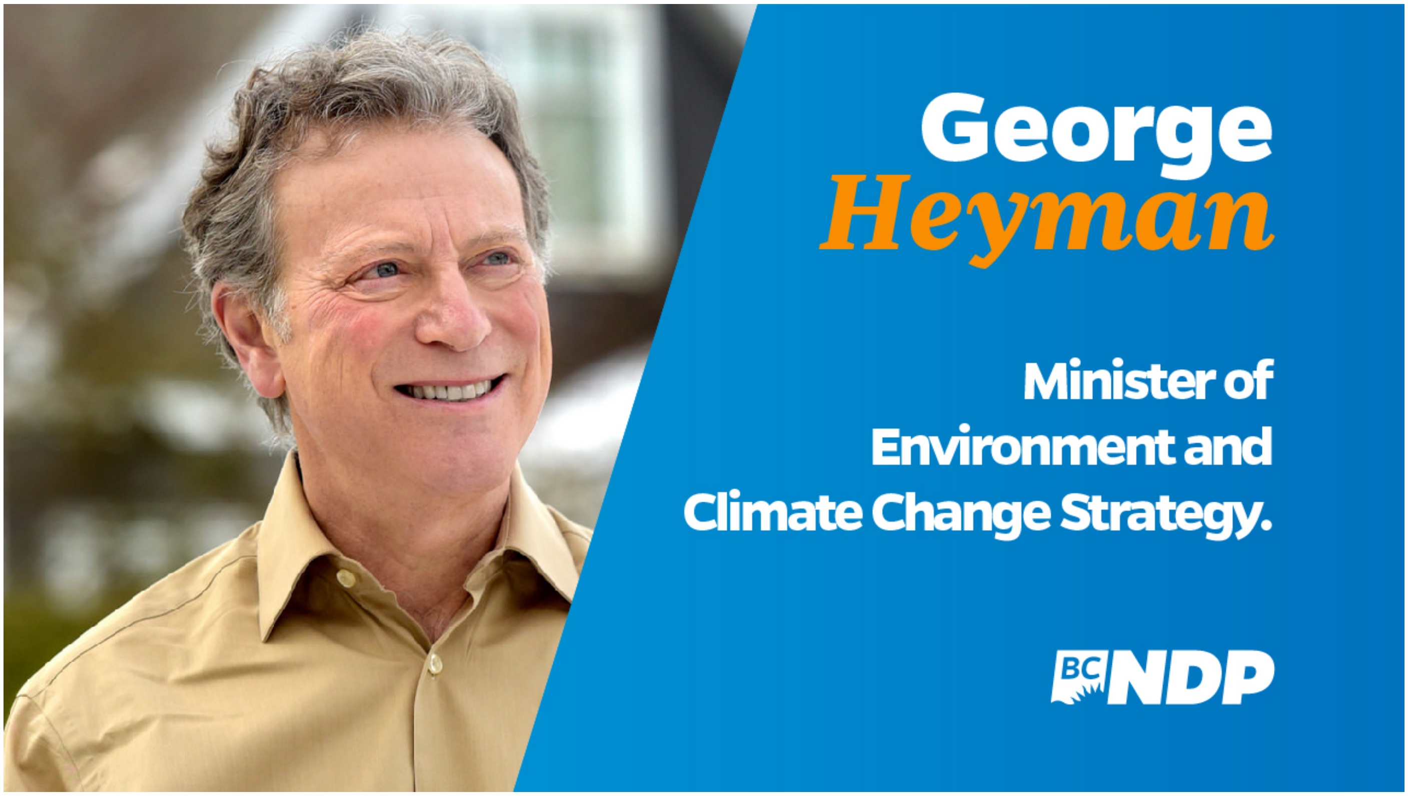
9. The Honourable George Heyman, Minister of Environment and Climate Change Strategy



Key priorities for his Ministry include:

- Implement a comprehensive climate-action strategy that provides a pathway for B.C. to prosper economically while meeting carbon pollution reduction targets, including setting a new legislated 2030 reduction target and establishing separate sectoral reduction targets and plans.
- Work with the Minister of Finance to implement an increase of the carbon tax by $5 per tonne per year, beginning April 1, 2018 to meet the federal government's carbon-pricing mandate. Take measures to expand the carbon tax to fugitive emissions and to slash-pile burning.
- Revitalize the Environmental Assessment process and review the professional reliance model to ensure the legal rights of First Nations are respected, and the public's expectation of a strong,transparent process is met.
- Employ every tool available to defend B.C.'s interests in the face of the expansion of the Kinder Morgan pipeline, and the threat of a seven-fold increase in tanker traffic on our coast.
- Enact an endangered species law and harmonize other laws to ensure they are all working towards thegoal of protecting our beautiful province

Read the full letter:

BRITISH
COLUMBIA

July 18, 2017

Honourable George Heyman
Minister of Environment and Climate Change Strategy
Parliament Buildings
Victoria, British Columbia V8V 1X4

Dear Minister Heyman:

Congratulations on your new appointment as Minister of Environment and Climate Change Strategy.

It has never been more important for new leadership that works for ordinary people, not just those at the top.

It is your job to deliver that leadership in your ministry.

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Our third key commitment is to build a strong, sustainable, innovative economy that works for everyone,

10. The Honourable Carole James, Minister of Finance and Deputy Premier

Key priorities for her Ministry include:

- Take measures to improve tax fairness and ensure the tax system reflects our commitment to work forall British Columbians, not just those at the top.
- Create a Medical Service Plan task force and eliminate Medical Service Plan fees within four years,starting with a 50% reduction on January 1, 2018.
- Eliminate tolls on the Port Mann and Golden Ears bridges.
- Take measures to improve housing affordability, close real estate speculation loopholes, and reducetax fraud and money laundering in the B.C. real estate marketplace.

Read the full letter:

BRITISH COLUMBIA

July 18, 2017

Honourable Carole James
Minister of Finance and Deputy Premier
Parliament Buildings
Victoria, British Columbia V8V 1X4

Dear Minister James:

Congratulations on your new appointment as Minister of Finance and Deputy Premier.

It has never been more important for new leadership that works for ordinary people, not just those at the top.

It is your job to deliver that leadership in your ministry.

Our government made three key commitments to British Columbians.

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11. The Honourable Doug Donaldson, Minister of Forests, Lands, Natural Resource Operations, and Rural Development

Key priorities for his ministry include:

- Protect and create jobs by fighting for a fair deal for B.C. wood products in softwood lumbernegotiations with the United States.
- Work with communities and industry to develop a fair, lasting strategy to create more jobs by processing more logs in B.C. and to renew our forests by expanding investments in reforestation.
- Expand our innovative wood-products sector by addressing regulatory and capital barriers hamperingthe growth of engineered wood production and work with other ministers to ensure public projects prioritize the use of B.C. wood.
- Improve wildlife management and habitat conservation, and collaborate with stakeholders to developlong and short term strategies to manage B.C.'s wildlife resources.

Read the full letter:

BRITISH
COLUMBIA

July 18, 2017

Honourable Doug Donaldson
Minister of Forests, Lands, Natural Resource
Operations and Rural Development
Parliament Buildings
Victoria, British Columbia V8V 1X4

Dear Minister Donaldson:

Congratulations on your new appointment as Minister of Forests, Lands, Natural Resource Operations, and Rural Development.

It has never been more important for new leadership that works for ordinary people, not just those at the top.

It is your job to deliver that leadership in your ministry.

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12. The Honourable Adrian Dix, Minister of Health

Key priorities for his Ministry include:

- Prioritize the provision of team-based primary care by establishing urgent family-care centres across the province.
- Improve rural health services and expand the medical travel allowance for those who must travel for care.
- Work with the Parliamentary Secretary for Seniors to improve and strengthen services to ensure seniors receive dignified and quality care.
- Invest in more paramedics.
- Work to reduce wait times and implement province-wide co-ordination to manage and actively monitor waitlists.
- Work with the federal government towards a national Pharmacare program and work with the B.C.Green caucus to develop a proposal to implement an essential drugs program

Read the full letter:

BRITISH COLUMBIA

July 18, 2017

Honourable Adrian Dix
Minister of Health
Parliament Buildings
Victoria, British Columbia V8V 1X4

Dear Minister Dix:

Congratulations on your new appointment as Minister of Health.

It has never been more important for new leadership that works for ordinary people, not just those at the top.

It is your job to deliver that leadership in your ministry.

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Our third key commitment is to build a strong, sustainable, innovative economy that works for everyone,

13. The Honourable Scott Fraser, Minister of Indigenous Relations and Reconciliation

Key priorities for his Ministry include:

- Work collaboratively and respectfully with First Nations to establish a clear, cross-government visionof reconciliation to guide the adoption of the United Nations Declaration on the Rights of Indigenous Peoples, the Truth and Reconciliation Commission Calls to Action, and the Tsilhqot'in Supreme Court decision.
- In partnership with First Nations, transform the treaty process so it respects case law and the United Nations Declaration on the Rights of Indigenous Peoples.
- Support Indigenous communities seeking to revitalize connections to their languages.

Read the full letter:

BRITISH
COLUMBIA

July 18, 2017

Honourable Scott Fraser
Minister of Indigenous Relations and Reconciliation
Parliament Buildings
Victoria, British Columbia V8V 1X4

Dear Minister Fraser:

Congratulations on your new appointment as Minister of Indigenous Relations and Reconciliation.

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Our third key commitment is to build a strong, sustainable, innovative economy that works for everyone,

14. The Honourable Bruce Ralston, Minister of Jobs, Trade and Technology

Key priorities for his Ministry include:

- Establish B.C. as a preferred location for new and emerging technologies by supporting venture capital investment in B.C. startups, taking measures to increase the growth of domesitic B.C. techcompanies, and removing barriers to attracting and repatriating skilled workers.
- Ensure that the benefits of technology and innovation are felt around the province by working with rural and northern communities and equity-seeking groups to make strategic investments that supportinnovation and job growth.
- Establish an Emerging Economy Task Force and establish an Innovation Commission to advocate forthe technology sector.

Read the full letter:

BRITISH
COLUMBIA

July 18, 2017

Honourable Bruce Ralston
Minister of Jobs, Trade, and Technology
Parliament Buildings
Victoria, British Columbia V8V 1X4

Dear Minister Ralston:

Congratulations on your new appointment as Minister of Jobs, Trade, and Technology.

It has never been more important for new leadership that works for ordinary people, not just those at the top.

It is your job to deliver that leadership in your ministry.

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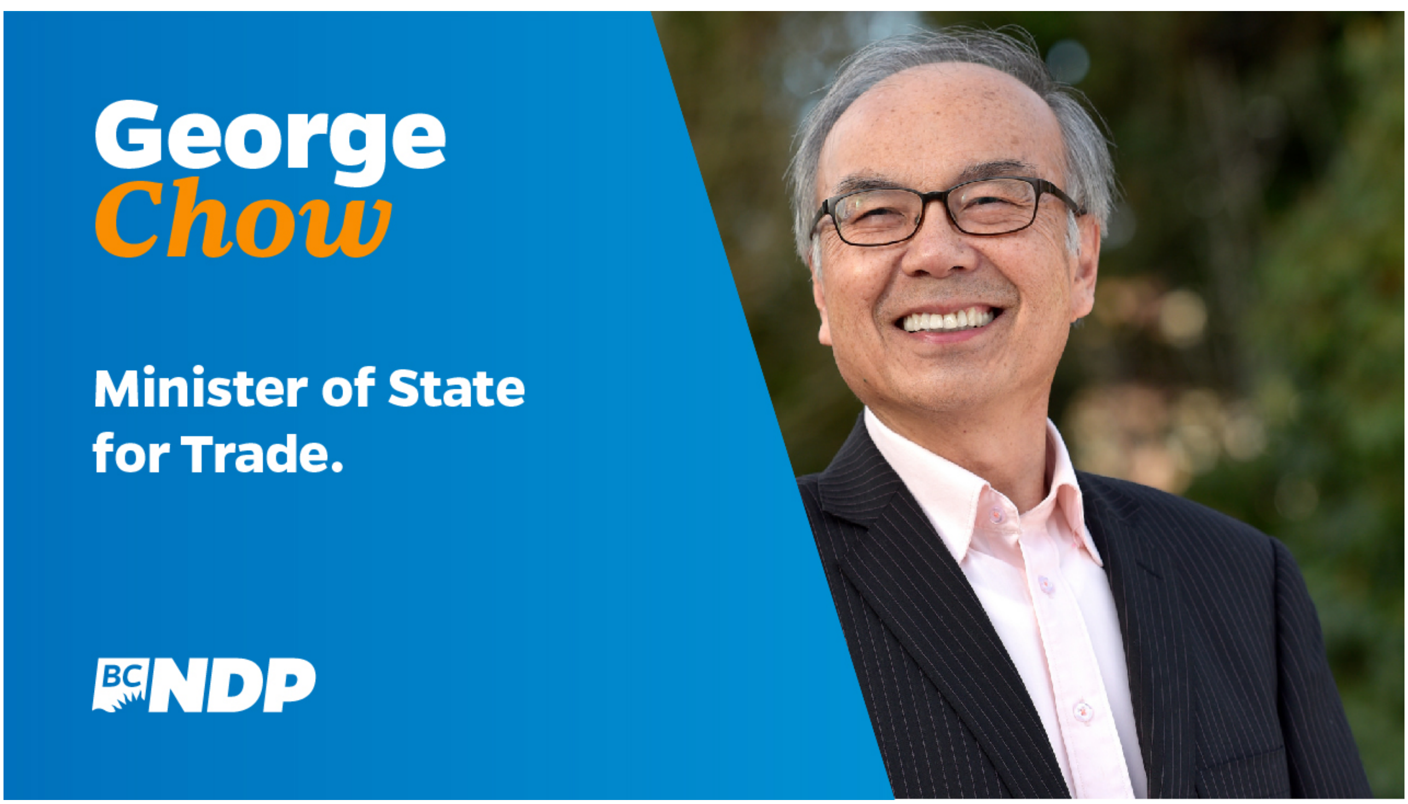
15. The Honourable George Chow, Minister of State for Trade



Key priorities for his Ministry of State include:

- Work across ministries and with the federal government to ensure British Columbia's interests are protected and advanced in trade negotiations and disputes.
- Work across ministries and with the B.C. chapter of the Canadian Manufactures and Exporters Association to further export opportunities for B.C. businesses.
- Work with the Minister of Forests, Lands, Natural Resource Operations, and Rural Development to advocate for a fair deal for B.C. in softwood lumber negotiations with the United States.
- Work with the Minister of Forests, Lands, Natural Resource Operations, and Rural Development, and with BC's forest industry to expand efforts to market innovative manufactured wood products to world markets.

Read the full letter:

BRITISH COLUMBIA

July 18, 2017

Honourable George Chow
Minister of State for Trade
Parliament Buildings
Victoria, British Columbia V8V 1X4

Dear Minister Chow:

Congratulations on your new appointment as Minister of State for Trade.

It has never been more important for new leadership that works for ordinary people, not just those at the top.

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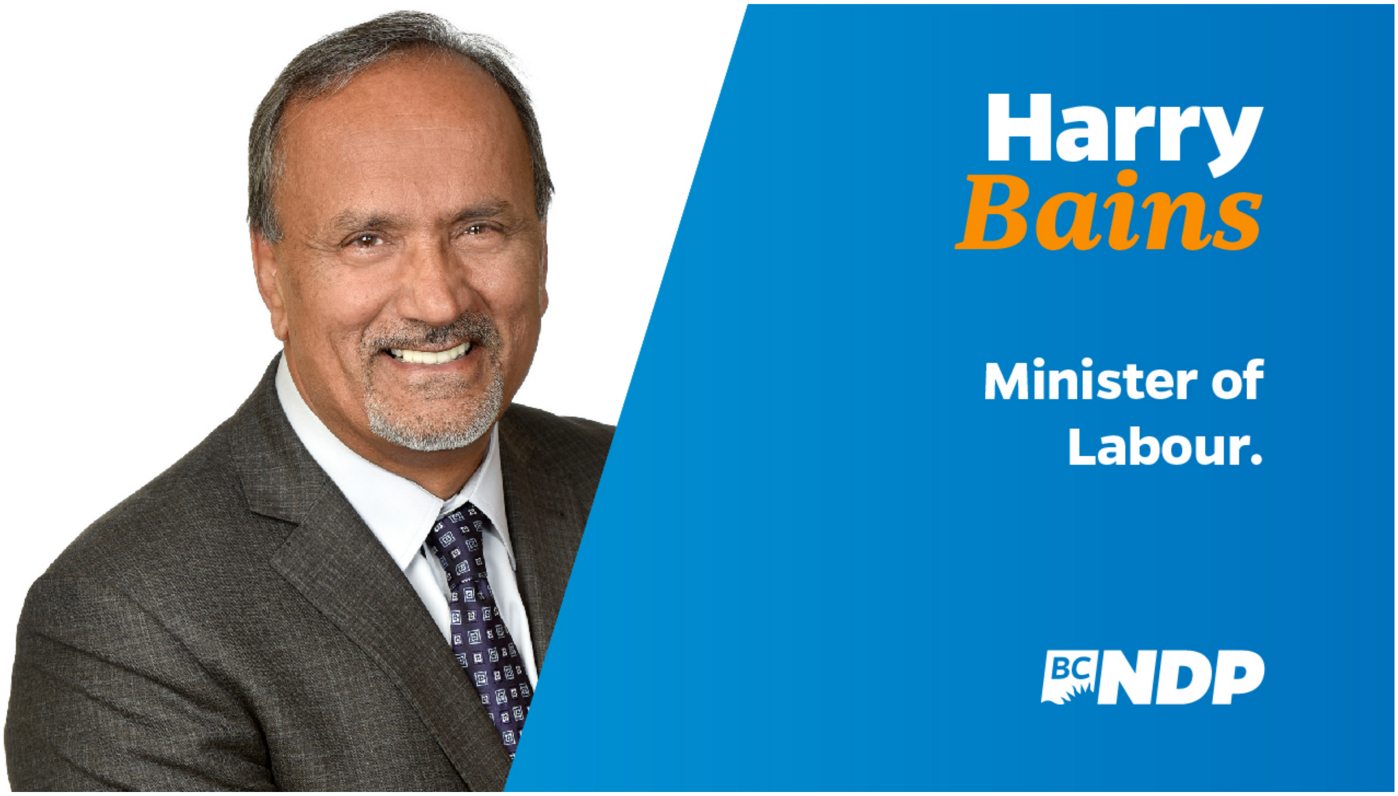
16. The Honourable Harry Bains, Minister of Labour



Key priorities for his Ministry include:

- Establish a Fair Wage Commission to support the work of implementing the $15-per-hour minimum wage by 2021 and to bring forward recommendations to close the gap between the minimum wage and livable wages. The commission will make its first report within90 days of its first meeting.
- Create a Temporary Foreign Worker registry to help protect vulnerable workers from exploitation and to track the use of temporary workers in our economy.
- Update employment standards to reflect the changing nature of workplaces and ensure they are applied evenly and enforced.
- Review and develop options with WorkSafe B.C. to increase compliance with employment laws and standards put in place to protect the lives and safety of workers.

Read the full letter:

BRITISH
COLUMBIA

July 18, 2017

Honourable Harry Bains
Minister of Labour
Parliament Buildings
Victoria, British Columbia V8V 1X4

Dear Minister Bains:

Congratulations on your new appointment as Minister of Labour.

It has never been more important for new leadership that works for ordinary people, not just those at the top.

It is your job to deliver that leadership in your ministry.

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17. The Honourable Judy Darcy, Minister of Mental Health and Addictions

Key priorities for her Ministry include:

- Work in partnership to develop an immediate response to the opioid crisis that includes crucial investments and improvements to mental-health and addictions services.
- Create a mental-health and addiction strategy to guide the transformation of B.C.'s mental-health-care system. As part of this strategy, include a focus on improving access, investing in early prevention and youth mental health.
- Consult with internal and external stakeholders to determine the most effective way to deliver quality mental-health and addiction services.

Read the full letter:

BRITISH
COLUMBIA

July 18, 2017

Honourable Judy Darcy
Minister of Mental Health and Addictions
Parliament Buildings
Victoria, British Columbia V8V 1X4

Dear Minister Darcy:

Congratulations on your new appointment as Minister of Mental Health and Addictions.

It has never been more important for new leadership that works for ordinary people, not just those at the top.

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18. The Honourable Selina Robinson, Minister of Municipal Affairs and Housing

Key priorities for her Ministry include:

- Partnering with local governments and First Nations to develop a community capital infrastructure fund to upgrade and build sports facilities, playgrounds, local community centres, and arts and culture spaces.
- Through partnerships with local governments, the federal government, and the private and not-for- profit sectors, begin to build 114,000 units of affordable market rental, non-profit, co-op, supported social housing and owner-purchase housing.
- Amending the Residential Tenancy Act to provide stronger protections for renters, and provide additional resources to the Residential Tenancy Branch.
- With the Minister of Finance, delivering an annual renter's rebate of $400 dollars per rental household to improve rental affordability.

Read the full letter:

BRITISH COLUMBIA

July 18, 2017

Honourable Selina Robinson
Minister of Municipal Affairs and Housing
Parliament Buildings
Victoria, British Columbia V8V 1X4

Dear Minister Robinson:

Congratulations on your new appointment as Minister of Municipal Affairs and Housing.

It has never been more important for new leadership that works for ordinary people, not just those at the top.

It is your job to deliver that leadership in your ministry.

Our government made three key commitments to British Columbians.

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19. The Honourable Mike Farnworth, Minister of Public Safety and Solicitor General

Key priorities for his Ministry include:

- Provide more support to police efforts to disrupt the supply chain and advocate for increased penalties for drug dealers who knowingly distribute death-dealing drugs.
- Take action on gang and gun violence.
- Increase annual funding to support women who experience domestic violence, sexual assault and other crimes.
- Work with First Nations to set targets and take action to reduce the numbers of Aboriginal people involved in the justice system.
- Recognize culture for its role in rehabilitation and recovery and provide culturally diverse and appropriate programming in prisons, particularly for Aboriginal people.

Read the full letter:

BRITISH
COLUMBIA

July 18, 2017

Honourable Mike Farnworth
Minister of Public Safety and Solicitor General
Parliament Buildings
Victoria, British Columbia V8V 1X4

Dear Minister Farnworth:

Congratulations on your new appointment as Minister of Public Safety and Solicitor General.

It has never been more important for new leadership that works for ordinary people, not just those at the top.

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20. The Honourable Shane Simpson, Minister of Social Development and Poverty Reduction

Key priorities for his Ministry include:

- Encourage and support assistance recipients as they re-enter the workforce by allowing them to keepan additional $200 a month in earnings exemptions.
- Further support those on disability assistance by fully restoring the BC Bus Pass program.
- Develop a basic-income pilot to test whether giving people a basic income is an effective way toreduce poverty, improve health, housing and employment.
- Design and implement a province-wide poverty-reduction strategy with legislated targets andtimelines.

Read the full letter:

BRITISH
COLUMBIA

July 18, 2017

Honourable Shane Simpson
Minister of Social Development and Poverty Reduction
Parliament Buildings
Victoria, British Columbia V8V 1X4

Dear Minister Simpson:

Congratulations on your new appointment as Minister of Social Development and Poverty Reduction.

It has never been more important for new leadership that works for ordinary people, not just those at the top.

It is your job to deliver that leadership in your ministry.

Our government made three key commitments to British Columbians.

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21. The Honourable Lisa Beare, Minister of Tourism, Arts and Culture

Key priorities for her Ministry include:

- Champion tourism as a job creator throughout British Columbia and work to expand tourism-marketing efforts internationally.
- Work with the Minister of Jobs, Trade, and Technology to ensure that British Columbia's tourism sector is represented on trade missions.
- Double the Province's investment in the B.C. Arts Council over four years.
- Increase investments in Creative B.C. over four years.
- Establish an arts infrastructure fund to help provide space for B.C. artists

Read the full letter:

BRITISH
COLUMBIA

July 18, 2017

Honourable Lisa Beare
Minister of Tourism, Arts and Culture
Parliament Buildings
Victoria, British Columbia V8V 1X4

Dear Minister Beare:

Congratulations on your new appointment as Minister of Tourism, Arts and Culture.

It has never been more important for new leadership that works for ordinary people, not just those at the top.

It is your job to deliver that leadership in your ministry.

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These and other government services touch the lives of British Columbians every day. It is your job as minister to work within your budget to deliver quality services that are available and effective.

22. The Honourable Claire Trevena, Minister of Transportation and Infrastructure

Key priorities for her Ministry include:

- Lead planning to address the infrastructure needs of rural and urban British Columbia under the government's comprehensive capital infrastructure plan to build a Better B.C.
- Work with the Minister of Finance to eliminate tolls on the Port Mann and Golden Ears Bridges.
- Accelerate Highway 1 upgrades to the Alberta border.
- Work with the Minister of Municipal Affairs and Housing to secure federal funding for the Pattullo Bridge replacement and rapid transit in Metro Vancouver as part of implementing the mayor's 10-year plan for transit and transportation.
- Work with B.C. Transit, the federal government, and local governments to fund transit improvements across the province, including improving HandyDART service
- Work with B.C. Ferries to freeze and reduce fares, and reinstate the senior's weekday 100% discount, while conducting a comprehensive operating review.
- Work with the Minister of Public Safety and Solicitor General to create a fair approach to ridesharing.

Read the full letter:

BRITISH COLUMBIA

July 18, 2017

Honourable Claire Trevena
Minister of Transportation and Infrastructure
Parliament Buildings
Victoria, British Columbia V8V 1X4

Dear Minister Trevena:

Congratulations on your new appointment as Minister of Transportation and Infrastructure.

It has never been more important for new leadership that works for ordinary people, not just those at the top.

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Our second commitment is to deliver the services that people count on. Together, we can ensure that children get access to the quality public education they need to succeed, that families can get timely medical attention, and that our senior citizens are able to live their final years with dignity.

These and other government services touch the lives of British Columbians every day. It is your job as minister to work within your budget to deliver quality services that are available and effective.

Our third key commitment is to build a strong, sustainable, innovative economy that works for everyone,

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LEVERAGING NATURAL GAS TO REDUCE GREENHOUSE GAS EMISSIONS

June 2013

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EXECUTIVE SUMMARY

Recent technological advances have unleashed a boom in U.S. natural gas production, with expanded supplies and substantially lower prices projected well into the future. Because combusting natural gas yields fewer greenhouse gas emissions than coal or petroleum, the expanded use of natural gas offers significant opportunities to help address global climate change. The substitution of gas for coal in the power sector, for example, has contributed to a recent decline in U.S. greenhouse gas emissions. Natural gas, however, is not carbon-free. Apart from the emissions released by its combustion, natural gas is composed primarily of methane (CH_4), a potent greenhouse gas, and the direct release of methane during production, transmission, and distribution may offset some of the potential climate benefits of its expanded use across the economy.

This report explores the opportunities and challenges in leveraging the natural gas boom to achieve further reductions in U.S. greenhouse gas emissions. Examining the implications of expanded use in key sectors of the economy, it recommends policies and actions needed to maximize climate benefits of natural gas use in power generation, buildings, manufacturing, and transportation (Table ES-1). More broadly, the report draws the following conclusions:

- The expanded use of natural gas—as a replacement for coal and petroleum—can help our efforts to reduce greenhouse gas emissions in the near- to mid-term, even as the economy grows. In 2013, energy sector emissions are at the lowest levels since 1994, in part because of the substitution of natural gas for other fossil fuels, particularly coal. Total U.S. emissions are not expected to reach 2005 levels again until sometime after 2040.
- Substitution of natural gas for other fossil fuels cannot be the sole basis for long-term U.S. efforts to address climate change because natural gas is a fossil fuel and its combustion emits greenhouse gases. To avoid dangerous climate change, greater reductions will be necessary than natural gas alone can provide. Ensuring that low-carbon investment dramatically expands must be a priority. Zero-emission sources of energy, such as wind, nuclear and solar, are critical, as are the use of carbon capture-and-storage technologies at fossil fuel plants and continued improvements in energy efficiency.
- Along with substituting natural gas for other fossil fuels, direct releases of methane into the atmosphere must be minimized. It is important to better understand and more accurately measure the greenhouse gas emissions from natural gas production and use in order to achieve emissions reductions along the entire natural gas value chain.

TABLE ES-1: Sector-Specific Conclusions and Recommendations

POWER SECTOR
It is essential to maintain fuel mix diversity in the power sector. Too much reliance on any one fuel can expose a utility, ratepayers, and the economy to the risks associated with commodity price volatility. The increased natural gas and renewable generation of recent years has increased the fuel diversity of the power sector (by reducing the dominance of coal). In the long term, however, concern exists that market pressures could result in the retirement of a significant portion of the existing nuclear fleet, all of which could be replace by natural gas generation. Market pressures also could deter renewable energy deployment, carbon capture and storage, and efficiency measures. Without a carbon price, the negative externalities associated with fossil fuels are not priced by society, and therefore there will be less than optimal investment and expansion of zero-carbon energy sources.
Instead of being thought of as competitors, however, natural gas and renewable energy sources such as wind and solar can be complementary components of the power sector. Natural gas plants can quickly scale up or down their electricity production and so can act as an effective hedge against the intermittency of renewables. The fixed fuel price (at zero) of renewables can likewise act a hedge against potential natural gas price volatility.

TABLE ES-1: Sector-Specific Conclusions and Recommendations—continued

BUILDINGS SECTOR
It is important to encourage the efficient direct use of natural gas in buildings, where natural gas applications have a lower greenhouse gas emission footprint compared with other energy sources. For thermal applications, such as space and water heating, onsite natural gas use has the potential to provide lower-emission energy compared with oil or propane and electricity in most parts of the country. Natural gas for thermal applications is more efficient than grid-delivered electricity, yielding less energy losses along the supply chain and therefore less greenhouse gas emissions. Consumers need to be made aware of the environmental and efficiency benefits of natural gas use through labeling and standards programs and be incentivized to use it when emissions reductions are possible.
MANUFACTURING SECTOR
The efficient use of natural gas in the manufacturing sector needs to be continually encouraged. Combined heat and power systems, in particular, are highly efficient, as they use heat energy otherwise wasted. Policy is needed to overcome existing barriers to their deployment, and states are in an excellent position to take an active role in promoting combined heat and power during required industrial boiler upgrades and new standards for cleaner electricity generation in coming years. For efficiency overall, standards, incentives, and education efforts are needed, especially as economic incentives are weak in light of low natural gas prices.
DISTRIBUTED GENERATION
Natural gas-related technologies, such as microgrids, microturbines, and fuel cells, have the potential to increase the amount of distributed generation used in buildings and manufacturing. These technologies can be used in configurations that reduce greenhouse gas emissions when compared with the centralized power system as they can reduce transmission losses and use waste heat onsite. To realize the potential of these technologies and overcome high upfront equipment and installation costs, policies like financial incentives and tax credits will need to be more widespread, along with consumer education about their availability.
TRANSPORTATION SECTOR
The greatest opportunity to reduce greenhouse gas emissions using natural gas in the transportation sector is through fuel substitution in fleets and heavy-duty vehicles. Passenger vehicles, in contrast, likely represent a much smaller emission reduction opportunity even though natural gas when combusted emits fewer greenhouse gases than gasoline or diesel. The reasons for this include the smaller emission reduction benefit (compared to coal conversions), and the time it will take for a public infrastructure transition. By the time a passenger fleet conversion to natural gas would be completed, a new conversion to an even lower-carbon system, like fuel cells or electric vehicles, will be required to ensure significant emissions reductions throughout the economy.
INFRASTRUCTURE
Transmission and distribution pipelines must be expanded to ensure adequate supply for new regions and to serve more thermal loads in manufacturing, homes, and businesses. Increased policy support and innovative funding models, particularly for distribution pipelines, are needed to support the rapid deployment of this infrastructure.

I. OVERVIEW OF MARKETS AND USES

By Meg Crawford and Janet Peace, C2ES

INTRODUCTION

Recent technological advances have unleashed a boom in natural gas production, a supply surplus, and a dramatically lower price. The ample supply and lower price are expected to continue for quite some time, resulting in a relatively stable natural gas market. As a consequence, interest in expanding the use of natural gas has increased in a variety of sectors throughout the economy, including power, buildings, manufacturing, and transportation. Given that combusting natural gas yields lower greenhouse gas emissions than that of burning coal or petroleum, this expanded use offers significant potential to help the United States meet its climate change objectives. Expanded use of gas in the power sector, for example, has already led to a decrease in U.S. greenhouse gas emissions because of the substitution of gas for coal. It is important to recognize, however, that natural gas, like other fossil fuel production and combustion, does release greenhouse gases. These include carbon dioxide and methane; the latter is a higher global warming greenhouse gas. Accordingly, a future with expanded natural gas use will require diligence to ensure that potential benefits to the climate are achieved. This report explores the opportunities and challenges, sector by sector throughout the U.S. economy, and delves into the assortment of market, policy, and social responses that can either motivate or discourage the transition toward lower-carbon and zero-carbon energy sources essential for addressing climate change.

CONTEXT: A NEW DOMINANT PLAYER

Throughout its history, the United States has undergone several energy transitions in which one dominant energy source has been supplanted by another. Today, as the country seeks lower-carbon, more affordable, domestically sourced fuel options to meet a variety of market, policy, and environmental objectives, the United States appears poised for another energy transition. Past energy transitions, for example, from wood to coal, took place largely without well-defined policies and were not informed by other big-picture considerations. Transitions of the past were largely shaped by regional and local economic realities and only immediate, local environmental considerations. The potential next energy transition can be more deliberately managed to achieve economic and environmental goals. The United States possesses the technological capacity and policy structures to do this. This report outlines, sector by sector, those technological options and policy needs.

The history of energy consumption in the United States from 1800 to 2010 moved steadily from wood to coal to petroleum (Figure 1). In the latter half of the 19th century, coal surpassed wood as the dominant fuel. Around 1950, petroleum consumption exceeded that of coal.

Petroleum still reigns supreme in the United States; however, due to a number of factors including improving fuel economy standards for vehicles, its use since 2006 is in decline. At the same time, for reasons that this report explores in depth, natural gas use is on the rise. As these trends continue, it is entirely possible in the coming decades that natural gas will overtake petroleum as the most popular primary energy source in the United States.[1]

Natural gas already plays a large role in the U.S. economy, constituting 27 percent of total U.S. energy consumption in 2012. Unlike other fossil fuels, natural gas has applications in almost every sector, including generating electricity; providing heat and power to industry, commercial buildings, and homes; powering vehicles; and as a feedstock in the manufacture of industrial products.

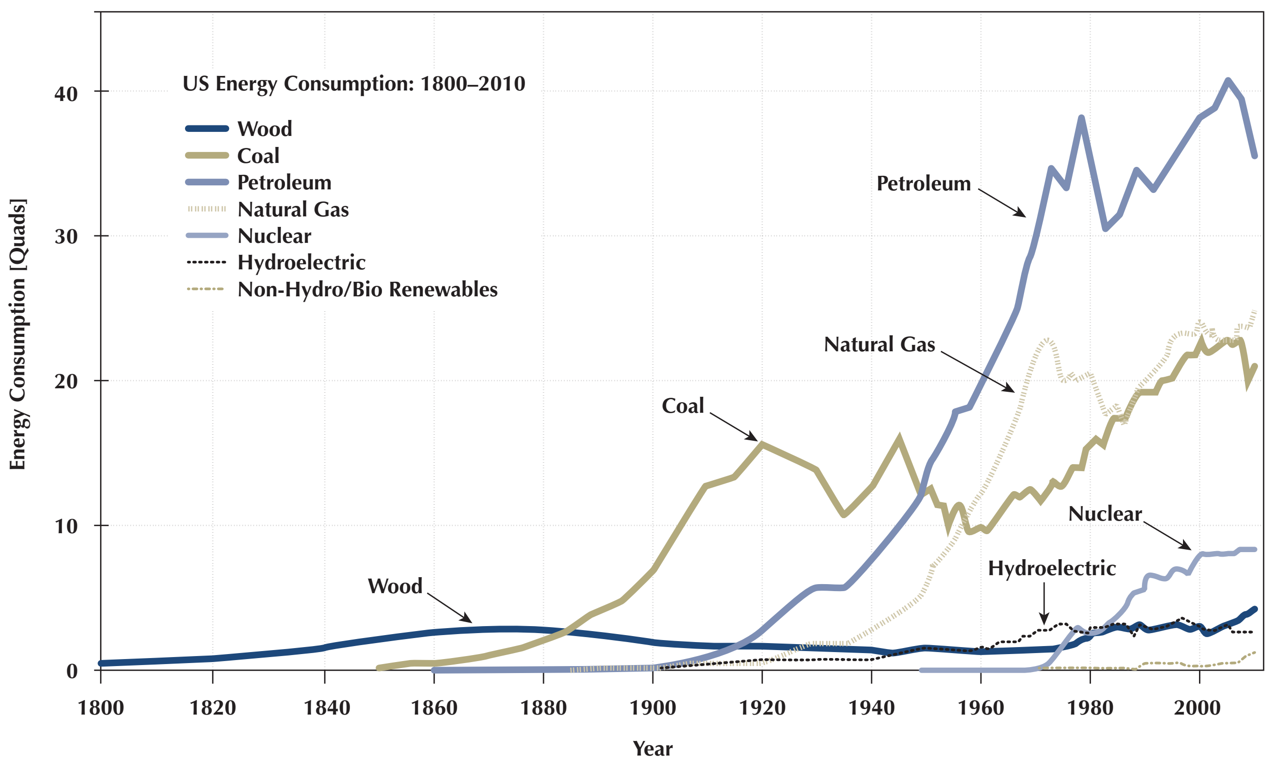
By all accounts, the existing increase in natural gas supply appears very certain, and the large domestic supply is expected to keep natural gas prices relatively low in the near to medium term. Furthermore, the domestic supply already has and is forecasted to deliver substantial benefits to the U.S. economy, providing jobs and increasing the gross domestic product. The primary uncertainties for the natural gas market are how quickly the expanded use will occur and the specific ways in which specific sectors of the economy will be affected. This report delves into the assortment of market, policy, and social responses that can motivate or discourage this transition. It places this energy transition firmly in the context of the closely related climate impacts of different types of energy use, and explores the interplay between economic opportunities and the pressing need to dramatically reduce the economy's emissions of greenhouse gases.

CLIMATE IMPLICATIONS

The expanding use of natural gas is already reducing emissions of carbon dioxide (CO_2), the primary greenhouse gas, at a time in which the U.S. economy is growing. In 2011, total U.S. CO_2 emissions were down by nearly 9 percent from peak levels of 6,020 million metric tons in 2007. This decrease is due to a number of factors, of which the increased use of natural gas in the power sector is prominent. Demand is increasing as new and significantly more efficient natural gas power plants have been recently constructed, existing natural gas power plants are being used more extensively, and fuel-substitution from coal to natural gas is taking place. Compared to coal, natural gas is considered relatively clean because when it is burned in power plants, it releases about half as much CO_2 (and far fewer pollutants) per unit of energy delivered than coal. As the fraction of electric power generated by coal has fallen over the last six years and been replaced mostly by natural gas-fueled generation and renewables, total U.S. CO_2 emissions have decreased.

According to several sources, including the U.S. Energy Information Administration (EIA), additions in electric power capacity over the next 20 years are expected to be predominantly either natural gas-fueled or renewable (discussed further in chapter 4 of

FIGURE 1: Total U.S. Energy Consumption, 1800 to 2010



Source: Energy Information Administration, "Annual Energy Review," Table 1.3. September 2012. Available at: http://www.eia.gov/totalenergy/data/annual/index.cfm#summary

Note: Wood, which was the dominant fuel in the United States for the first half of the 19th century, was surpassed by coal starting in 1885. Coal as the dominant fuel was surpassed by petroleum in 1950. Within one to two decades, natural gas might surpass petroleum as the dominant energy provider.

this report). Therefore, as coal's share of generation continues to diminish, the implications for climate in the near and medium term are reduced CO_2 emissions from the power sector. Further reductions in CO_2 emissions are possible if natural gas replaces coal or petroleum in other economic sectors. In addition, wider use of distributed generation technologies in the manufacturing, commercial, and residential sectors, namely natural gas-fueled combined heat and power (CHP) systems, has great potential to significantly reduce U.S. CO_2 emissions.

In the long term, however, the United States cannot achieve the level of greenhouse gas emissions necessary to avoid the serious impacts of climate change by relying on natural gas alone. Also required is the development of significant quantities of zero-emission sources of energy, which economic modeling shows will require policy intervention. Since many of these energy sources, such as wind and solar, are intermittent and current energy storage technology is in its infancy, natural gas will likely also be needed in the long term as a reliable, dispatchable backup for these renewable sources.

Crucially, natural gas is primarily methane, which is itself a very potent greenhouse gas. Methane is about 21 times more powerful in its heat-trapping ability than CO_2 over a 100-year time scale. With increased use of natural gas, the direct releases of methane into the atmosphere throughout production and distribution have the potential to be a significant climate issue. Regulations have already been promulgated by the Environmental Protection Agency (EPA) that address this key issue. For example, "green completion" rules for production will require all unconventional wells to virtually eliminate venting during the flow-back stage of well completion through flaring or capturing natural gas. Releases need to be carefully managed, and EPA regulation of the natural gas sector will ensure that the climate benefits from transitioning to natural gas are truly maximized.

ABOUT THIS REPORT

To examine the possible ways in which this energy transition might unfold and the potential implications for the climate, the Center for Climate and Energy Solutions and researchers at The University of Texas prepared 9 discussion papers looking at individual economic sectors, natural gas technologies, markets, infrastructure, and environmental considerations. Then, two workshops brought together dozens of respected thought leaders and stakeholders to analyze the potential to leverage natural gas use to reduce greenhouse gas emissions. Stakeholders included representatives of electric and natural gas utilities, vehicle manufacturers, fleet operators, industrial consumers, homebuilders, commercial real estate operators, pipeline companies, independent and integrated natural gas producers, technology providers, financial analysts, public utility and other state regulators, environmental nonprofits, and academic researchers and institutions.

This report is the culmination of these efforts. First, it provides background on natural gas and the events leading to the present supply boom. Next, it lays out the current and projected U.S. natural gas market, including the forecast price effects during the transition. It details the relationship between natural gas and climate change and then explores the opportunities and challenges in the power, buildings, and manufacturing sectors. It looks at technologies for on-site (distributed) electricity generation using natural gas, followed by prospects for increasing natural gas consumption in the transportation sector. Finally, the report examines the state of natural gas infrastructure and the barriers to its needed expansion.

This report offers insight into ways to lower the climate impact of natural gas while increasing its use in the electric power, buildings, manufacturing, and transportation sectors, and looks at infrastructure expansion needs and what future technologies may portend for low-emission natural gas use. This report is the product solely of the Center for Climate and Energy Solutions (C2ES) and may not necessarily represent the views of workshop participants, the C2ES Business Environmental Leadership Council or Strategic Partners, or project sponsors.

BACKGROUND

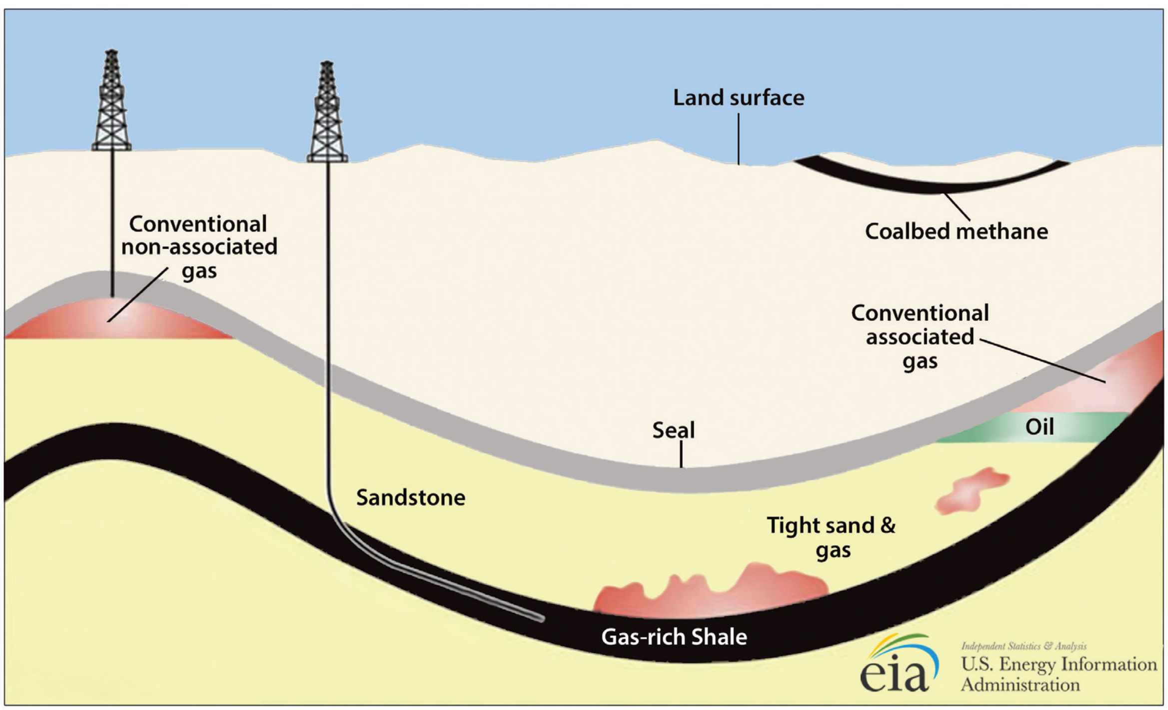
Natural gas is a naturally occurring fossil fuel consisting primarily of methane that is extracted with small amounts of impurities, including CO_2, hazardous air pollutants, and volatile organic compounds. Most natural gas production also contains, to some degree, heavier liquids that can be processed into valuable byproducts, including propane, butane, and pentane.

Natural gas is found in several different types of geologic formations (Figure 2). It can be produced alone from reservoirs in natural rock formations or be associated with the production of other hydrocarbons such as oil. While this "associated" gas is an important source of domestic supply, the majority (89 percent) of U.S. gas is extracted as the primary product, i.e., non-associated.[2]

With relatively recent advances in seismic imaging, horizontal drilling, and hydraulic fracturing, U.S. natural gas is increasingly produced from unconventional sources such as coal beds, tight sandstone, and shale formations, where natural gas resources are not concentrated or are in impermeable rock and require advanced technologies for development and production and typically yield much lower recovery rates than conventional reservoirs.[3] Shale gas extraction, for example, differs significantly from the conventional extraction methods. Wells are drilled vertically and then turned horizontally to run within shale formations. A slurry of sand, water, and chemicals is then injected into the well to increase pressure, break apart the shale to increase permeability, and release the natural gas. This technique is known as hydraulic fracturing or "fracking."

The remarkable speed and scale of shale gas development has led to substantial new supplies of natural gas making their way to market in the United States. The U.S. EIA projects that by 2040 more than half of domestic natural gas production will come from shale gas extraction and that production will increase by 10 trillion cubic feet (Tcf) above 2011 levels (Figure 3). The current increase was largely unforeseen a decade ago. This increase has raised awareness of natural gas as a key component of the domestic energy supply and has dramatically lowered current prices as well as price expectations for the future. In recent years, the abundance of natural gas in the United States has strengthened its competitiveness relative to coal and oil,

FIGURE 2: Geological Formations Bearing Natural Gas



Source: Energy Information Agency, "Schematic Geology of Natural Gas Resources," January 2010. Available at: http://www.eia.gov/oil_gas/natural_gas/special/ngresources/ngresources.html

Notes: Gas-rich shale is the source rock for many natural gas resources, but, until now, has not been a focus for production. Horizontal drilling and hydraulic fracturing have made shale gas an economically viable alternative to conventional gas resources.

Conventional gas accumulations occur when gas migrates from gas rich shale into an overlying sandstone formation, and then becomes trapped by an overlying impermeable formation, called the seal. Associated gas accumulates in conjunction with oil, while non-associated gas does not accumulate with oil.

Tight sand gas accumulations occur in a variety of geologic settings where gas migrates from a source rock into a sandstone formation, but is limited in its ability to migrate upward due to reduced permeability in the sandstone.

Coalbed methane does not migrate from shale, but is generated during the transformation of organic material to coal.

has expanded its use in a variety of contexts, and has raised its potential for reducing greenhouse gas emissions and strengthening U.S. energy security by reducing U.S. reliance on foreign energy supplies.

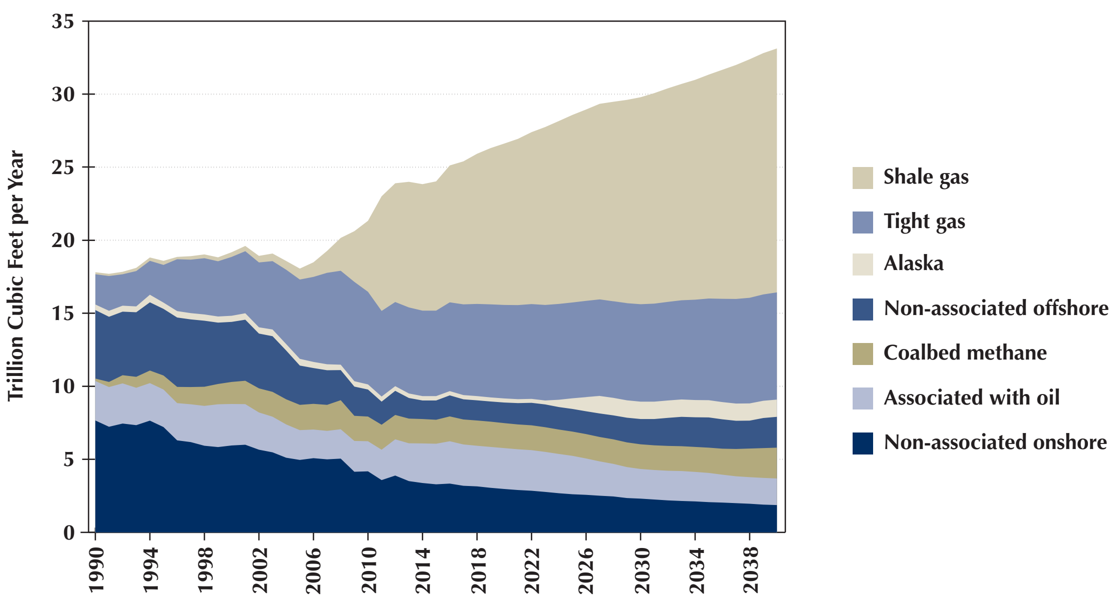
A HISTORY OF VOLATILITY: 1990 TO 2010

U.S. natural gas markets have only been truly open and competitive for about 20 years, when U.S. gas markets were deregulated and price controls were removed in the early 1990s. Before that time, government regulation controlled the price that producers could charge for certain categories of gas placed into the interstate market (the wellhead price) as well as pipeline access to market and in some cases specific uses of natural gas. The results were price signals that periodically resulted in supply shortages and little incentive for increased production. Since deregulation, price fluctuations have been pronounced, ranging from less than $2 to more than $10 per thousand cubic feet (Mcf) (Figure 4). Periods of high market prices have resulted from changes in regulation, weather disruptions, and broader trends in the economy and energy markets—but also from perceptions of abundance or scarcity in the market. A number of supply-side factors also affect prices, including the volume of production added to the market and storage availability to hedge against production disruptions or demand spikes. Looking forward, the average wellhead price is expected to be much less volatile and remain below $5 per Mcf through 2026 and rise to $6.32 per Mcf in 2035, as production gradually shifts to resources that are less productive and more expensive to extract.[4]

SUPPLIES

Since 1999, U.S. proven reserves of natural gas have increased every year, driven mostly by shale gas advancements.[5] In 2003, the National Petroleum Council estimated U.S. recoverable shale gas resources at 35 Tcf.[6] In 2012, the EIA put that estimate closer to 482 Tcf out of an average remaining U.S. resource base of 2,543 Tcf,[7] and in 2011, the Massachusetts Institute of Technology's mean projection estimate of recoverable shale gas resources was 650 Tcf out of a resource base of 2,100 Tcf.[8] By comparison, annual U.S. consumption of natural gas was 24.4 Tcf in 2011.[9] So, these estimates represent nearly 100 years of domestic supply at current levels of consumption.[10]

FIGURE 3: U.S. Dry Natural Gas Production, 1990 to 2040



Source: Energy Information Administration, "Annual Energy Outlook 2013 Early Release" December 2012. Available at http://www.eia.gov/forecasts/aeo/er/executive_summary.cfm

Game-Changing Technologies

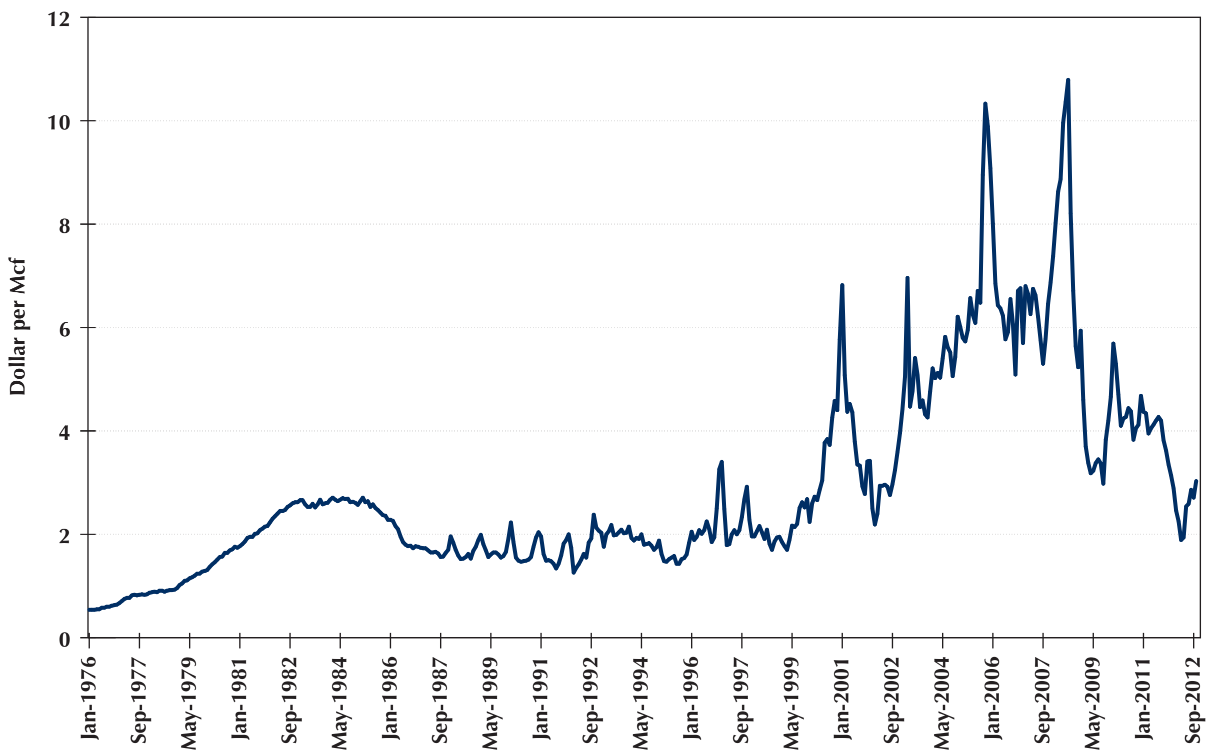
Rising natural gas prices after deregulation offered new economic incentives to develop unconventional gas resources. Advances in the efficiency and cost-effectiveness of horizontal drilling, new mapping tools, and hydraulic fracturing technologies—enabled by investments in research and development from the Department of Energy and its national labs along with private sector innovations—have led to the dramatic increase in U.S. shale gas resources that can be economically recovered.

Even as supply estimates have increased, the cost of producing shale gas has declined as more wells are drilled and new techniques are tried. In one estimate, approximately 400 Tcf of U.S. shale gas can be economically produced at or below \$6 per Mcf (in 2007 dollars).[11] Another estimate suggests that nearly 1,500 Tcf can be produced at less than \$8 per Mcf, 500 Tcf at less than \$8 per Mcf, and 500 Tcf at \$4 per Mcf.[12]

The Geography of Shale Gas Production

Shale gas developments are fundamentally altering the profile of U.S. natural gas production (Figure 3). Since 2009, the United States has been the world's leading producer of natural gas, with production growing by more than 7 percent in 2011—the largest year-over-year volumetric increase in the history of U.S. production.[13] The proportion of U.S. production that is shale gas has steadily increased as well. In the decade of 2000 to 2010, U.S. shale gas production increased 14-fold and comprised approximately 34 percent of total U.S. production in 2011.[14] From 2007 to 2008 alone, U.S. shale gas production increased by 71 percent.[15] Shale gas production is expected to continue to grow, estimated to increase almost fourfold between 2009 and 2035, when it is forecast to make up 47 percent of total U.S. production.[16] The geographic distribution of shale gas production is also shifting to new geologic formations with natural gas potential, called "plays," such as the Barnett shale play in Texas and the Marcellus shale play

FIGURE 4: **U.S. Natural Gas Monthly Average Wellhead Price History, 1976 to 2012**



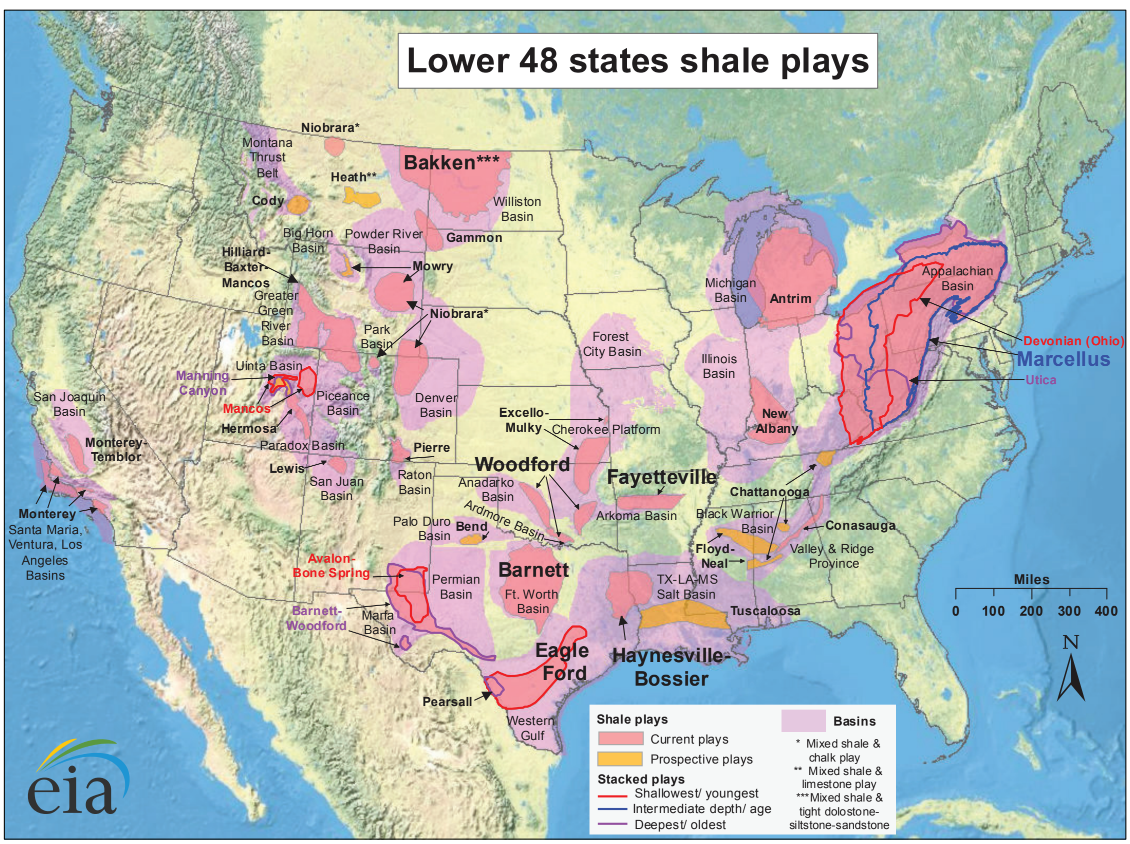
Source: Energy Information Administration, "Natural Gas Prices," 2013. Available at: http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm in the Midwest (Figure 5).[17] Natural gas is currently produced in 32 states and in the Gulf of Mexico, with 80.8 percent of U.S. production occurring in Texas, the Gulf of Mexico, Wyoming, Louisiana, Oklahoma, Colorado, and New Mexico in 2010. An increasing percentage of production is coming from states new on the scene, including Pennsylvania and Arkansas. This new geography of production has particularly large impacts for the development of natural gas infrastructure, as examined in chapter 9.

These dramatic increases in production, in combination with a weak economy and the accompanying decrease in demand for energy, are reflected in unexpectedly low and less volatile market prices, prices that encourage energy consumers to look at new uses for the fuel. Yet uncertainties remain that could hinder future development and production. For one thing, very low prices may result in producers temporarily closing down wells, particularly if the associated liquids produced along with the gas are not sufficient to make up for low natural gas prices and make well production economically viable.[18] In the long term, the dynamic nature of natural gas supply and demand will determine the price levels and volatility. Of particular importance is the extent and speed of demand expansion, a topic explored in the following section.

DEMAND

Just as supply has implications for the price path of natural gas, so does the demand. Natural gas is consumed extensively in the United States for a multitude of uses: for space and water heating in residential and commercial buildings, for electricity generation and process heat in the industrial sector, and as industrial feedstock, where natural gas constitutes the base ingredient for such varied products as plastic, fertilizer, antifreeze, and fabrics.[19] In 2012, natural gas use constituted roughly one-quarter of total U.S. primary energy consumption and was consumed in every sector of the

FIGURE 5: Lower 48 Shale Plays

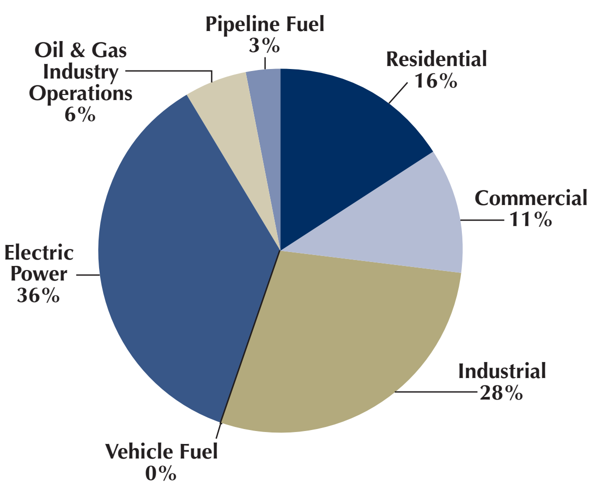


Source: Energy Information Administration, "Lower 48 States Shale Plays," May 2011. Available at: http://www.eia.gov/oil_gas/rpd/shale_gas.pdf

U.S. economy (Figure 6). Total U.S. consumption of natural gas grew from 23.3 Tcf in 2000 to 25.4 in 2012.[20] Within the overall growth, consumption in several sectors held steady, while consumption in the industrial sector declined (due to increased efficiency and the economic slowdown) and consumption in the power sector grew at an annual average rate of 3.5 percent.

In the U.S. power sector in 2010, natural gas fueled 23.9 percent of the total generation. From 2000 to 2010, electricity generation fueled by natural gas grew at a faster rate than total generation (5.1 percent versus 0.8 percent per year) (Figure 7). This growth can be attributed to a number of factors, including low natural gas prices in the early part of the decade that made natural gas much more attractive for power generation. In addition, gas-fired plants are relatively easy to construct, have lower emissions of a variety of regulated pollutants than coal-fired plants, and have lower capital costs and shorter construction times than coal-fired plants. Transportation has remained the smallest sectoral user of natural gas, with natural gas vehicles contributing to a significant percentage of the total fleet only among municipal buses and some other heavy-duty vehicles.

FIGURE 6: U.S. Natural Gas Consumption by Sector, 2012



Source: Energy Information Administration, "Natural Gas Consumption by End Use," 2013. Available at http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm

LARGELY REGIONAL NATURAL GAS MARKETS

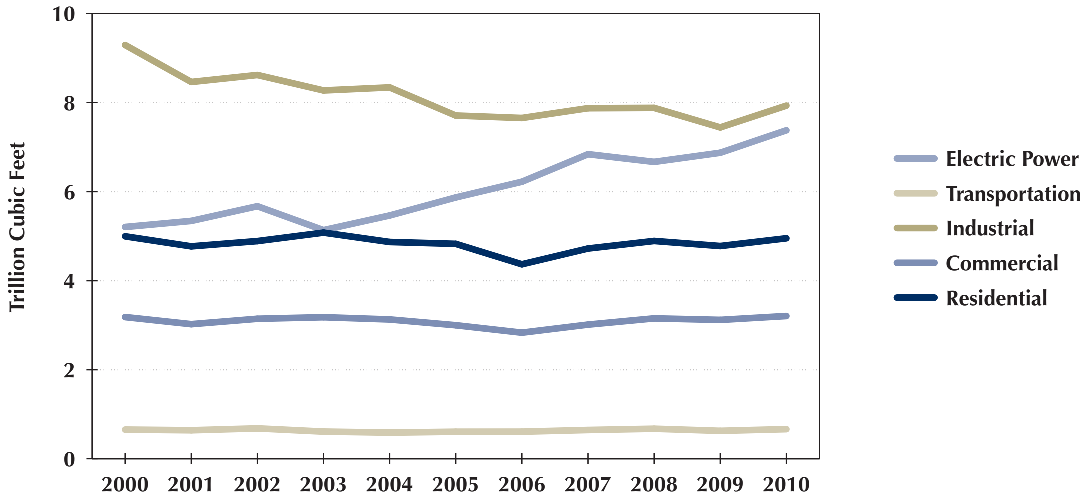
In contrast to oil, which is widely traded across national boundaries and over long distances, natural gas has been primarily a domestic resource. The low density of natural gas makes it difficult to store and to transport by vehicle (unless the gas is compressed or liquefied). (See chapter 8 for an extended discussion of liquefied and compressed natural gas.) Natural gas is therefore transported via pipelines that connect the natural gas wells to end consumers. Trade patterns tend to be more regional (particularly in the United States), and prices tend to be determined within regional markets. On the world stage, resources are concentrated geographically. Seventy percent of the world's gas supply (including unconventional resources) is located in only three regions—Russia, the Middle East (primarily Qatar and Iran), and North America. Within the United States, 10 states or regions account for nearly 90 percent of production: Arkansas, Colorado, Gulf of Mexico, Louisiana, New Mexico, Oklahoma, Pennsylvania, Texas, Utah, and Wyoming. Significant barriers exist to establishing a natural gas market that is truly global. While most natural gas supplies can be developed economically with relatively low prices at the wellhead or the point of export,[21] high transportation costs—either via long-distance pipeline or via tankers for liquefied natural gas (LNG)—have, until recently, constituted solid barriers to establishing a global gas market.

In 2011, net imports of natural gas, delivered via pipeline and LNG import facilities, constituted only 8 percent of total U.S. natural gas consumption (1.9 Tcf), the lowest proportion since 1993.[22] Of this amount, about 90 percent came from Canada.[23] (By contrast, 45 percent of U.S. oil consumption was imported in 2011, of which 29 percent came from Canada.[24]) Net imports of natural gas have decreased by 31 percent since 2007, with U.S. production growing significantly faster than U.S. demand. These trends and greater confidence in U.S. domestic gas supply suggest that prices between crude oil and gas will continue to diverge, establishing a new relationship that may fundamentally change the way energy sources are used in the United States.

THE RISE OF AN INTEGRATED GLOBAL MARKET

Although most of the world's gas supply continues to be transported regionally via pipeline, the global gas trade is accelerating because of the growing use of LNG. Natural gas, once liquefied,[25] can be transported

FIGURE 7: Trends in U.S. Natural Gas Consumption by Sector, 2000 to 2010



Source: Energy Information Administration, "Natural Gas Consumption by End Use," 2013. Available at http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm

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by tanker to distant destinations and regasified for use. Between 2005 and 2010, the global market for LNG grew by more than 50 percent,[26] and LNG now accounts for 30.5 percent of global gas trade.[27] From 2009 to 2011 alone, global capacity for gas liquefaction increased by almost 40 percent, with global LNG trade set to rise by 30 percent by 2017.[28]

In the United States, prospects for exports of LNG depend heavily on the cost-competitiveness of U.S. liquefaction projects relative to those at other locations. During 2000 to 2010, new investments were made in the United States in infrastructure for natural gas importation and storage, prompted by lower supply expectations and higher, volatile domestic prices. Since 2000, North America's import capacity for LNG has expanded from approximately 2.3 billion cubic feet (Bcf) per day to 22.7 Bcf per day, around 35 percent of the United States' average daily requirement.[29] However by 2012, U.S. consumption of imported LNG had fallen to less than 0.5 Bcf per day, leaving most of this capacity unused.[30] The ability to make use of and repurpose existing U.S. import infrastructure—pipelines, processing plants, and storage and loading facilities—would help reduce total costs relative to "greenfield," or new, LNG facilities. Given natural gas surpluses in the United States and substantially higher prices in other regional markets, several U.S. companies have applied for export authority and have indicated plans to construct liquefaction facilities.[31]

The EIA projects that the United States will become a net exporter of LNG in 2016, a net pipeline exporter in 2025, and a net exporter of natural gas overall in 2021. This outlook assumes continuing increases in use of LNG internationally, strong domestic natural gas production, and relatively low domestic natural gas prices.[32] In contrast, a study done by the Massachusetts Institute of Technology presents another possible scenario in which a more competitive international gas market could drive the cost of U.S. natural gas in 2020 above that of international markets, which could lead to the United States importing 50 percent of its natural gas by 2050.[33] Yet while increased trade in LNG has started to connect international markets, these markets remain largely distinct with respect to supply, contract structures, market regulation, and prices.

The increase in domestic production (supplies) of natural gas, low prices, and forecasts of continued low prices have not gone unnoticed. The implications for energy consumption are far-reaching and extend across all sectors of the economy. This report examines how each sector may take advantage of this energy transformation and evaluates the greenhouse gas emission implications of each case.

II. PRICE EFFECTS OF THE LOOMING NATURAL GAS TRANSITION

By Michael Webber, The University of Texas at Austin

INTRODUCTION

Given technology developments that have fundamentally altered the profile of U.S. natural gas production and recent low prices that have pushed demand for natural gas in all sectors of the economy, the importance of natural gas relative to other fuels is growing. If recent trends continue, it seems likely that natural gas will overtake petroleum as the most-used primary energy source in the United States. in the next one to two decades.

Such a transition will be enabled (or inhibited) by a mixed set of competing price pressures and a complicated relationship with lower-carbon energy sources that will trigger an array of market and cultural responses. This chapter seeks to layout some of the key underlying trends while also identifying some of these different axes of price tensions (or price dichotomies). These trends and price tensions will impact the future use of natural gas in all of the sectors analyzed later in this report.

NATURAL GAS COULD BECOME DOMINANT IN THE UNITED STATES WITHIN ONE TO TWO DECADES

For a century, oil and natural gas consumption trends have tracked each other quite closely. Figure 1 shows normalized U.S. oil and gas consumption from 1920 to 2010 (consumption in 1960 is set to a value of 1.0). These normalized consumption curves illustrate how closely oil and gas have tracked each other up until 2002, at which time their paths diverged: natural gas consumption declined from 2002 to 2006, while petroleum use grew over that time period. Then, they went the other direction: natural gas consumption grew and oil production dropped. That trend continues today, as natural gas pursues an upward path, whereas petroleum is continuing a downward trend.

The growing consumption of natural gas is driven by a few key factors:

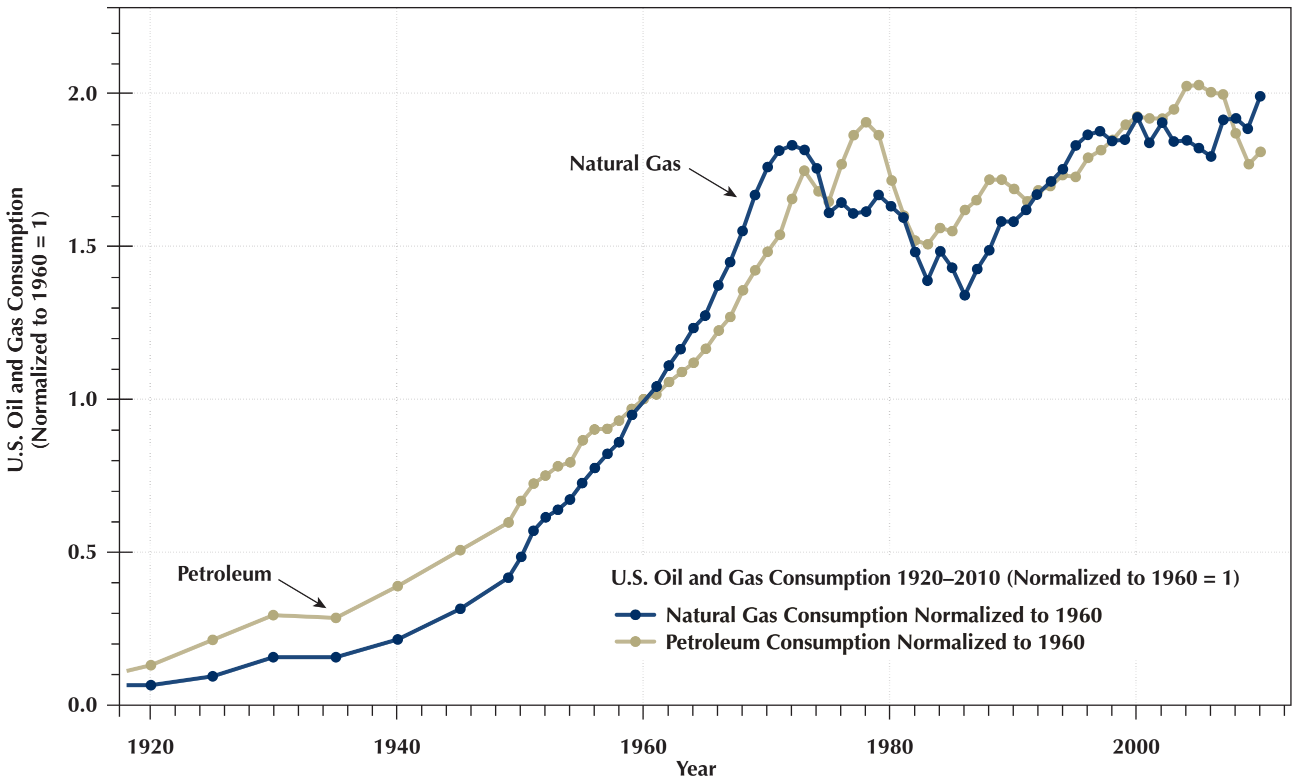
1. It has flexible use across many sectors, including direct use on-site for heating and power; use at power plants; use in industry; and growing use in transportation.
2. It has lower emissions (of pollutants and greenhouse gases) per unit of energy than coal and petroleum
3. It is less water-intensive than coal, petroleum, nuclear, and biofuels
4. Domestic production meets almost all of the annual U.S. consumption

By contrast, the trends for petroleum and coal are moving downwards. Petroleum use is expected to drop as a consequence of price pressures and policy mandates. The price pressures are triggered primarily by the split in energy prices between natural gas and petroleum (discussed in detail below). The mandates include biofuels production targets (which increase the production of an alternative to petroleum) and fuel economy standards (which decrease the demand for liquid transportation fuels). At the same time, coal use is also likely to drop because of projections by the EIA for price doubling over the next 20 years and environmental standards that are expected to tighten the tolerance for emissions of heavy metals, sulfur oxides, nitrogen oxides, particulate matter, and CO_2.

Petroleum use might decline 0.9 percent annually from the biofuels mandates themselves. Taking that value as the baseline, and matching it with an annual growth of 0.9 percent in natural gas consumption (which is a conservative estimation based on trends from the last six years, plus recent projections for increased use of natural gas by the power and industrial sectors), indicates that natural gas will surpass petroleum in 2032, two decades from now, as depicted in Figure 2. A steeper projection of 1.8 percent annual declines in petroleum matched with 1.8 percent annual increase in natural gas consumption sees a faster transition, with natural gas surpassing petroleum in less than a decade.

While such diverging rates might seem aggressive, they are a better approximation of the trends over the

FIGURE 1: U.S. Oil and Gas Consumption, 1920 to 2010



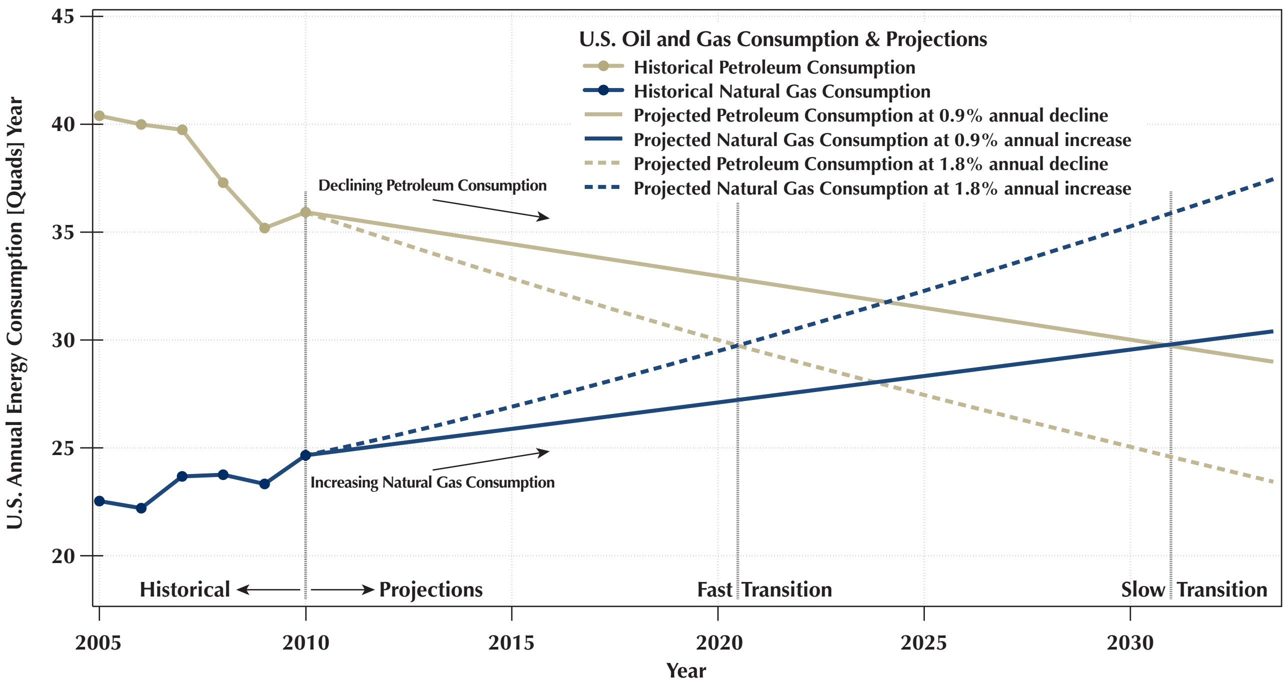
Source: Energy Information Agency, "Annual Energy Review 2010" Technical Report, 2011.

Note: U.S. oil and gas consumption from 1920 to present day (normalized to a value of 1 in 1960) shows how oil and gas have tracked each other relatively closely until 2002, after which their paths diverge. Since 2006, natural gas consumption has increased while petroleum consumption has decreased.

last six years than the respective 0.9 percent values. An annual decline in petroleum of 1.8 percent is plausible through a combination of biofuels mandates (0.9 percent annual decline), higher fuel economy standards (0.15 percent annual decline), and price competition that causes fuel-switching from petroleum to natural gas in the transportation (heavy-duty, primarily) and industrial sectors (0.75 percent annual decline). Natural gas growth rates of 1.8 percent annually can be achieved by natural gas displacing 25 percent of diesel use (for on-site power generation and transportation) and natural gas combined-cycle power plants displacing 25 percent of 1970s and 1980s vintage coal-fired power plants by 2022. While this scenario is bullish for natural gas, it is not implausible, especially for the power sector, whose power plants face retirement and stricter air quality standards. Coupling those projections with reductions in per-capita energy use of 10 percent (less than 1 percent annually) over that same span imply that total energy use would stay the same.

These positive trends for natural gas are not to say it is problem-free. Environmental challenges exist for water, land, and air. Water challenges are related to quality (from risks of contamination) and quantity (from competition with local uses and depletion of reservoirs). Land risks include surface disturbance from production activity and induced seismicity from wastewater reinjection. Air risks are primarily derived from leaks on site, leaks through the distribution system, and flaring at the point of production. Furthermore, while natural gas prices have been relatively affordable and stable in the last few years, natural gas prices have traditionally been very volatile. However, if those economic and environmental risks are managed properly, then these positive trends are entirely possible.

FIGURE 2: U.S. Oil and Gas Consumption and Projections



Source: Energy Information Agency, "Annual Energy Review 2010" Technical Report, 2011.

Note: Natural gas might pass petroleum as the primary fuel source in the United States within one to two decades, depending on the annual rate of decreases in petroleum consumption and increases in natural gas consumption. Historical values plotted are from EIA data.

THERE ARE SIX PRICE DICHOTOMIES WITH NATURAL GAS

In light of the looming transition to natural gas as the dominant fuel in the United States, it is worth contemplating the complicated pricing relationship that natural gas in the United States has with other fuels, market factors, and regions. It turns out that there are several relevant price dichotomies to keep in mind:

1. Natural Gas vs. Petroleum Prices,
2. U.S. vs. Global Prices,
3. Prices for Abundant Supply vs. Prices for Abundant Demand,
4. Low Prices for the Environment vs. High Prices for the Environment,
5. Stable vs. Volatile Prices, and
6. Long-Term vs. Near-Term Prices.

The tensions along these price axes will likely play an important role in driving the future of natural gas in the United States and globally.

DECOUPLING OF NATURAL GAS AND PETROLEUM PRICES

One of the most important recent trends has been the decoupling of natural gas and petroleum prices. Figure 3 shows the U.S. prices for natural gas and petroleum (wellhead and the benchmark West Texas Intermediate (WTI) crude at Cushing, Oklahoma respectively) from 1988 to 2012.[34, 35] While natural gas and petroleum prices have roughly tracked each other in the United States for decades, their trends started to diverge in 2009 as global oil supplies remained tight, yet shale gas production increased. This recent divergence has been particularly stark, as it's driven by the simultaneous downward swing in natural gas prices and upward swing in petroleum prices. For many years, the ratio in prices (per million BTU, or MMBTU) between petroleum and natural gas oscillated nominally in the range of 1–2, averaging 1.6 for 2000–2008. However, after the divergence began in 2009, this spread became much larger, averaging 4.2 for 2011 and, remarkably, achieving ratios greater than 9 spanning much of the first quarter of 2012 (for example, natural gas costs approximately $2/MMBTU today, whereas petroleum costs $18/MMBTU).

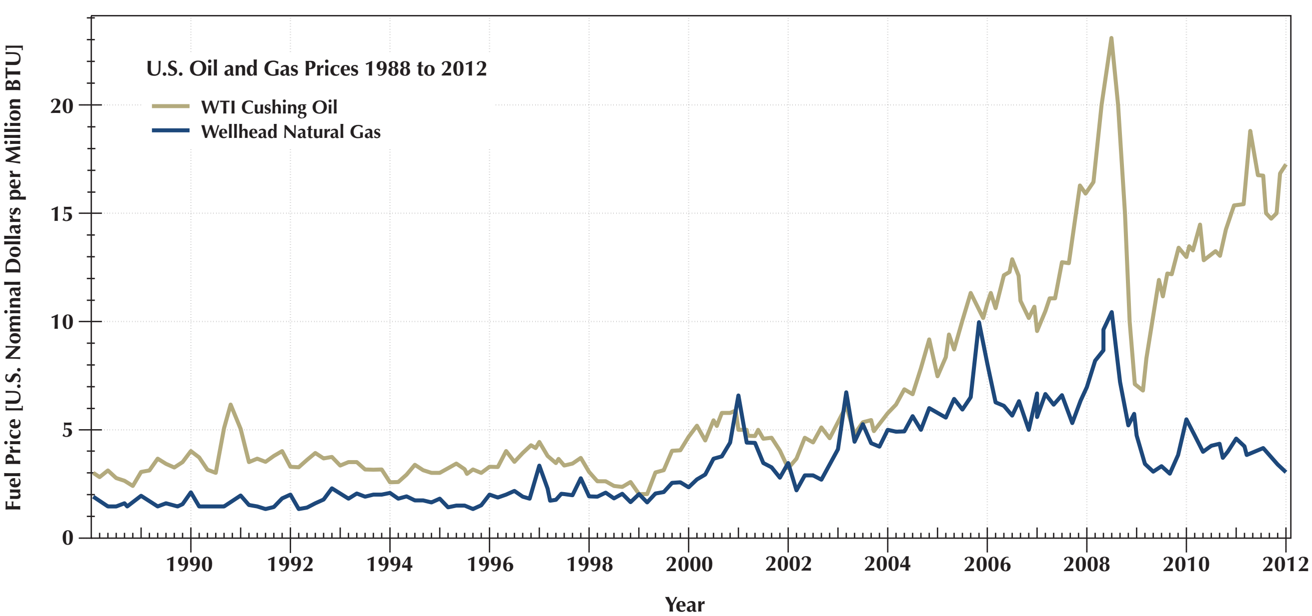
This spread is relatively unprecedented and, if sustained, opens up new market opportunities for gas to compete with oil through fuel-switching by end-users and the construction of large-scale fuel processing facilities. For the former, these price spreads might inspire institutions with large fleets of diesel trucks (such as municipalities, shipping companies, etc.) to consider investing in retrofitting existing trucks or ordering new trucks that operate on natural gas instead of diesel to take advantage of the savings in fuel costs. For the latter, energy companies might consider investing in multi-billion dollar gas-to-liquids (GTL) facilities to convert the relatively inexpensive gas into relatively valuable liquids.

DECOUPLING OF U.S. AND GLOBAL PRICES

Another important trend has been the decoupling of U.S. and global prices for natural gas. Figure 4 shows the U.S. prices for natural gas (at Henry Hub) compared with European Union and Japanese prices from 1992 to 2012.[36, 37, 38, 39] In a similar fashion as discussed below, while natural gas prices in the U.S. and globally (in particular, the European Union and Japan) have tracked each other for decades, their price trends started to diverge in 2009 because of the growth in domestic gas production. In fact, from 2003–2005, U.S. natural gas prices were higher than in the EU and Japan because of declining domestic production and limited capacity for importing liquefied natural gas (LNG). At that time, and for the preceding years, the U.S. prices were tightly coupled to global markets through its LNG imports setting the marginal price of gas.

Consequently, billions of dollars of investments were made to increase LNG import capacity in the United States That new import capacity came online concurrently with higher domestic production, in what can only be described as horribly ironic timing: because domestic production grew so quickly, those new imports were no longer necessary, and much of that importing capacity remains idle today. In fact, once production increased in 2009, the United States was then limited by its capacity to export LNG (which is in contrast to the situation just a few years prior, during which the United States was limited by its capacity to import gas), so gas prices plummeted despite growing global demand. Thus, while the United States was tightly coupled to global gas markets

FIGURE 3: U.S. Oil and Gas Prices, 1988 to 2012



Sources: Energy Information Administration, U.S. Natural Gas Prices, Tech. rep., April 2, 2012. Available at: http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm

Energy Information Administration, Cushing, OK WTI Spot Price FOB (Dollars per Barrel), Tech. rep., April 4, 2012. Available at: http://tonto.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=RWTC&f=M

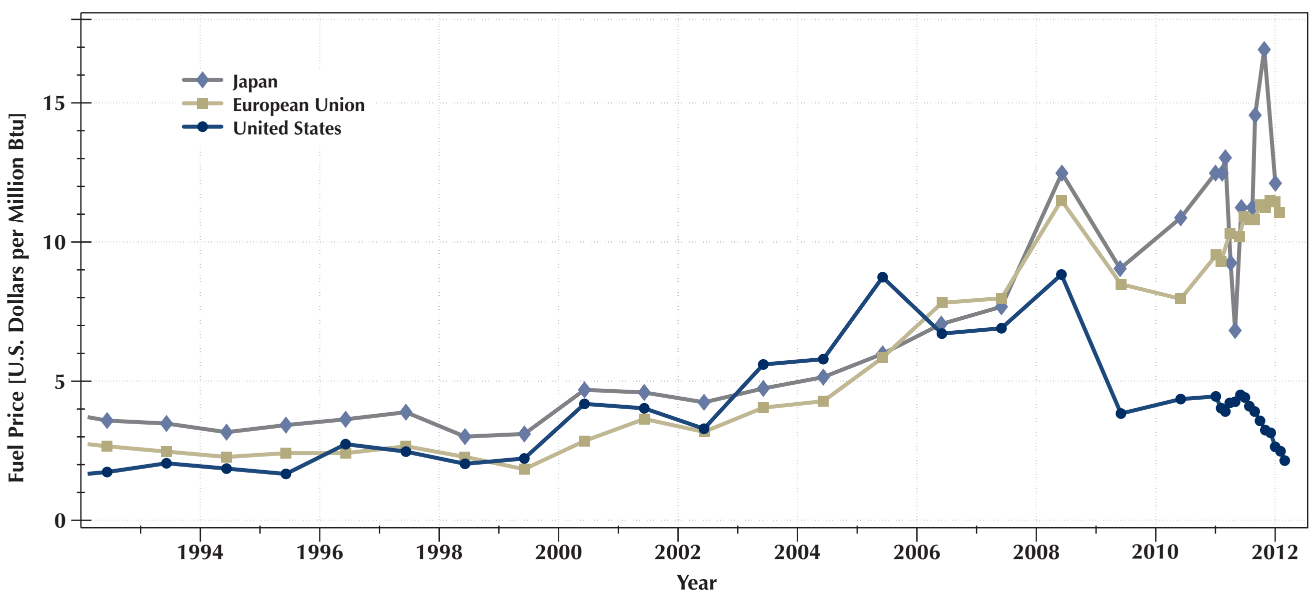
Note: While natural gas and petroleum prices have roughly tracked each other in the U.S. for decades, their price trends started to diverge in 2009.

for well over a decade, it has been decoupled for the last several years. At the same time, the European Union and Japan are tightly coupled to the world gas markets, (with the European Union served by LNG and pipelines from the Former Soviet Union, and Japan served by LNG). How long these prices remain decoupled will depend on U.S. production of natural gas, U.S. demand for natural gas, and the time it takes for these isolated markets to connect again. In fact, LNG terminal operators are now considering the investment of billions of dollars to turn their terminals around so that they can buy cheap natural gas in the U.S. that they can sell at higher prices to the EU and Japan. Once those terminals are turned around, these geographically-divergent market prices could come back into convergence.

PRICES FOR ABUNDANT SUPPLY VS. PRICES FOR ABUNDANT DEMAND

Another axis to consider for natural gas prices is the tension between the price at which we have abundant supply, and the price at which we have abundant demand. These levels have changed over the years as technology improves and the prices of competing fuels have shifted, but it seems clear that there is still a difference between the prices that consumers wish to pay and producers wish to collect. In particular, above a certain price (say, somewhere in the range of $4–8/MMBTU, though there is no single threshold that everyone agrees upon), the United States would be awash in natural gas. Higher prices make it possible to economically produce many marginal plays, yielding dramatic increases in total production. However, at those higher prices, the demand for gas is relatively lower because cheaper alternatives (nominally coal, wind, nuclear and petroleum) might be more attractive options. At the same time, as recent history has demonstrated, below a certain price (say, somewhere in the range of $1–3/MMBTU), there is significant demand for natural gas in the power sector (as an alternative to coal) and the industrial sector (because of revitalized chemical manufacturing, which depends heavily on natural gas as a feedstock). Furthermore, if prices are expected to remain low, then demand for natural gas would increase in the residential and commercial sectors (as an alternative

FIGURE 4: Natural Gas Prices in Japan, the European Union and the United States, 1992 to 2012



Sources: BP, "BP Statistical Review of World Energy," Tech. rep., June 2011, Available at: bp.com/statisticalreview

Energy Information Administration, Henry Hub Gulf Coast Natural Gas Spot Price, Tech. rep., April 6, 2012. Available at: http://tonto.eia.gov/dnav/ng/hist/rngwhhdm.htm

Energy Information Administration, Price of Liquefied U.S. Natural Gas Exports to Japan, Tech. rep., April 6, 2012. Available at: http://www.eia.gov/dnav/ng/hist/n9133ja3m.htm

YCharts, European Natural Gas Import Price, Tech. rep., April 6, 2012. Available at: http://ycharts.com/indicators/europe_natural_gas_price

Note: While natural gas prices in the U.S. and globally (EU and Japan) have tracked each other for decades, their price trends started to diverge in 2009.

to electricity for water heating, for example) and in the transportation sector (to take advantage of price spreads with diesel, as noted above).

The irony here is that it is not clear that the prices at which there will be significant increases in demand will be high enough to justify the higher costs that will be necessary to induce increases in supply, and so there might be a period of choppiness in the market as the prices settle into their equilibrium. Furthermore, as global coal and oil prices increase (because of surging demand from China and other rapidly-growing economies), the thresholds for this equilibrium are likely to change. As oil prices increase, natural gas production will increase at many wells as a byproduct of liquids production, whether the gas was desired or not. Since the liquids are often used to justify the costs of a new well, the marginal cost of the associated gas production can be quite low. Thus, natural gas production might increase even without upward pressure from gas prices, which lowers the price threshold above which there will be abundant supply. At the same time, coal costs are increasing globally, which raises the threshold below which there is abundant demand. Hopefully, these moving thresholds will converge at a stable medium, though it is too early to tell. If the price settles too high, then demand might retract; if it settles too low, the production might shrink, which might trigger an oscillating pattern of price swings.

LOW PRICES FOR THE ENVIRONMENT VS. HIGH PRICES FOR THE ENVIRONMENT

Another axis of price tension for natural gas is whether high prices or low prices are better for achieving environmental goals such as reducing the energy sector's emissions and water use. In many ways, high natural gas prices have significant environmental advantages because they induce conservation and enable market penetration by relatively expensive renewables. In particular, because it is common for natural gas to be the next fuel source dispatched into the power grid in the United States, high natural gas prices trigger high electricity prices. Those higher electricity prices make it easier for renewable energy sources such as wind and solar power to compete in the markets. Thus, high natural gas prices are useful for reducing consumption overall and for spurring growth in novel generation technologies.

However, inexpensive natural gas also has important environmental advantages by displacing coal in the power sector. Notably, by contrast with natural gas prices, which have decreased for several years in a row, prevailing coal prices have increased steadily for over a decade due to higher transportation costs (which are coupled to diesel prices that have increased over that span), depletion of mines, and increased global demand. As coal prices track higher and natural gas prices track lower, natural gas has become a more cost-effective fuel for power generation for many utility companies. Consequently, coal's share of primary energy consumption for electricity generation has dropped from 53 percent in 2003 to less than 46 percent in 2011 (with further drops in the first quarter of 2012), while the share fulfilled by natural gas grew from 14 percent to 20 percent over the same span. At the same time, there was a slight drop in overall electricity generation due to the economic recession, which means the rise of natural gas came at the expense of coal, rather than in addition to coal. Consequently, for those wishing to achieve the environmental goals of dialing back on power generation from coal, low natural gas prices have a powerful effect.

These attractive market opportunities are offset in some respects by the negative environmental impacts that are occurring from production in the Bakken and Eagle Ford shale plays in North Dakota and Texas. At those locations, significant volumes of gases are flared because the gas is too inexpensive to justify rapid construction of the pricey distribution systems that would be necessary to move the fuel to markets.[40, 41] Consequently, for many operators it ends up being cheaper in many cases to flare the gas rather than to harness and distribute it.

And, thus, the full tension between the "environmental price" of gas is laid out: low prices are good because they displace coal, whereas high prices are good because they bring forward conservation and renewable alternatives. This price axis will be important to watch from a policymaker's point of view as time moves forward.

STABLE VS. VOLATILE PRICES

One of the historical criticisms of natural gas has been its relative volatility, especially as compared with coal and nuclear fuels, which are the other major primary energy sources for the power sector. This volatility is a consequence of large seasonal swings in gas consumption (for example, for space and water heating in the winter) along with the association of gas production with oil, which is also volatile. Thus, large magnitude swings in demand and supply can be occurring simultaneously, but in opposing directions. However, two forces are mitigating this volatility. Firstly, because natural gas prices are decoupling from oil prices (as discussed in above), one layer of volatility is reduced. Many gas plays are produced independently of oil production. Consequently, there is a possibility for long-term supply contracts at fixed prices. Secondly, the increased use of natural gas consumption in the power sector, helps to mitigate some of the seasonal swings as the consumption of gas for heating in the winter might be better matched with consumption in the summer for power generation to meeting air conditioning load requirements.

Between more balanced demand throughout the year and long-term pricing, the prospects for better stability look better. At the same time, coal, which has historically enjoyed very stable prices, is starting to see higher volatility because its costs are coupled with the price of diesel for transportation. Thus, ironically, while natural gas is reducing its exposure to oil as a driver for volatility, coal is increasing its exposure.

LONG-TERM VS. NEAR-TERM PRICE

While natural gas is enjoying a period of relatively stable and low prices at the time of this writing, there are several prospects that might put upward pressure on the long-term prices. These key drivers are: 1) increasing demand, and 2) re-coupling with global markets.

As discussed above, there are several key forcing functions for higher demand. Namely, because natural gas is relatively cleaner, less carbon-intensive, and less water-intensive than coal, it might continue its trend of taking away market share from coal in the power sector to meet increasingly stringent environmental standards. While this trend is primarily driven by environmental constraints, its effect will be amplified as long as natural gas prices remain low. While fuel-switching in the power sector will likely have the biggest overall impact on new natural gas demand, the same environmental and economic drivers might also induce fuel-switching in the transportation sector (from diesel to natural gas), and residential and commercial sectors (from fuel oil to natural gas for boilers, and from electric heating to natural gas heating). If cumulative demand increases significantly from these different factors but supply does not grow in a commensurate fashion, then prices will move upwards.

The other factor is the potential for re-coupling U.S. and global gas markets. While they are mostly empty today, many LNG import terminals are seeking to reverse their orientation, with an expectation that they will be ready for export beginning in 2014. Once they are able to export gas to EU and Japanese markets, then domestic gas producers will have additional markets for their product. If those external markets maintain their much higher prevailing prices (similar to what is illustrated in Figure 4), re-coupling will push prices upwards.

Each of these different axes of price tensions reflects a different nuance of the complicated, global natural gas system. In particular, they exemplify the different market, technological and societal forces that will drive—and be driven by—the future of natural gas.

CONCLUSION

Overall, it is clear that natural gas has an important opportunity to take market share from other primary fuels. In particular, it could displace coal in the power sector, petroleum in the transportation sector, and fuel oil in the commercial and residential sectors. With sustained growth in demand for natural gas, coupled with decreases in demand for coal and petroleum because of environmental and security concerns, natural gas could overtake petroleum to be the most widely used fuel in the United States within one to two decades. Along the path towards that transition, natural gas will experience a variety of price tensions that are manifestations of the different market, technological and societal forces that will drive—and be driven by— the future of natural gas. How and whether we sort out these tensions and relationships will affect the fate of natural gas and are worthy of further scrutiny.

III. GREENHOUSE GAS EMISSIONS AND REGULATIONS ASSOCIATED WITH NATURAL GAS PRODUCTION

By Joseph Casola, Daniel Huber, and Michael Tubman, C2ES

INTRODUCTION

Natural gas is a significant source of greenhouse gas emissions in the United States. Approximately 21 percent of total U.S. greenhouse gas emissions in 2011 were attributable to natural gas.[42] When natural gas is combusted for energy, it produces carbon dioxide (CO_2), which accounts for most of greenhouse gas emissions associated with this fuel. Natural gas is composed primarily of methane (CH_4), which has a higher global warming potential than CO_2. During various steps of natural gas extraction, transportation, and processing, methane escapes or is released to the atmosphere. Although this represents a relatively smaller portion of the total greenhouse gas emissions associated with natural gas production and use, vented and leaked or "fugitive" emissions can represent an opportunity to reduce greenhouse gas emissions, maximizing the potential climate benefits of using natural gas.

Total methane emissions from natural gas systems (production, processing, storage, transmission, and distribution) in the United States have improved during the last two decades, declining 13 percent from 1990 to 2011, driven by infrastructure improvements and technology, as well as better practices adopted by industry. This has occurred even as production and consumption of natural gas has grown. Methane emissions per unit of natural gas consumed have dropped 32 percent from 1990 to 2011. Since 2007, methane emissions from all sources have fallen almost 6 percent, driven primarily by reductions of methane emissions from natural gas systems. Nevertheless, given its impact on the climate, emphasis on reducing methane emissions from all sources must remain a high priority. This chapter discusses the differences between methane and CO_2, emission sources, and state and federal regulations affecting methane emissions.

GLOBAL WARMING POTENTIALS OF METHANE AND CO_2

On a per-mass basis, methane is more effective at warming the atmosphere than CO_2. This is represented by methane's global warming potential (GWP), which is a factor that expresses the amount of heat trapped by a pound of a greenhouse gas relative to a pound of CO_2 over a specified period of time. GWP is commonly used to enable direct comparisons between the warming effects of different greenhouse gases. By convention, the GWP of CO_2 is equal to one.

The GWP of a greenhouse gas (other than CO_2) can vary substantially depending on the time period of interest. For example, on a 100-year time frame, the GWP of methane is about 21.[43] But for a 20-year time frame, the GWP of methane is 72.[44] The difference stems from the fact that the lifetime of methane in the atmosphere is relatively short, a little over 10 years, when compared to CO_2, which can persist in the atmosphere for decades to centuries.

Since models that project future climate conditions are often compared for the target year of 2100, it is often convenient to use 100-year GWPs when comparing emissions of different greenhouse gases. However, these comparisons may not accurately reflect the relative reduction in radiative forcing (the extent to which a gas traps heat in the atmosphere) arising from near-term abatement efforts for greenhouse gases with short lifetimes. Whereas near-term reductions in CO_2 emissions provide reductions in radiative forcing benefits spread out over a century, near-term abatement efforts for methane involve a proportionally larger near-term reduction in radiative forcing. In light of potential climate change over the next 50 years, the control of methane has an importance that can be obscured when greenhouse gases are compared using only their 100-year

GWPs. Accordingly, reducing methane emissions from all sources is important to efforts aimed at slowing the rate of climate change.

EMISSIONS FROM NATURAL GAS COMBUSTION

On average, natural gas combustion releases approximately 50 percent less CO_2 than coal and 33 percent less CO_2 than oil (per unit of useful energy) (Figure 1). In addition, the combustion of coal and oil emits other hazardous air pollutants, such as sulfur dioxides and particulate matter. Therefore, the burning of natural gas is considered cleaner and less harmful to public health and the environment than the burning of coal and oil.

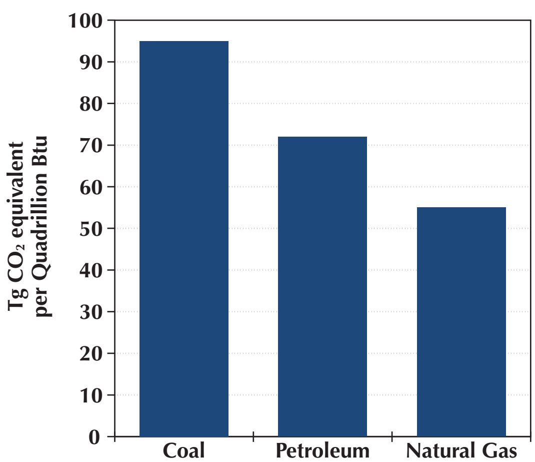
The U.S. Energy Information Administration (EIA) has projected that U.S. energy-related CO_2 emissions will remain more than 5 percent below their 2005 level through 2040, a projection based in large part on the expectation that: 1) natural gas will be steadily substituted for coal in electricity generation as new natural gas power plants are built and coal-fired power plants are converted to natural gas, and 2) state and federal programs that encourage the use of low-carbon technologies will continue.[45] The EIA predicts that natural gas—fired electricity production in the United States will increase from 25 percent in 2010 to 30 percent in 2040, in response to continued low natural gas prices and existing air quality regulations that affect coal-fired power generation.

VENTING AND LEAKED EMISSIONS ASSOCIATED WITH NATURAL GAS PRODUCTION

In 2011, natural gas systems contributed approximately one-quarter of all U.S. methane emissions (Figure 2), of which over 37 percent are associated with production.[46] In the production process, small amounts of methane can leak unintentionally. In addition methane may be intentionally released or vented to the atmosphere for safety reasons at the wellhead or to reduce pressure from equipment or pipelines. Where possible, flares can be installed to combust this methane (often at the wellhead), preventing much of it from entering the atmosphere as methane but releasing CO_2 and other air pollutants instead.

These methane emissions are an important, yet not well understood, component of overall methane emissions. In recent years greenhouse gas measurement and reporting requirements have drawn attention to the need for more accurate data. This uncertainty can be seen in the revisions that have accompanied sector emission

FIGURE 1: CO_2 **Emissions from Fossil Fuel Combustion**

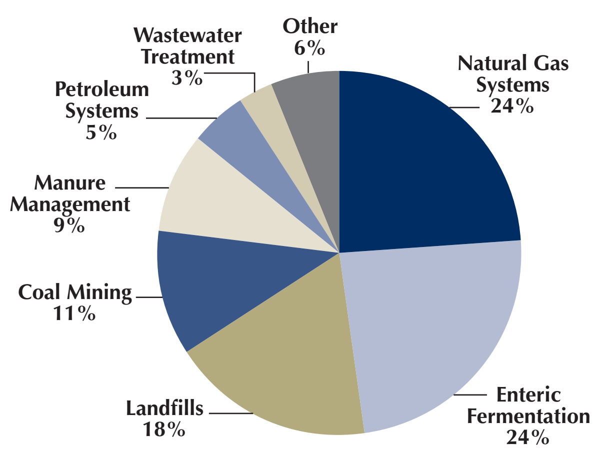


Source: Environmental Protection Agency, Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011. 2013. Chapter 3 and Annex 2. Available at: http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html

Notes: CO_2 content for petroleum has been calculated as an average of representative fuel types (e.g., jet fuel, motor gasoline, distillate fuel) using 2011 data.

This graphic does not account for the relative efficiencies of end-use technologies.

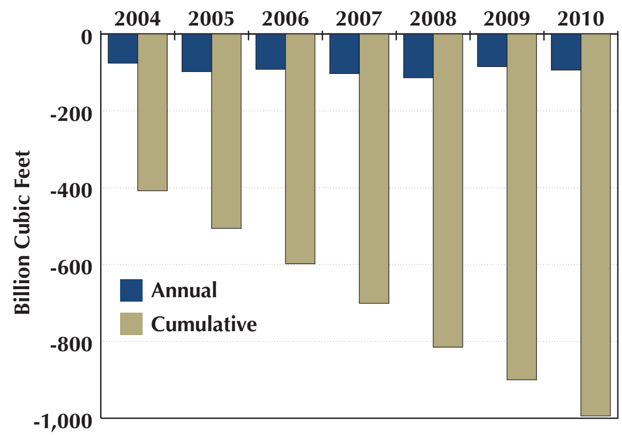
FIGURE 2: **Sources of Methane Emissions in the United States, 2011**



Source: Environmental Protection Agency, Draft U.S. Greenhouse Gas Inventory Report, 2013. Available at: http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html estimates. Just recently for example, EPA revised downward the estimated level of methane emissions attributable to production of natural gas. In 2010, it estimated about 58 percent of methane emission in the natural gas system came from production. In 2013, EPA reduced that number to 37 percent. A major reason for this revision was a change in EPA's assumption about emission leakage rates. Based on EPA's GHG inventory data, the assumed leakage rate for the overall natural gas system was revised downward from 2.27 percent in 2012 to 1.54 percent in 2013.[47] Independent studies have estimated leak rates ranging from 0.71 to 7.9 percent.[48, 49, 50] EPA and others are trying to better understand the extent of leakage and where this leakage is occurring.

Given the climate implications of methane, considerable effort is also being focused on reducing leakage and methane emissions overall. According to EPA, methane emissions from U.S. natural gas systems have declined by 10 percent between 1990 and 2011 even with the expansion of natural gas infrastructure.[51] This decline is largely the result of voluntary reductions including greater operational efficiency, better leakage detection, and the use of improved materials and technologies that are less prone to leakage.[52] In particular, the EPA's Natural Gas Star Program has worked with the natural gas industry to identify technical and engineering solutions that minimize emissions from infrastructure, including zero-bleed pneumatic controllers, improved valves, corrosion-resistant coatings, dry-seal compressors, and improved leak-detection and leak-repair strategies. The EPA has tracked methane reductions associated with its Natural Gas STAR program (Figure 3) and estimates that voluntary actions undertaken by the natural gas sector reduced emissions by 94.1 billion cubic feet (Bcf) in 2010. Notably, many of the solutions identified by this voluntary program have payback periods of less than three years (depending on the price of natural gas).[53] The success of the Natural Gas STAR program further highlights the importance of understanding where emission leakage is occurring because without accurate data, it is difficult to prioritize reduction efforts or make the case for technologies and processes like those highlighted by the program.

FIGURE 3: Annual and Cumulative Reductions in Methane Emissions Associated with the Environmental Protection Agency's Natural Gas STAR Program, 2004 to 2010



Source: Environmental Protection Agency, "Accomplishments," July 2012. Available at http://www.epa.gov/gasstar/accomplishments/index.html

REGULATION OF LEAKAGE AND VENTING

Regulations applicable to methane leakage and venting from natural gas operations have been implemented at both the federal and state level. Although air pollution from natural gas production has been regulated in various forms since 1985 (e.g., toxic substances such as benzene and volatile organic compounds that contribute to smog formation), over the past few years, due to the recent increase in natural gas production and the use of new extraction methods (particularly hydraulic fracturing), natural gas operations have come under renewed scrutiny from policy-makers, non-governmental organizations, and the general public. In response to potential environmental and climate impacts from increased natural gas production including deployment of new technologies, new state and national rules are being developed.

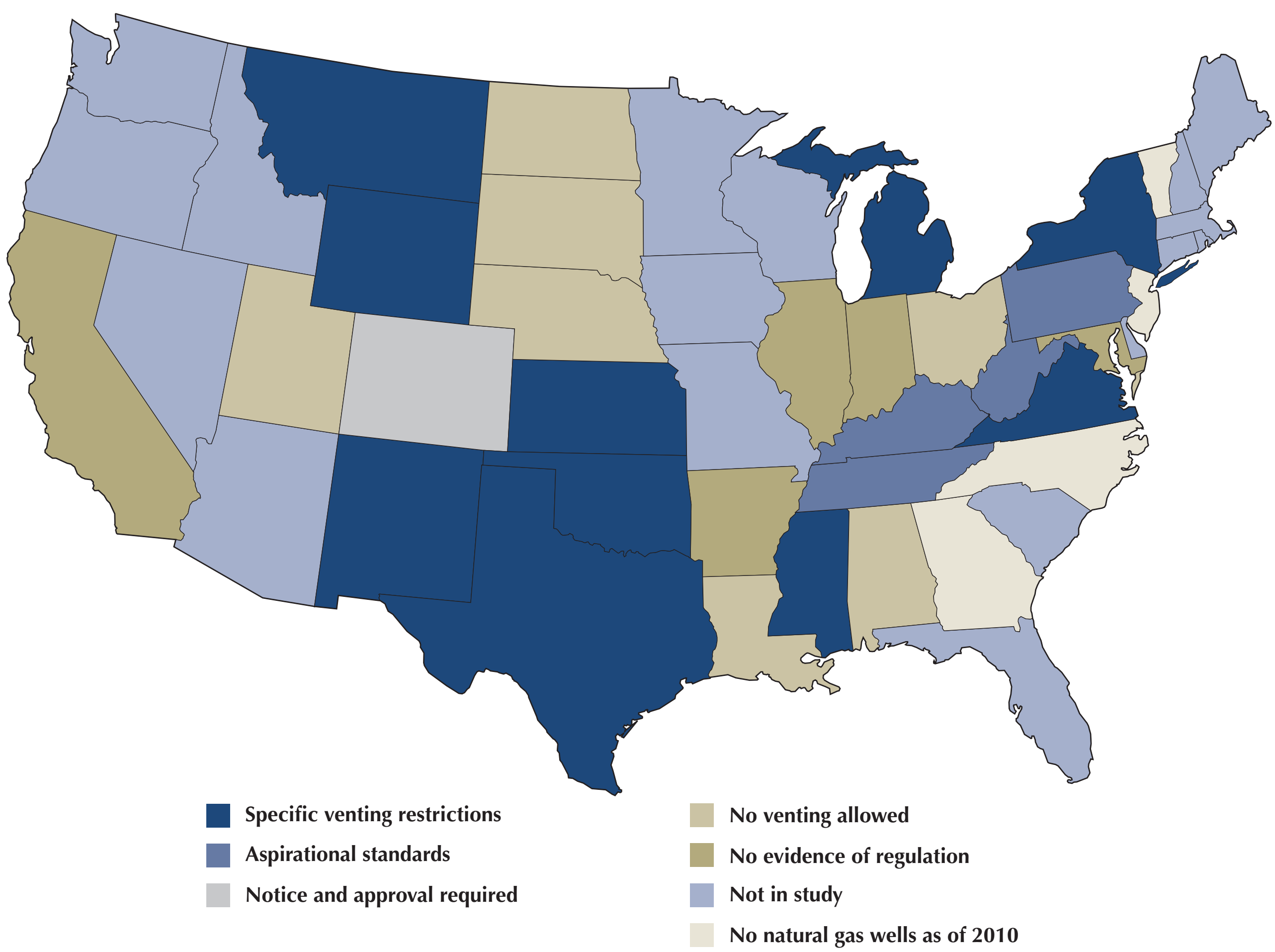
FEDERAL REGULATIONS

EPA released new air pollution standards for natural gas operations on August 16, 2012. The New Source Performance Standards and National Emissions Standards for Hazardous Air Pollutants are the first federal regulations to specifically require emission reductions from new or modified hydraulically fractured and refractured natural gas wells. The New Source Performance Standards require facilities to reduce emissions to a certain level that is achievable using the best system of pollution control, taking other factors into consideration, such as cost.[54] Under the National Emissions Standards for Hazardous Air Pollutants program, EPA sets technology-based standards for reducing certain hazardous air pollutant emissions using maximum achievable control technology. The regulations target the emission of volatile organic compounds, sulfur dioxide, and air toxics, but have the co-benefit of reducing emissions of methane by 95 percent from well completions and recompletions.[55]

Among several emission controls, these rules also require the use of "green completions" at natural gas drilling sites, a step already mandated by some jurisdictions and voluntarily undertaken by many companies. In a "green completion," special equipment separates hydrocarbons from the used hydraulic fracturing fluid, or "flowback," that comes back up from the well as it is being prepared for production. This step allows for the collection (and sale or use) of methane that may be mixed with the flowback and would otherwise be released to the atmosphere. The final "green completion" standards apply to hydraulically fractured wells that begin construction, reconstruction, or modification after August 23, 2011, estimated to be 11,000 wells per year. The "green completion" requirement will be phased-in over time, with flaring allowed as an alternative compliance mechanism until January 1, 2015.

While the "green completion" regulations are expected to reduce methane emissions from natural gas wells, concern has been expressed that the regulations do not apply to onshore wells that are not hydraulically

FIGURE 4: Venting Regulations by State

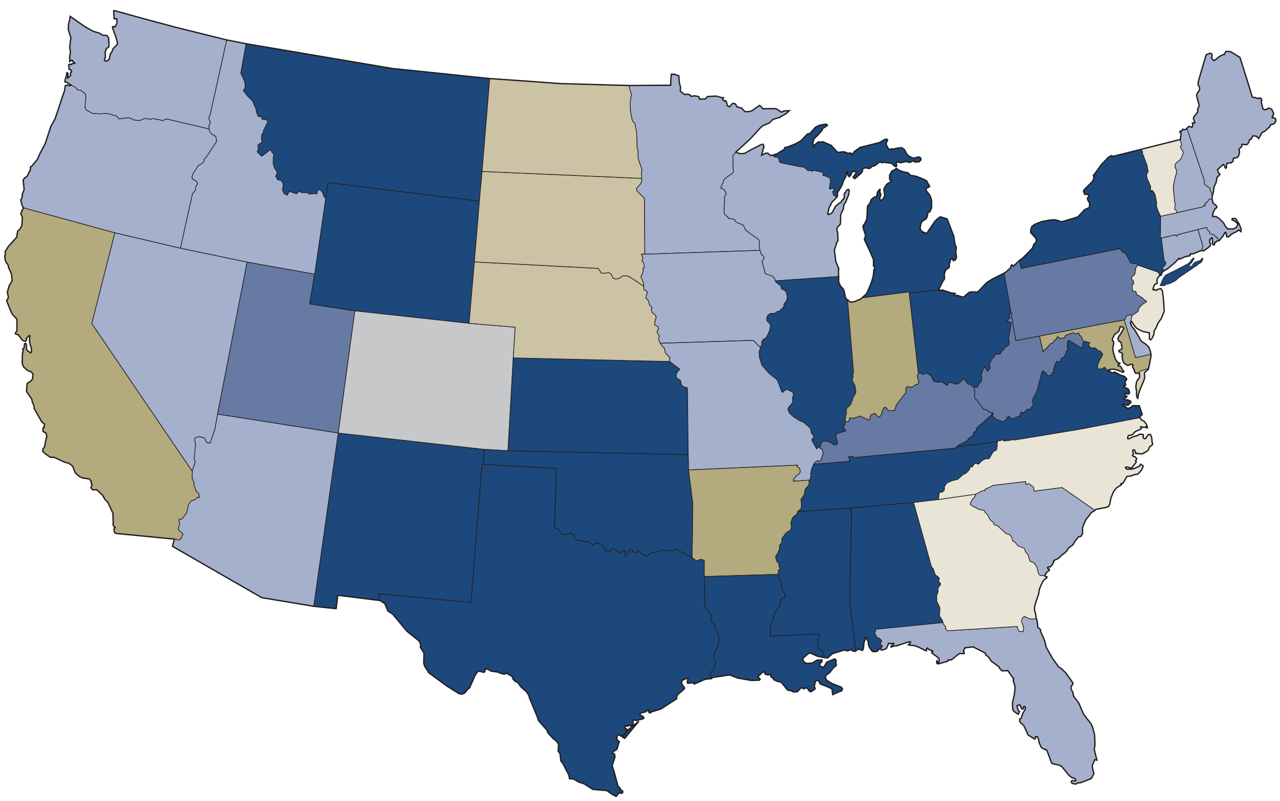


Source: Resources for the Future. "A Review of Shale Gas Regulations by State." July 2012. Available at: http://www.rff.org/centers/energy_economics_and_policy/Pages/Shale_Maps.aspx fractured, existing hydraulically fractured wells until such time as they are refractured, or oil wells, including those that produce associated natural gas.[56] However, geologic and market barriers may limit the applicability of this type of rule to other sources of natural gas.

STATE REGULATIONS

Numerous states have also implemented regulations that address venting and flaring from natural gas exploration and production. Some states with significant oil and gas development, such as Colorado, North Dakota, Ohio, Pennsylvania, Texas, and Wyoming, already have venting and/or flaring requirements in place. For example, Ohio requires that all methane vented to the atmosphere be flared (with the exception of gas released by a properly functioning relief device and gas released by controlled venting for testing, blowing down, and cleaning out wells). North Dakota allows gas produced with crude oil from an oil well to be flared during a one-year period from the date of first production from the well. After that time period, the well must be capped or connected to a natural gas gathering line.[57] These regulations may be changed or upgraded as the national "green completion" rules come into effect. Maps produced by Resources for the Future, show the diversity of state regulations that apply to venting and flaring in natural gas development in 31 states (Figures 4 and 5).

FIGURE 5: Flaring Regulations by State



- Specific flaring restrictions
- Aspirational standards
- Notice and approval required
- Flaring required
- No evidence of regulation
- Not in study
- No natural gas wells as of 2010

Source: Resources for the Future. "A Review of Shale Gas Regulations by State." July 2012. Available at: http://www.rff.org/centers/energy_economics_and_policy/Pages/Shale_Maps.aspx

CONCLUSION

The climate implications associated with the production and use of natural gas differ from other fossil fuels (coal and oil). Natural gas combustion yields considerably lower emissions of greenhouse gases and other air pollutants; however, when methane is released directly into the atmosphere without being burned—through accidental leakage or intentional venting—it is about 21 times more powerful as a heat trapping greenhouse gas than CO_2 when considered on a 100-year time scale. As a result, considerable effort is underway to accurately measure methane emission and leakage. Policy-makers should continue to engage all stakeholders in a fact-based discussion regarding the quantity and quality of available emissions data and what steps can be taken to improve these data and accurately reflect the carbon footprint of all segments of the natural gas industry. To that end, additional field testing should be performed to gather up-to-date, accurate data on methane emissions. Policy-makers have begun to create regulations that address methane releases, but a better understanding and more accurate measurement of the emissions from natural gas production and use could potentially identify additional cost-effective opportunities for emissions reductions along the entire natural gas value chain.

IV. POWER SECTOR

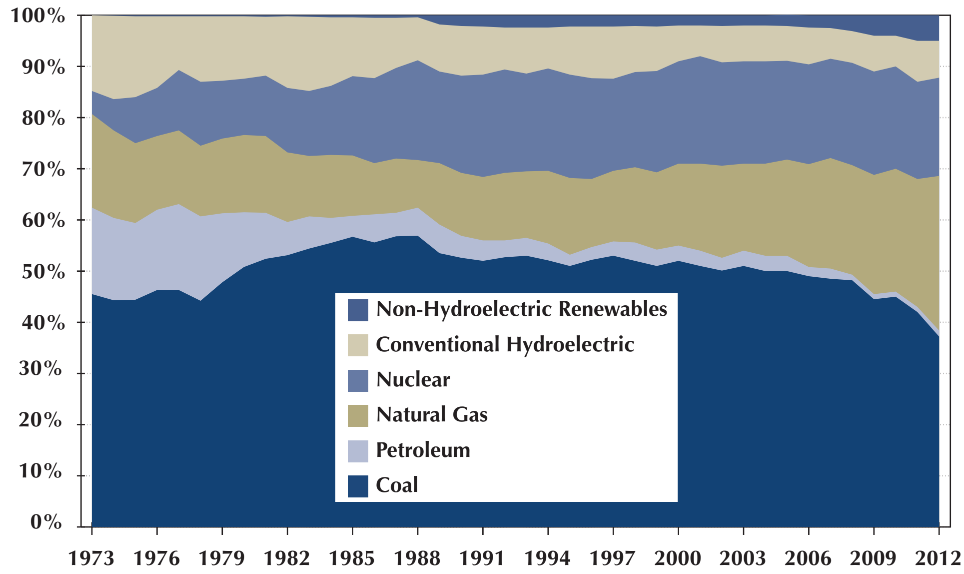
By Doug Vine, C2ES

INTRODUCTION

The U.S. power industry produces electricity from a variety of fuel sources (Figures 1 and 2). In 2012, coal-fueled generation provided a little more than 39 percent of all electricity, down from 50 percent in 2005. Nuclear power provided around 19 percent of net generation. Filling the gap left by the declining use of coal, natural gas now provides nearly 29 percent of all electricity and renewables, including wind and large hydroelectric power, provide about 12 percent. Petroleum-fueled generation is in decline, providing less than 1 percent of electricity in 2012.

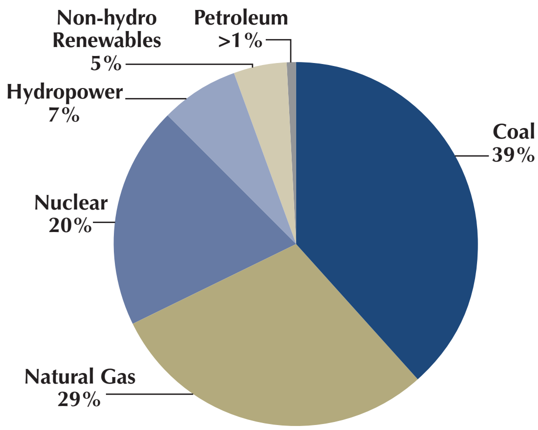
Natural gas use in the power sector during the 1970s and 1980s was fairly consistent and low, contributing a declining share of total electricity generation as coal and nuclear power's share of total electricity significantly increased. In 1978, in response to supply shortages (the result of government price controls), Congress enacted the Power Plant and Industrial Fuel Use Act.[58] The law prohibited the use of oil and natural gas in new industrial boilers and new power plants, with the goal of preserving the (thought to be) scarce supplies for residential customers.[59] As a consequence, the demand for natural gas declined during the 1980s, contributing to an oversupply of gas for much of the decade. The falling natural gas demand and prices spurred the repeal in 1987 of sections of the Fuel Use Act that restricted the use of natural gas by industrial users and electric utilities.[60] (For an overview of key policies impacting natural gas supply, see Appendix A). Continued low natural gas prices in the 1990s stimulated the rapid construction of gas-fired power plants.[61] In the early 2000s, the building boom in natural gas-fired generation was tempered

FIGURE 1: U.S. Electricity Generation by Fuel Type, 1973 to 2012



Source: Energy Information Administration, "Electricity Net Generation: Total (All Sectors). Table 7.2a," March 2013. Available at: http://www.eia.gov/totalenergy/data/monthly/#electricity

FIGURE 2: **U.S. Electricity Generation by Fuel Type, 2012**



Source: Energy Information Administration, "March 2013 Monthly Energy Review. Table 7.2b. Electricity Net Generation: Electric Power Sector," Available at: http://www.eia.gov/totalenergy/data/monthly/#electricity

somewhat by price spikes, although natural gas-fired generating capacity continues to be added more than any other fuel type. Since 1990, electricity generation from natural gas has increased from around 11 percent to 29 percent of the total net generation in 2012 (Figure 1). In 2006, natural gas surpassed nuclear power's share of the total generation mix, and in April 2012, natural gas and coal each contributed a little more than 32 percent of total generation.

This chapter explores the combination of factors driving change in the power sector. It examines the advantages and disadvantages of natural gas use, the competitive nature of alternative energy sources, and the synergy between natural gas and renewable energy generation. Finally, it explores relevant policy options that could lower greenhouse gas emissions in the sector.

ADVANTAGES AND DISADVANTAGES OF NATURAL GAS USE IN THE POWER SECTOR

From the perspective of an electrical system operator, a power plant owner, or an environmental perspective, natural gas-fueled power generation has many advantages. Natural gas can provide baseload, intermediate, and peaking electric power, and can thus meet all types of electrical demand. It is an inexpensive, reliable, dispatchable source of power that is capable of supplying firm backup to intermittent sources such as wind and solar.[62] Natural gas power plants can be constructed relatively quickly, in as little as 20 months.[63] Air emissions are significantly less than those associated with coal generation, and compared to other forms of electric generation, natural gas plants have a small footprint on the landscape. However, even though combustion of natural gas produces lower greenhouse gas emissions than combustion of coal or oil, natural gas does emit a significant amount of carbon dioxide (CO_2), and its direct release into the atmosphere, as discussed in chapter 3, adds quantities of a greenhouse gas many times more potent than CO_2. Finally, natural gas-fired power plants must be sited near existing natural gas pipelines, or else building new infrastructure may significantly increase their cost.

Cost of Building Natural Gas-Fired Power Plants

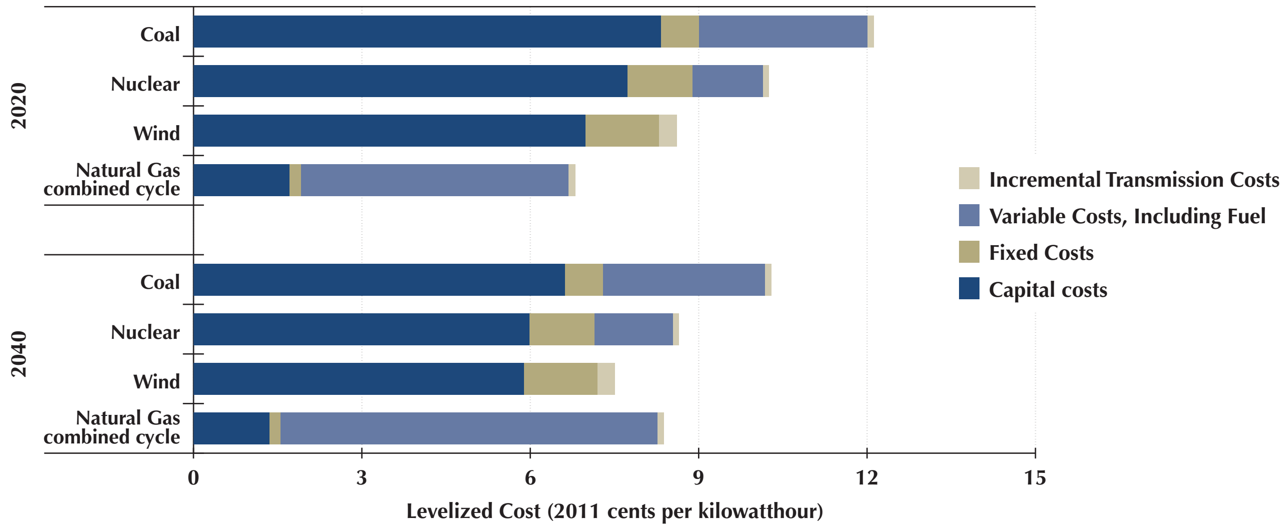
Natural gas-fired combined-cycle electricity generation (see Appendix B for a list of power plant technologies) is projected to be the least expensive generation technology in the near and mid-term, taking into account a range of costs over an assumed time period. These costs include capital costs, fuel costs, fixed and variable operation/maintenance costs, financing costs, and an assumed utilization rate for the type of generation plant (Figure 3). The availability of various incentives including state or federal tax credits can also impact the cost of an electricity generation plant, but the range of values shown in Figure 3 do not incorporate any such incentives. Based purely on these market forces, utilities looking at their bottom lines and public utility commissions looking for low-cost investment decisions will favor the construction of natural gas-fired technologies in the coming years.

Emissions

For each unit of energy produced, a megawatt-hour (MWh) of natural gas-fired generation contributes around half the amount of CO_2 emissions as coal-fired generation and about 68 percent of the amount of CO_2 emissions from oil-fired generation (Table 1).

While combustion of natural gas produces lower greenhouse gas emissions than combustion of coal or oil, natural gas does emit a significant amount of carbon dioxide (CO_2). In 2011, the power sector contributed about 33 percent of all U.S. CO_2 emissions.[64] Since 2005, total greenhouse gas emissions from the electricity sector have decreased, even as net electricity generation has remained steady, a result of natural gas-fired electricity

FIGURE 3: Estimated Levelized Cost of New Generation Resource, 2020 and 2040



Source: Energy Information Administration, "Annual Energy Outlook 2013," April 15, 2013. Available at: http://www.eia.gov/forecasts/aeo/MT_electric.cfm#cap_addition

Note: Price in 2011 cents per kilowatt-hour.

TABLE 1: Average Fossil Fuel Power Plant Emission Rates (pounds per Megawatt Hour)

GENERATION FUEL TYPE	CO_2 LB/MWH	SULFUR DIOXIDE LB/MWH	NITROGEN OXIDES LB/MWH
Coal	2,249	13	6
Natural Gas	1,135	0.1	1.7
Oil	1,672	12	4

Source: Environmental Protection Agency, "Clean Energy—Air Emissions," 2012. Available at: http://www.epa.gov/cleanenergy/energy-and-you/affect/air-emissions.html

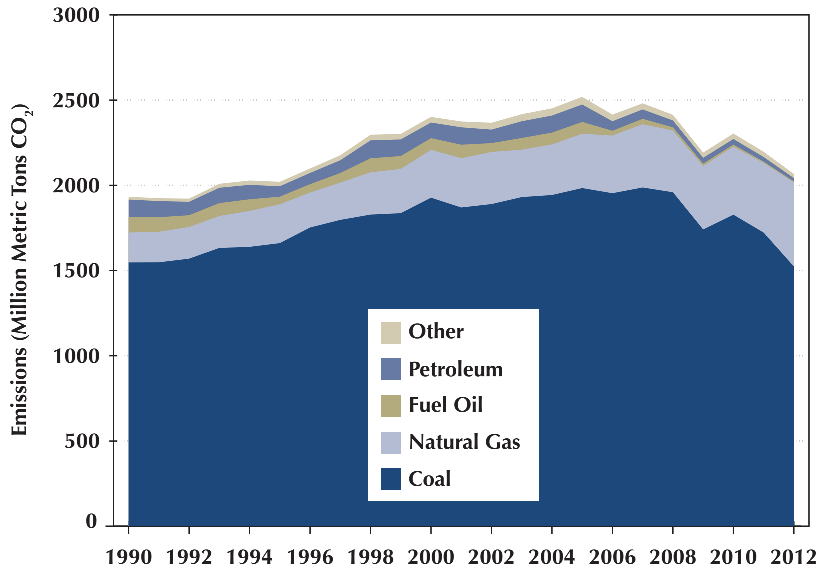
generation displacing petroleum- and coal-fired generation and an increase in the use of renewable generation. In 2012, CO_2 emissions from power generation were at their lowest level since 1993 (Figure 4).

Future Additions to Electricity Generation Capacity

There is strong evidence that the trends toward more natural gas in the power sector will continue in the near and medium term. With natural gas prices expected to stay relatively low and stable and the increasing likelihood of a carbon-constrained future, natural gas has become the fuel of choice for electricity generation by utilities in the United States.[65, 66] In 2012, the electric power industry planned to bring 25.5 gigawatts (GW) of new capacity on line, with 30 percent being natural gas-fired (and the remainder being 56 percent renewable energy and 14 percent coal.[67] Between 2012 and 2040, the U.S. electricity system will need 340 GW of new generating capacity (including combined heat and power additions), given rising demand for electricity and the planned retirement of some existing capacity.[68] Natural gas-fired plants will account for 63 percent of cumulative capacity additions between 2012 and 2040 in the Energy Information Administration (EIA) Annual Energy Outlook 2013 reference case, compared with 31 percent for renewables, 3 percent for coal, and 3 percent for nuclear (Figure 5).

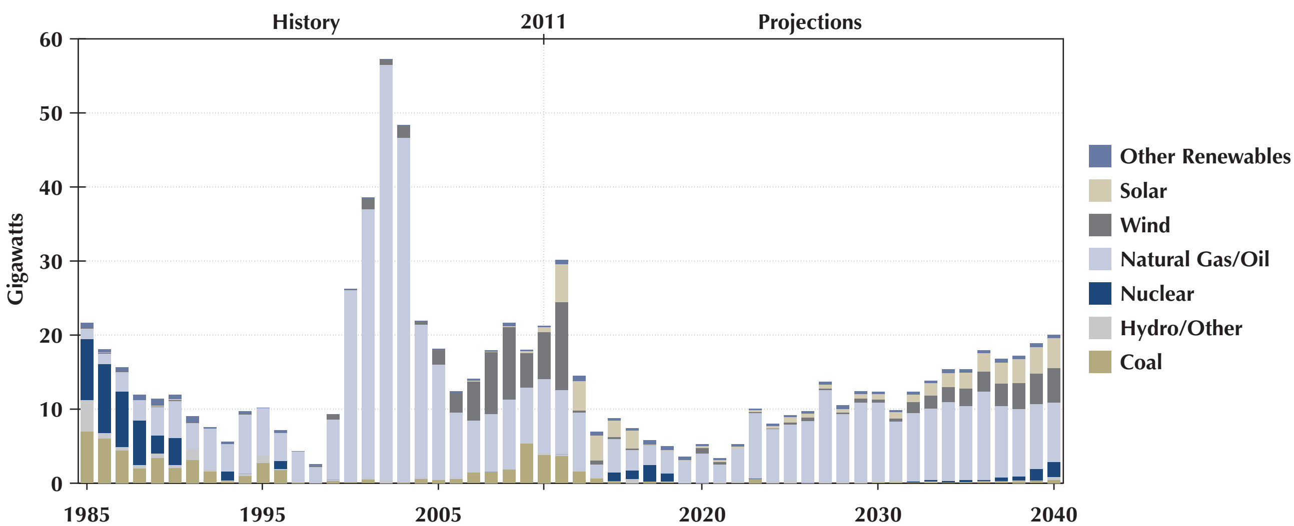
Federal tax incentives and state programs will contribute substantially to renewables' competitiveness in the near term.[69] For example, with the wind production tax credit, wind generation is expected to increase more than 18 GW from 2010 to 2015. Similarly

FIGURE 4: U.S. Emissions in the Power Sector, 1990 to 2012



Source: Energy Information Administration, "Monthly Energy Review," Table 12.6, March 27, 2013. Available at: http://www.eia.gov/forecasts/archive/aeo11/index.cfm

FIGURE 5: Additions to Electricity Generation Capacity, 1985 to 2040



Source: Energy Information Administration, "Annual Energy Outlook 2013," April 15, 2013. Available at: http://www.eia.gov/forecasts/aeo/MT_electric.cfm#cap_addition

with the solar investment tax credit, utility and end-use solar capacity additions are forecast to increase by 7.5 GW through 2016.[70] In addition to federal incentives, state energy programs mandate increased renewable energy capacity additions in thirty-eight states. These states have set standards specifying that electric utilities deliver a certain amount of electricity from renewable or alternative energy sources. Increasing the deployment of zero-carbon energy technologies such as renewables, nuclear, and carbon capture and storage needs to be a priority in order for the United States (and the rest of the world) to address climate change.

Fuel Mix Diversity

Since 1990 the share of generation from natural gas has increased from around 11 percent to 29 percent of the total net generation in 2012 (Figure 1), substantially increasing the diversity of the fuel mix. Natural gas-fired generation is expected to constitute just over 27 percent of the total generation mix in 2020, rising to 30 percent in 2035.[71] Fuel diversity is an important consideration for utilities looking to reduce their reliance on any particular energy source, as too much reliance on any one fuel can expose utilities or other power generation owners to the risks associated with price volatility. From a national perspective, fuel diversity is projected by EIA to remain about the same through 2040 with no single fuel being dominant.[72] Two things could change this outlook, however. One is a scaling back or reversal of the state and federal policies supporting zero-carbon generation, such as state renewable portfolio standards and federal tax incentives.[73] The other is a change in the outlook for the U.S. nuclear generation fleet. Competitive pressures from low natural gas prices have already caused one small, older (1974) plant—the 586 MW Kewaunee plant in Wisconsin—to announce its closure (even though its operating license does not expire until 2033).[74] Should more nuclear generation follow suit, these would likely be replaced by natural gas-fired generation. Given that 19 percent of U.S. electricity comes from nuclear power, there is concern that replacing these with natural gas and decreasing the emphasis on renewable energy deployment would push the U.S. power sector into a situation where fuel diversity is significantly reduced.

OPPORTUNITIES FOR FURTHER GREENHOUSE GAS REDUCTIONS

Beyond the increased use of lower-emitting fuels in the traditional, centralized power-generation system, certain fundamental changes in where and how electricity is generated have the potential to dramatically reduce greenhouse emissions from the sector. These opportunities and challenges are detailed below and are crucial if long-term emission reductions are to be made.

Distributed Generation

Generating electricity at or near the site where it is used is known as distributed generation. A common example is solar panels on the rooftops of homes and businesses, but natural gas is also used in conjunction with distributed generation technologies. For example, natural gas combined heat and power (CHP) systems in industrial, commercial, and residential settings are becoming a more commonplace type of distributed generation.

Traditionally, the power sector functions with centrally located power stations generating large quantities of electricity, which is transported to end users via electrical transmission and distribution lines. With distributed generation systems (also referred to as on-site generation or self-generation, and described in more detail in chapter 7), smaller quantities of electricity are generated at or near the location where it will be consumed, obviating the need for long electrical transmission lines. Additionally, natural gas CHP systems (discussed in more detail in chapter 6) are able to use waste heat from electricity production for practical purposes. Switching from a primarily centrally generated power generation system to a more efficient distributed system that captures waste heat avoids electrical transmission losses, requires less electricity to be generated, and uses less fossil fuel in aggregate, and therefore lowers greenhouse gas emissions.

Supply Side Efficiency

For a host of practical and economic reasons, centralized power generation will not be going away in the near or medium term. Basically, there are three categories of natural gas-fueled central power station: steam turbines, combustion turbines, and combined-cycle power plants (Appendix B). Each of these plant types has an average thermal efficiency. Thermal efficiency measures how well a technology converts the fuel energy input (heat) into electrical energy output (power). A higher thermal efficiency, other things being equal, indicates that less fuel is required to generate the same amount of electricity, resulting in fewer emissions. Steam turbines have the lowest efficiency at around 33 to 35 percent. Combustion turbines are around 35 to 40 percent efficient, and combined-cycle plants have thermal efficiencies in the range of 50 to 60 percent.

More efficient designs should be considered as new natural gas-fired capacity is added to the power sector. The Electric Power Research Institute (EPRI) asserts that it is technologically and economically feasible to improve the thermal efficiencies of steam turbine technology by 3 percent, increase combustion turbines to 45 percent efficient, and construct combined-cycle plants with 70 percent efficiency by 2030.[75] Higher thermal efficiencies translate into less fuel required to generate the same amount of electricity. EPRI's 2009 analysis estimates a potential CO_2 emissions reduction in 2030 of 3.7 percent from the power sector as a result of increasing the efficiency of new and existing fossil fuel-fired generation.[76]

Carbon Capture and Storage

In a carbon-constrained future, and with natural gas potentially playing a greater role in the future of the total generation mix natural gas plants with carbon capture and storage capability will need to be deployed to ensure greenhouse gas emissions are reduced over the long term. Carbon capture and storage projects have already been initiated, and several projects are planned in the next several years to demonstrate the feasibility of the technology, such as the Texas Clean Energy Project and the Kemper County integrated-gasification, combined-cycle (IGCC) project.[77] To date, these projects have been undertaken almost exclusively in conjunction with coal-fired power plants or industrial sources.[78] However, one international project in Norway, set to begin in 2012, endeavors to capture CO_2 from a natural gas CHP plant (similar to a combined-cycle plant) and sequester the CO_2 in an underground saline formation.[79]

In addition to sequestering CO_2 in saline formations, CO_2 is currently being injected into oil wells as part of tertiary, or enhanced, oil production (CO_2-EOR).[80] This storage option has the added benefit of providing an economic incentive, that is, compensation from the oil-field operator to the captured-CO_2 provider. In 2011, the National Enhanced Oil Recovery Initiative (NEORI) was formed to help realize CO_2-EOR's full potential as a national energy security, economic, and environmental strategy. In addition, NEORI suggests federal- and state-level action to support CO_2-EOR.[81]

Economics and Fuel Selection

For power plant operators, the economics of switching from coal to natural gas ultimately depend on underlying fuel prices, which in turn depend on individual location, operational and reliability requirements, and environmental regulations. In mid-2011, natural gas prices fell below coal prices on a dollar-per-energy-output basis. As the gap between the two fuels widened, the share of natural gas-fired power generation increased. However, by July 2012, natural gas prices had rebounded above \$3.10 per thousand cubic feet, the cost point for coal at the time. Accordingly, coal-fired generation increased relative to natural gas-fired generation.[82] Future fuel substitution will depend on the variable prices of both coal and natural gas.

Competitive electric power markets, in some form, exist in 43 states. In competitive power markets, electricity is bid into the market based on production costs. Typically, fuel cost is the main driver of production cost, but fuel costs can vary depending on a plant's location. Other factors such as plant efficiency will also affect production cost, with newer more efficient plants able to bid into the market at lower prices than older plants. Renewable technologies such as hydro and wind have the lowest production costs (Figure 6), and can be bid into a market at near zero dollars. Next in the merit or price order is nuclear power, followed by lignite, a cheaper, softer coal with a high moisture content. Hard coal plants and natural gas combined-cycle plants are in the middle of the supply curve or bid stack. Finally, natural gas combustion turbine plants and oil and diesel plants are the most expensive plants to run and are basically only used during times of peak demand. Electricity system operators employ a least-cost dispatch methodology. The point at which the quantity of electricity demanded at any point in time crosses the price-ordered supply curve is known as the marginal generator, and this sets the market price. Coal- or natural gas-fired plants are the marginal generator in most competitive power markets. Even though other suppliers such as wind and nuclear have bid into the market at a price lower than the marginal generator, all units receive the marginal or market price for that time period.

Lower natural gas prices and greater quantities of low variable cost renewables are contributing to lower prices in competitive electricity markets. Current and forecast low natural gas prices were cited as one of the reasons behind the recently announced decision to shut down a 556 megawatt (MW) Wisconsin-based nuclear power station.[83] Additionally, there is evidence to suggest that lower natural gas prices suppress the development of renewables.[84] In this situation, government policies are undoubtedly necessary to ensure that zero-carbon generation sources are a growing, rather than declining, share of the U.S. energy mix.

Relationship Between Natural Gas and Renewables

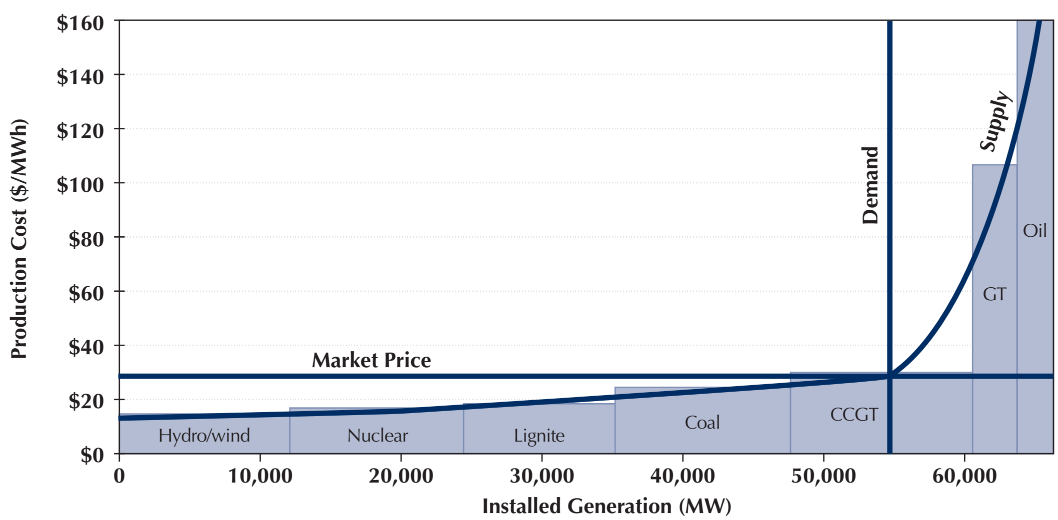
There is a complicated relationship between natural gas and renewables in the power sector, stemming from two aspects: 1) competition in the dispatch order between natural gas and renewables, and 2) the potential to produce renewable forms of natural gas.

For the most part, the relationship between natural gas and renewables is interpreted as competition in the power sector, by which renewables are seen as a threat to natural gas because they push natural gas-fired power plants off the bid stack. This phenomenon occurs because the power markets take bids on marginal costs rather than all-in costs. Because the marginal cost of wind is zero, it bids zero (or negative in some cases, reflecting the effect of production tax credits for wind power). Consequently, it is a price-taker in the markets, and it displaces the highest bidders, which are the price-setters. Historically, those price-setters are natural gas power plants, and so wind power displaces natural gas. Consequently, the relationship between gas and wind is one of rivalry. Natural gas interests audibly complain about this rivalry, with the criticism that policy supports for wind give it an unfair advantage in this competition. Renewable energy supporters counter that natural gas interests are not required to pay for their pollution (which is a form of indirect subsidy) and have enjoyed government largesse in one form or another for many decades.

Despite the perception that wind and natural gas are vicious competitors in a zero-sum game where the success of one must come at the demise of the other, the relationship is actually more nuanced. In fact, wind and gas benefit from each other because they both mitigate each other's worst problems. For wind, intermittency is a problem, and for natural gas, price volatility has been a problem historically. It turns out that the ability for natural gas power plants to serve as rapid response firming power is an effective hedge against wind's intermittency. And, it turns out the fixed fuel price (at zero) of wind farms is an effective hedge against natural price volatility. Thus, they are complementary partners in the power markets.

Almost all natural gas used today comes from geologic reserves formed many millions of years ago. Therefore, many people seeking a long-term sustainable energy option reject natural gas automatically because it is widely considered a fossil fuel that has a finite resource base. It is important to note that there are also renewable forms of natural gas, known as biogas or biomethane. This form of gas is mostly methane (CH_4) with a balance of CO_2, and is created from the anaerobic decomposition of organic matter. While renewable natural gas is a small fraction of the overall gas supply, it is not negligible. For example, landfill gas is already an important contributor to local fuel supplies at the local scale. And, recent studies have noted that the total potential supply available from wastewater treatment plants and anaerobic digestion of livestock waste is over 1 quadrillion British thermal units annually in the United States, which is more than 10 percent of the amount of renewable energy consumed in the United States in 2011.[85, 86, 87]

FIGURE 6: Generalized Representation of a Competitive Power Market



Source: Adapted from Rawls, Patricia, U.S. Department of Energy: National Energy Technology Laboratory, "The PJM Region: A GEMSET Characterization for DOE." December 13, 2002. Available at http://www.netl.doe.gov/energy-analyses/pubs/200220DecPJMregionHandout.pdf

KEY POLICY OPTIONS FOR THE POWER SECTOR

Significant policy decisions affecting the U.S. power sector today include regulations to address the interstate air pollution transport, the National Emissions Standards for Hazardous Air Pollutants, and the proposed New Source Performance Standards issued by the U.S. Environmental Protection Agency (EPA). For electricity generation plants to comply with the Cross State Air Pollution Rule and National Emissions Standards for Hazardous Air Pollutants, they will need to install pollution control technologies, a requirement that will affect coal-fired plants in particular.[88] PJM, the operator of the world's largest wholesale electricity market, located in the eastern United States, predicts that approximately 14 GW of coal-fired generation (out of an installed capacity of 78.6 GW of coal-fired generation) could be retired by 2015, largely due to these rules.[89] Questions have been raised about the implications of these retirements on the electricity system's capacity and ability to meet demand and specifically reserve margins. Reserve margins are the spare capacity that electricity system or market operators are required to maintain above the projected peak loads in order to ensure system reliability. While reserve margins appear sufficient in the short run, new, reliable baseload generation will be required in the next 10 to 20 years to fill the gap.

In late March 2012, EPA proposed CO_2 pollution standards for new electric power plants as part of its New Source Performance Standards program. The proposed standard is 1,000 pounds of CO_2 per megawatt-hour, and under this new standard all new power plants would need to match the CO_2 emissions performance currently achieved by highly efficient natural gas combined-cycle power plants. While new efficient natural gas, nuclear, or renewable energy plants would meet this standard easily, new coal-fired power plants could meet the standard only by capturing and permanently sequestering their greenhouse gas emissions using carbon capture and storage technologies. If adopted, this standard would favor new natural gas-fired generation over coal in the future.[90]

In the past few years, there has also been some interest in a federal-level renewable portfolio standard and, more recently, in a broader federal clean energy standard. Whereas a renewable portfolio standard typically credits only 100 percent-renewable generation such as wind, solar, geothermal, or new hydro power, a clean energy standard would create a mechanism to credit "cleaner" electricity generation as well, that is, generation that emits some CO_2 although less than a reference power plant technology such as a generic coal power plant. Under a clean energy standard proposal, credits would be available to new and incremental (upgrades and improvements to) natural gas-fired generation, natural gas with carbon capture and storage, and other relatively cleaner forms of electricity production.[91] Indiana and West Virginia have alternative energy portfolio standards, similar to a renewable portfolio standard; however, these standards allow natural gas-fueled generation to be a part of their clean energy goals. In this way, some policy-makers have recognized that there are significant emissions benefits to natural gas use.

There is a need, however, to continue moving the power generation sector to even cleaner generation (zero-emission sources), to reduce CO_2 emissions to levels that will stave off the worst effects of climate change.

A price on carbon is a highly effective policy that can provide an incentive for zero-emission sources but it is not the only option. Tax credits for renewable generation, carbon capture and storage, nuclear loan guarantees, and policies that promote energy efficiency are all being used, to some extent, in the United States to acccelerate the deployment of low-carbon energy.

CONCLUSION

Market forces are driving greater use of natural gas in the power sector, and the inherent qualities of natural gas combustion are leading to lower greenhouse gas emissions. Adoption of distributed generation technologies, more efficient technology, and carbon capture and storage with natural gas have the potential to lower greenhouse gas emissions further. Market forces are joined by policy decisions, enacted and pending, that impact coal-fired generation and will further discourage its use. In addition, some states' alternative energy portfolios count natural gas-fueled generation toward their medium-term clean energy goals.

Low natural gas prices are having an impact on the diversity of the fuel mix used in electricity generation. In the near term, the diversity of the fuel mix is increasing as fuel-switching from coal to natural gas proceeds; however, in the long term, a sustained low natural gas price may discourage investment in nuclear generation and renewables. Policy is necessary to ensure that the percentage of zero carbon-emission power generation is growing sufficiently to mitigate the most dangerous effects of climate change.

APPENDIX A: NATURAL GAS POLICY

1938	The Natural Gas Act of 1938 establishes federal authority over interstate pipelines, including the authority to set "just and reasonable" rates. It also establishes a process for companies seeking to build and operate interstate pipelines. Oversight of The Act is given to the Federal Power Commission.
1954–1978	Natural gas price controls eventually lead to scarcity and shortage.
1978	In response to supply shortages, Congress enacts the Power Plant and Industrial Fuel Use Act. The law prohibits the use of natural gas in new industrial boilers and new electric power plants. The goal is to preserve "scarce" supplies for residential customers.
1985	The Federal Power Commission is replaced by the Federal Energy Regulatory Commission, which issues Order 436, intended to provide for open access to interstate pipelines that would offer transportation service for gas owned by others.
1987	President Reagan signs into law the repeal of the remaining Fuel Use Act restrictions and incremental pricing, believing that the country's natural gas resources should be free from regulatory burdens, which some saw as costly and counterproductive.
1990	On April 3rd, trading on natural gas futures begins at the New York Mercantile Exchange.
2005	The Energy Policy Act 2005 is passed, a bill exempting fluids used in the natural gas extraction process of hydraulic fracturing from protections under the Clean Air Act, Clean Water Act, Safe Drinking Water Act, and Comprehensive Environmental Response, Compensation, and Liability Act. The Act exempts companies drilling for natural gas from any requirement to disclose the chemicals involved in fracking operations, normally required under federal clean water laws. The proposed Fracturing Responsibility and Awareness of Chemicals Act would repeal these exemptions.
2011	Tough pollution limits (Cross State Air Pollution Rule) and limits on mercury, sulfur oxides (SO_x), and nitrogen oxides (NO_x) emissions (National Emissions Standards for Hazardous Air Pollutants) begin to drive older inefficient coal plants out of the market.
2011	A proposed Federal Clean Energy Standard credits natural gas relative to a coal reference power plant.
2012	New Source Performance Standard for CO_2 is proposed by EPA.

APPENDIX B: POWER PLANT TECHNOLOGIES

Steam Turbines

A common method of generating electricity is with steam turbines (Figure B-1). A power plant uses a combustible fuel—coal, oil, natural gas, wood waste—or nuclear fission to heat water in a boiler, which creates steam. The high-temperature, high-pressure steam is piped toward turbine blades, which move and rotate the attached turbine shaft, spinning a generator, where magnets within wire coils produce electricity.[92] Steam units have a relatively low efficiency. Only about 33 to 35 percent of the thermal energy used to generate the steam is converted into electrical energy, and the remaining heat is left to dissipate. Baseload electricity generation commonly relies on large coal- and nuclear-powered steam units on the order of 500 to 1000 MW or greater, as they can supply low-cost electricity nearly continuously.

Combustion Turbine

Combustion turbines are another widespread technology for centralized power generation (Figure B-2). In a combustion turbine, compressed air is ignited by burning fuel (e.g., diesel, natural gas, propane, kerosene, or biogas) in a combustion chamber. The resulting high-temperature, high-velocity gas flow is directed at turbine blades, which spin a turbine driving the air compressor and the electric power generator. Combustion turbine plants are typically operated to meet peak load demand, as they can be switched on relatively quickly. Another advantage is their ability to be a firm backup to intermittent wind and solar power on the grid, if needed. The typical size is 100 to 400 MW, and their thermal efficiency is slightly higher than steam turbines at around 35 to 40 percent.

Combined Cycle

A basic combined-cycle power plant combines a combustion turbine and a steam turbine in one facility (although there are other possible configurations) (Figure B-3). Combined-cycle plants waste considerably less heat than does either turbine alone. As combustion turbines became more advanced in the 1950s, they began to operate at ever-higher temperatures, which created increasing amounts of exhaust heat.[93] In a combined-cycle power plant, this waste heat is captured and used to boil water for a steam turbine generator, thereby creating additional generation capacity from the same amount of fuel. Combined-cycle plants have thermal efficiencies in the range of 50 to 60 percent. Historically,

FIGURE B-1: Steam Turbine

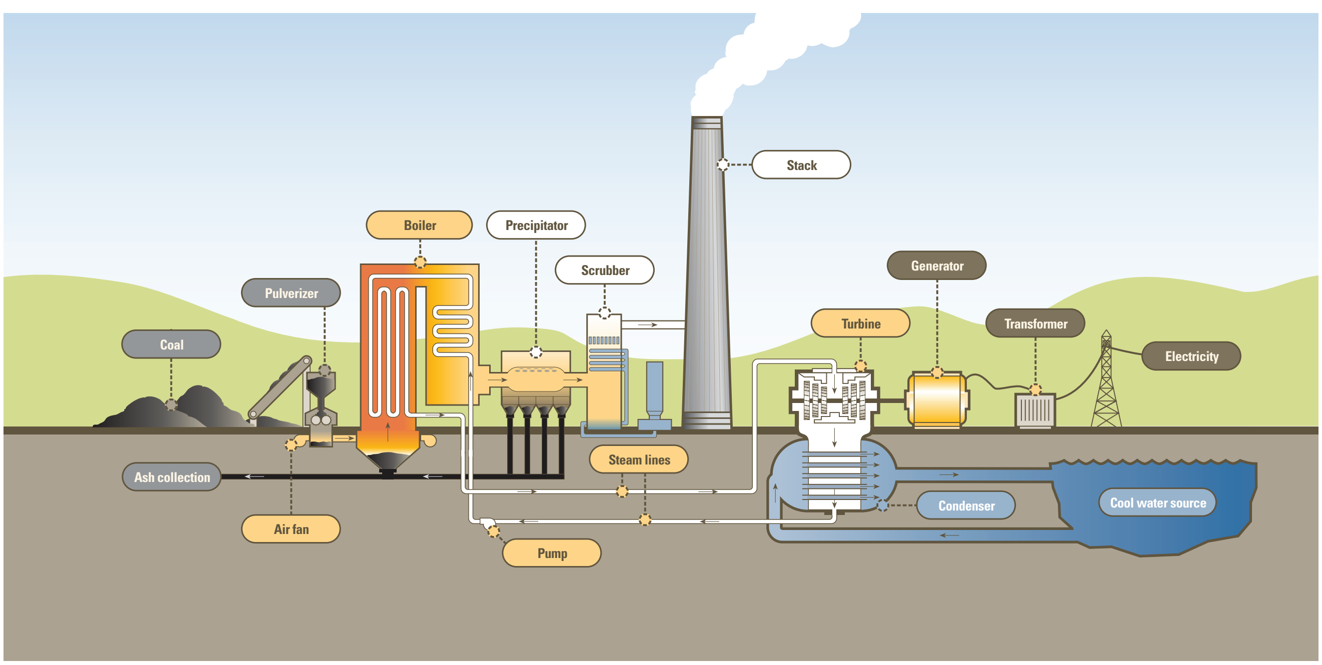


FIGURE B-2: Combustion Turbine

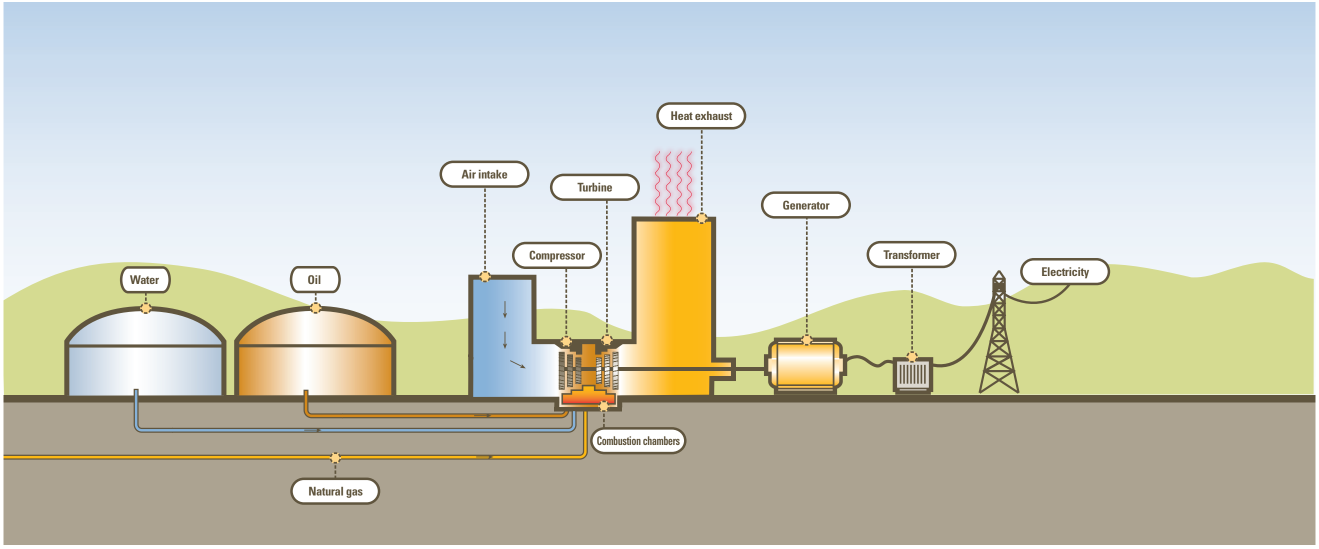
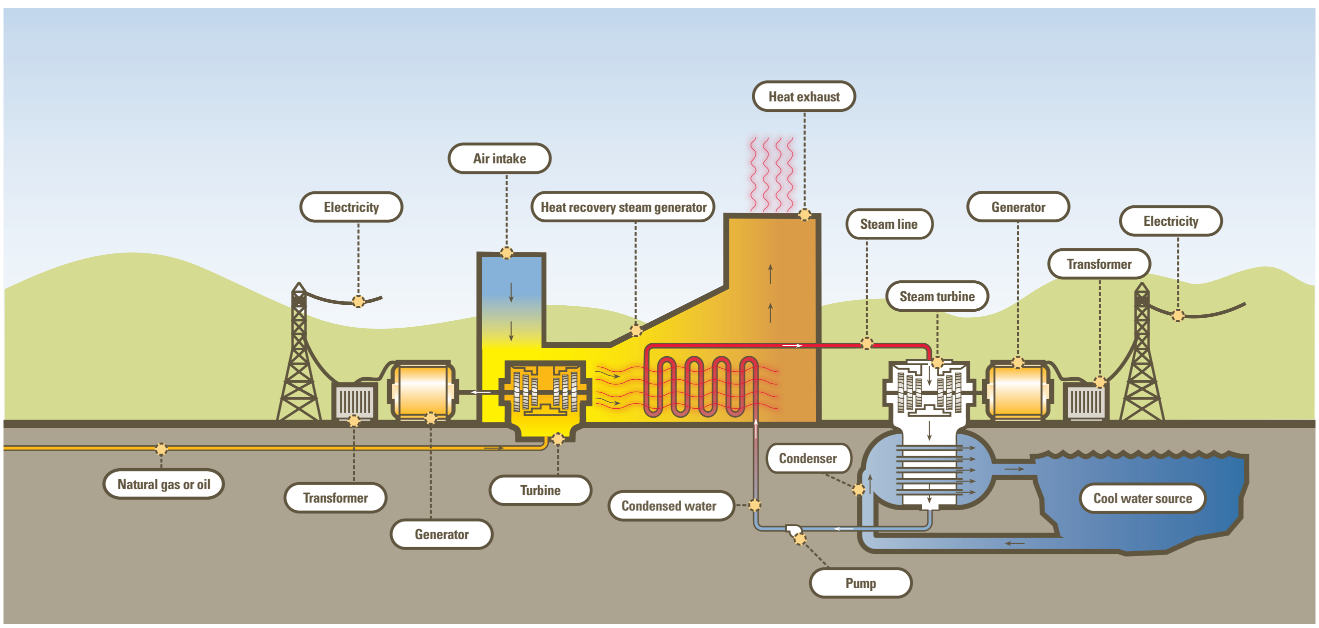


FIGURE B-3: Combined-Cycle Power Plant



they have been used as intermediate power plants, supporting higher daytime loads; however, newer plants are providing baseload support. Cutting edge natural gas combined-cycle power plants are coming online with thermal efficiencies at 61 percent with a correspondingly smaller emission of greenhouse gases; these plants are able to cycle on and off more frequently (than most of the installed power plant fleet) to more efficiently complement intermittent renewable generation.[94]

V. BUILDINGS SECTOR

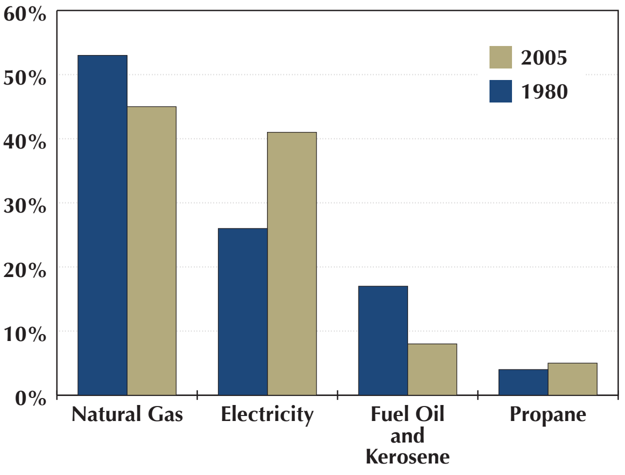
By Fred Beach, The University of Texas at Austin

INTRODUCTION

In 2009, the U.S. buildings sector accounted for about 41 percent of primary energy consumption.[95] Energy was delivered to more than 113 million residences and 4.8 million commercial and institutional buildings by four primary means: electricity, natural gas, district heat, and fuel oil. In both residential and commercial building sectors, natural gas and electricity have been the dominant fuel sources over the last 30 years. In the residential sector the proportion of electricity used has grown rapidly compared to other energy sources, largely driven by the proliferation of home electronics (Figure 1). In 2003 in the commercial sector, electricity and natural gas accounted for 87 percent of all energy used (Figure 2).[96] In 2011, residential and commercial buildings accounted for 34 percent of greenhouse gas emissions in the United States. Among fuels typically used in residential and commercial buildings, electricity usage accounted for 74 percent of carbon dioxide (CO_2) emissions from fossil fuel combustion, which accounts for the majority of greenhouse gas emissions from the buildings sector. Natural gas and other fuel combustion accounted for the remaining 26 percent.[97]

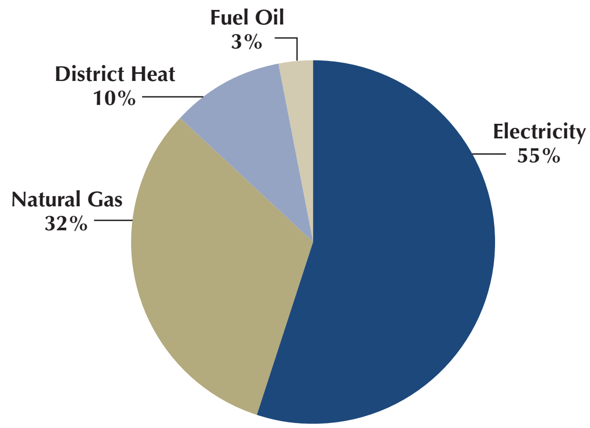
The fuel mix in the buildings sector heavily influences its greenhouse gas emissions. Natural gas consumed on site has relatively low emissions compared with the average emissions associated with liquefied petroleum gas (propane), fuel oil, or electricity. Electricity in particular typically has emissions far above those of natural gas. In 2011, more than 40 percent of U.S. electricity production came from coal-fired power plants, which create more CO_2 per unit of energy delivered than natural gas,

FIGURE 1: U.S. Residential Energy Consumption On-Site During 1980 and 2005, by Source



Source: Energy Information Administration, "Residential Energy Consumption Survey 2005, Table US3," 2005. Available at: http://www.eia.gov/consumption/residential/data/2005/c&e/summary/pdf/tableus3.pdf

FIGURE 2: U.S. Commercial Energy Consumption by Source, 2003



Source: Energy Information Administration, "Overview of Commercial Buildings, 2003," 2003. Available at: http://www.eia.gov/emeu/cbecs/cbecs2003/overview1.html propane, and fuel oil used on site.[98] Coal-fired electricity also produces sulfur dioxide (SO_2), nitrogen oxides (NO_X), and mercury, which are associated with environmental damage and harmful health effects.

Because of the significant amounts of primary energy and greenhouse gas emissions associated with electricity generation and consumption, and the relatively higher greenhouse gas emissions footprint associated with fuel oil, switching from inefficient electricity or fuel oil to high-efficiency natural gas in buildings can yield significant emission reductions. This chapter provides an overview of energy consumption in residential and commercial buildings, which is driven by climate zone, business needs and activities, building size, and, in large part, consumer behavior. It explains why consideration of primary and "source-to-site" energy, a measure of energy consumption that occurs prior to consumer energy use on site, contributes to a more complete picture of energy consumed and emissions emitted. Accordingly, this chapter makes use of the concept of full-fuel-cycle efficiency, which is the appropriate energy and efficiency metric with which to compare consumer fuel choices and consequences for greenhouse gas emissions. It demonstrates how using natural gas appliances could lead to dramatic reductions in fuel consumption and greenhouse gas emissions. Finally, the chapter looks at how policy support, including efficiency programs, consumer information, and innovative funding models, can help to overcome the barriers to increased natural gas access and utilization in the buildings sector.

ENERGY USE IN RESIDENTIAL AND COMMERCIAL BUILDINGS

There are strong regional variations in the types of energy available to and used in buildings. A significant factor affecting energy use is where a building is located. Homes in colder climates tend to consume more energy, driven by heating (often called thermal) requirements. Nationally, 61 percent of residential energy is used for space heating and water heating (41 percent and 20 percent, respectively), while air conditioning (space cooling) consumes only 8 percent. Overall, thermal uses are dominant in all regions of the country (Figure 3). In the commercial sector as well, the dominant energy uses are thermal loads (space and water heating), followed by lighting (Figure 4).

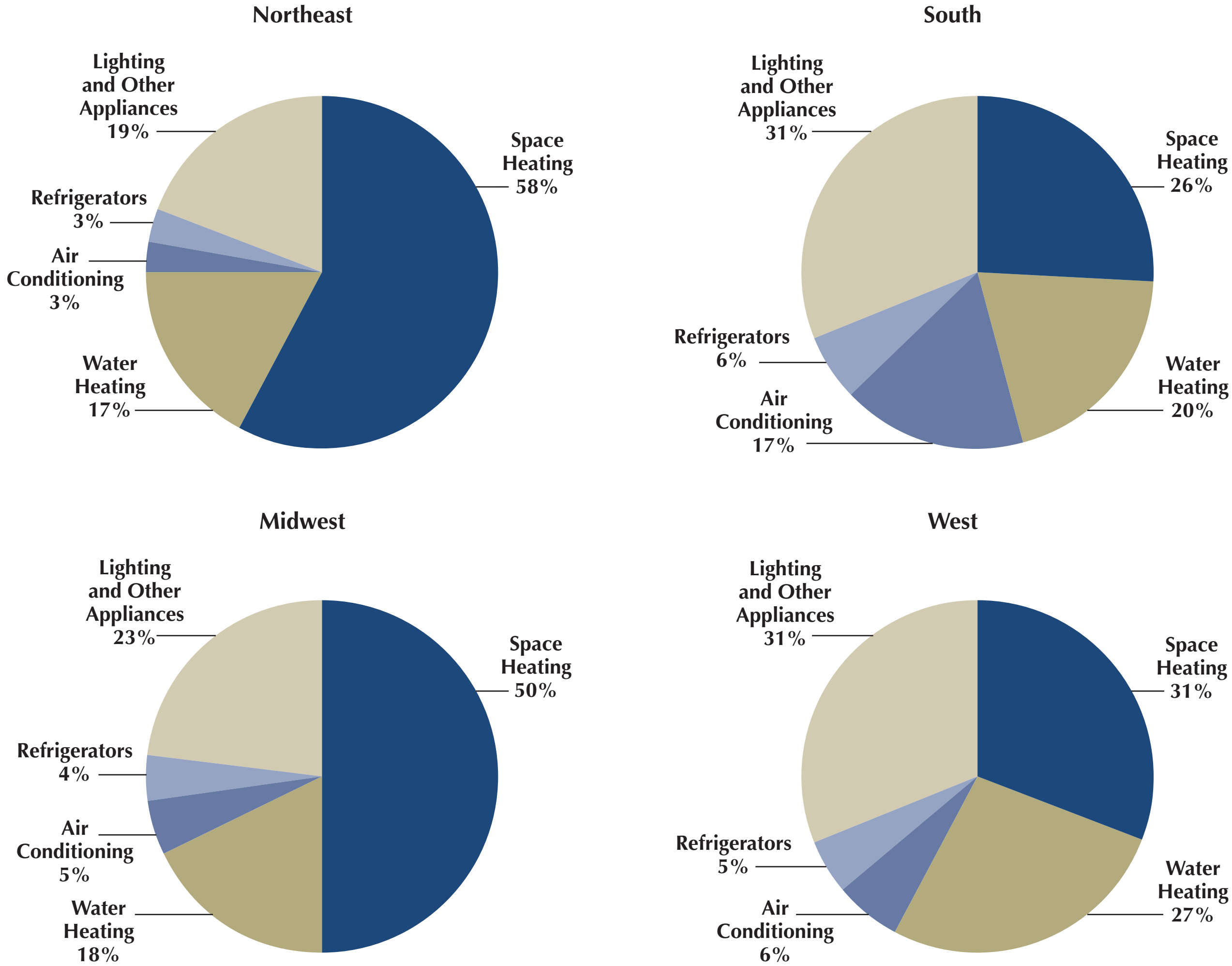
Energy Use in Commercial Buildings

Energy use among U.S. commercial buildings is quite diverse. Among commercial buildings, significant variation exists in the purpose and size of buildings, energy use, and emission profiles. Office space is the largest energy consumer, consuming 719 trillion Btu of electricity on site. Educational facilities are the second largest commercial consumer, using 371 trillion Btu of electricity on site. These two types of commercial buildings account for 36 percent of all the electricity used in buildings. Because they rely on relatively inefficient grid-delivered electricity rather than on-site generation (see below), they also have the highest emissions profiles.[99]

Commercial buildings vary in terms of energy intensity, measured in Btu consumption per square foot. The three most energy-intensive building sectors are food service, food sales, and health care, which use 258, 200 and 188 Btu per square foot per year, respectively.[100] While 84 percent of food service square footage is served by natural gas, only 60 percent of food sales square footage uses this fuel. The food service sector requires a large amount of thermal energy for cooking and cleaning, while energy use for food sales is predominantly for refrigeration. Thermal demands for in-patient healthcare are also heavy, with large amounts of food preparation, water heating, and cleaning. With these demands, 95 percent of building stock used for in-patient health care is served by natural gas, while only 59 percent of outpatient health care facilities use natural gas where are there are lower thermal loads.[101]

Building size also plays an important role in energy consumption and fuel source. Commercial buildings of more than 100,000 square feet account for only 2 percent of the total number of buildings, but they account for more than 34 percent of total floor space and more than 40 percent of total energy use (Figure 5). Clearly, this segment exhibits a higher concentration of high energy consumption, while being less fragmented in ownership than smaller buildings. Among large buildings of over 100,000 square feet, 77 percent use natural gas for space heating.[102, 103] The predominance of natural gas for heating in the largest of buildings, food service, and in-patient hospitals can be directly attributed to the greater overall efficiency and lower cost of natural gas over electricity for thermal applications such as space heating, water heating, and cooking.

FIGURE 3: U.S. Home Energy Consumption By End Use, 2005

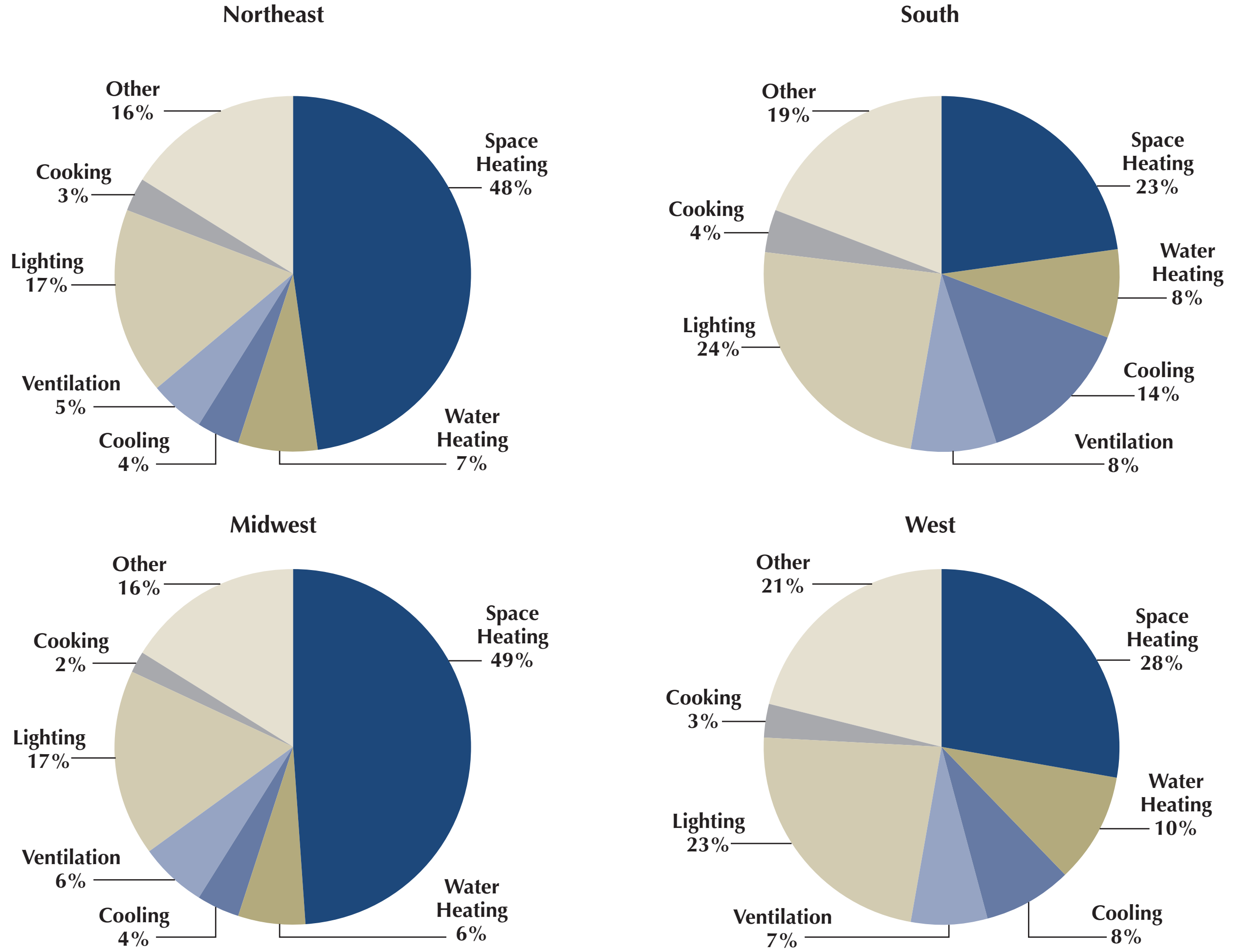


Source: Energy Information Administration, "Annual Energy Review 2009," Table US12. Available at http://www.eia.gov/consumption/residential/data/2009/#consumption-expenditures

The types of activities carried out in commercial buildings also influence the type of energy used. Office buildings tend to utilize electricity rather than natural gas because many of their primary loads, such as lighting, elevators, personal computers, servers, scanners, and printers, cannot be served by natural gas. Lodging, health care, and food service, in contrast, can more easily use natural gas for cooking, hot water, cleaning, and laundry, and, consequently, they use proportionally more natural gas than office buildings.

Local climate plays a large role in determining what type of energy is used, and how. The majority of commercial (and residential) buildings are located in colder climate zones (zones 1 to 4), which encompass much of the country except for the Deep South and the Southwest. In colder zones, winters are cold enough for frequent, substantial space heating, and the average amount of energy needed to heat a building during the winter, measured in heating degree days, is two to four times the average amount of energy needed to cool a building during the summer (measured in cooling degree days) (Figure 6). Still, space and water heating account for the greatest energy use in buildings regardless of climate zone (Figures 3 and 4).

FIGURE 4: U.S. Commercial Energy Consumption by End Use, 2003



Source: Energy Information Administration, Commercial Buildings Energy Consumption Survey 2009, "Building Characteristics," Table E1a. Available at: http://www.eia.gov/emeu/cbecs/cbecs2003/detailed_tables_2003/detailed_tables_2003.html#consumexpen03

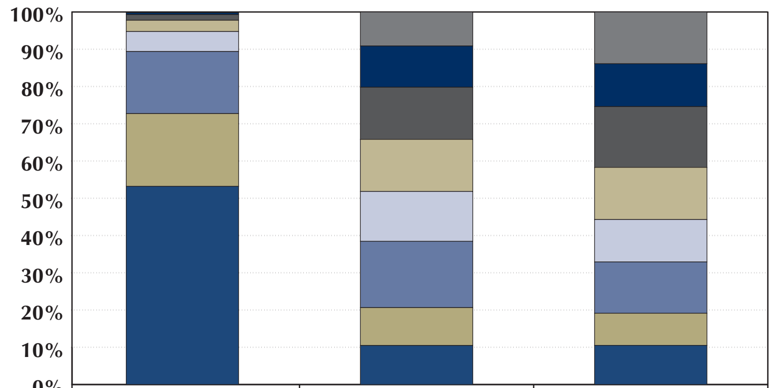
Energy Use in Residential Buildings

The prevalence of natural gas access and use in homes varies across U.S. climate zones, even though natural gas is a more efficient fuel choice for thermal loads. Natural gas appliances tend to be underrepresented in use, even when there is access to the fuel. In the two coldest regions in the country, natural gas is the preferred fuel for heating water in 23.7 million homes, while electricity is used in 10.8 million homes. The numbers suggest that nearly all of the homes using gas for space heating are also using it for water heating.[104] Nationwide, the story is different. Forty percent of households with natural gas access used electric appliances for space heating, water heating, or both in 2009, and that number has increased in recent years, with a four-million-household increase in residences with natural gas access using electric space heating.[105]

In warmer climates, natural gas use is less common than electricity for space heating—12.3 million residences use natural gas compared with 16.5 million using electricity.[106] However, natural gas and electricity are equally popular for water heating with an even split at 16 million homes each.[107] In these areas, more than 3 million homes had access to natural gas (as indicated by water heating usage) but did not use it for space heating.

Appliances, such as clothes dryers, ovens, and cooktops, are available in either electric, natural gas, propane, or fuel oil models, with electric and natural

FIGURE 5: Number of Non-Mall Commercial Buildings, Floor Space and Consumption by Size, 2003



	Total Buildings (thousand)	Total Floorspace (million square feet)	Total Consumption (trillion BTU)
Over 500,000 square feet	8	5,908	906
200,001 to 500,000 square feet	26	7,176	751
100,001 to 200,000 square feet	74	9,064	1,064
50,001 to 100,000 square feet	147	9,057	913
25,001 to 50,000 square feet	261	8,668	742
10,001 to 25,000 square feet	810	11,535	899
5,001 to 10,000 square feet	948	6,585	563
1,001 to 5,000 square feet	2,586	6,789	685

Source: Energy Information Administration, "Natural Gas Consumption and Conditional Energy Intensity by Building Size for All Buildings, 2003" Table C31. Available at: http://www.eia.gov/consumption/commercial/data/archive/cbecs/cbecs2003/detailed_tables_2003/2003set16/2003html/c31a.html

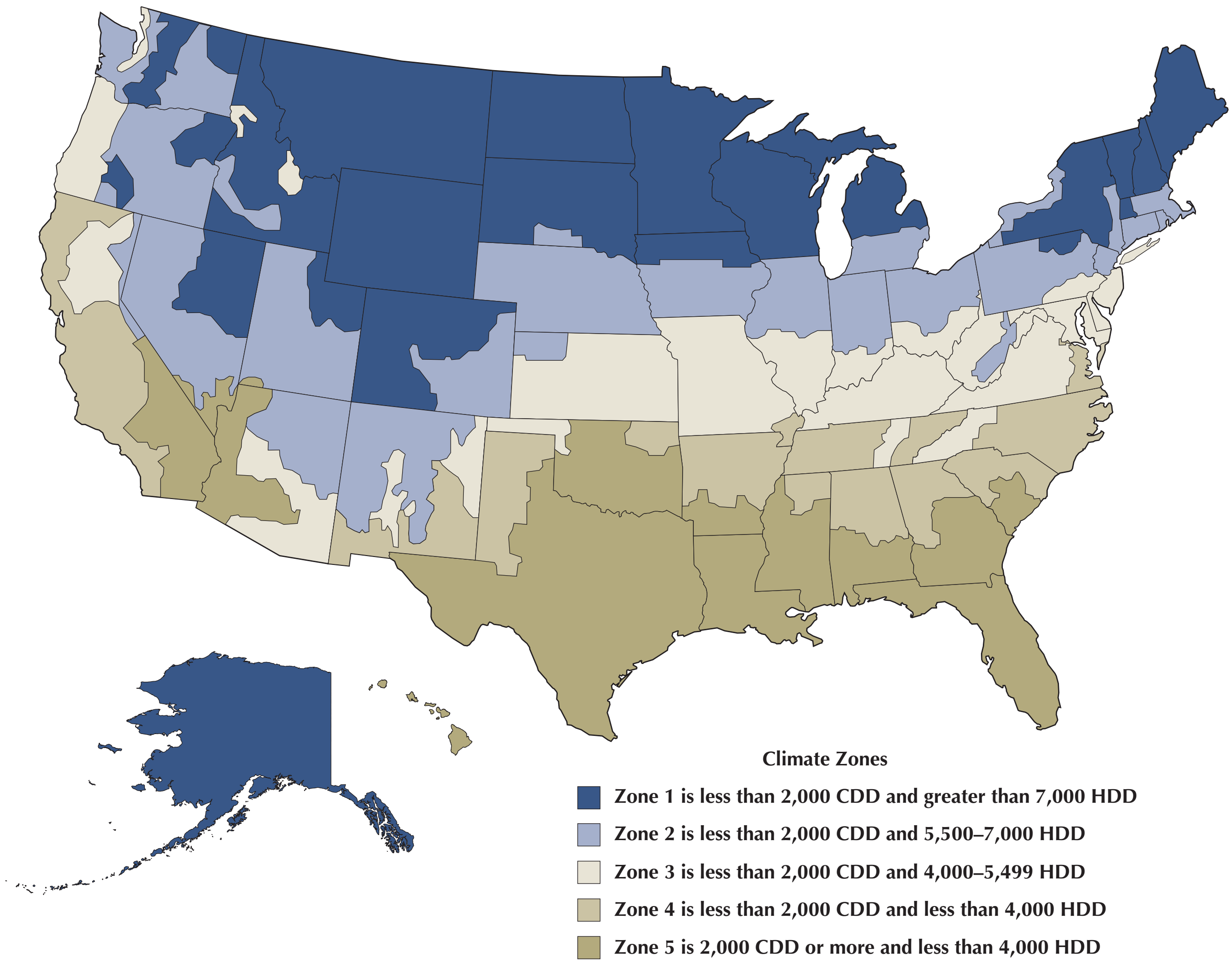
gas models being the most common by far (Figure 7). Nationwide, electric dryers outnumber gas models 4 to 1 (71.8 million compared to 17.5 million). For cooking appliances, whether ovens or cooktops, the ratio is almost 2 to 1 (68.1 million homes use electricity and 38.4 million use natural gas).[108] In theory, the use of these appliances should be independent of climate zone variations since they operate within the heated and cooled space of homes. Yet, natural gas appliances are significantly underrepresented in all climate zones.[109]

In the two coldest regions, zones 1 and 2, natural gas is the dominant space heating fuel, heating 24.8 million homes in 2005. In contrast, only 5.6 million homes used electric space heating in the same year (Figure 4).[110] Nationally, natural gas is also the chief fuel source for heating in commercial buildings. In 2003 in colder climate zones, it provided heat for 69 to 75 percent of all commercial floor space, but only 47 percent in zone 5, the warmest region.[111]

SOURCE-TO-SITE EFFICIENCY, SITE EFFICIENCY, AND FULL-FUEL-CYCLE EFFICIENCY

Building energy consumption can be measured in terms of fuel use on site: kilowatts of electricity, cubic feet of gas, and gallons of propane or fuel oil. This site energy is the total of all energy consumed at a building as measured by the electric and natural gas meters as it enters the building and/or by fuel oil or propane delivery. However, site energy does not tell the full energy story, because energy, whatever the source, must be extracted and delivered to the point of use, incurring losses along the way that are not reflected in the readings on customers' meters or delivery bills. As discussed in chapter 4, fossil fuels, such as coal or natural gas, are most often used to generate electricity. The term "source-to-site" generally refers to the total energy consumed in the course of extracting, processing, and delivering a unit of energy to a building, and in the case of electricity, energy associated with generation, transmission, and distribution. In other

FIGURE 6: **U.S. Climate Zones, Heating Degree Days vs. Cooling Degree Days**



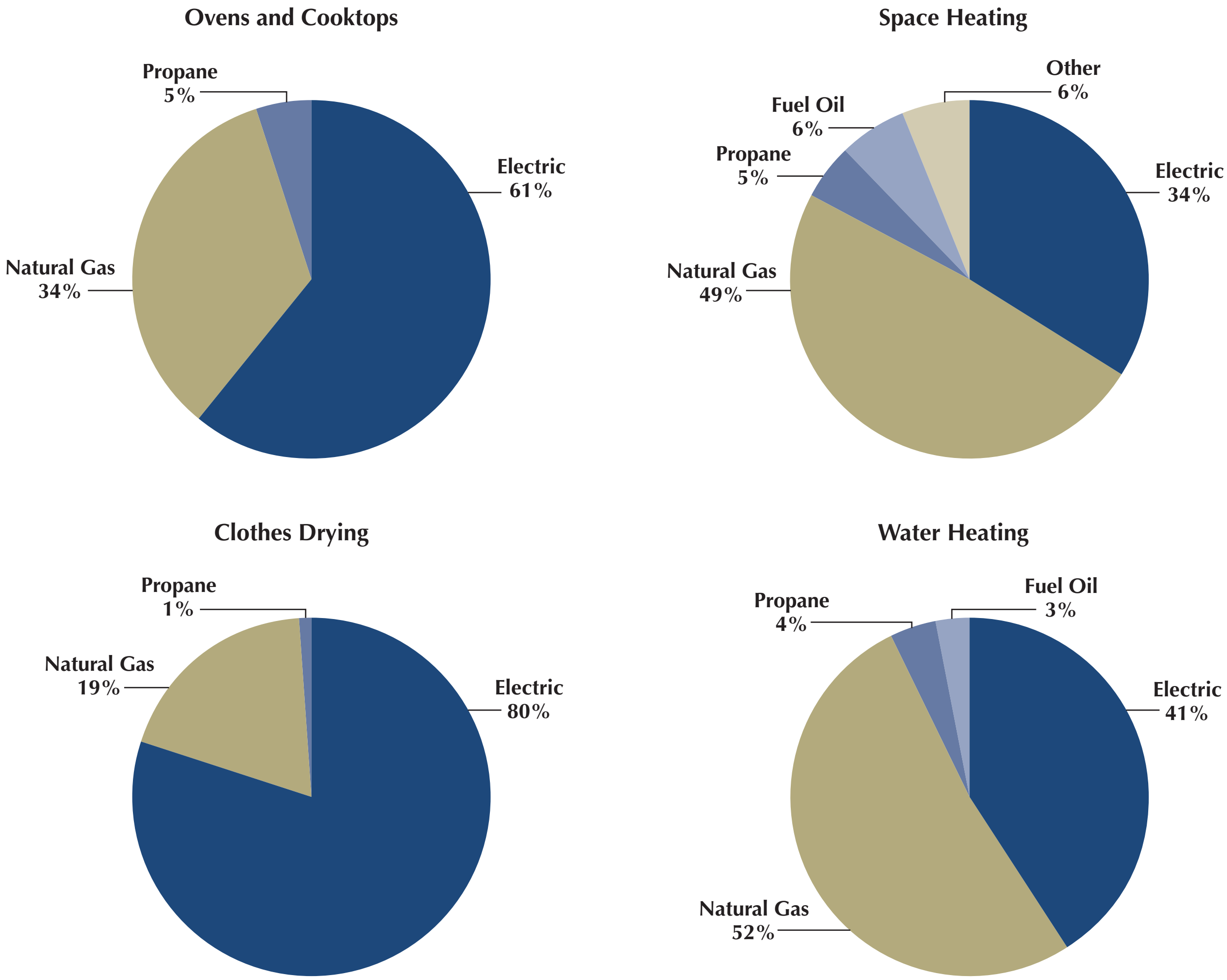
Source: Energy Information Administration, "U.S. Climate Zones," 2004. Available at http://www.eia.gov/emeu/recs/climate_zone.html

words, source-to-site efficiency is the energy required—accounting for losses—to bring usable energy to the consumer. Source-to-site efficiency varies widely by fuel. Often, direct fuel consumption has much higher source-to-site efficiencies compared with electricity, where energy is lost in the conversion and transmission of primary fuels to electrical energy. To assess the efficiency of total energy use, the source-to-site efficiency must be multiplied by the efficiency of the end-use appliances and equipment—the site efficiency. Combining source-to-site efficiency and site efficiency leads to the third—important and often overlooked—measure of efficiency, full-fuel-cycle efficiency.

Source-to-Site Efficiency

Electricity generation has the lowest source-to-site efficiency of all energy types. Centralized electricity generation and distribution through power lines is on average 32 percent efficient in the United States. The process of generating electricity incurs substantial losses, such that for every unit of electricity registered at a building's meter, three times the amount of primary energy was required to generate and distribute it. The majority of energy losses occur at the power plant, especially at cooling towers that emit waste heat into the atmosphere in the form of steam. The Western Electricity

FIGURE 7: Appliance Fuel Sources by Number of Units in U.S. Homes, 2009



Source: Energy Information Administration, "Residential Energy Consumption Survey 2009," Table HC3.1, Available at: http://www.eia.gov/consumption/residential/data/2009/

Coordinating Council, which covers the western United States, has the highest efficiency, at 38 percent, primarily due to its high percentage of hydropower, which has a higher conversion efficiency than coal- or natural gas-fired generation. The Midwest Reliability Council region in the Upper Midwest has the lowest efficiency, at 28 percent, due to a large percentage of coal plants using older, less efficient technology.[112] Transmission and distribution over power lines results in additional losses and reduces the source-to-site efficiency even further, by roughly an additional 7 percent, with longer lines experiencing greater losses. In total, up to two-thirds of the fuel that is burned for electricity production is wasted. In addition to providing no useful work in the economy, it releases significant greenhouse gas emissions in the process.

The production and distribution of natural gas, fuel oil, and propane also have inefficiencies. These fuels must be extracted from the ground, processed or refined to remove impurities and other liquids and gases, and finally transported to the building. During each of these steps, energy is used and a small amount of energy is lost but, in total, these losses are considerably less than the losses associated with electricity production and distribution. The source-to-site efficiency of natural gas is approximately 92 percent, around three times higher than the source-to-site efficiency of centrally generated electricity.[113] Other fuels commonly consumed onsite in residential buildings, fuel oil and propane, are also much more efficient than electricity. The average source-to-site efficiency of fuel oil is about 88 percent, and of propane, about 89 percent.[114]

Considering the source-to-site efficiency of different fuels offers a more accurate comparison of the fuel used in buildings. For example, in 2008, the total site consumption by residential and commercial buildings was 9.37 quadrillion Btu for electricity and 8.28 quadrillion Btu for natural gas. However, the amounts of primary energy consumed differed dramatically between electricity and natural gas, because of their different source-to-site efficiencies (compare Figures 8 and 9). About three times as much primary energy is used to generate and transmit electricity than is ultimately consumed onsite in buildings.

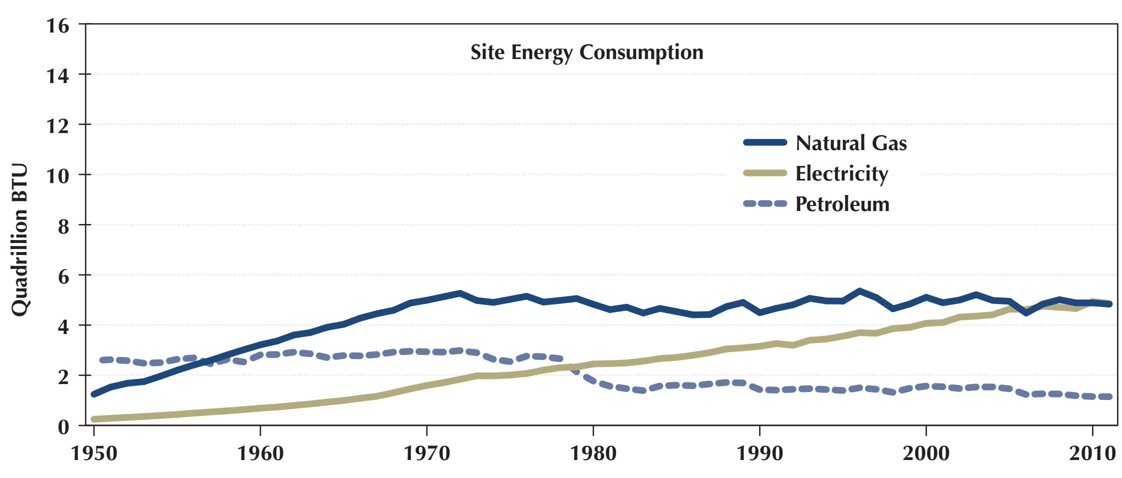
The relative efficiencies of on-site fuel use and grid-supplied electricity have major consequences for the greenhouse gas emissions associated with the U.S. building stock. Only accounting for site energy consumption misses energy losses and resulting greenhouse gas emissions associated with energy production and delivery. These losses account for a significant portion of total greenhouse gas emissions from the residential and commercial sector and should be accounted for when comparing fuel options. The use of grid-supplied electricity is growing, while direct natural gas consumption by residential and commercial buildings remains relatively flat. Increasing the amount of natural gas instead of electricity used in buildings would require fewer resources to provide the same amount of on-site energy and would lower the greenhouse gas emissions per unit of useful energy consumed.

Site Efficiency and Full-Fuel-Cycle Efficiency

Once energy is delivered to a building, it is used in an appliance or piece of equipment that has its own distinct efficiency level. Taken together, the source-to-site efficiency of the fuel delivered and the site efficiency of its use give a more complete picture of the total efficiency of consumer fuel and appliance choice and the resulting emissions. Source-to-site efficiency considered along with site efficiency yields an appliance's full-fuel-cycle efficiency.

To find the full-fuel-cycle efficiency of an appliance or piece of equipment, the efficiency of the source-to-site energy is multiplied by the efficiency of the appliance and associated equipment. For example, energy efficiency standards established in 2012 by the Department of Energy (DOE) for water heaters with storage tanks are 93 percent for electric-resistance units and 62 percent for natural gas models.[115] However, when these models' respective source-to-site efficiency is factored in, their full-fuel-cycle efficiencies are 30 percent for the electric model and 75 percent for the natural gas model. Therefore, despite the higher site efficiency rating of the electric-resistance water heater, it requires the use of significantly more primary energy

FIGURE 8: Residential Site Energy Consumption, 1950 to 2010



Source: Energy Information Administration, "Today in Energy," March 6, 2013. Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=10251 and leads to the emission of more greenhouse gases than does the natural gas appliance for the same level of output in the building. Consequently, electric-resistance water heaters consume roughly twice the primary energy of the natural gas models.

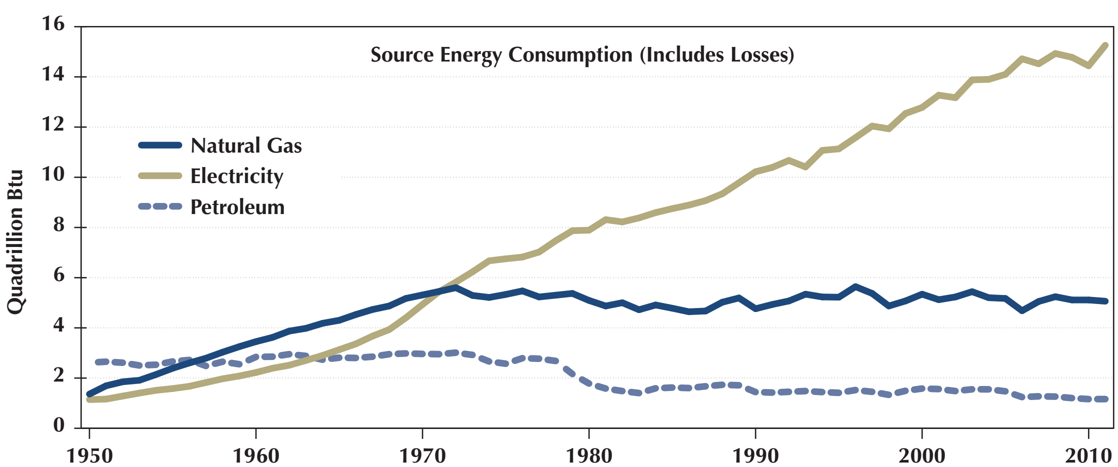
Source efficiencies and site efficiencies can vary even further. Minimum efficiency standards for appliances promulgated by DOE are continuing to push the site efficiency ratings of new appliances higher. While this discussion compares widely used electric and natural gas water heaters, newer technologies such as electric heat-pump water heaters are also available that are two to three times more efficient than the conventional electric-resistance models analyzed here,[116] and solar water heating technologies offer high full-fuel-cycle efficiencies and can be a cost-effective option.[117] Furthermore, the source efficiencies and associated greenhouse gas emissions vary, because of the regional differences in source efficiency of power generation. It is clear that, despite geographic variation, a natural gas water heater yields significant energy savings compared with an electric-resistance water heater in every North American Electric Reliability Corporation Region in the country (Figure 10).[118]

EMISSIONS COMPARISON: NATURAL GAS VERSUS OTHER DIRECT FUELS

In addition to the energy savings delivered by the higher full-fuel-cycle efficiency of appliances using natural gas, there is also a large difference in greenhouse gas emissions. Residential energy use has been a growing contributor to CO_2 emissions for the last two decades, and the trend is expected to continue (Figure 11).[119] The negative consequences in terms of emissions of this upward trend in electricity use are exacerbated by the low average efficiency of grid electricity and the high average carbon fuel intensity of the U.S. electricity generation portfolio. Furthermore, given the high level of coal use in U.S. electricity production, increased electricity use leads to significant increases in sulfur dioxide, nitrogen oxides, and mercury emissions, where pollution controls are not in place.

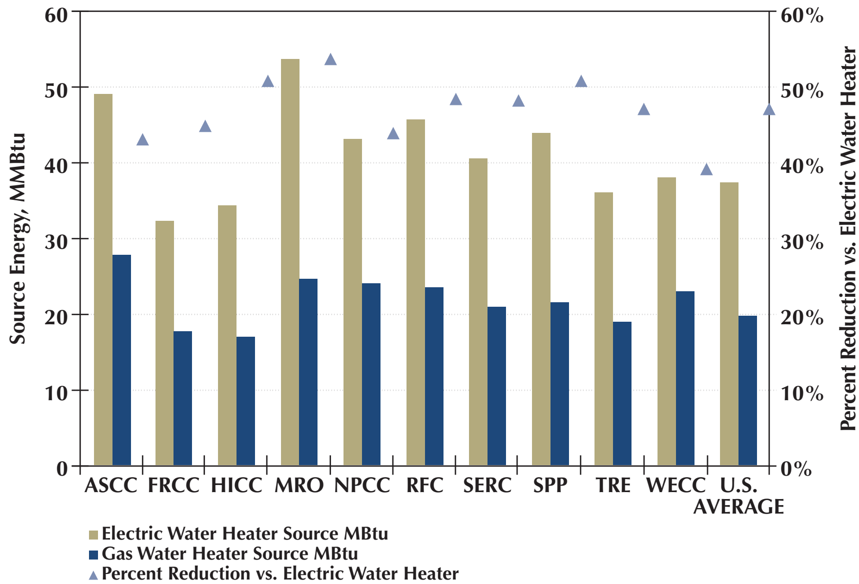
Greenhouse gas emissions can be reduced by switching from lower-efficiency fuels and appliances such as an electric-resistance water heater to higher efficiency fuels and appliances such as a natural gas water heater. However, the reductions will vary by region. The relative percentage reductions of greenhouse gas emissions by switching appliances or fuels is a combination of the full-fuel-cycle efficiency of the appliances and the CO_2-emission intensity of the electricity generation portfolio in a given region. The varied carbon intensities of electric generation in each North American Reliability Council (NERC) region offer different relative benefits from switching an electric-resistance water heater to a natural gas model (Figure 12). The relative benefits are most clearly demonstrated in the following examples. In the NERC region overseen by the Northeast Power Coordinating Council in the northeast United States and Eastern Canada, where a large percentage of the electricity comes from

FIGURE 9: Residential Primary Energy Consumption, 1950 to 2010



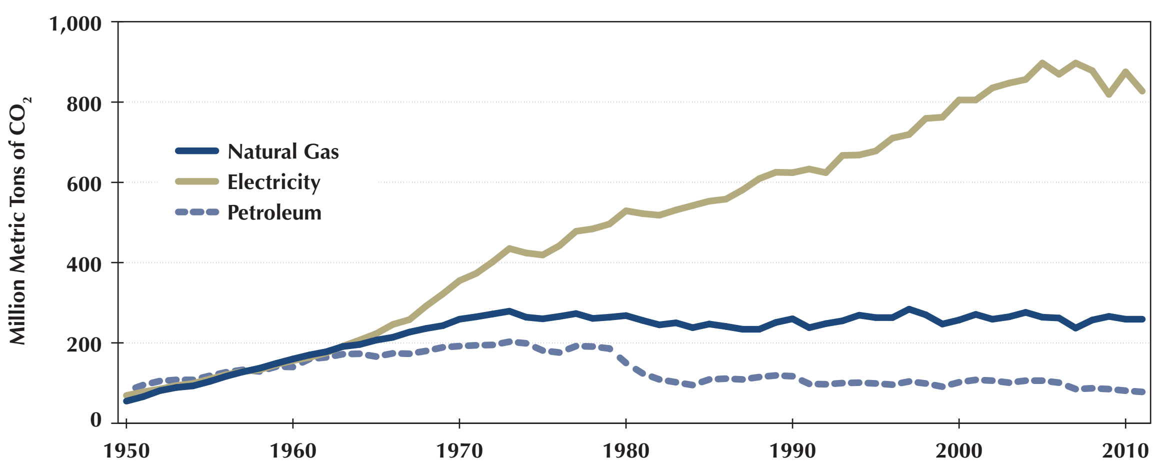
Source: Energy Information Administration, "Today in Energy," March 6, 2013. Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=10251

FIGURE 10: Consumption of Source Energy by Water Heaters by North American Electric Reliability Corporation Region, 2005



Source: Gas Technology Institute, "Source Energy and Emission Factors for Building Energy Consumption" 2009, Tech. rep., Natural Gas Codes and Standards Research Consortium, American Gas Foundation. Available at: http://www.aga.org/SiteCollectionDocuments/KnowledgeCenter/OpsEng/CodesStandards/0008ENERGYEMISSIONFACTORSRESCONSUMPTION.pdf

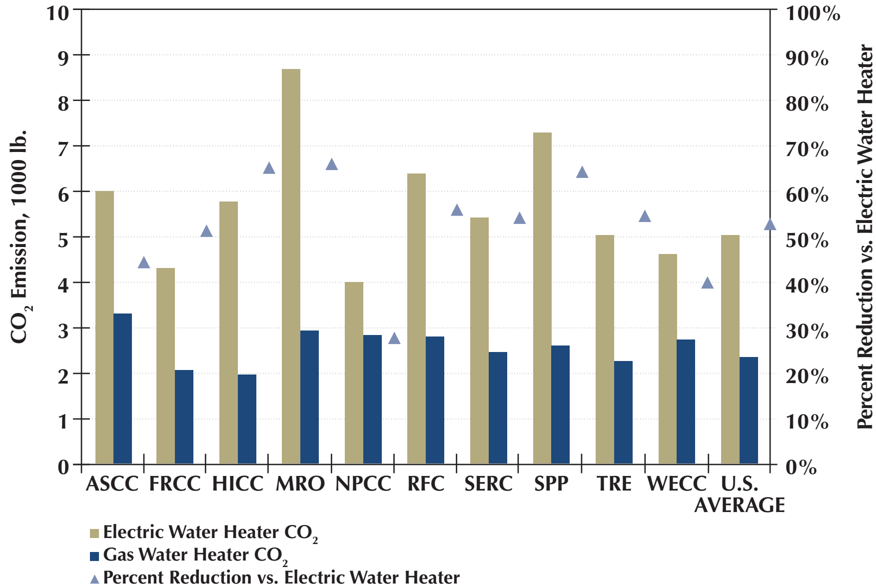
FIGURE 11: Residential CO_2 Emissions from Energy Consumption, 1950 to 2010



Source: Energy Information Administration, "Today in Energy," March 6, 2013. Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=10251

less carbon-intensive hydroelectric and nuclear power, switching from an electric to natural gas water heater results in CO_2 reductions of 30 percent. By contrast, the same switch results in emissions reductions of 70 percent in the Midwest Reliability Organization region in the Midwest where substantial amounts of older coal-fired power generation contributes to a significantly more carbon-intensive electric generation mix.

FIGURE 12: CO_2 Emissions from Water Heaters by North American Electric Reliability Corporation Region, 2005

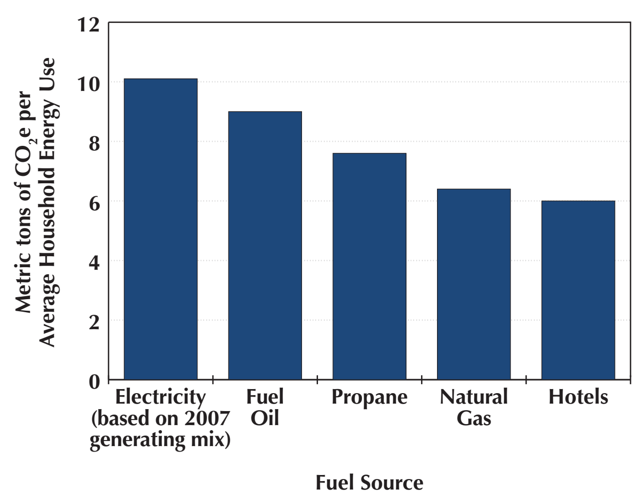


Source: Gas Technology Institute, "Source Energy and Emission Factors for Building Energy Consumption" 2009, Tech. rep., Natural Gas Codes and Standards Research Consortium, American Gas Foundation. Available at: http://www.aga.org/SiteCollectionDocuments/KnowledgeCenter/OpsEng/CodesStandards/0008ENERGYEMISSIONFACTORSRESCONSUMPTION.pdf

An average U.S. home using natural gas for space heating, water heating, cooking, and clothes drying is responsible for substantially fewer greenhouse gas emissions than homes using other fuel sources (Figure 13). In this example, natural gas use produces an average of 44 percent fewer emissions than electricity use.[120] Such a difference in energy use and CO_2 emissions is true for all energy uses in buildings where natural gas is an alternative to grid electricity as well as the direct use of propane and fuel oil. The two main factors determining the efficiency and emissions benefits from appliance to appliance are the full-fuel-cycle efficiency of the appliance and the emission-intensity of the primary fuel.

Emissions associated with natural gas use compared with electricity are lower for CO_2 and some pollutants. Considering the lower emissions of natural gas and its higher full-fuel-cycle efficiency, residential natural gas use results in 40 to 65 percent lower emissions of CO_2, 90 to 98 percent lower emissions of SO_2, and 50 to 88 percent lower emissions of NO_X. Residential natural gas use is free of any mercury emissions.[121]

FIGURE 13: Full-Fuel-Cycle Greenhouse Gas Emissions for Average New Homes



Source: Source: American Gas Association, "A Comparison of Energy Use, Operating Costs, and CO_2 Emissions of Home Appliances," October 20, 2009. Available at: http://www.aga.org/Kc/analyses-and-statistics/studies/demand/Pages/Comparison-Energy-Use-Operating-Costs-Carbon-Dioxide-Emissions-Home-Appliances.aspx

Note: Assumes fuel used for space heating, water heating, cooking, and clothes drying. All appliances are assumed to meet federal minimum efficiency standards. The fuel oil home assumes electricity is used for cooking and clothes drying. The new home assumes a one-story single-family detached home with 2,072 square feet of conditioned space and 4,811 heating degree days.

Reducing Emissions Through Fuel Substitution and On-Site Energy Production

Natural gas can provide a means to increase a building's total full-fuel-cycle efficiency and decrease its emissions profile in many cases. This improvement is most readily achieved in thermal applications, such as natural gas space heating and water heating. While buildings with older natural gas- or oil-fired boilers and furnaces can improve their efficiency and lower their emissions by upgrading to newer models, greater emission reductions may be achieved by removing electric appliances and replacing them with models using natural gas. While natural gas appliances have a comparable or slightly lower site efficiency than electric-resistance appliances, natural gas is often, on a full-fuel-cycle basis, two to three times more efficient than electricity.[122]

Significantly greater benefits can be realized when grid power is replaced by power produced on site. Combined heat and power (CHP) systems provide a means for buildings with high electrical demand to increase their efficiency and reduce emissions. A CHP system uses a fuel such as natural gas to generate electricity on site, capturing waste heat to meet on-site thermal loads (Table 1). (For a more extensive treatment of CHP see chapter 6.) Fuel cells and micro-turbine technologies provide another means for buildings to generate their own electrical power on site using natural gas. The waste heat generated by these devices can then be used for space heating, water heating, and other thermal loads to raise the overall full-fuel-cycle efficiency of these devices to greater than 80 percent.[123] (These technologies and others are explained in chapter 7.)

The potential for CHP in commercial settings may be quite large, with office buildings/retail, education buildings, and hospitals having the greatest potential (Figure 14). However, practical limits on thermal load matching and the utilization of waste heat may affect the potential of different building types. Hospitals are an ideal application, but hotels and other commercial buildings may be more difficult—though not impossible. The use of CHP microturbines has gained acceptance primarily in in-patient hospitals, hotels, and resorts. These facilities have large electrical loads and nearly as high thermal loads, for space heating, water heating, cooking, and laundry. These large and year-round thermal loads (in the case of all but space heating) provide a ready use for the waste thermal energy provided by the microturbine, allowing them to operate at near peak efficiency not only around the clock but 365 days per year. Nevertheless, there are many challenges to commercial CHP operations. To expand commercial CHP potential, policy is needed to support advanced technologies and innovative business models in this arena.

TABLE 1: Technology Comparisons

CATEGORY	10 MW NATURAL GAS CHP	10 MW PHOTOVOLTAIC ARRAY	10 MW WIND FARM	CENTRALIZED NATURAL GAS COMBINED CYCLE POWER PLANT (10 MW PORTION)
Annual Capacity Factor	85%	25%	34%	67%
Annual Electricity	74,446 MWh	21,900 MWh	29,784 MWh	58,692 MWh
Annual Useful Heat	103,417 MWht	0	0	0
Capital Cost	$24 million	$60.5 million	$24.4 million	$10 million
Annual Energy Savings	343,747 MMBtu	225,640 MMBtu	306,871 MMBtu	156,708 MMBtu
Annual CO_2 Savings	44,114 Tons	20,254 Tons	27,546 Tons	27,023 Tons

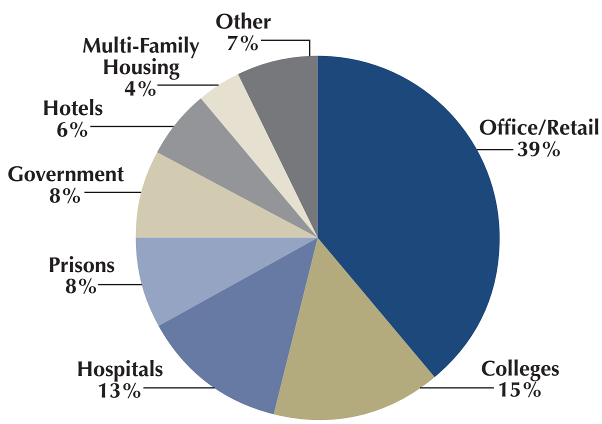
Source: ICF International 2012

Notes: A 10 MW Gas Turbine CHP –is assumed to have 30 percent electric efficiency and 70 percent total efficiency.

Electricity generation onsite is assumed to displace grid-supplied electricity generation of 9,720 Btu/kWh, with emissions of 1,745 lbs. CO_2/MWh; includes assumed 6 percent transmission and distribution losses.

Thermal generation on-site is assumed to displace an 80 percent efficient onsite natural gas boiler.

FIGURE 14: **CHP Potential for Systems Greater than 1 MW to 33 GW, Percent of Potential Capacity**



Source: ICF International 2012

Technological advances in gas-fired equipment are also needed. More affordable tank-less water heaters and combination space and water heating appliances can help reduce the market barriers to natural gas. Demonstration and deployment of such technologies can help natural gas utilities design the next generation of gas efficiency programs, provide whole-building solutions, and make natural gas service more attractive to customers and builders.

THE ROLE OF EFFICIENCY PROGRAMS AND STANDARDS

Current efficiency programs and federal efficiency codes and standards reduce greenhouse gas emissions from buildings in two important ways: by reducing the overall amount of energy used in buildings and by improving the baseline efficiency of specific appliances, equipment, and building stock. A third strategy could be to encourage the use of certain fuels, taking into account the total energy consumption of an appliance, the fuel used (full-fuel-cycle efficiency), and the associated greenhouse gas emissions. Historically, efficiency programs and standards have not considered full-fuel-cycle efficiency or the emissions reductions that could be achieved comparing across fuel types, although this is beginning to change, as in the case of appliance labeling described later in this chapter.

Conservation

At the broadest level, increasing the overall efficiency of new and existing buildings reduces the amount of fuel used of any type and is therefore beneficial. Energy efficiency minimizes energy use, and thus lowers greenhouse gas emissions. The United States has made remarkable progress in this regard. Energy use in buildings between 1972 and 2005 increased at less than half the rate of growth of gross domestic product, despite the growth in home size and the increased demand for energy from air conditioning and electronic equipment. But although great strides have been made, numerous untapped opportunities exist for further reductions in energy use and greenhouse gas emissions. Many of these require only modest levels of investment. Advances such as energy-efficient building designs and appliances provide quick payback to consumers through reduced energy bills. For example, new wall designs can minimize heat loss in buildings by as much as 50 percent by reducing the amount of framing used and by optimizing the use of insulated materials. The result is a diminished need for space heating—the largest energy use in a home.[124]

State and Local Building Codes

Building codes for new construction can improve the efficiency of buildings by ensuring that new technologies and methods are used that will reduce a building's energy use. Although new buildings constitute only 2 to 3 percent of the existing building stock in any given year, new construction practices have a compounding impact over time.[125] New construction can more easily incorporate novel energy efficiency technologies and is therefore often a harbinger of future trends. New building technologies are often introduced in the new construction market and then spill over into the arena of retrofits and renovation. Building codes can even affect a building's fuel options, for example, by encouraging or discouraging natural gas access by facilitating or slowing the approval of new, easier-to-install and less expensive indoor natural gas piping materials.[126.]

Low adoption rates for building codes are a barrier to the development of higher efficiency and lower emissions buildings. For example, in 1992 the commercial building code requirements of the Federal Energy Policy Act, which were based on 1989 industry standards, were met by only five states. By 2008, 40 states had statewide commercial building codes that met or exceeded the 1989 federal standards, but only 27 met the higher standards issued by DOE in 2004. This lead/lag effect in the setting and meeting of standards is indicative of a non-owner-operated building market that still places operating costs at a lower priority than construction costs. However, federal requirements are not the only drivers. California, for example, has set standards higher than those of the federal government, and some utilities, such as Austin Energy in central Texas, have worked with city governments to push standards and building codes beyond the industry norm.

Traditionally, building codes have been designed to look at the overall on-site energy usage of buildings. Accordingly, they are typically fuel-neutral, favoring neither natural gas nor electric appliances. As a result, building codes do little to take into consideration the full-fuel-cycle climate impacts of electricity versus natural gas and other fuels. Likewise, Leadership in Energy and Environmental Design (LEED) standards fail to take into account the relative full-fuel-cycle efficiencies of electricity, natural gas, and other fuels. LEED standards, developed by the U.S. Green Building Council, have been adopted by many municipalities, school districts, counties, and states for their new buildings, leading to an exponential growth in the number of LEED-certified buildings.[127] However, the U.S. Green Building Council is investigating ways to take these benefits into account, with particular focus on performance standards and nationwide applicability.

Appliance Standards

DOE is required by law to set minimum efficiency standards for appliances, and currently has standards that cover appliances and equipment responsible for 82 percent of home energy use and 67 percent of commercial energy use.[128] Appliance standards, first instituted in the 1980s and repeatedly strengthened since then, have greatly contributed to reducing appliance energy use and associated greenhouse gas emissions. However, appliance standards are based on the site efficiency of the appliance and do not consider the efficiency of the fuel. While this works well to encourage improved efficiency for each type of appliance, it does have implications for efficiency labeling programs and the ability of consumers to compare the true environmental performance of appliances using differing energy sources.

Appliance Labeling

Labeling programs such as ENERGY STAR strive to inform consumers about the energy consumption and energy cost implications associated with use of each appliance. ENERGY STAR uses a market-based approach having four parts: 1) using the ENERGY STAR label to clearly identify which products, practices, new homes, and buildings are the most energy efficient; 2) empowering decision-makers by making them aware of the benefits of products, homes, and buildings that qualify for ENERGY STAR, and by providing tools to assess energy performance and guidelines for efficiency improvements; 3) helping retail and service companies to easily offer energy-efficient products and services; and 4) partnering with other energy efficiency programs to leverage national resources and maximize impacts. The Environmental Protection Agency (EPA) estimates that in 2012 the ENERGY STAR program helped avoid more than 150 million tons of greenhouse gas emissions through encouraging the purchase of efficient products, with the amount of avoided greenhouse gas emissions increasing annually.[129]

While appliance labeling efforts like ENERGY STAR have educated consumers about the annual operating costs and site efficiency of appliances, current labels do not accurately or sufficiently connect consumers' economic interests with the environmental impacts of appliance use. Specifically, current labels do not inform consumers of the full-fuel-cycle efficiency of appliance models because the efficiency calculations are based on the appliance standards program, which again is based on site efficiency. As a result, consumers cannot compare the true quantity of energy required by each appliances or the true climate implications associated with using that appliance.

In 2009, the National Research Council released a report that recommended the gradual conversion of current labeling efforts to ones that would take full-fuel-cycle efficiencies into consideration. Full-fuel-cycle labeling will certainly be more challenging because it will require more data and analysis from appliance manufacturers, and the efficiency of an appliance will vary by geographical location because of different regional climates and power generation fuel mixes. However, as discussed earlier in this chapter, such information is essential to understanding the total amount of energy required to operate an appliance and the associated greenhouse gas emissions and will better equip consumers to make more informed choices when evaluating their appliance options.[130] In June 2011, DOE took the first steps toward a more regionalized labeling program with standards for furnaces and central air conditioning units that had a variable regional component.[131] In addition, in August 2012, DOE issued a policy amendment stating that it would begin consideration of full-fuel-cycle efficiency in setting future appliance standards and would work with the Federal Trade Commission to educate consumers about the full fuel cycle.[132]

While no appliance standards based on the full fuel cycle have yet been issued, if the success of current appliance standards and related labeling are any indication, moving to standards and labels based on full-fuel-cycle efficiency could move consumers to purchase appliances that use significantly less energy and provide a significant benefit to the climate.

ENERGY STAR for Buildings

In addition to having labels for appliances, EPA's ENERGY STAR program also assesses the efficiency of buildings and provides labels that allow comparison of energy usage across buildings. To be an ENERGY STAR-certified building, a variety of energy performance standards must be met and these differ by facility type. EPA provides tools to assess energy systems and management, building design, and a host of energy-related benchmarks to help building owners, architects, and even prospective tenants assess and make public the energy and cost implications of a building. In contrast to the appliance program, the ENERGY STAR program for commercial buildings does use primary or full-fuel-cycle efficiency to compare energy usage across building types.

Utility-Based Incentive Programs

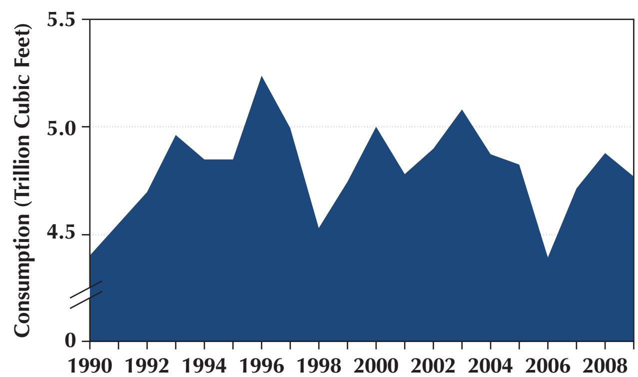
Utility-based financial incentive programs have been used since the early 1980s, when it became clear that information and education alone produced only limited energy and demand savings. Utilities have offered rebates, low-interest loans, and direct installation programs, and these have led to the accelerated market penetration of many energy-efficient building products such as attic insulation and high-efficiency appliances. However, these programs represent only a partial solution because not all states or all utilities offer such programs. More importantly, these incentives are based on site efficiency and are fuel-specific—since buildings are often served by separate electric and natural gas utilities, meaning that while incentive programs can encourage the efficient site use of a fuel, they do not allow consumers to compare fuel options based full-fuel-cycle efficiency. Thus, most utility-based incentive programs miss an opportunity to help consumers further reduce emissions.

BARRIERS TO INCREASED NATURAL GAS ACCESS AND UTILIZATION

The emissions benefits of natural gas use in homes and businesses will require greater access to the fuel for and within buildings. In 2005, 71 percent of U.S. homes had access to natural gas, and yet only 61 percent of U.S. homes made use of natural gas in an appliance. In addition, only 54 percent of new homes constructed in 2010 had natural gas service installed, and this access was primarily for heating and not necessarily for other natural gas appliances.[133] Similarly, in commercial buildings approximately half had natural gas access in 2003 (49 percent) and, as with homes, the use was primarily for heating.[134]

Annual consumption of natural gas in the residential sector has been declining since 1996 in spite of a growing residential customer base (Figure 15). Analysis by the Energy Information Administration suggests that the cause of this decrease is a combination of historically high natural gas prices from 2000 to 2009, which

FIGURE 15: Residential Natural Gas Consumption, 1990 to 2009



Source: Energy Information Administration, "Trends in U.S. Residential Natural Gas Consumption," 2010. Available at: http://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2010/ngtrendsresidcon/ngtrendsresidcon.pdf discouraged consumers from buying natural gas model appliances, a general migration of Americans to warmer climate zones with lower thermal loads, and an increase in home construction standards and appliance efficiency that reduced the amount of fuel consumed for the same purposes.[135]

Barriers to the Use of Natural Gas in Homes

The United States has, as a policy, pursued universal residential access to electricity for decades. Through taxpayer-funded rural electrification programs and customer-funded electric utility grid extension programs, the United States has achieved greater than 99.5 percent residential access to public or private electricity.[136] The same policy has not been implemented for natural gas.

When municipalities approve planning and development for new buildings, electric utility access is almost universally required through developer or utility funding, or a combination of the two. In contrast, running natural gas lines in new developments is often viewed as merely an option, and, as such, only 54 percent of new homes have natural gas access. In many cases, the decision is determined by financial analysis conducted by a local gas distribution company, or the combination local electric and gas utility, based on narrow first-cost criteria with little concern for the occupants' energy efficiency, operating cost, or greenhouse gas emissions. Prospective building owners often have little participation in this decision process. If the decision is made not to supply natural gas, retrofitted access to and within the building is significantly more expensive.

Even when natural gas infrastructure has been included in a new residential development, a homeowner may still be unable to choose how natural gas will be used in her home. Often, during architectural design and construction, the builder decides which appliances will have natural gas lines run to them, thereby "locking in" the decision and limiting consumer choice. In cases where the homeowner enters the process prior to construction, he may be offered a choice of appliance fuel options, but choosing natural gas may come at a cost premium for both the appliance and the cost of running the gas lines. In this choice, one between higher up-front costs of purchasing a home with gas appliances, on the one hand, and a lower long-term cost of operation (subject to gas prices), on the other, the immediacy of a slightly lower purchase price for electric appliances may prevail, even as low natural gas prices may lead to consumer savings in just a few years when compared to electric models.

Natural gas access, regulation, and price play important roles in residential fuel choice. The trend over the last decade, toward a lower percentage of new homes using natural gas, will have a long-term effect. Even though the trend was likely influenced by temporarily high gas prices, it effectively locks out the option for these "all electric" homeowners to benefit economically from what may be several decades of low natural gas prices as well as to benefit environmentally by lowering greenhouse gas emissions.

Moving beyond infrastructure constraints, an essential component shaping residential fuel choice is public education. For nearly a century, industry and government have portrayed electricity as a clean and efficient fuel, and it is—on site at the point of use.[137] Perceptions of natural gas are similarly affected by public opinion and government policy that focus on the point of use, which has not received the promotional policy that electricity has. This point-of-use perception is reinforced by the way in which most people interact with electricity and natural gas in their everyday lives: flipping a switch, turning on a burner, and paying a monthly bill. They rarely see or understand the generation side of electricity, the power plant, or the extraction and transportation of natural gas. Generally, the public has little basis for comparisons among fuels on issues of health, the environment, and the economy. Moreover, culture and family history can be important drivers of consumer choice, as individuals may be most comfortable with appliance types that they grew up with. Public education is critical for helping consumers understand the issues of efficiency and emissions and how they relate to common life choices, and to know what questions to ask when purchasing an appliance, renting an apartment, or buying a home.

Use of Natural Gas in Commercial Buildings

A significant barrier to the increased use of natural gas is the high percentage of non-owner-occupied commercial buildings, particularly office and warehouse floor space. On a floor-space basis, 49 percent of private commercial buildings are owner-occupied and 51 percent are non-owner-occupied.[138] Non-owner-occupied buildings are designed and built by real-estate developers who then rent or lease the space to tenants. The "for lease" building sector is extremely competitive, and rental cost per square footage is a key metric in attracting renters. In addition to paying rent, tenants may also pay utility or maintenance costs that may increase each year because of rising operating expenditures. Energy costs are a meaningful portion of these operating expenditures, but for billing purposes they are often combined with other costs, such as labor, water, and snow removal. Therefore, it can be difficult for tenants to discern specific financial benefits of energy efficiency upgrades, leaving building owners without a financial incentive to make such upgrades. This situation prevents lower operating costs from being reflected in market rental prices, since only exceptionally sophisticated tenants consider long-term gains from efficiency in rental decisions. In new buildings, owners' focus on achieving low rental costs can drive builders to prioritize construction cost over operating costs. This approach can preclude the installation of high-efficiency and lower-emission systems, including those that use natural gas on site for both electricity generation and heating applications.[139]

When energy efficiency upgrades are proposed for existing, occupied buildings, building owners may have the opportunity to recover capital outlays according to the terms of the leases. Most leases allow the installation of energy savings equipment or systems with cost recovery through amortization of the improvement over the life of the equipment installed. However, if a tenant does not renew her lease, a newly signed tenant cannot be charged the amortization; therefore, a portion of the cost of the project cannot be recovered. Since rents are based largely on market conditions and not by the operating costs incurred by the building owner, before owners undertake an energy efficiency project, they must evaluate what portion of the tenant base might leave before the project costs are recovered and what enduring benefits might accrue to the owner.[140]

Some low-cost energy efficiency upgrades can be treated as repair costs and added to the operating expenses within an existing lease. These stand-alone efficiency projects are very often subsidized with incentives from utilities. Projects of this nature usually have relatively short payback periods. The tenants see the benefit of the improvements very quickly, and the owner can justify the expense to the tenant regardless of whether the lease is renewed.[141]

In 2003, 46 percent of commercial buildings were owner-occupied, meaning they are designed and constructed for the owner's own use.[142] Compared to owners of leased buildings, owner-operators are more inclined to factor in the operating costs of their buildings because they have a long-term interest in the building and are concerned less with competitive rental markets. Therefore, they tend to install more energy-efficient systems and subsystem components as long as these have a payback period of 10 years or less. The government owners of 635,000 public buildings in the United States in 2003 share this focus on long-term operational costs and the advantage of higher efficiency systems; they may also have legal mandates or executive orders to reduce energy use and/or greenhouse gas emissions.[143] Owners constructing new buildings or performing retrofits, when faced with longer-term decisions about energy use and costs, will see expanded natural gas use as an attractive option, and large numbers of owner-occupied and government buildings using natural gas instead of electricity could yield significant emission reductions.

CONCLUSION

This chapter identified the full-fuel-cycle efficiency benefits and lower greenhouse gas emissions of the direct use of natural gas when compared to electricity, particularly for thermal loads. There is significant potential for increased direct use of natural gas in homes and businesses both in terms of increased access to new buildings and additional applications within buildings that already have access. In order for this potential to be fully realized, building standards, appliance standards, and appliance labels must take full-fuel-cycle energy use and associated emissions into account, and greater attention must be given to consumer education, regulatory changes, and increased access.

VI. MANUFACTURING SECTOR

By Michael Tubman, C2ES

INTRODUCTION

With prospects for cheap, abundant natural gas in the near and medium term virtually certain, demand for natural gas from manufacturing industries is expected to grow. In 2010, natural gas supplied 30 percent of the U.S. manufacturing sector's direct energy use, for combustion as well as non-combustion uses.[144] The U.S. Energy Information Administration forecasts that natural gas use in the industrial sector will increase by 16 percent between 2011 and 2025, from 6.8 to 7.8 trillion cubic feet.[145] Recent estimates indicate that $45 billion in new investment has recently occurred in chemical manufacturing alone. Lower natural gas prices are likely to provide a real economic advantage to U.S. manufacturing in the near and medium term.

The entire industrial sector (manufacturing and non-manufacturing industries combined) consumed 32 percent of all natural gas in the United States in 2011. This energy use emitted 401 million metric tons of carbon dioxide (CO_2).[146] This chapter examines the role of natural gas in the manufacturing sector today as well as its likely expansion, given forecasts of low and stable prices. With a resurgent and changing manufacturing sector comes the opportunity to reduce these emissions. This chapter also looks at promising strategies for reducing emissions include replacing older, less efficient industrial boilers and expanding the use of combined heat and power (CHP) systems.

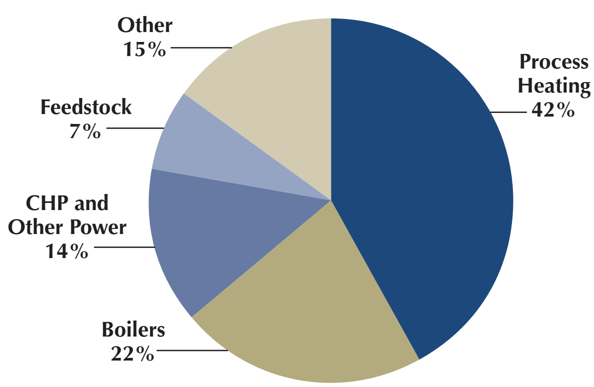
NATURAL GAS USE IN MANUFACTURING

The manufacturing sector includes diverse industries such as bulk chemicals, oil refining, and the production of steel, aluminum, cement, glass, paper, and food. It does not include the industrial activities of mining, construction, and oil and gas extraction. Natural gas usage within these industries varies significantly. It is used for heating and cooling; for process heat to melt glass, process food, preheat metals, and dry various products; and for on-site electricity generation (fueling boilers and turbines). Natural gas is also used as a feedstock (a material input) to make chemical products, fertilizers, plastics, and other materials.[147]

Overall, the largest direct use of energy by the manufacturing sector is for process heating, the production of heat directly from fuel sources, electricity, or steam that is used to heat raw material inputs during manufacturing. Natural gas is the dominant fuel used to generate heat, and process heating accounts for 42 percent of the natural gas use in the industrial sector overall (Figure 1). In 2010, process heating using all fuel sources produced 315.4 million metric tons of CO_2, which represents 40 percent of the CO_2 emissions for the entire manufacturing sector.[148]

Industrial boilers generating heat and steam are another large consumer of natural gas. Eighty-three percent of boilers run on natural gas, and they consume 22 percent of this fuel used in manufacturing.[149] While some are fueled by coal or other fuel, the dominant fuel

FIGURE 1: Natural Gas Use in Manufacturing, 2009

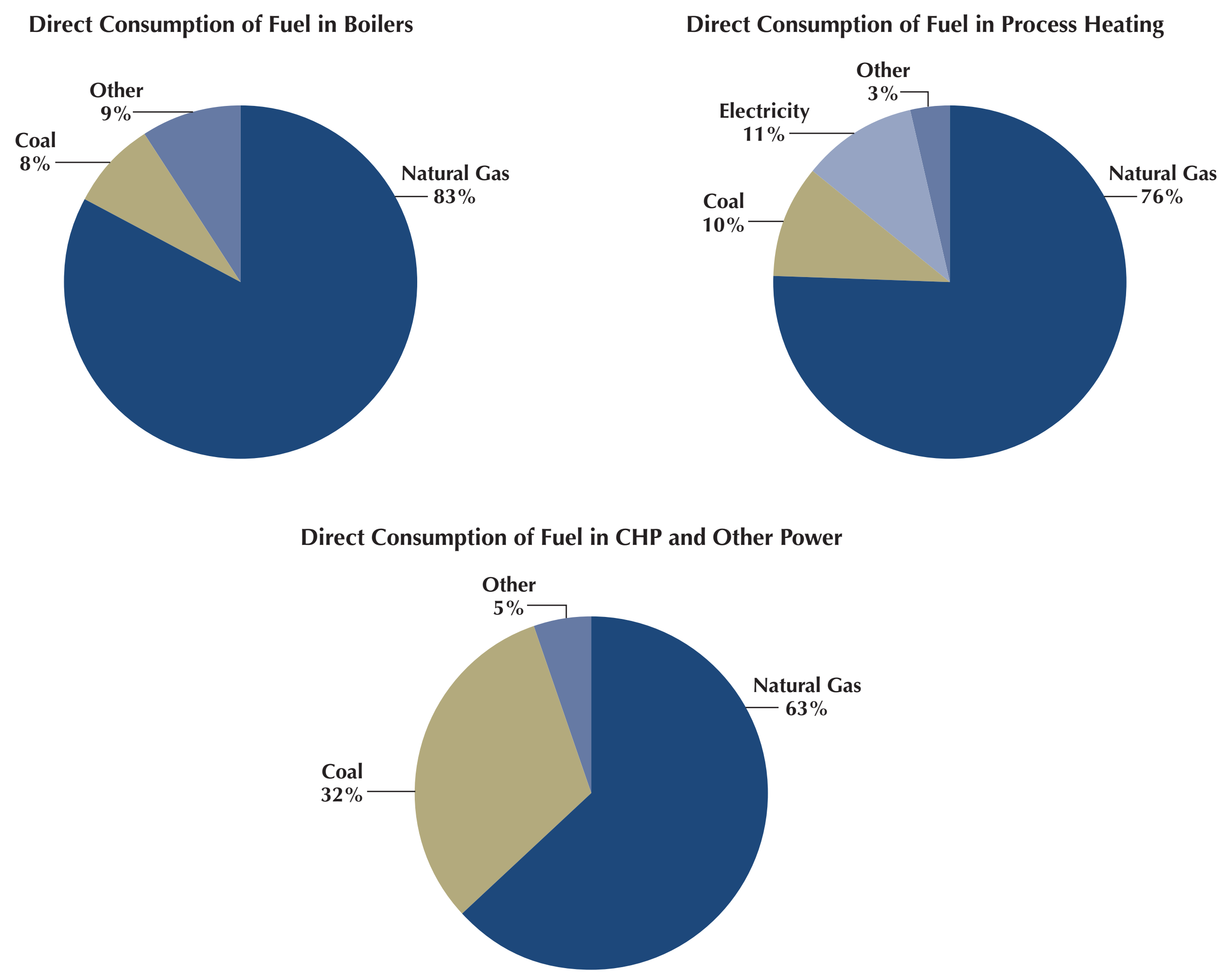


Source: Energy Information Administration, "Manufacturing Energy Consumption Survey," June 2009, Tables 2.2 and 5.2. Available at http://www.eia.gov/emeu/mecs/mecs2006/2006tables.html source is natural gas. Boilers are commonly used for a variety of purposes by chemical manufacturers, food processors, pulp and paper manufacturers, and the petroleum- and coal-derivatives industries (including chemicals, coke, and coal tar) (Figure 2).[150]

CHP—also known as cogeneration—is a third major use of natural gas in the manufacturing sector.[151] Natural gas is used to generate electricity on site, with the waste heat being captured and used for a variety of industrial purposes, greatly increasing the efficiency of the system overall. Additional efficiencies and emission reductions are also achieved through avoided transmission losses.[152] In 2010, 14 percent of natural gas used in manufacturing was consumed by CHP and other power systems. Natural gas is the most common fuel used for CHP systems. Nationwide, the added efficiencies of these systems avoid the emission of 35 million metric tons of CO_2 equivalent annually.[153]

Feedstock is raw material used as an input in manufacturing for creating value-added products. Natural gas production and its byproducts provide feedstock for the bulk chemicals industry, constituting a non-combustion use of natural gas. Methane—pure natural gas—is the source for hydrogen used in industrial processes, in fuel cells, and in the production of ammonia. Liquids extracted in association with natural gas, including ethane, propane, and butane, are processed and transformed to become other intermediate and final products including adhesives, insulation, paint, plastics, and vinyl.[154]

FIGURE 2: Direct Consumption of Fuels in the Manufacturing Sector, 2009



Source: Energy Information Administration, "Manufacturing Energy Consumption Survey," June 2009, Tables 2.2 and 5.2. Available at http://www.eia.gov/emeu/mecs/mecs2006/2006tables.html

Chemical companies are the largest consumers of natural gas-associated liquids, and they commonly use up to two-thirds of their delivered natural gas as feedstock.[155]

The emissions implications of using natural gas as a feedstock are very different from its other uses because feedstock use transforms hydrocarbon molecules into other products, rather than burning them. When natural gas is used as a feedstock, therefore, very low greenhouse gases emissions are produced. These low-emitting uses are enhancing U.S. competitiveness in the manufacturing sector. Whereas U.S. companies are reliant on low-cost natural gas liquids as a feedstock, European competitors use more expensive, oil-based naphtha.[156] In 2010, for example, domestic ethane sold at half the price of imported naphtha in Europe, and, consequently, U.S. chemical manufacturers have reaped a competitive advantage in international markets for intermediate and final goods.[157]

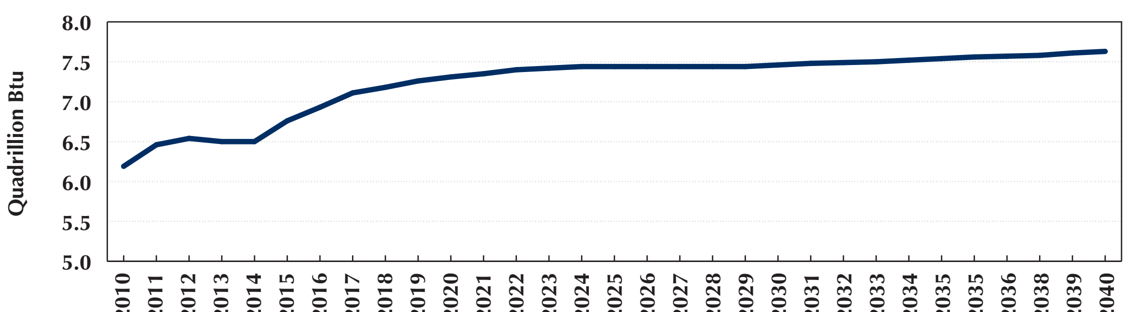
POTENTIAL FOR EXPANDED USE

Increased availability and low prices of natural gas have significant implications for domestic manufacturing. Large manufacturers dependent on natural gas for production are vulnerable to resource availability and price volatility. Accordingly, they have historically been concerned about policies or technologies that may impact these factors. Recently, abundant supply and low prices have led to greater confidence and an increase in domestic manufacturing, creating new jobs and economic value.[158] Numerous companies have cited natural gas supply and price in announcing plans to open new facilities in the chemicals, plastics, steel, and other industries in the United States,[159] including $41.6 billion worth of industrial investments that are planned between 2012 and 2018. One analysis has noted that the number of firms disclosing the positive impact of new gas resources for facility power generation and feedstock use increased substantially just between 2008 and 2011.[160] In 2010, exports of basic chemicals and plastics increased 28 percent from the previous year, yielding a trade surplus of $16.4 billion.[161] Continued low natural gas prices could have significant long-term economic benefits. A study by the American Chemistry Council estimates that a 25 percent increase in ethane supplies, for example, could yield a $32.8 billion increase in U.S. chemical production.[162]

EIA's Annual Energy Outlook 2013 Early Release of projections to 2040 reflects the expected increase in industrial natural gas demand. Total industrial consumption of natural gas for heat and power is projected to rise by 19 percent between 2010 and 2021 before increasing at a slower rate through 2040 (Figure 3). Efficiency measures are forecasted keep the amount of natural gas used per dollar of output declining over the same period (Figure 4).

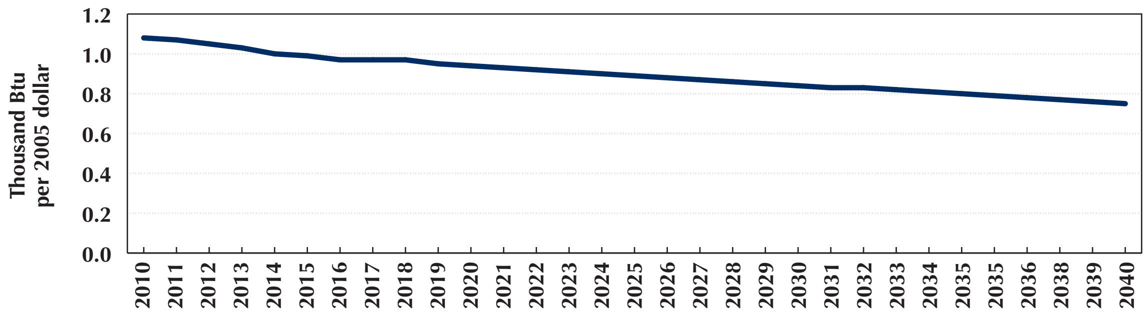
Total industrial consumption of feedstock (natural gas liquids) is projected to rise by 23 percent between 2010 and 2023 before declining from peak levels (Figure 5). Feedstock growth will be tempered by long-term changes in the natural gas market, including higher prices and international competition in chemicals manufacturing and future energy efficiency improvements expected to offset increased demand for feedstock while maintaining output levels (Figure 6). The use of CHP is projected to increase by 113 percent over the same period (Figure 7). Increases in the use of on-site electricity generation through CHP systems would partially reduce facilities'

FIGURE 3: Projected Total Industrial Consumption of Natural Gas for Heat and Power, 2010 to 2040



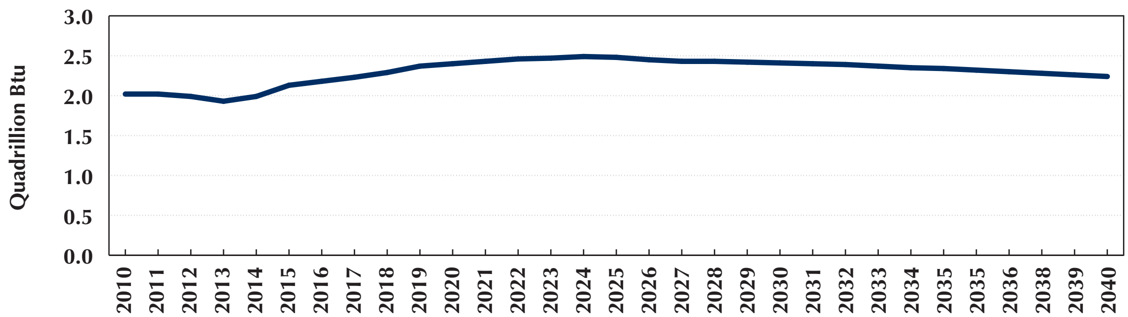
Source: Energy Information Administration, "Annual Energy Outlook 2013 Early Release," 2013. Available at: http://www.eia.gov/forecasts/aeo/er/pdf/tbla2.pdf

FIGURE 4: Projected Energy Consumption of Natural Gas for Heat and Power per Dollar of Shipments, 2010 to 2040



Source: Energy Information Administration, "Annual Energy Outlook 2013 Early Release," 2013. Available at: http://www.eia.gov/forecasts/aeo/er/pdf/tbla2.pdf

FIGURE 5: Projected Total Industrial Consumption of Natural Gas Liquids Feedstock, 2010 to 2040



Sources: Energy Information Administration, "Annual Energy Outlook 2013 Early Release," 2013. Available at: http://www.eia.gov/forecasts/aeo/er/pdf/tbla2.pdf

reliance on grid-supplied electricity while providing heat for industrial uses. CHP systems are designed to balance heat production with electric power needs within a facility; electricity can be bought from the grid if needed, or sold to the grid if there is excess on-site production.[163]

These changes in the manufacturing sector will have mixed impacts on greenhouse gas emissions. Absolute increases in natural gas used for heat and power operations are likely to increase total emissions coming from the sector. However, improvements in energy efficiency and especially the substantial deployment of CHP operations will allow the manufacturing sector to increase output with relatively smaller increases in the amount of natural gas input.

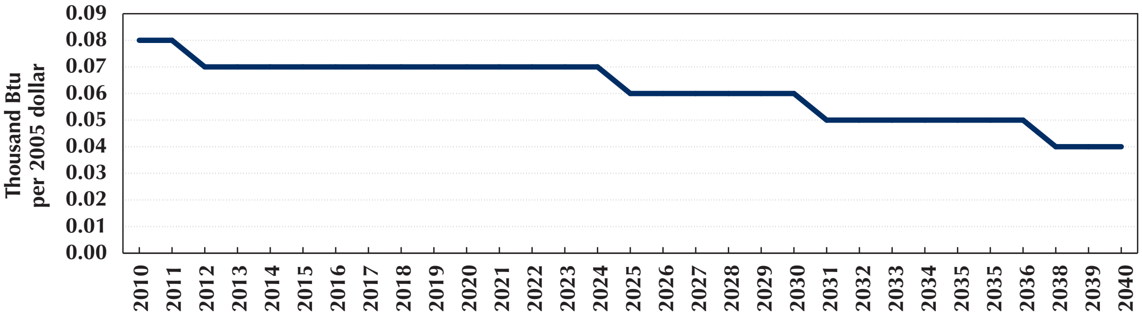
POTENTIAL FOR EMISSION REDUCTIONS

Even as the manufacturing sector expands, opportunities exist to reduce its emission intensity—the amount of CO_2 emitted per unit of output. Replacement of lower-efficiency boilers and greater deployment of CHP systems are ways to reduce emission intensity while using more natural gas.

Replacement of Lower-Efficiency Boilers

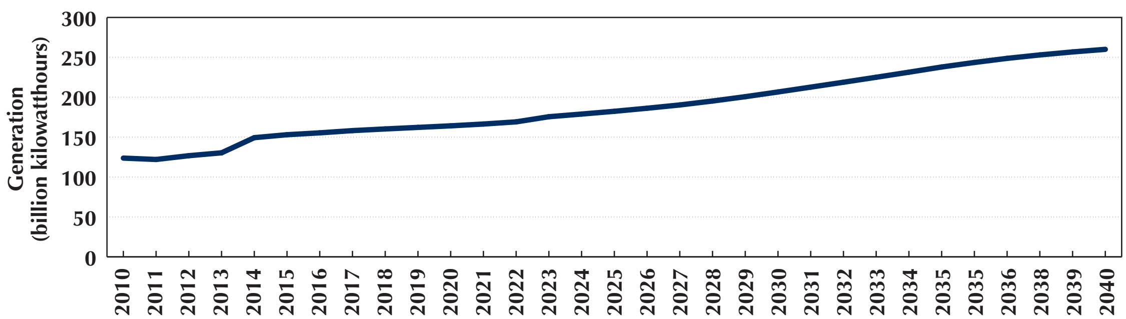
Improving the efficiency of industrial boilers is one such opportunity to reduce emission intensity. Boilers tend to have a low turnover rate, and older units are typically less efficient than newer ones. The pre-1985 fleet of boilers has an average efficiency of 65 to 70 percent, while new boilers have efficiency rates of 77 to 82 percent, and new, super-high-efficiency units can reach efficiencies of up to 95 percent.[164]

FIGURE 6: Projected Energy Consumption Natural Gas Liquids Feedstock per Dollar of Shipments, 2010 to 2040



Source: Energy Information Administration, "Annual Energy Outlook 2013 Early Release," 2013. Available at: http://www.eia.gov/forecasts/aeo/er/pdf/tbla2.pdf

FIGURE 7: Projected Total Industrial CHP Generation for All Fuels, 2010 to 2040



Source: Energy Information Administration, "Annual Energy Outlook 2013 Early Release," 2013. Available at: http://www.eia.gov/forecasts/aeo/er/pdf/tbla2.pdf

Analysis performed by the Massachusetts Institute of Technology found that replacing older natural gas boilers with high-efficiency or super-high-efficiency units would decrease CO_2 emissions by 4,500 to 9,000 tons or more per year per boiler. The analysis also found a strong economic incentive to make these replacements, highlighting annualized monetary savings of 20 percent (given certain assumptions, including 2010 natural gas prices) with a payback period for the new equipment of 1.8 to 3.6 years.[165]

While natural gas is the most commonly used fuel source for industrial boilers, 17 percent of boilers use coal or other fuels (Figure 2). Because of the air pollutants released from coal-fired boilers, these boilers are now subject to the U.S. Environmental Protection Agency (EPA) 2012 Maximum Achievable Control Technology standard (also known as the Boiler MACT). This standard requires the largest and highest-emitting boilers at industrial facilities, typically coal-fired boilers, to meet numeric pollution limits for the emission of air toxics, although it does not specifically require reductions in greenhouse gas emissions.[166] An analysis was performed to determine the results of replacing the Boiler MACT-affected coal boilers with efficient or super-high-efficiency natural gas boilers (natural gas boilers are not regulated under the new rule because of their already low emissions of the specified air toxics). This analysis found that replacement of coal boilers with natural gas boilers would reduce annual CO_2 emissions by 56 to 59 percent, or about 52,000 to 57,000 tons per year per boiler.[167]

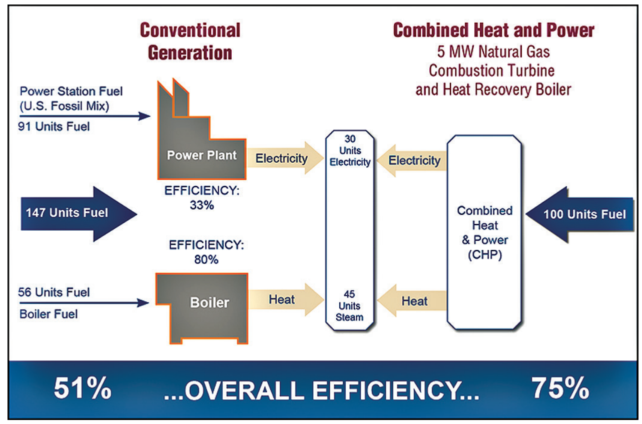
Expanded Use of Onsite CHP

Increasing the use of CHP also has the potential to reduce emissions produced in the manufacturing sector. An Oak Ridge National Laboratory study in 2008 calculated that increasing CHP's share of total U.S. electricity generation capacity from 9 percent in 2008 to 20 percent by 2030 would lower U.S. CO_2 emissions by 600 million metric tons compared with business as usual.[168] A study by McKinsey & Company in 2009 estimated that the potential exists for an additional 50.4 gigawatts of CHP capacity by 2020, which would avoid an estimated 100 million metric tons of CO_2 emissions per year compared with business as usual. Additionally, this study found that 70 percent of the potential cost-effective CHP capacity was through large-scale industrial cogeneration systems greater than 50 megawatts (MW).[169]

CHP units at industrial facilities have the added benefit of bolstering system reliability during a period of transition in the electric sector. Recent years have seen a wave of announced coal plant retirements, and power generation from natural gas-fueled CHP units could make up for some of this lost generation—with lower emissions than centralized coal power plants. A study from the American Council for an Energy-Efficient Economy found that natural gas-fueled CHP at industrial facilities could quickly and cost-effectively replace some of the electric power from retiring coal plants. In South Carolina and Kansas, it could replace all of the expected lost capacity, while in industrial, coal-dependent states such as Ohio and North Carolina, it could replace 16 and 56 percent of lost capacity, respectively.[170]

Figure 8 compares conventional, centralized power generation augmented with a boiler (left side) with a CHP system (right side). Each system is required to provide 30 units of electricity and 45 units of usable heat. However, the power station and boiler together require 154 units of fuel, and the CHP system requires only 100 units of fuel. Therefore, the power station is 49 percent efficient and the CHP unit is 75 percent efficient. At least 7 percent of the electricity delivered from the conventional power station to the industrial facility is lost during transmission. Although most of the losses occur as primary fuel-to-electricity conversion heat losses at the power plant, this heat is unable to be captured for useful purposes. Consequently, a boiler is required on the industrial site to create the necessary heat, which consumes additional fuel. In contrast, the CHP system is able to generate the electricity and heat together with far fewer losses. Since less fuel is required, overall emissions are lower. Some operations also use waste heat in an absorptive chiller to provide cooling services as well. Such operations are referred to as trigeneration or combined cooling, heating, and power. These operations offer even greater efficiencies and opportunities for emissions reductions.

FIGURE 8: CHP versus Conventional Generation



On the right, 100 units of fuel are converted into 30 units of electricity and 45 units of useful heat by a single CHP unit; 75/100 = 75 percent efficiency. On the left, 91 units of fuel are converted into 30 units of electricity by a large power plant and 56 units of fuel are converted into 45 units of useful heat by a separate boiler; 75/(91 + 56) = 51 percent efficient.

Source: Environmental Protection Agency, "Efficiency Benefits," 2012. Available at: http://www.epa.gov/chp/basic/efficiency.html.

BARRIERS TO DEPLOYMENT OF CHP SYSTEMS

Although CHP systems have dramatically higher efficiencies than grid power combined with simple natural gas combustion, and they result in much lower greenhouse gas emissions, barriers currently limit their application. Electric utilities often cite safety concerns as a barrier to deployment, specifically, perceived risks related to electricity being added to the grid outside of the central power plant. For example, some utilities cite the concern that miscommunication could occur between CHP operators and the utilities in the event of an emergency such as a storm causing downed power lines, which utilities say could lead to dangerous situations in which their line workers are not certain whether lines are energized or not. In addition, utilities may be concerned about risk and liability involved as their employees could be affected by safety and technical decisions of CHP operators, decisions they are concerned could be made independently of utilities.[171] Other concerns have to do with CHP systems' potential need for backup power. Many utilities are concerned about the need to provide backup power to industrial facilities if CHP systems are taken offline or are otherwise unavailable. For utilities, the ability to provide backup power requires capacity; to pay for investments in new or maintenance of existing capacity, utilities often charge CHP operators higher rates than other customers and additional interconnection fees to compensate for these necessary investments.

From the standpoint of industry, technical and economic considerations also may need to be taken into account when considering the installation of a CHP system. Some facilities may face shortages of trained CHP installers and operators. Another challenge is that CHP retrofits can be costly. Installation is easier during new construction or a major redesign of a facility. Lastly, some industrial users may face difficulties finding buyers for excess heat or power not needed for their own use. However, if buyers are found, the project may be not only environmentally sound, but economically viable as well.

Current regulatory and electric utility policies have inhibited the growth of CHP capacity, with its attendant climate benefits, because they prevent the alignment of financial interests between electricity producers and energy consumers. Power sector regulation in many states leads utilities to view CHP as unprofitable.[172] This negative view of CHP is often reflected in regulations established by public utility commissions that do not encourage new CHP deployment. However, innovative policy approaches can overcome this conflict between competing goals among utilities and CHP operators. One approach is decoupling, removing or modifying the link between a utility's volume of sales and its profits. Decoupling makes it profitable for utilities to encourage CHP systems.[173] Another potential policy solution is a lost-revenue adjustment policy, which compensates utilities through a charge on customer bills for revenues lost because efficiency measures were effective.[174, 175] State incentives can also encourage the use of CHP. State-level policies include standardizing grid-interconnection guidelines, offering tax incentives, and including CHP as a compliance mechanism for the state's clean-energy standards.[176] Some states have enacted these policies, and, as with many state-led policies, there is a diversity of approaches to (and success with) their implementation.[177]

An example of a state working to overcome barriers to CHP deployment is Ohio. The U.S. Department of Energy (DOE) estimates Ohio has a potential CHP capacity of up to 8,000 MW if CHP systems are installed and limited from selling power into the broader power market, and up to 11,000 MW if sales into the market are allowed. However, despite this vast potential, by 2011 only 766 MW of CHP was installed in the state.[178] Many of the boilers in Ohio will be affected by the new EPA 2012 Boiler MACT rule, making them candidates for upgrades or complete conversions to CHP systems. At the same time, new CHP facilities have the potential to address state regulators' concerns about several announced coal plant retirements affecting system reliability. In response to the benefits of CHP systems in Ohio at this time and to this technology's current underutilization, the Public Utilities Commission of Ohio launched a pilot project with DOE to encourage installation of CHP systems. This project identifies candidate systems and assists in the dialogue between potential CHP operators, utilities, and the electric market operator to facilitate installations while working to overcome regulatory and other barriers.[179] In 2012, the state legislature also added CHP systems as a qualifying resource in the state's clean-energy standard.[180]

CONCLUSION

The increased availability of low-priced natural gas has had positive economic impact on U.S. manufacturing and sector expansion is expected to continue. Given that natural gas is a feedstock and a fuel source for this industry, the efficient use of natural gas needs to be continually encouraged. Options to increase efficiency include the replacement of older boilers with more efficient ones and the expansion of CHP. CHP systems are highly efficient, as they use heat energy otherwise wasted. Policy is needed to overcome barriers to expanded deployment. States are in an excellent position to take an active role in promoting CHP when required industrial boiler upgrades and new standards for cleaner electricity generation are implemented.

VII. DISTRIBUTED GENERATION IN COMMERCIAL AND RESIDENTIAL BUILDINGS AND THE ROLE OF NATURAL GAS

By Doug Vine, C2ES

INTRODUCTION

Distributed generation is the production of electricity from smaller sources at or near the location where the energy will be consumed. Slightly more than 6.5 percent of electricity in the United States is generated at distributed locations outside of central generation plants.[181] Distributed generation using natural gas has a number of potential benefits, including the potential to capture heat associated with electricity generation that can be put to use on site. When waste heat is captured and used and/or highly efficient generation technologies are used, distributed generation decreases the total demand for primary fuels, thereby decreasing greenhouse gas emissions.

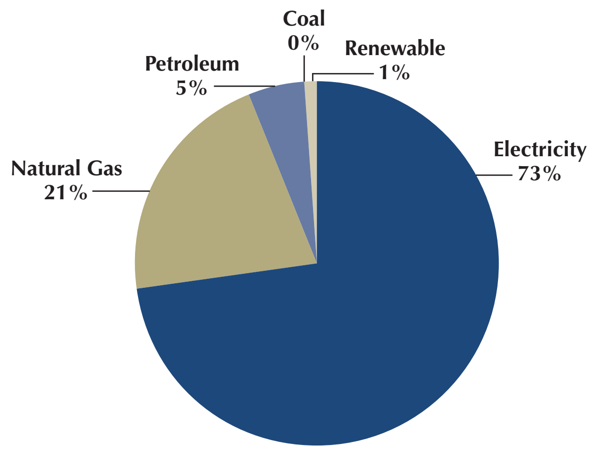
This chapter explores the potential climate-related benefits of distributed generation technologies as they apply to the residential and commercial sectors. (For a discussion of combined heat and power (CHP) systems in the manufacturing sector, see chapter 6.) The chapter discusses three major technologies for distributed generation: microgrids, fuel cells, and microturbines. Next, it explores policies that encourage the deployment of these technologies, and, lastly, it discusses barriers to deployment.

Electricity is the most widely used form of energy by residential and commercial buildings on a primary-energy basis (Figure 1). Since the majority of electricity generation emits greenhouse gases, it makes sense to consider technologies with lower emissions. Several promising technologies make use of natural gas as the primary fuel, and many of these technologies could significantly reduce greenhouse gas emissions from electricity use in the residential and commercial sectors. Distributed generation technologies either can be placed on site at a home or business or can be located a short distance away, serving several buildings together. While the majority of existing natural gas-fueled distributed generation technologies are not as efficient as central generation, the ones discussed in this chapter are highly efficient, can be used in highly-efficient configurations with CHP, and/or facilitate the deployment of renewable energy sources. Distributed generation technologies that supply power to multiple locations include microgrids. On-site or end-use technologies include natural gas-fueled electricity (and heating) devices such as fuel cells and microturbines, which can also be used as small CHP systems.

THE ADVANTAGES OF DISTRIBUTED GENERATION

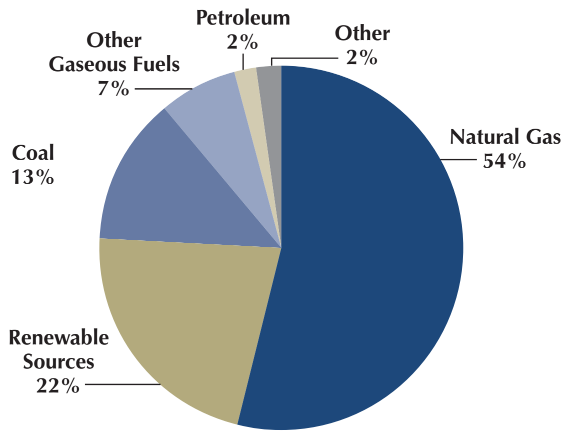
In 2010, natural gas-fueled electricity comprised approximately 54 percent of the total net U.S. distributed generation (Figure 2). These figures are for industrial and commercial sector distributed generation only and represent approximately 3.5 percent of the total electricity generated in that year.

FIGURE 1: Projected U.S. Residential and Commercial Buildings Primary Energy Consumption, 2010



Source: Energy Information Administration, Residential Energy Consumption Survey, 2009. Available at http://www.eia.gov/consumption/residential/data/2009/

FIGURE 2: Distributed Generation by Fuel Source, 2009



Source: Source: Energy Information Administration, Residential Energy Consumption Survey, 2009. Available at http://www.eia.gov/consumption/residential/data/2009/

Distributed generation has many advantages over centralized electricity generation, including end-users' access to waste heat, easier integration of renewable energy, heightened reliability of the electricity system, reduced peaking power requirements, lower greenhouse gas emissions, and less vulnerability to terrorism due to more geographically dispersed, smaller power plants.[182] In addition, producing electricity closer to where it is used reduces the amount of electricity lost as it is delivered over long distances from power stations to end users. Annual electricity transmission and distribution losses in the United States average about 7 percent of the electricity transmitted.[183] Lowering transmission (or line) losses means less electricity generation (less fuel and fewer emissions) is required to serve the same electrical demand.

Generally, natural gas-fueled distributed generation technologies are not as efficient in producing electricity as natural gas-fired generation from the grid. In general, distributed generation only improves efficiency and reduces greenhouse gas emissions when it includes CHP. By definition, distributed generation is physically located close to loads, so use of heat is often an option. However, CHP requires tight matching, in space and especially in time, between power generation and thermal loads. This matching can make CHP technologies difficult to effectively install. Nevertheless, where possible, this technology is significantly more efficient and should be deployed.

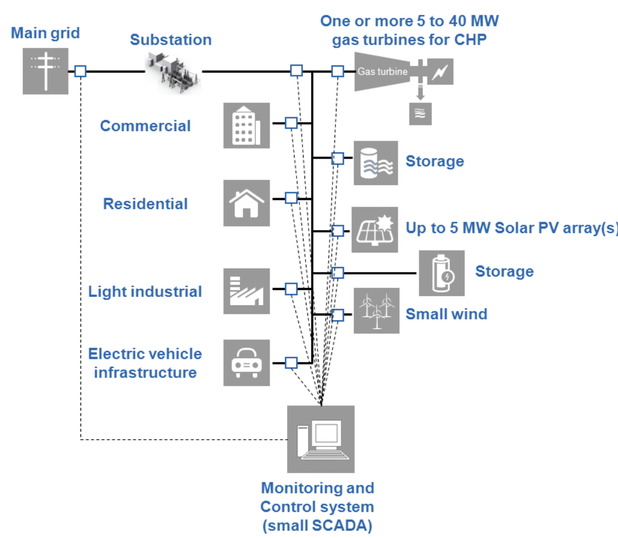
MICROGRIDS

One increasingly employed distributed generation technology is the microgrid. A microgrid is a small power system composed of one or more electrical generation units that can be operated either in conjunction with or independently from the central power system (Figure 3).[184] Micrograms can serve a small grouping of buildings. Additionally, microgrids offer the potential to integrate renewable sources of electricity with fossil fuel-based backup power; they are able to integrate distributed, dispatchable natural gas-fueled electricity (or CHP systems) with local renewable power and energy storage. Furthermore, since the electricity is generated close to where it will be used, it becomes feasible to use the waste heat in a productive manner, such as for heating water or space in nearby homes and businesses. Microgrids can be particularly attractive if new or upgraded long-distance electricity transmission cannot be developed in a timely or cost-effective fashion.[185]

FUEL CELLS

Fuel cells are another promising distributed generation technology. Natural gas-powered fuel cells use natural gas and air to create electricity and heat through an

FIGURE 3: Microgrid Concept



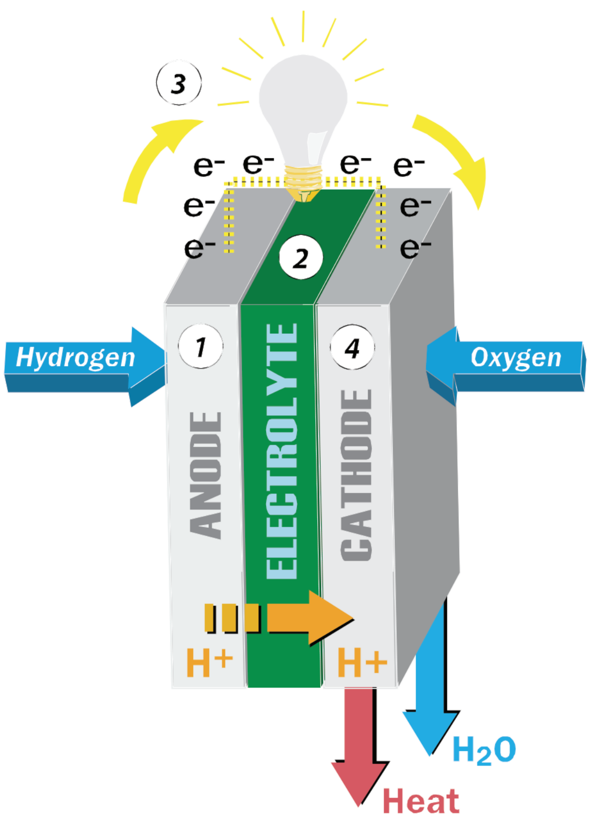
Source: Siemens, "The Business Case for Microgrids," 2011. Available at: http://www.energy.siemens.com/us/pool/us/energy/energy-topics/smart-grid/downloads/The%20business%20case%20for%20microgrids_Siemens%20white%20paper.pdf

Note: Individual microgrid elements will vary.

electrochemical process rather than combustion.[186] First, natural gas is converted into hydrogen gas inside the fuel cell in a process known as reformation. When the hydrogen passes across the anode of the fuel cell stack (Figures 4 and 5), electricity, heat, water, and carbon dioxide (CO_2) are created.

Fuel cell technology has been around for many decades; it has been used by the National Aeronautics and Space Administration on space projects for nearly 50 years. Commercially available fuel cells operate in a

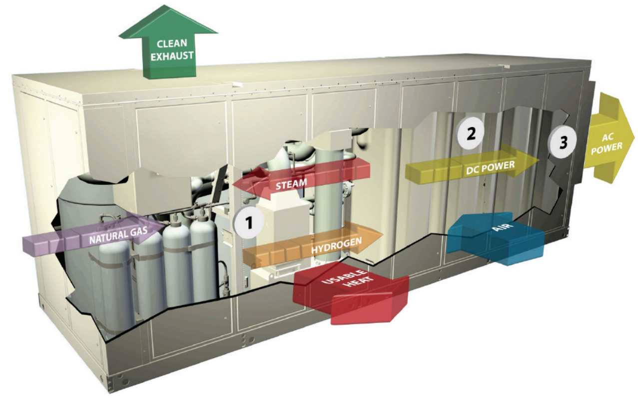
FIGURE 4: Fuel Cell Stack



1) Anode: As hydrogen flows into the fuel cell anode, a catalyst layer on the anode helps to separate the hydrogen atoms into protons (hydrogen ions) and electrons. 2) Electrolyte: The electrolyte in the center allows only the protons to pass through the electrolyte to the cathode side of the fuel cell. 3) External Circuit: The electrons cannot pass through this electrolyte and, therefore, must flow through an external circuit in the form of electric current. This current can power an electric load. 4) Cathode: As oxygen flows into the fuel cell cathode, another catalyst layer helps the oxygen, protons, and electrons combine to produce pure water and heat.

Source: ClearEdge Power

FIGURE 5: How Fuel Cells Work



Source: ClearEdge Power

Notes: 1) Fuel Processor: Converts natural gas fuel to hydrogen. 2) Fuel Cell Stack: Generates direct current (DC) power from hydrogen and air. 3) Power Conditioner: Converts DC power to high-quality alternating current (AC) power 4) Heat Recovery: On-board heat exchangers for recovering useful thermal energy.

wide range of climates, from very cold to very warm (-20° to 110°F), and they have electrical efficiencies of around 40 to 60 percent (Table 1). They are quiet devices with a fairly small footprint. The only greenhouse gas emitted is a pure stream of CO_2, which could allow for capture and sequestration. Despite these benefits, skeptics question the durability, cost (see below) and reliability of fuel cells. In the past, materials have corroded within months or a few years. Bloom Energy estimates that its current devices will have a 10-year life as long as the fuel stacks are replaced at least twice. However, since Bloom's introduction is recent, there are currently no operational fuel cell systems that have approached this age.[187]

There are many types of fuel cells, each with its unique chemistry, operating temperature, catalyst, and electrolyte.[188] Phosphoric acid fuel cells, molten carbonate fuel cells, and solid oxide fuel cells, among others, have been commercialized for stationary electrical power generation. Since many units operate at high temperatures and contain corrosive materials, a key concern is their durability or stack life. For example, natural gas-fueled phosphoric acid fuel cells operate at temperatures of around 450°F, and solid oxide fuel cells operate at temperatures of about 1,800°F.[189] Phosphoric acid fuel cells are the most durable type in the less-than-one megawatt (MW) range and have a demonstrated stack life of more than 10 years, although designs of many other fuel cell types are improving rapidly.[190]

ClearEdge Power and Bloom Energy are among a handful of manufacturers of stationary fuel cells. Their main products are described below for illustrative purposes. There are an additional half-dozen or so manufacturers of non-stationary fuel cells (fuel cells for vehicles).

ClearEdge Power, based in Oregon and established in 2003, manufactures refrigerator-sized fuel cell units that generate baseload or backup electric power as well as provide useable heat for hot water and/or space heating in a CHP configuration. These units are scalable to suit the energy requirements of individual homes, apartment buildings, hotels, and other commercial businesses, and can be installed indoors or outdoors. They have efficiencies of up to 90 percent. They are 50 to 60 percent efficient in natural gas conversion to electricity, in addition to providing useful heat. Therefore, they require considerably less natural gas to generate the same amount of energy provided from a combination of centrally generated electricity and a heating appliance.[191] In February 2013, ClearEdge Power acquired UTC Power, an early pioneer in fuel cell research that conducted experiments with many types of fuel cells beginning in the late 1950s.[192] Stationary fuel cell products from UTC Power, now ClearEdge Power, are deployed in residential, commercial, and industrial applications around the world.[193]

Bloom Energy, based in California and founded in 2001, markets energy servers that consist of arrays of fuel cell boxes in various sizes that must be installed outdoors (Figure 6). The energy servers are scalable and are used by large corporate customers such as Wal-Mart, eBay, and FedEx, and not residential consumers.[194] These servers achieve conversion efficiencies above 60 percent. These are very high-temperature devices, but the heat is not used for water or space heating. The average emissions are 773 pounds of CO_2 per megawatt-hour (MWh), which is just below the average U.S. natural gas power plant at 800 to 850 pounds of CO_2/MWh.[195, 196]

FIGURE 6: Bloom Energy Server Outdoor Installation

Source: Bloom Energy

MICROTURBINES

Microturbines are small combustion turbines approximately the size of a refrigerator with individual unit outputs of up to 500 kilowatts (kW).[197] These devices can be fueled by natural gas, hydrogen, propane, or diesel. In a cogeneration configuration (Figure 7), the combined thermal-electrical efficiency can be as high as 90 percent.[198] Like fuel cells, microturbines can achieve much higher energy efficiencies, because the electricity is generated close to the location where it will be used, and the heat byproduct can be captured and utilized on site or nearby.

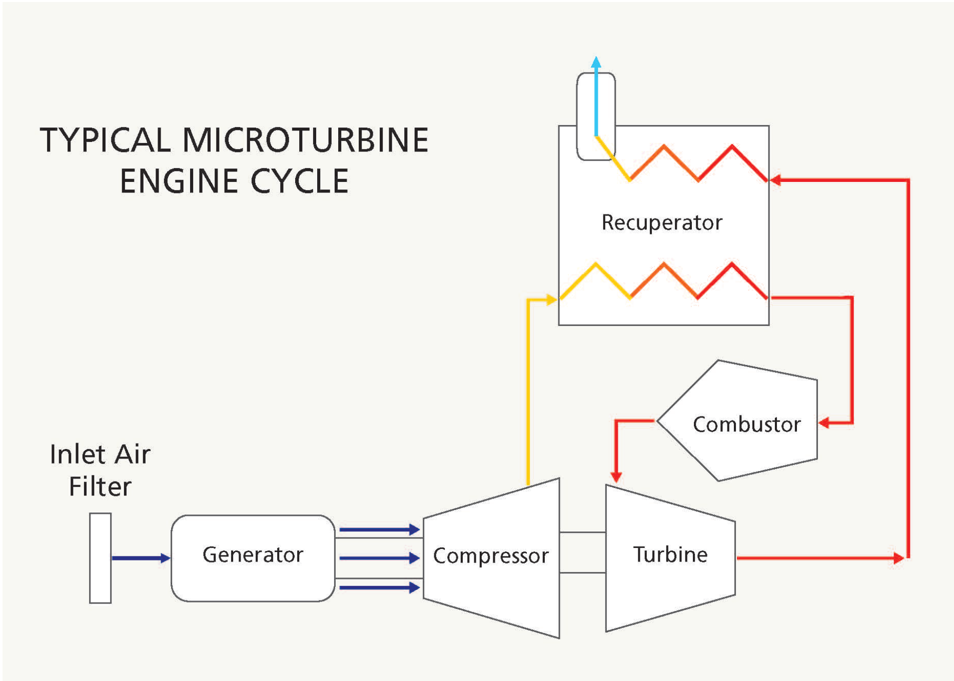
Microturbines are an established technology, and there are more than 20 companies worldwide involved

TABLE 1: Fuel Cells Summary

COMPANY	ELECTRICAL EFFICIENCY	USABLE HEAT	TOTAL EFFICIENCY FOR CHP SYSTEM	MARKETS
ClearEdge	50-60 percent	Yes	90 percent	Residential, Commercial, Industrial
Bloom Energy	60 percent	No	60 percent	Commercial

Source: Clear Edge, Bloom Energy

FIGURE 7: Microturbine Schematic



Fuel enters the combustor and the hot gases ejected from the combustor spin a turbine, which is connected to a generator that creates electricity. The exhaust gases transfer heat to the incoming air. A recuperator captures waste heat and helps improve the efficiency of the compressor.

Source: Capstone Turbine Corporation

in the development and commercialization of microturbines for distributed generation applications.

Los Angeles-based Capstone Turbine Corporation is a global market leader in the commercialization of microturbines.[199] The company offers individual units in the range of 30 kW to 200 kW, and greater quantities of power can be achieved by using multiple units, with electrical efficiencies from 25 to 35 percent (Figure 8). Using the heat produced by a microturbine for water or space heating, space cooling (in conjunction with absorption chillers) and/or process heating or drying, increases the efficiency of these units to 70 to 90 percent.[200] Capstone products service the commercial and industrial sectors, and they have installations all over the world, including universities, a winery, and a 35-story office tower in New York City (Figure 9).[201]

Flex Energy, also headquartered in California, is Capstone's main competitor. Its 250 kW microturbine has an electrical efficiency of 30 percent, and it too provides useful heat energy, which when used would improve the overall efficiency of the system.[202] Flex Energy and Capstone microturbines can use low-quality

FIGURE 8: Microturbine Unit

Source: Capstone Turbine Corporation

FIGURE 9: Microturbine Installation

Source: Capstone Turbine Corporation

and unrefined natural gas, making them capable of generating electricity at landfills and hydraulic fracturing sites.[203] Using unrefined natural gas at a well site for power requirements can reduce the need for diesel power generation and utilize natural gas that may have been flared otherwise.

Micro Turbine Technology, a company in the Netherlands, is developing a 3 kW electrical with 15 kW thermal microturbine CHP for homes and small businesses that is expected to be ready for market in early 2013.[204]

At 31 percent average electrical efficiency, much lower than a modern natural gas combined-cycle plant or fuel cell (both around 50 percent), microturbines produce 1,290 pounds of CO_2/MWh, about 50 percent higher emissions than a modern combined-cycle plant.[205] However, due to their ability to capture and use waste heat onsite, they are capable of achieving thermal efficiencies of up to 85 percent. When this heat is captured and used, the total efficiency of the system offsets the lower efficiency of electricity generation part of the system, reducing overall greenhouse gas emissions per MWh. Additional strengths of microturbines include their compact size, small number of moving parts, generally lower noise than other engines, and long maintenance intervals. Weaknesses include parasitic load loss from running a natural gas compressor and loss of power output and efficiency with higher ambient temperatures and elevation.[206] According to U.S. Environmental Protection Agency data, at an 80°F outdoor air temperature, the microturbines are about 3 percent less efficient than at a 50°F outdoor air temperature.[207]

RESIDENTIAL UNIT CHP

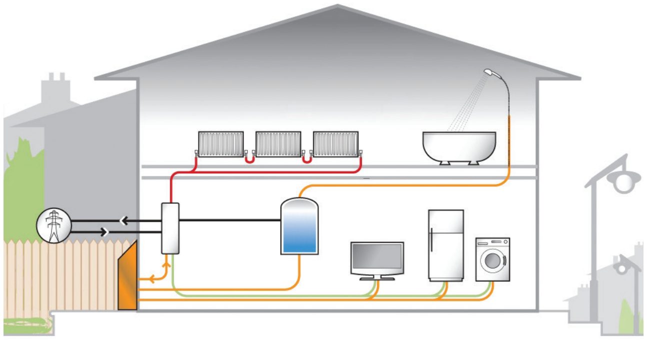
There are even smaller systems than the microturbines discussed that can provide CHP to individual residential units. At less than 50 kW, these microCHP units are small enough to provide electric power for a residential or commercial building while also supplying heat for thermal applications or absorption cooling (Figure 10). Common in Europe and Japan, microCHP is rare in the United States. These small units may use a variety of engine types, including combustion, steam, Brayton, and Stirling.[208] For example, the WhisperGen, developed in New Zealand, is a microCHP technology based on the Stirling engine. The company is currently headquartered in Spain, where the product is being marketed to European customers. The washing machine-sized technology is designed to produce hot water and space heating. Under normal operation the unit will provide around 1 kW of electrical power.[209] Other companies, such as Japan's Honda, also offer microCHP units to consumers.[210]

TABLE 2: Microturbine Summary

COMPANY	ELECTRICAL EFFICIENCY	USABLE HEAT	TOTAL EFFICIENCY FOR CHP SYSTEM	MARKETS
Capstone	25-35 percent	Yes	70-90 percent	Commercial, Industrial
Flex Energy	30 percent	Yes	Not Available	Commercial, Industrial
MTT	N/A	Yes	Not Available	Residential

Source: Capstone, Flex Energy, MTT

FIGURE 10: Residential CHP Unit



Residential CHP unit (bottom left outside of house) is capable of supplying hot water and heating as well as electricity to several appliances. Home is still grid connected for any consumption unable to be met by the CHP unit and excess power generated by the unit can be sold back to the electric utility.

Source: Fuel Cell Today

POLICIES TO ENCOURAGE THE DEPLOYMENT OF NEW TECHNOLOGIES

Although these new technologies have great potential to use less primary energy and to reduce greenhouse gas emissions from energy use in the residential and commercial sectors, there are some hurdles to overcome. Higher upfront capital costs hinder investment in distributed generation technologies overall. In addition, utility regulations often do not encourage, and in some case actively discourage, distributed generation technologies.

Some state and federal incentive programs help home- and business-owners with upfront costs. At least 10 states provide financial incentives for self-generation.[211, 212] The federal Investment Tax Credit, designed to help defray capital expenditure costs, applies to fuel cells, CHP, and microturbines for use in the commercial, industrial, utility, and agricultural sectors.[213]

Another potential incentive for consumer investment in on-site energy generation is net metering. Net metering allows customers to receive retail prices for their excess generation; the electricity meter turns backwards (literally or digitally) when the site generates more electricity than it consumes.[214] Forty-three states and the District of Columbia have rules enabling net metering.[215] Eligible generation technologies vary. Fuel cells using any fuel type often qualify, and CHP sometimes qualifies, although less often.

Sites using distributed generation often rely on a grid interconnection as a source of backup power. Establishing a connection between an on-site system and the power grid can be difficult, confusing for the on-site operator, and lengthy. Standard interconnection rules greatly simplify this process, establishing clear and uniform processes and technical requirements that apply to all utilities within a state. These rules reduce uncertainty and prevent delays that installers and operators of distributed generation systems can encounter when obtaining approval for electric grid connection, and thus make the prospect of installing a system less daunting to newcomers.[216] As of April 2012, 34 states had interconnection standards for fuel cells, and 29 states had such standards for microturbines.[217]

A final area where policies could encourage the installation of more distributed generation systems pertains to utility charges. As mentioned above, distributed generation systems rely on a grid connection for backup power during outages, whether scheduled or emergency. Standby rates are charges levied by utilities when a distributed generation system must purchase all of its power from the grid. These charges generally include an energy charge, reflecting the actual energy provided, and a demand charge, which is a way for the utility to recover its costs in maintaining the capacity to meet the facility's peak demand whenever that may be required. Utilities often argue that the demand charges act as a strong incentive for system owners to manage their peak demand. However, the likelihood of unplanned outages during times of peak demand is very low, and the use of demand charges likely discourages the expansion of distributed generation. Regulators should carefully weigh the discouraging effect of demand charges against the substantial benefits of distributed generation, including increased system reliability, reduced distribution losses, and the climate benefits of the higher system efficiencies.[218]

BARRIERS TO DEPLOYMENT

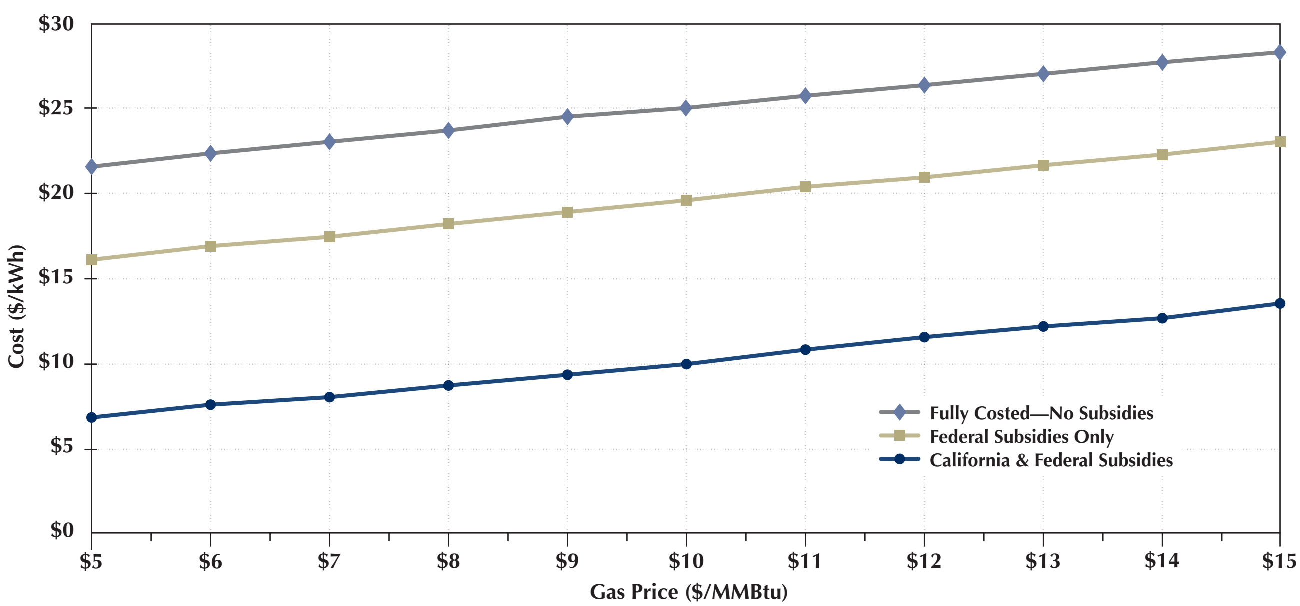
A variety of factors converge to discourage potential owners of distributed generation systems. First, consumers are largely unfamiliar with these technologies. Moreover, they are not compelled to search for innovative strategies to generate energy. Their utility bills are stable, due to low wholesale electricity prices (a result of lower natural gas prices). Local building and fire codes may also provide disincentives or even make it impossible for consumers to consider distributed generation. And the limited availability of many distributed generation products in the United States is a barrier to even those with natural gas access.[219]

Even if these hurdles are removed, the cost of many distributed generation technologies can be a barrier. According to the National Institute of Building Sciences, microturbine capital costs were $700 to $1,100 per kW in 2010, with installation costs adding 30 to 50 percent of the total installed cost. Combining heat recovery technology to units increased the cost by $75 to $350 per kW. A future cost below $650 per kW may be possible with future economies of scale.[220] Fuel cells could be cost-competitive with grid electricity if they were to reach an installed cost of $1,500 or less per kW; however, the current installed, unsubsidized cost is at least $4,000 per kW.[221] Nevertheless, a combination of state and federal incentives, low natural gas prices, and high grid-electricity prices could result in a 100 kW energy server making economic sense, as shown in an analysis by Seattle City Light (Figure 11). Similarly, natural gas microCHP units could be cost competitive with a 1.5- to two-year payback period at an installed cost of $1,500 for a 1 kW unit.[222]

CONCLUSION

To realize the potential of distributed generation technologies, policies such as financial incentives and tax credits will need to be more widespread. Additionally, net metering, grid interconnection requirements, and standby rate issues will need to be worked through. Also, low consumer awareness and higher costs of these emerging technologies will slow their deployment. Finally, utilities may perceive distributed generation technologies as a threat, as they have the potential to capture a large share of utilities' electricity sales business. Nevertheless, some supporters of distributed generation have claimed that their technology will replace the grid and have designed their business strategies accordingly.[223]

FIGURE 11: Bloom Energy Server Cost Depends on Gas Price and Subsidies



Source: Seattle City Light, "Integrated Resource Plan." 2010. Available at: http://www.seattle.gov/light/news/issues/irp/docs/dbg_538_app_i_5.pdf

VIII. TRANSPORTATION SECTOR

By Fred Beach, The University of Texas at Austin

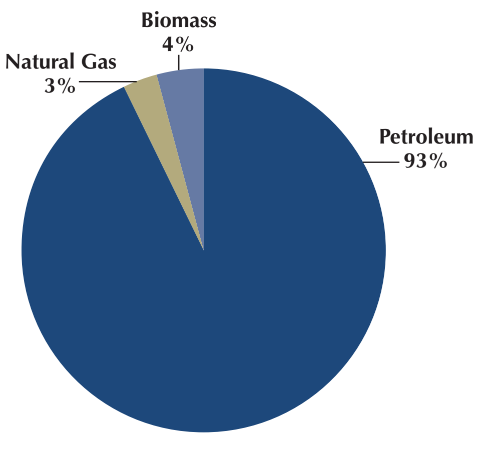
INTRODUCTION

Historically, natural gas has not been widely used as an energy source for transportation; rather, the sector has long been dominated by petroleum use. In 2010 (Figure 1), the U.S. transportation sector used 27.47 quadrillion British thermal units (Btu) of energy, of which 25.59 quadrillion came from petroleum and just 0.72 quadrillion came from natural gas—93 percent and 3 percent of the sector, respectively.[224] Natural gas used in the transportation sector resulted in the emission of just 40.1 million metric tons of carbon dioxide equivalent (CO_2e) in 2010, out of a total 1,746 million metric tons emitted by all fuel sources in the transportation sector.[225] As in other sectors of the economy, fuel substitution from other fossil fuels to natural gas in some parts of the transportation sector has the potential to yield climate benefits. In addition, it would benefit U.S. national security by decreasing reliance on the global oil market. Although the potential for natural gas use is less in the transportation sector than in others, the potential does exist, primarily for medium- and heavy-duty trucks as well as fleet vehicles and buses.

A main driver of the increased interest natural gas fleets and passenger vehicles is the relative abundance and low price of domestic natural gas in comparison to oil. On April 30, 2012, the national average price of diesel fuel was $4.07 per gallon and gasoline cost $3.83 per gallon,[226] while a gasoline-gallon-equivalent of natural gas cost only $2.09.[227] On the same day, the price of petroleum was $104.87 per barrel,[228] and the price of natural gas was only $12 on an energy-equivalent basis.[229] In recent years, oil prices rose while natural gas prices decreased, creating an ever-widening gulf (Figure 2). This differential has made natural gas vehicles increasingly economical.[230]

This chapter looks at the currently available natural gas technologies for vehicles. Next, it explores the barriers to adoption for various types of vehicles. Finally, it examines the potential implications of broader direct use of natural gas in the transportation sector for greenhouse gas emissions.

FIGURE 1: Energy Sources in the U.S. Transportation Sector, 2010



Source: Energy Information Administration, "Annual Energy Review," Table 2.1e. October 2011. Available at: http://www.eia.gov/totalenergy/data/annual/showtext.cfm?t=ptb0201e

AVAILABLE NATURAL GAS TRANSPORTATION TECHNOLOGIES

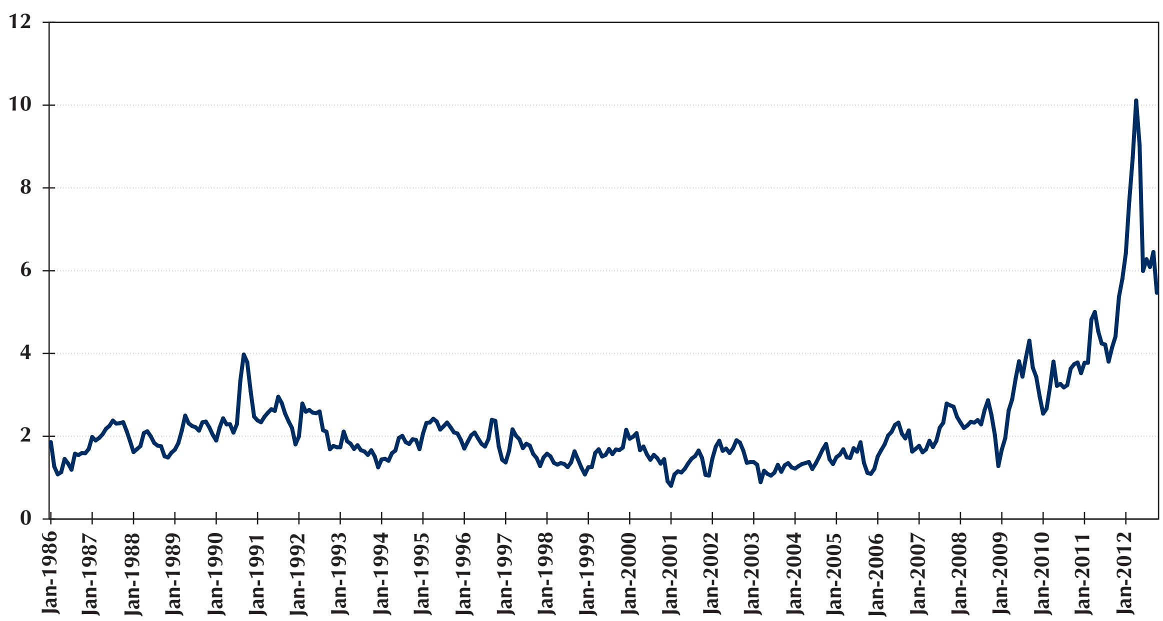
A variety of available vehicle technologies allow natural gas to be used in light-, medium-, and heavy-duty vehicles. Most commonly, natural gas is used in a highly pressurized form as compressed natural gas (CNG) or as liquefied natural gas (LNG). While CNG and LNG are ultimately burned in the vehicle, natural gas can also power vehicles in other ways. Natural gas can be converted into liquid fuel such as gasoline and diesel (distinct from LNG) that can be used in conventional internal combustion engines, reformed into hydrogen for use in fuel-cell vehicles, or be used to generate electricity for electric vehicles. Despite the existence of these technologies, only about 117,000 of the more than 250 million vehicles on the road in 2010 (about 0.05 percent) were powered directly by natural gas.[231] The majority of natural gas-powered vehicles are buses and trucks.[232]

Compressed and Liquefied Natural Gas

CNG is the most common natural gas fuel used in transportation today. There were 115,863 compressed-natural gas vehicles on U.S. roads in 2010, using 988 fueling sites.[233] The majority is found in larger transportation fleets. Although Honda offers a CNG passenger vehicle, only 4,000 vehicles were scheduled for production in 2012.[234] Public transit buses are the largest users of natural gas in the transportation sector, with about one-fifth of buses running on CNG or LNG. Some commercial fleets use natural gas-powered trucks, including thousands of trucks at FedEx, UPS, and AT&T.[235, 236] Waste Management has the largest fleet of natural gas vehicles in the country with 1,700 trucks that can run partially on biogas supplied from its own landfill assets.[237] The low cost and environmental benefits of this biogas are encouraging the company to continue conversions and to open some of its refueling infrastructure to the public.

To a lesser extent than CNG vehicles, vehicles powered by LNG (primarily heavy-duty trucks) are also used on U.S. roads and a fueling infrastructure has begun to develop. LNG is created by chilling natural gas to -260°F at normal pressures, at which point it condenses into a liquid that occupies 0.0017 percent of the volume of the gaseous form.[238] The conversion of natural gas to LNG removes compounds such as water, carbon dioxide (CO_2), and sulfur compounds from the raw material, leaving a purer methane product whose combustion results in less air pollution.[239] The stable, non-corrosive form also makes LNG more easily transportable, and it can be moved by ocean tankers or trucks.[240] Use of LNG requires large, heavy, and highly insulated fuel tanks to keep the fuel cold, which adds a significant cost to the vehicle.[241] Today, LNG is mainly used as a replacement for diesel fuel in heavy-duty trucks because they can accommodate this hefty storage system and can use LNG fueling infrastructure currently limited to trucking routes.[242] In 2010, there were only 40 public and private LNG refueling sites,[243] serving 3,354 LNG vehicles.[244] Recently, the Clean Energy Fuels network launched the development of an interstate LNG refueling network, mainly taking advantage of existing diesel fueling

FIGURE 2: Oil Price as a Multiple of Natural Gas Prices, 1986 to 2012

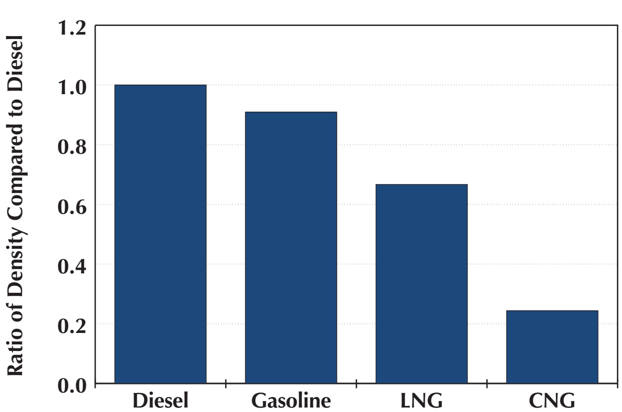


Source: Energy Information Administration, "Annual Energy Outlook 2012 Early Release," 2012. Available at: http://www.eia.gov/oiaf/aeo/tablebrowser/#release=EARLY2012&subject=0-EARLY2012&table=7-EARLY2012&region=0-0&cases=full2011-d020911a,early2012-d121011b

stations along highways and trucking distribution centers. Seventy stations were opened in 2012, with plans for 70 to 80 more in 2013.[245]

CNG and LNG are less dense forms of energy than conventional gasoline and diesel fuel (Figure 3), requiring vehicles running on them to have larger fuel tanks in order to store the same amount of energy. CNG requires special storage because the gas is compressed to less than 1 percent of its volume at standard atmospheric pressure.[246] Vehicles use cylindrical storage tanks capable of fuel pressures of up to 3,600 pounds per square inch. These tanks are significantly larger and heavier than conventional gasoline or diesel fuel tanks, and their placement in passenger vehicles can take up valuable passenger or trunk space.[247, 248] The energy density of CNG is so low that CNG vehicles with ranges greater than 300 miles are unlikely to be produced unless current space and weight limitations are overcome. Therefore, CNG is primarily suitable for fleet passenger vehicles, municipal buses, and other vehicles where travel distances are shorter. The greater energy density of LNG, however, makes it practical for long-haul tractor-trailers that can accommodate larger fuel tanks.[249] Despite being less energy-dense than gasoline or diesel, both CNG and LNG can be an attractive fuel source for certain applications, from both an economic and environmental perspective.

FIGURE 3: Comparison of the Energy Density of Natural Gas and Diesel Fuel



Source: Energy Information Administration, "Annual Energy Outlook 2010 with Projections to 2035," 2010. Available at: http://www.eia.gov/oiaf/aeo/otheranalysis/aeo_2010analysispapers/factors.html

Fuel Cell-Powered Vehicles

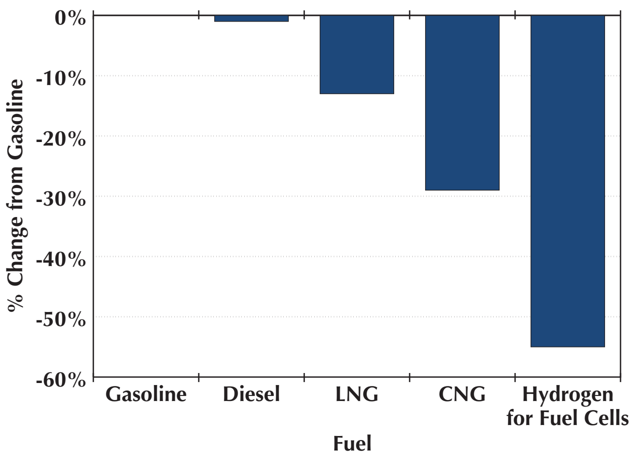
Natural gas also plays a role in supplying fuel cell vehicles (see chapter 7 for a discussion of stationary fuel cells in distributed generation). Fuel cells produce electricity through an electrochemical process rather than through combustion, resulting in heat and water and far lower emissions of greenhouse gases and other pollutants. Fuel cells are fueled by hydrogen, and the most common source of hydrogen today is natural gas. Hydrogen can be extracted on board the vehicle using a reformer, or it can be externally extracted and subsequently added to the vehicle.[250] Today, no light-duty fuel cell vehicles are commercially available in the United States, although there are certain test vehicles on the road as well as rudimentary hydrogen fueling infrastructure in California.[251] Companies are working to introduce fuel cell vehicles to the market. In the United States, Hyundai plans to build 1,000 fuel cell vehicles for distribution in 2013,[252] and Toyota has suggested that production costs are decreasing such that it should be able to sell fuel cell vehicles for $50,000 by 2015.[253]

Gas to Liquids

While CNG and LNG are today the most common forms of natural gas fuels in vehicles, other available technologies could increase the use of natural gas in the broader transportation system. Gas-to-liquids technology refines natural gas into gasoline or diesel hydrocarbons, which can be used in existing vehicles and moved through existing infrastructure. Gas-to-liquids products have energy densities similar to those of traditionally produced gasoline and diesel, properties that allow for better engine performance and potentially fewer emissions of greenhouse gases and regulated pollutants,[254] although more empirical study is needed on emissions.

Conversion technologies typically require 10 thousand cubic feet (Mcf) of natural gas to produce one barrel of oil-equivalent product output, such as diesel, naphtha, and other petrochemical products.[255] Using $4 per Mcf of natural gas as inputs to this conversion, the outputs are equivalent to $40 per barrel of oil-equivalent. Gas-to-liquids products have been produced at facilities elsewhere in the world, and new facilities in the United States are being developed. Several companies are considering gas-to-liquids facilities on the Gulf Coast because of favorable natural gas supplies and current domestic prices.[256]

FIGURE 4: Full Lifecycle, Total Carbon Intensity of Selected Transportation Fuel Options as a Percentage Reduction from Gasoline Carbon Intensity



Source: California Air Resources Board, "Proposed Regulation to Implement the Low Carbon Fuel Standard," March 5, 2009. Table ES-8. Available at: http://www.arb.ca.gov/fuels/lcfs/030409lcfs_isor_vol1.pdf

Notes: The carbon intensities compared above were calculated specifically for California's Low Carbon Fuel Standard program using the GREET model.

Results from the GREET model rely on the assumptions included in the model. Other models may use other assumptions and yield different results. Models are useful for insights, but their results depend on the assumptions made.

Electric Vehicles

Natural gas also plays a role in electric vehicles, which are becoming more common on U.S. roads. These vehicles use electricity from the electrical grid, which is increasingly powered by natural gas as a fuel source. From January 2011 to December 2012, Americans purchased more than 60,000 plug-in electric vehicles, including Chevrolet Volts, Nissan LEAFs, and Toyota plug-in Priuses.[257] Additionally, plug-in electric vehicles are now available from BMW, Ford, Tesla, Mitsubishi, and Daimler.[258] When fueled by electricity generated by a combined-cycle natural gas power plant, such natural gas-powered electric vehicles offer significant efficiency and emissions benefits over conventional diesel- or gasoline-powered vehicles.[259]

GREENHOUSE EMISSIONS OF NATURAL GAS AS A TRANSPORTATION FUEL

Transportation accounts for more than 25 percent of U.S. greenhouse gas emissions and is an important focus of U.S. emission reduction efforts. Natural gas emits fewer greenhouse gases than gasoline or diesel when combusted or used in fuel cells (Figure 4). Fuel Cells offer the greatest potential emission reduction benefit but today are also the most expensive. CNG offers the next largest greenhouse gas reduction potential and can be used in many transportation options including fleets, heavy-duty vehicles and passenger vehicles. The barriers and potential for emission reductions associated with fuel switching to natural gas in major segments of the transportation sector are described below.

NATURAL GAS IN BUSES AND MEDIUM- AND HEAVY-DUTY VEHICLE FLEETS

Buses produce a very small share of overall greenhouse gases, contributing only 1 percent of emissions from on-road vehicle transportation in 2011, but as previously mentioned, they are the most common use of natural gas in vehicles today.[260] In contrast, long-haul tractor-trailers play a more important role in U.S. energy consumption and greenhouse gas emissions. These vehicles account for two-thirds of all fuel consumption for freight trucks (medium- and heavy-duty trucks), and freight trucks' emissions are increasing more rapidly than those of other transportation sources. Over time, freight trucks will likely account for an even larger percentage of the sector's greenhouse gas emissions, as they will take on a greater portion of deliveries for consumer products, using more vehicles for just-in-time shipping and taking advantage of lower labor costs and changing land use patterns.[261] Consequently, reducing the carbon intensity of freight trucks will be critical to reducing transportation sector greenhouse gas emissions, and increased natural gas use is one opportunity to do so.

Barriers to Expanded Natural Gas Use

Significant barriers exist for the expansion of natural gas use in medium- and heavy-duty vehicles. Currently, trucks utilizing CNG or LNG have shorter ranges, fewer refueling options, and lower resale value than traditional diesel-powered trucks. A diesel truck with a 150-gallon tank and a 6 to 7 miles-per-gallon fuel economy can travel about 1,000 miles on one tank, which is significantly more than its natural gas-powered counterparts. Depending on the mounting of the cylindrical storage tanks, CNG trucks can travel between 150 miles and 400 miles between fueling, while LNG trucks can travel around 400 miles.[262]

The limited availability of fueling infrastructure also hampers the deployment of natural gas-powered trucks, and better infrastructure is required for greater use.[263] In May 2012, there were 1,047 fueling stations for CNG and 53 fueling stations for LNG in the United States, and 53 percent of the CNG stations and 57 percent of the LNG stations were closed to the public.[264] Also, speed of fueling can be a barrier to deployment in certain fleet types, as the more common and less expensive fueling technology requires long filling times. On-time delivery operations of trucking fleets may not be able to accommodate long filling. Slow filling is more appropriate for trucks such as waste trucks or buses that may idle for long periods overnight or between uses.[265]

Fuel pricing differentials are a clear driver for natural gas conversions in the transportation sector since fuel costs are a significant portion of the overall operating budgets for fleet owners. Medium-duty trucks use about 6,000 gallons of fuel per year, while heavy-duty trucks use about 18,000 gallons. At $3.50 per gallon of diesel fuel, annual fuel costs are $21,000 for a medium-duty truck and $63,000 for a heavy-duty truck. Natural gas fuel costs are substantially lower than diesel fuel. At a price of $2.80 per diesel gallon equivalent—a typical price for LNG or retail CNG—annual fuel costs would fall to $16,800 per medium-duty truck and $50,400 per heavy-duty truck. At a slow-fill CNG cost of $1.00 per diesel-gallon-equivalent, costs drop to less than one-third the cost of diesel, to $6,000 per medium-duty truck and $18,000 per heavy-duty truck. These fuel savings offer great incentives for fuel-switching.[266]

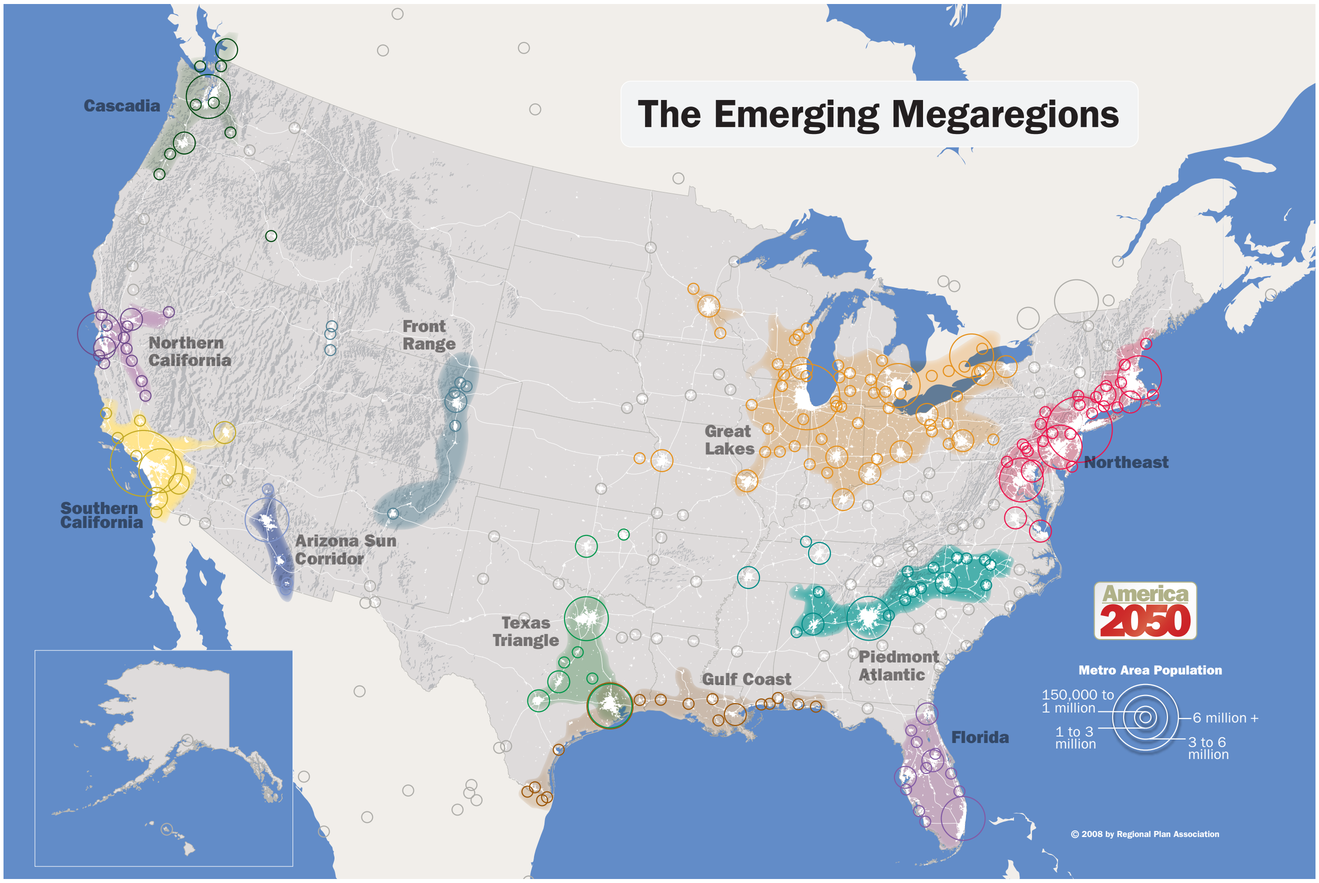
However, fleet economics are often more complex, extending beyond just fuel costs. Natural gas trucks are about $30,000 to $50,000 more expensive than their diesel counterparts, a substantial additional capital cost. Adoption of natural gas trucks also requires fleet owners to invest in additional maintenance capacity for natural gas vehicles, requiring investments in new materials and job training. Complying with standards for maintaining natural gas trucks, such as those required under Occupational Safety and Health Administration regulations for compressed gases, adds costs.[267] These costs may further rise as regulations for this nascent industry develop and change. Resale value of natural gas trucks is another important factor for some fleet owners. Trucks from some large fleets may be resold in as little as three to four years, often to smaller trucking companies that may not be able to use natural gas vehicles due to a lack of available infrastructure or a skilled workforce. As a consequence, even with the potential fuel savings, many fleet owners may have little economic incentive to switch to natural gas trucks.

Overcoming Barriers

The cost-benefit ratio of CNG vehicles for fleet owners depends on the many variables inherent in the composition and use of vehicle fleets and the costs of refueling infrastructure. For fleet owners, range requirements may not be a significant issue, since fleet vehicles travel regular and known paths. Refueling can take place at a centralized facility or along a set route.[268] The U.S. Department of Energy's National Renewable Energy Laboratory conducted research into three different types of CNG fleets that might be used by municipal governments—transit buses, school buses, and refuse trucks—and possible refueling infrastructures. This segment was targeted based on the potential for long-term cost-effectiveness, consistency of operational costs, lower greenhouse gas emissions, and other factors.[269] The research led to the creation of a model for fleet profitability that highlighted the importance of fleet size and vehicle miles driven in calculating the cost and benefits of CNG vehicles. It estimated payback periods of three to 10 years that were sensitive to the costs related to refueling stations and vehicle conversion, operations, and maintenance.

This model includes the cost of building and operating centralized fleet-specific refueling infrastructure and thus avoids the "chicken versus egg" refueling quandary that is challenging to non-municipal fleet applications, such as small private trucking operations. The lack of a public CNG refueling infrastructure hinders fleet owners' decisions to convert heavy-duty vehicles to CNG. Conversely, the low numbers of heavy-duty vehicles converted to CNG dampens private and public sector investor motivation to build CNG refueling infrastructure. Were it not for the lack of a public refueling infrastructure, the rationale for fleet owners to convert heavy-duty vehicles would be much more compelling, as their high annual miles driven provide a much quicker

FIGURE 5: Emerging Megaregions with High Tractor-Trailer Usage



Source: Regional Plan Association, "Maps," 2012. Available at: http://www.america2050.org/maps/

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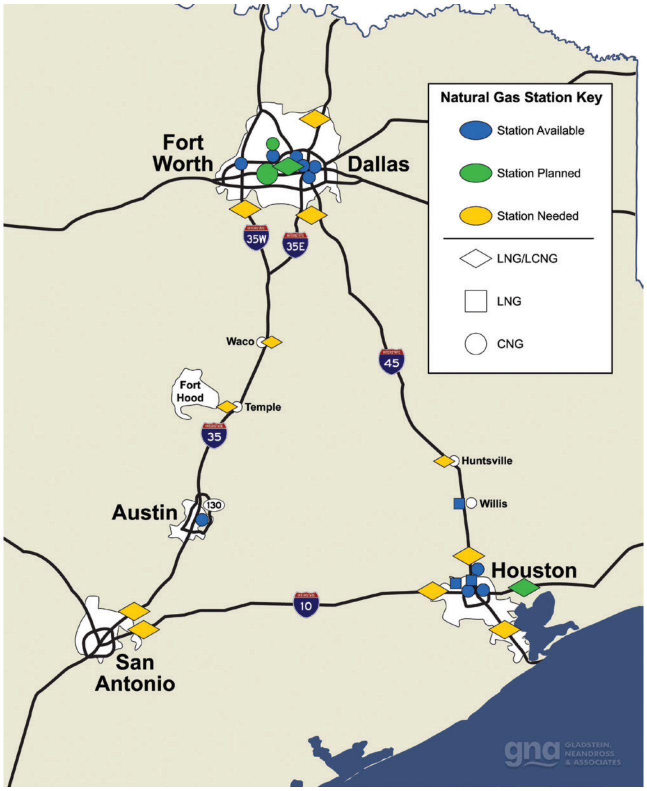
return on the upfront cost of vehicle conversion than do the annual miles driven of municipal fleet vehicles.

One approach that may help to overcome the vehicle-conversion-versus-refueling-infrastructure hurdle is to focus on one subset of the high-mileage, heavy-duty tractor-trailer industry segment, namely, intercity (as opposed to interstate) transport. In intercity regions with areas of high tractor-trailer usage, a very small number of public CNG refueling stations can serve a large number and percentage of the heavy-vehicle transportation segment. The United States has 11 "Megaregions" where tractor-trailers travel tens of thousands of miles annually but never leave the confines of a relatively small geographic area (Figure 5). Natural gas infrastructure can be built out in these Megaregions, such as through the proposed Texas Clean Transportation Triangle (Figure 6). Nearly 75 percent of the intrastate heavy and medium transport in Texas occurs within the triangle, making it an excellent candidate for CNG infrastructure.[270] Nominal public refueling infrastructure for CNG vehicles in the 11 Megaregions could also prove sufficient to service the interstate CNG tractor-trailer segment for a significant portion of the nation and create enough consumer demand to encourage the installation of refueling capability throughout the nation's network of commercial truck stops.

NATURAL GAS IN PASSENGER VEHICLES

Passenger vehicles account for nearly three-fifths of the total energy use and greenhouse gas emissions in the transportation sector. The lower price of natural gas and the energy security benefits of reducing U.S. consumption of oil have both contributed to recent interest in using natural gas in passenger vehicles.

FIGURE 6: Texas Clean Transportation Triangle



Source: Gladstein, Neandross & Associates / America's Natural Gas Alliance

Barriers to Deployment

Potential barriers to wider deployment of natural gas-powered passenger vehicles include lack of access to refueling sites and the vehicles' limited ranges.[271] Home refueling is one way to potentially increase the number of refueling sites. While there are 159,006 retail gasoline stations in the United States,[272] more than 65 million U.S. homes have natural gas service.[273] Home refueling of a CNG vehicle requires the installation of a wall-mounted electric compressor to deliver the low-pressure gas from the residential system into the high-pressure CNG vehicle tank. The compressors are small and unobtrusive, but require several hours to fill the vehicle's tank.[274] Home refueling options may, in addition to providing lower fuel prices, persuade some consumers to consider purchasing CNG passenger cars or to convert existing ones from gasoline-powered cars. Yet, home fueling infrastructure has remained expensive. Home fueling appliances, such as Phil, can cost more than $4,000,[275] not including the construction and permitting costs of extending home natural gas pipe access to the garage or carport. Other barriers to adoption exist. CNG vehicles, when compared with conventional gasoline vehicles, have a reduced range because of CNG's lower energy density (the maximum range of the Honda Civic GX NG is 248 miles),[276] higher up-front costs, and smaller trunk capacity.

Fleets including taxis, business, and government vehicles may offer the greatest potential for natural gas use in passenger vehicles. In 2012, 22 states signed a memorandum of understanding to jointly solicit automaker proposals to produce seven categories of natural gas vehicles for purchase by state, local, and municipal fleets. The intention of this joint effort is to stimulate the market for natural gas vehicles and eventually expand opportunities for market growth in the private sector for passenger natural gas vehicles, as well as to decrease the fleets' associated air pollution.[277] Combined, the barriers associated with the deployment of light-duty natural gas vehicles are noticeably larger and more costly than those associated with CNG- and LNG-powered heavy-duty vehicles.

Energy Security

Increased use of these vehicles offers significant potential benefits to U.S. energy security. Energy security is the adequacy and resiliency of the energy system as it relates to energy production, delivery, and consumption. The U.S. transportation sector relies on a global oil market that is currently dominated by an oligopoly—the Organization of the Petroleum Exporting Countries (OPEC)—as well as national oil companies. OPEC's ability to constrain supplies results in oil prices higher than a competitive market would produce. Monopoly power, combined with oil price shocks, mean that the U.S. economy loses hundreds of billions of dollars per year in productivity. Researchers at the Oak Ridge National Laboratory estimate that the combined total of these costs has surpassed $5 trillion (in 2008 dollars) since 1970.[278] Moreover, most experts believe that rising demand in emerging market economies coupled with supply-side challenges can be expected to lead to future volatility in oil prices, which would be highly damaging for U.S. consumers and businesses. Replacing oil with domestically produced natural gas would have significant benefits for U.S. energy security.

CONCLUSION

The transportation sector has long relied on petroleum fuels for the vast majority of its energy needs. While utilizing natural gas as a fuel source in this sector offers greenhouse benefits, in total these benefits are less likely than in other sectors of the economy, given the difficulty, cost and speed of converting passenger vehicles to natural gas. Moreover, in the near and medium term, fuel economy for gasoline-powered passenger vehicles is set to rise due to new Corporate Average Fuel Efficiency Standards, which could reduce the emissions advantage of natural gas vehicles. Hybrid and electric passenger vehicles are also becoming more common, and given the widespread availability of electricity compared to the availability of natural gas, they require less infrastructure investment than do natural gas vehicles. These factors indicate that, considering the need for substantial long-term reductions in greenhouse gas emissions from the transportation sector, by the time a fleet conversion to natural gas would be completed for passenger vehicles, a new conversion to an even lower-carbon fuel will be required. A passenger vehicle fleet conversion to natural gas would be short-lived and yield a low return on investment from a climate perspective.[279]

As in other sectors of the economy, fuel substitution from other fossil fuels to natural gas in some parts of the transportation sector has the potential to yield climate benefits. In addition, it would benefit U.S. national security by decreasing our reliance on a global oil market dominated by outside forces. Although the potential for natural gas use is less in the transportation sector than in others, the potential does exist, primarily for medium- and heavy-duty trucks as well as fleet vehicles and buses.

IX. INFRASTRUCTURE

By Michael Tubman, C2ES

INTRODUCTION

The United States has the world's most extensive infrastructure for transporting natural gas from production and importation sites to consumers all over the country. This transport infrastructure is made up of three main components: gathering pipelines, transmission pipelines, and distribution pipelines.[280] Though fundamentally similar in nature, each type of pipeline is designed for a specific purpose, operating pressure and condition, and length. These components are linked in networks to form the U.S. natural gas infrastructure system (Figure 1).

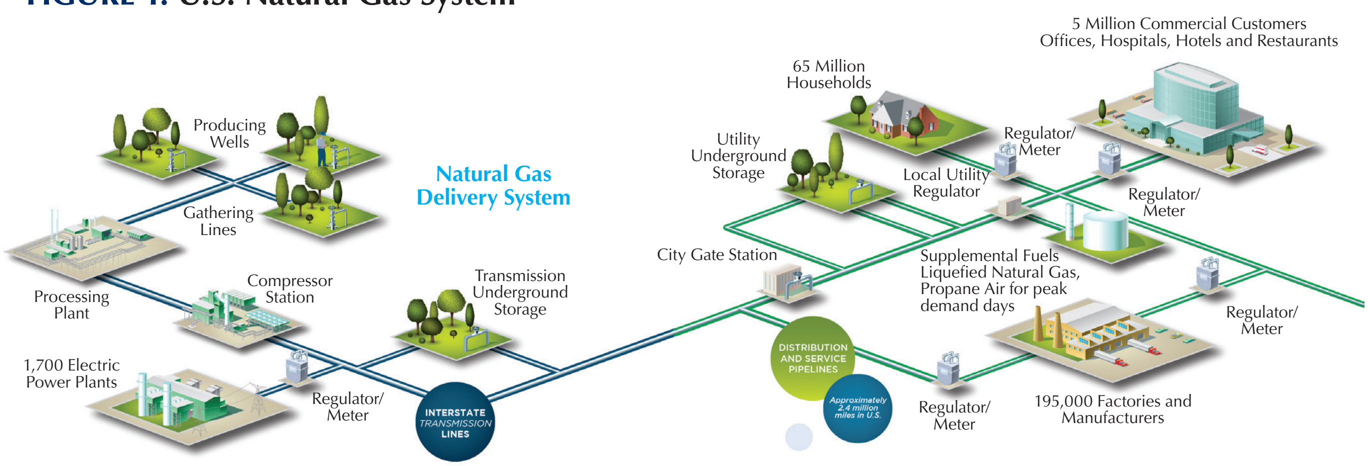
Rising demand for natural gas in the electric power, manufacturing, buildings, and transportation sectors requires significant expansion of the natural gas infrastructure system if these sectors are to reap the potential cost savings and energy security benefits. Increased use of natural gas, when substituted for other fuels, also can significantly reduce greenhouse gas emissions, as long as methane leakage emissions from natural gas systems are minimized. This chapter describes the elements of the U.S. natural gas system and how they function together. Next, it highlights the regional natural gas flows from producing basins to areas of consumption. Then, it discusses the critical issue of methane emissions. Finally, it explores the barriers to infrastructure development and outlines recent innovations in funding models.

ELEMENTS OF THE U.S. NATURAL GAS SYSTEM

Almost all natural gas consumed in the United States is produced in North America, from onshore or offshore wells or, to a much lesser extent, biogas production sites. Natural gas first enters the transport network through gathering pipelines that collect it from the point of production, most commonly the wellhead at the point of extraction, and carry it to processing facilities. Gathering pipelines are usually short and small in diameter and operate at low pressures. In 2011, there were almost 20,000 miles of gathering pipelines in the United States, originating at more than 460,000 wellheads.[281]

Once gathered from well sites, natural gas is processed to remove impurities such as sulfur and carbon dioxide

FIGURE 1: U.S. Natural Gas System



Source: American Gas Association, "About Natural Gas," 2013. Available at: http://www.aga.org/Kc/aboutnaturalgas/Pages/default.aspx

(CO_2) and is dehydrated to remove any water. It is then piped to where there is consumer demand, often hundreds of miles away, through transmission pipelines. Large-diameter (20- to 42-inch), high-pressure transmission pipelines, often called interstate pipelines or trunk lines, efficiently move the gas over vast distances. In 2011, there were 304,087 miles of transmission pipeline in the United States.[282] To ensure pressure in the pipeline and keep the natural gas flowing, compressor stations are placed every 40 to 100 miles. These stations apply pressure to the gas and often filter the gas again to maintain purity. Meters are placed along transmission pipelines to monitor the flow, and valves located at regular intervals can be used to stop flow if needed.[283]

At various points along the gathering and transmission networks, natural gas can be stored temporarily underground in depleted oil or natural gas fields, aquifers, and salt caverns. Storage is used to enhance supply reliability and serves as a physical hedge against the seasonality of natural gas demand. Traditionally, excess supplies of natural gas are stored during the summer and then withdrawn to serve heating demand during the winter or when there are unforeseen supply disruptions. However, as natural gas demand has increased for power generation, including for cooling needs in the summer months, the seasonality of natural gas demand has diminished to some extent. Natural gas can also be stored when purchased at low prices and withdrawn when prices rise, to be sold or consumed. In 2010, there were 400 storage facilities across the United States.[284]

To reach homes and businesses, natural gas leaves the transmission pipeline network and enters the "city gate station," where local distribution companies (local gas utilities) add odorant and lower the pressure before distributing it to residential and commercial customers. Local distribution companies move the gas through a series of larger distribution pipelines, called mains, throughout their service territory, and individual service lines branch off of the mains to reach each consumer. Natural gas regulators, devices in homes and commercial buildings, accept the incoming gas from the highly pressured pipelines and employ a series of valves to lower the pressure of the gas to meet appliance specifications. Distribution pipelines are much smaller pipelines, often only 0.5 to 2 inches in diameter, with pressures at a small fraction of those of the larger transmission pipelines. They may be made of plastic, which is less likely to leak than metal. Distribution networks used by local distribution companies are extensive, having more than 2 million miles of main and individual service pipelines as of 2011.[285]

Together, these components of natural gas infrastructure comprise an important asset that provides access to energy for all sectors of the economy. However, it is a large, dispersed asset that is mostly out of sight. Gathering and transmission pipelines are often in remote locations, while distribution pipelines, though located near the customers they serve, are buried underground. Some pipelines exist within rights-of-way occupied by other users, such as roads or private property, and pipelines often cross local, state, and even national boundaries. These factors make monitoring and regulating pipelines the responsibility of multiple jurisdictions and many levels of government.

Pipelines are regulated by both the federal and state governments. In 2007, 81 percent of natural gas in the United States flowed through transmission pipelines that cross state boundaries. The Federal Energy Regulatory Commission regulates the rates and services of these interstate pipelines as well as the construction of new interstate pipelines. Other pipelines located within states (intrastate pipelines) are regulated by state regulatory commissions. State regulatory commissions regulate both transmission lines and local distribution companies for pipeline siting, construction, operation, and expansion, as well as consumer rate structure.[286]

The federal government also regulates and enforces pipeline safety through the Department of Transportation, which works closely with state governments on pipeline inspection and safety protocols. Corrosion and defects can lead to leaks that have serious safety and environmental implications. Visual inspection of natural gas infrastructure is difficult, and complete replacements are nearly impossible given the vast extent of the network and its location underground. Instead, robotic inspection tools, often called "pigs," can be sent through pipelines to detect leaks, check pipeline conditions, and monitor for weaknesses.[287]

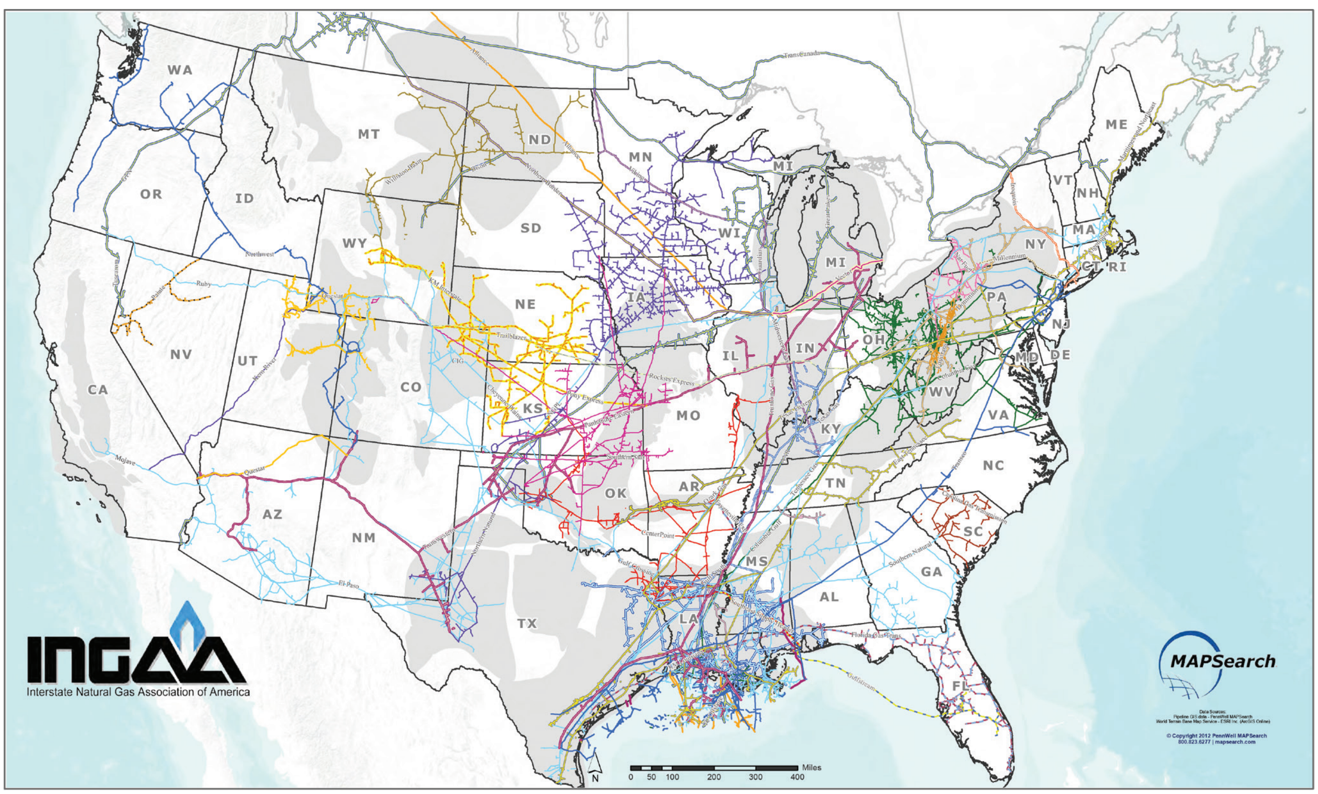
REGIONAL DIFFERENCES IN INFRASTRUCTURE AND EXPANSION

The capacity, extensiveness, and flow direction of existing natural gas infrastructure varies across the country, reflecting historical supply and demand for the fuel as well as disparate state and local policies that enabled infrastructure expansion. Gathering line networks are most extensive from wellheads in traditional gas-producing states such as Texas, Oklahoma, and Louisiana, and most existing intrastate transmission lines take the fuel from those states to manufacturers and consumers in the Midwest and Northeast (Figure 2).

Recent supply increases, lower prices, and increased demand have all led to a need for expanded infrastructure, including gathering, transmission, and distribution pipelines that can bring natural gas to users and may allow natural gas to replace higher-carbon fuel sources and achieve climate benefits. Changes in supply and demand will require that 28,000 to 61,900 miles of new pipelines be constructed in North America by 2030, and \$108 to \$163 billion worth of investment will be needed. Additional storage capacity of 371 to 598 billion cubic feet (Bcf) will also be needed over the same time period, at a cost of \$2 to \$5 billion.[288] Current trends in natural gas supply and demand indicate that expansion is likely to fall on the higher ends of these estimates.

Infrastructure needs related specifically to shale gas are growing across the country, reflecting the location of the shale gas resources. Significant investments related to shale gas have been made in states such as Texas and Louisiana that have historically been supply states for conventional gas deposits. Significant additional infrastructure expansion is also needed in parts of the country that have not historically produced natural gas but have been traditional destinations, such as Ohio, Pennsylvania, North Dakota, and West Virginia. Furthermore, new sources of biogas need infrastructure to collect, process, and either transport the gas to existing transmission infrastructure or use it on site. Although the potential of renewable biogas to reduce greenhouse gas emissions is large, further research is needed to ensure that it can be processed properly and safely added to the existing system, which was built specifically to withstand the constituents of geologically formed natural gas.[289] In sum, several of the new supply sources require new infrastructure, and in other cases, existing infrastructure may be repurposed and deployed to bring new sources to market. As more new sources are

FIGURE 2: Interstate Pipelines, 2013



Source: Interstate Natural Gas Association of America and PennWell tapped, the existing transmission pipeline infrastructure must continue to be creatively deployed and expanded to serve regional market needs.

Similarly, local distribution networks will need to be expanded, with new demand for natural gas appliances, industrial uses, distributed generation, and vehicle fueling in homes and businesses. Investments are necessary in new mains, service lines, meters, and regulators that can service new customers. Indirect investments will also be required to enhance the capacity of the overall system, including for control rooms, main reinforcements, and improved flow design.[290]

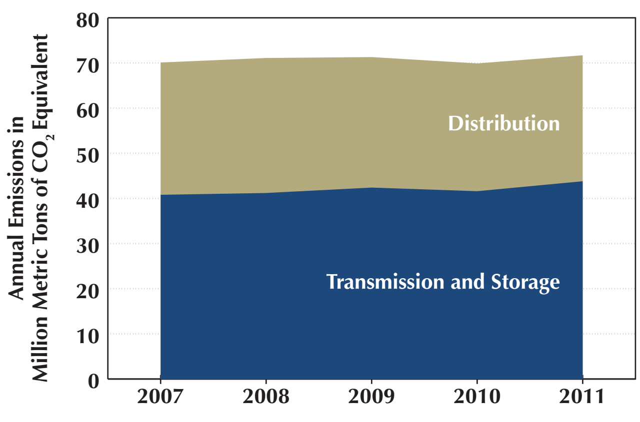
DIRECT EMISSIONS FROM NATURAL GAS INFRASTRUCTURE

In 2011, methane emissions from transmission pipelines and storage totaled 44 million metric tons of CO_2 equivalent (CO_2e), while emissions from distribution networks totaled 27 million metric tons CO_2e.[291] These figures have been fairly consistent over time as network expansion has been offset by better system management (including leak detection), more energy-efficient technology, and the replacement of equipment with new materials that are less subject to leakage, including replacing cast iron and steel pipe with plastics.[292, 293] While methane emissions from natural gas infrastructure are a very small portion of the nation's total greenhouse gas emissions (Figure 3 and Figure 4), methane is a potent greenhouse gas, as described in chapter 3. Given methane's potency, it is critical to reduce leakage to ensure that its climate benefits are maximized when compared with other fossil fuels that it may replace.[294]

Leaked Methane

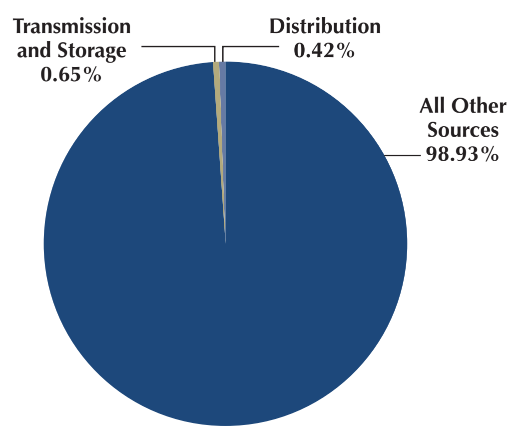
Throughout the transportation of the fuel from gathering at the well to distribution to end-use consumers, there is potential for methane to leak into the atmosphere. Potential leakage points include production wells, valves, compressor stations, faulty seals, pressure regulators, and even broken pipes. Because methane leakage and accumulation can be an important safety issue, natural gas operators have robust safety programs in compliance with federal and state pipeline safety requirements to detect and repair leaks that pose safety risks. Methane emissions that do not pose safety concerns nevertheless can have significant implications for the climate and for the relative benefits of substituting natural gas for other fuel sources. At natural gas storage facilities, methane emissions may leak from compressors and dehydrators. At the local distribution level, methane emission leakage can occur at city gate station valves, seals, and pressure regulators, or from the joints of cast iron or unprotected steel pipe.[295] The majority of all greenhouse gas emissions from natural gas infrastructure are due to leaked emissions.[296]

FIGURE 3: Historical Emissions from Transmission, Storage and Distribution, 2007 to 2011



Source: Environmental Protection Agency, "U.S. Greenhouse Gas Inventory Report," 2013. Available at: http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2011-Chapter-3-Energy.pdf

FIGURE 4: Emissions from Natural Gas Infrastructure as a Percentage of Total U.S. Greenhouse Gas Emissions, 2011



Source: Environmental Protection Agency, "U.S. Greenhouse Gas Inventory Report," 2013. Available at: http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2011-Chapter-3-Energy.pdf

Venting and Flaring

In addition to leaked emissions, methane can be intentionally released or vented as part of the production process at the wellhead or to reduce pipeline pressure. For safety and environmental reasons, however, intentionally-released methane is often burned off in a process called flaring. Flaring combusts the methane on site, forming CO_2, a less potent, though very significant, greenhouse gas.[297] (The climate implications of CO_2 and methane are compared in chapter 3.) Flaring of methane most often occurs when natural gas is found as a byproduct or co-product of other fossil fuel production and insufficient gathering pipeline infrastructure or market incentives exist to take the natural gas to market. In 2012 in Texas, where gathering pipeline networks are well developed, less than 1 percent of the natural gas produced was flared.[298] In North Dakota, where oil production from the Bakken Shale formation is a much newer phenomenon, almost 32 percent of the associated natural gas is flared, primarily because of a lack of gathering infrastructure.[299] With relatively low natural gas prices, there is less economic incentive for companies to build gathering infrastructure and monetize the resource.

In August 2012, a new federal requirement to minimize venting and flaring was established as part of the Environmental Protection Agency's New Source Performance Standards for oil and gas wells. The new regulations require that all new natural gas wells flare rather than vent, and as of 2015 use "green completion" technology that will allow excess natural gas from the well completion process to be taken to market. Many natural gas producers already use such technology.300 However, for the "green completion" rule to apply to the gathering of natural gas from the Bakken Shale or other primarily oil production sites, it would have to be expanded from its present form (see the discussion of "green completion" rules in chapter 3).

Reducing Emissions from Infrastructure

Many technologies and process improvements can reduce methane emissions from natural gas infrastructure. The federal Natural Gas STAR program, for example, has worked with industry to identify technical and engineering solutions to vented, leaked, and combustion-related emissions, including zero-bleed pneumatic controllers, improved valves, corrosion-resistant coatings, and dry-seal compressors, as well as improved leak detection and repair strategies. The solutions identified by this voluntary program often have payback periods of less than three years, depending on the price of natural gas. Participants in Natural Gas STAR reported that methane emissions from infrastructure were reduced by 15.9 Bcf in 2010, and overall, a total of 276.5 Bcf of greenhouse gases have been avoided since the program began in 1993.[301] Local distribution companies have reduced emissions from their low-pressure networks by continuing to replace cast iron and steel pipes with inexpensive and durable plastic pipes; however, this plastic is not strong enough to be used in high-pressure transmission lines.[302]

BARRIERS TO INFRASTRUCTURE DEVELOPMENT

As other chapters in this report explain, natural gas may be used to reduce greenhouse gas emissions in multiple sectors of the economy, including electric power, manufacturing, buildings, and transportation. While new pipelines are being built every day, there is a dramatic need for new pipeline investment to move new sources of natural gas supply to new regions and new users. Distribution pipeline networks, in particular, are challenged by financial and other barriers to expansion and improvement.

Funding Distribution Pipeline Expansion

For local distribution networks, the cost of expansion varies considerably depending on whether the network is being expanded to new or existing communities, the density of the neighborhood, and the terrain. For new distribution pipelines in urban areas, challenges include costly repairs of overlaying roads and landscaping, negotiations with entities holding surface and other subsurface rights-of-way, and public inconveniences. Accordingly, new urban pipelines can cost five times as much as rural ones.[303] Costs can be lowered when buildings are designed and constructed to be ready for natural gas access; retrofitting existing buildings with internal piping and hook-ups to natural gas supplies is more expensive.

Funding local distribution networks can be challenging and is typically dealt with through a formal regulatory proceeding called a rate case where public utility commissions determine allowable utility rates based on factors including utility operation costs, depreciation, investment, and consumer needs. Traditionally, expansion costs are considered during the rate case proceedings, but costs can only be recovered after investments are made. This time lag discourages or prevents utilities from investing in infrastructure. State-level regulatory innovations have provided some policy options to overcome these investment challenges. Some states, such as Nevada, allow the use of a deferred accounting mechanism so that costs can be better aligned temporally with ratemaking cases before state regulatory commissions. Seven southern states, including Texas, have decoupled gas consumption and cost recovery to create what is known as a "rate stabilization method." This method allows rates to adjust annually for infrastructure replacement and construction rather than simply the amount of natural gas throughput.[304]

Funding models that can foster greater access to natural gas are being explored throughout the country. For example, in North Carolina, rules established by the public utilities commission allow for dedicated funds for new distribution pipelines. A local distribution company may petition the public utilities commission to establish a Natural Gas Expansion Fund to help pay for the otherwise economically infeasible expansion of distribution pipelines. Additional money may be added to the Natural Gas Expansion Fund, including refunds from natural gas suppliers to the local distribution company, expansion surcharges, and other resources, and then, with approval by the public utilities commission, the company may pay for the specified distribution pipeline construction projects.[305] In 2011, the Vermont Public Service Board approved a plan by Vermont Gas Systems to use $17.6 million previously planned for ratepayer refunds to instead support expansion of its distribution network over four years, although these funds will cover only part of the needed finance.[306] This plan transferred some of the costs of expansion onto existing customers and offered the reduction of statewide greenhouse gas emissions as one rationale.[307] A 2012 law passed by the Maine Legislature authorizes the Finance Authority of Maine to issue up to $275 million in loans and $55 million in bonds for natural gas distribution system expansions. The funds will be available only if the applicant contributes at least 25 percent of the expected cost of the project.[308] Municipal utilities can also offer innovative solutions. For example, the municipal natural gas utility in Sunrise, Florida, will install main and service lines to neighborhoods at no cost as long as 25 percent of residents commit to installing a natural gas space or water heater, range, or clothes dryer within six months. Natural gas piping within the homes must be paid for by residents.[309]

Funding Upgrades and Replacements

Other innovative policy mechanisms are being developed to pay to upgrade and replace existing pipelines. Some states, such as Colorado, authorize tracker mechanisms allowing rates to change in response to the utility's operating costs and conditions outside of a complex rate case proceeding, specifically in response to federal and state safety requirements. A similar process outside the rate case in states such as Kentucky permits temporary surcharges for partial program cost recovery. The Georgia Public Services Commission has permitted Atlanta Gas Light Company to institute a surcharge on customer bills throughout its service territory to help fund pipeline replacement, improvement, and pressure increases through the Georgia Strategic Infrastructure Development and Enhancement (STRIDE) Program. The Georgia Public Services Commission reviews the surcharge and related plans every three years, thereby eliminating the need for rate cases and associated regulatory lag. Also, from 2009 to 2012, a pilot program called the Customer Growth Program was paid for through the STRIDE surcharge. It helped fund new pipeline construction and extensions, including strategic development corridors to regions far removed from existing Atlanta Gas Light Company infrastructure. It also helped overcome the barrier of high upfront costs for new natural gas pipelines.[310] However, the STRIDE program has not been renewed. The Atlanta Gas Light Company Universal Service Fund can also be used to pay for distribution pipeline expansion, and its monies may contribute up to 5 percent of Atlanta Gas Light Company's capital budget during a fiscal year.

Other Challenges

Beyond questions of funding, pipelines are affected by a number of project-specific requirements and regulations at the federal, state, and local levels. These requirements pertain to route selection, siting, and project approval by regulatory agencies that may all be affected by environmental, safety, community, operation, construction timing, and cost concerns. The size of the challenge for any individual project will vary significantly depending on the pipeline and the jurisdictions it crosses.[311] For natural gas to realize its climate benefits, infrastructure projects must meet these requirements, allowing the system to expand for greater low-emission use across the economy.

CONCLUSION

Natural gas is transported from areas of production to final consumers through networks of gathering pipelines, transmission pipelines, and distribution pipelines. These extensive networks are necessary to provide opportunities for low-emission end uses of natural gas. Given the recent surge in natural gas supply, the new source regions, and new uses, infrastructure must rapidly adapt. Gathering pipelines must be brought to more points of production, including areas where associated gas can be captured for use. Transmission pipelines must be expanded to ensure adequate supply can reach new regions of the country. Distribution pipeline networks must be built out to serve more manufacturing facilities, homes, and businesses. Increased policy support and innovative funding, particularly for distribution pipelines, are needed to support the rapid deployment of this infrastructure.

X. CONCLUSIONS AND RECOMMENDATIONS

Natural gas plays a role in all sectors of the U.S. economy, constituting 27 percent of total U.S. energy use in 2012. Its prominence is expected to grow as the supply boom unleashed by new drilling technologies continues in coming decades. Expectations of sustained abundance and correspondingly low and relatively stable natural gas prices are sparking widespread interest in additional ways that this domestic energy resource can replace oil and coal as the major fuel undergirding a growing economy. Indeed, natural gas is projected to displace petroleum as the dominant fuel used in the United States within a few decades.

In these early days of this energy transition, it is imperative to set a course for using this increasingly abundant domestic resource in ways that help meet, rather than aggravate, the challenge of climate change. This report examines ways that natural gas can be leveraged to reduce greenhouse gas emissions across a growing economy and reaches three crosscutting conclusions.

First, substitution of natural gas for other fossil fuels can contribute to U.S. efforts to reduce greenhouse gas emissions in the near to mid-term, even as the economy grows. At the beginning of 2013, energy sector emissions are at the lowest levels since 1994, in part because of the substitution of natural gas for coal in the power sector. Substitution of natural gas for coal, petroleum, and grid-supplied electricity is underway in other parts of the economy and will bring similar benefits to the climate and air quality. In the buildings sector, for example, a large reduction in emissions is possible through greater direct use of natural gas in an array of more efficient appliances and expanded use of CHP. The manufacturing sector also has a significant opportunity to reduce emissions even as it expands. Manufacturers can increase their consumption of natural gas as feedstock and an energy source, while reducing the emissions intensity of production. Finally, in the transportation sector, natural gas fuel substitution can reduce greenhouse gas emissions when used in fleets and heavy-duty vehicles.

Second, in the long term, the United States cannot achieve the reduction in greenhouse gas emissions necessary to address the serious challenge of climate change by relying on fuel substitution to natural gas alone. Low-carbon investment must be dramatically expanded. Zero-emission sources of energy such as wind, nuclear, and solar are critical, as are the use of carbon capture and storage technologies at fossil fuel plants and continued improvements in energy efficiency. Given that many renewable energy sources are intermittent, natural gas can serve as a complementary and reliable backup. In addition, because fossil fuels will likely be part of the energy fuel mix for the foreseeable future, carbon capture and storage will need to be deployed. Without a price on carbon emissions, alternative policy support will be needed to ensure optimal investment in zero-carbon energy sources and technologies.

Third, direct releases of methane into the atmosphere must be minimized. The primary component of natural gas is methane, which is a very potent greenhouse gas. Total methane emissions from natural gas systems in the United States have improved during the last two decades, declining 13 percent from 1990 to 2011. Nevertheless, given its impact on the climate, especially in the short term, it is important to better understand and more accurately measure the greenhouse gas emissions from natural gas production and use in order to achieve emissions reductions along the entire natural gas value chain.

The basis for these cross-cutting conclusions is a detailed examination of the current and potential role of natural gas in major sectors of the economy. Sector-specific conclusions and recommendations include:

Expanded use of natural gas has improved fuel diversity in the power sector. From 2003 to 2012, the share of primary energy consumption from coal for electricity generation dropped from 53 percent to 37 percent, while the share fulfilled by natural gas grew from 14 percent to 29 percent. Accordingly, the fuel mix in electricity generation has become more diverse in recent years. However, concern exists that some regions may become too dependent upon natural gas in the long term, especially as market pressures affect nuclear and renewable energy generation. Too much reliance on any one fuel can expose utilities, ratepayers, and the economy to the risks associated with commodity price volatility. Furthermore, natural gas-fired generation should not displace investment in zero-carbon generation, carbon capture and storage, and energy efficiency measures. If this occurs, the United States will not be able to meet its long-term goals for reducing greenhouse gas emissions.

Natural gas can be complementary with renewable energy. Instead of being thought of as competitors, natural gas and renewable energy sources such as wind and solar can be complementary components of the power sector. Natural gas plants have the ability to quickly scale up or down their electricity production and so can act as an effective hedge against the intermittency of renewables. The fixed fuel price (at zero) of renewables can likewise act as a hedge against potential natural gas price volatility. Low natural gas prices can also help facilitate an increase in renewable energy in some regions. In order for this mutually beneficial relationship to flourish, carefully designed policy that allows the addition of both sources to the grid in a complementary fashion must come into play and be encouraged by public utility commissions. Natural gas plants expansion should be leveraged to enable the expansion of renewable generation.

Natural gas can increase the overall efficiency of buildings through use of equipment with higher full-fuel-cycle efficiency. Thermal applications of natural gas in buildings have a lower greenhouse gas emission footprint compared with other fossil energy sources. Natural gas for thermal applications is more efficient than grid-delivered electricity, yielding less energy losses along the supply chain and therefore fewer greenhouse gas emissions. Information and incentives should be modified to inform consumers of the environmental benefits of natural gas use and to encourage its increased use when it has the potential to reduce greenhouse gas emissions—particularly its direct use in buildings and manufacturing settings. At present, labeling, building codes, and economic incentives are not aligned to maximize the use of natural gas in low-emitting ways.

Aligning incentives is particularly important in the building sector, as consumers and developers seeking to minimize up-front cost often do not realize that operating costs and environmental costs may be much higher for electric appliances. In addition, although current energy efficiency programs aim to reduce greenhouse gas emissions from appliances and buildings in two important ways—by setting standards and efficiency labeling programs—these standards are based solely on site efficiency, which is reflected in the energy and cost savings identified on efficiency labels. But efficiency labels based only on site efficiency do little to educate consumers about the total energy needed to power appliances and the greenhouse gases associated with that energy and, as such, often steer consumers toward electric appliances even if a natural gas appliance may be more efficient overall and produce fewer greenhouse gas emissions. It is important, therefore, that the source-to-site efficiency of an appliance also be taken into consideration, and in regions with fossil fuel-dominated grid electricity, natural gas appliances should be encouraged.

The efficient use of natural gas in the manufacturing sector needs to be encouraged. Replacing old coal-fired boilers with more efficient natural gas boilers can yield significant emissions benefits. CHP systems should also be deployed to make use of waste heat and avoid transmission losses. The incentives for CHP are often not properly aligned. Specifically, while CHP has significant environmental benefits, it can significantly decrease the demand for grid-supplied electricity, which can impact the rate base remaining on the grid. Policies are needed to overcome this and other barriers to expanded CHP deployment. States are in an excellent position to take an active role in promoting CHP during required industrial boiler upgrades and new standards for cleaner electricity generation in coming years.

Distributed generation technologies can offer options for using natural gas and reducing emissions. Distributed generation technologies, such as microgrids, microturbines, and fuel cells, can be used in configurations that reduce greenhouse gas emissions when compared with the centralized power system because they can reduce transmission losses and use waste heat onsite. Distributed generation has many other advantages over centralized electricity generation, including end-users' access to waste heat, easier integration of renewable energy, heightened reliability of the electricity system, reduced peaking power requirements, and less vulnerability to terrorism due to more geographically dispersed, smaller power plants. To realize the potential of these technologies and overcome high upfront equipment and installation costs, policies like financial incentives and tax credits need to be more widespread, along with consumer education about their availability.

Fuel substitution in fleets and heavy-duty vehicles offers the greatest opportunity to reduce greenhouse gas emissions in the transportation sector. Passenger vehicles, in contrast, likely represent a much smaller emission reduction opportunity even though natural gas emits fewer greenhouse gases than gasoline or diesel when combusted. The reasons for this include the smaller emission reduction benefit (compared to coal conversions), and the time it will take for a public infrastructure transition. By the time a passenger fleet conversion to natural gas could be completed, a new conversion to an even lower-carbon system, like fuel cells or electric vehicles, will be required to ensure significant emissions reductions throughout the economy.

Natural gas infrastructure expansion is needed to ensure access for low-emitting uses. New domestic supplies of natural gas require significant investment in infrastructure. Additional gathering and transmission pipeline capacity is needed in parts of the country that have not historically produced natural gas but have been traditional destinations, such as Ohio, Pennsylvania, North Dakota, and West Virginia. Expanded distribution pipeline networks are needed to serve greater numbers of commercial, industrial, and residential natural gas customers throughout the U.S. Moreover, expanding natural gas delivery systems within homes and businesses that have existing access will be necessary to support a greater number of end-use applications, such as natural gas-fueled space and water heating. Innovative funding models and support are needed to make the expansion and upgrading of natural gas infrastructure economically feasible for customers and utilities.

In the coming years, abundant natural gas will play an increasingly prominent role across all sectors of the U.S. economy. Increased availability of natural gas can yield economic opportunities and lower greenhouse gas emissions. Yet, natural gas is not carbon-free. A future with expanded natural gas use will require diligence to ensure that potential benefits to the climate are achieved.

ENDNOTES

1 Primary energy sources include petroleum, natural gas, coal, renewable energy, and nuclear power.

2 Massachusetts Institute of Technology Energy Initiative, *The Future of Natural Gas: An Interdisciplinary MIT Study*, June 2011, page 17. Available at http://web.mit.edu/mitei/research/studies/natural-gas-2011.shtml.

3 Unconventional resource accumulations tend to be distributed over a larger area than conventional resources, require greater pressure for extraction (have "low permeability"), and they usually require advanced technologies and techniques such as horizontal wells or artificial stimulation in order to be economically productive.

4 Energy Information Administration, "Annual Energy Outlook 2013 Early Release," December 2012. Available at http://www.eia.gov/forecasts/aeo/er/index.cfm.

5 In economic terms, the supply of natural gas is often referred to as reserves and is classified with two primary categories, proven and unproven. Proven reserves are those that are economically recoverable from known resources using currently available technology. Unproven reserves are those considered not economically or technically recoverable or somehow not producible for regulatory reasons.

6 National Petroleum Council, "Balancing Natural Gas Policy–Fueling the Demands of a Growing Economy," National Petroleum Council, September, 2003. Available at Balancing Natural Gas Policy–Fueling the Demands of a Growing Economy.

7 Energy Information Administration, "Annual Energy Outlook 2012: Early Release Overview," Report Number DOE/EIA-0383ER(2012), January 23, 2012, page 9. Available at http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2013).pdf.

Note: EIA's estimated technically recoverable resource of U.S. shale gas was reduced from 827 Tcf in 2010 to 482 Tcf in 2011. The decline mostly reflects changes in the assessment for the Marcellus shale, from 410 Tcf to 141 Tcf, based on better data provided from the rapid growth in drilling in the Marcellus over the past two years.

8 Massachusetts Institute of Technology Energy Initiative, *The Future of Natural Gas: An Interdisciplinary MIT Study*, June 2011. Available at http://web.mit.edu/mitei/research/studies/natural-gas-2011.shtml.

9 Energy Information Administration, "AEO2013 Early Release," December 2012. Available at http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2013).pdf.

10 Energy Information Administration, "Total Energy: Natural Gas Consumption by Sector, 1949–2011," September 2012. Available at http://www.eia.gov/totalenergy/data/annual/showtext.cfm?t=ptb0605.

11 Massachusetts Institute of Technology Energy Initiative, *The Future of Natural Gas: An Interdisciplinary MIT Study*, June 2011, page 7. Available at http://web.mit.edu/mitei/research/studies/natural-gas-2011.shtml.

12 ICF International for the Ontario Energy Board, "2010 Natural Gas Market Review," August 2010, page 50. Available at http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0199/ICF_Market_Report_20100820.pdf.

13 The White House, "The Blueprint for a Secure Energy Future: Progress Report," March 2012, page 2. Available at http://www.whitehouse.gov/sites/default/files/email-files/the_blueprint_for_a_secure_energy_future_oneyear_progress_report.pdf.

14 Energy Information Administration, "Annual Energy Outlook 2011: Reference Case," December 2012. Available at http://www.eia.gov/forecasts/aeo/er/executive_summary.cfm.

15 C2ES, "Fact Sheet: Natural Gas," accessed April 2013. Available at http://www.c2es.org/technology/factsheet/natural-gas#7.

16 Energy Information Administration, "Annual Energy Outlook 2011," April 26, 2011, Report Number DOE/EIA-0383(2011), page 2. Available at http://www.eia.gov/forecasts/aeo/pdf/0383%282011%29.pdf.

17 Massachusetts Institute of Technology Energy Initiative, *The Future of Natural Gas: An Interdisciplinary MIT Study*, June 2011. Available at http://web.mit.edu/mitei/research/studies/natural-gas-2011.shtml.

Note: In addition to the Barnett, since 2005 producers have begun intensively developing plays in the Woodford, north of the Barnett in Texas and Oklahoma; the Fayetteville in Arkansas; and the Haynesville in Louisiana/East Texas. During this time, development also began in the Marcellus Shale of the eastern United States.

18 Massachusetts Institute of Technology Energy Initiative, *The Future of Natural Gas: An Interdisciplinary MIT Study*, June 2011, page 33. Available at http://web.mit.edu/mitei/research/studies/natural-gas-2011.shtml.

Note: Natural gas and natural gas liquids are a principal feedstock in the chemicals industry and a growing source of hydrogen production for petroleum refining. Natural gas liquids products can add value for gas producers, especially important in a low-price environment. The liquid content of a gas—the "condensate ratio"—is expressed as barrels of liquid per million cubic feet of gas (bbls/MMcf). In a typical Marcellus well, assuming a liquids price of $80/bbl for a condensate ratio in excess of approximately 50 bbls/MMcf, the liquid production alone can provide an adequate return on the investment, even if the gas were to realize no market value.

19 Naturalgas.org, "Uses in Industry," 2004. Available at http://www.naturalgas.org/overview/uses_industry.asp.

20 Energy Information Administration, "Natural Gas Consumption by End Use," 2013. Available at http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm.

21 A set of global supply curves describing the gas resources that can be developed economically at given prices is provided in MIT Energy Initiative, *The Future of Natural Gas: An Interdisciplinary MIT Study*, June 2011, page 25. Available at http://web.mit.edu/mitei/research/studies/natural-gas-2011.shtml.

22 Energy Information Administration, "Natural Gas Year-in-Review: Imports and Exports," December 9, 2011. Available at http://www.eia.gov/naturalgas/review/imports_exports.cfm

23 Energy Information Administration, "U.S. Natural Gas Imports by Country," accessed March 2013. Available at http://www.eia.gov/dnav/ng/ng_move_impc_s1_a.htm.

24 Energy Information Administration, "Annual Energy Review 2010," Report Number: DOE/EIA-0384(2010), October 2011, pages 7, 134 and 193. Available at http://www.eia.gov/totalenergy/data/annual/pdf/aer.pdf.

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This report provides an overview of natural gas production, the climate implications of expanded natural gas use, potential uses and benefits in key sectors, and related infrastructure issues.

The Center for Climate and Energy Solutions (C2ES) is an independent non-profit, non-partisan organization promoting strong policy and action to address the twin challenges of energy and climate change. Launched in 2011, C2ES is the successor to the Pew Center on Global Climate Change.

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POLICY REPORT
DEVELOPMENT AND BUILDING

Report Date:	July 5, 2016
Contact:	Sean Pander
Contact No.:	604.871.6542
RTS No.:	11195
VanRIMS No.:	08-2000-20
Meeting Date:	July 12, 2016

TO: Vancouver City Council

FROM: Green Building Manager, Sustainability Group

SUBJECT: Zero Emissions Building Plan

RECOMMENDATION

A. THAT Council approve the Zero Emissions Building Plan (attached as Appendix A) and adopt a target to reduce emissions from new buildings by 90% as compared to 2007 by 2025 and to achieve zero emissions for all new buildings by 2030 including intermediary time-stepped GHG emission and thermal energy demand targets as described in the Plan.

B. THAT Council direct staff to report back with specific recommendations to reflect the first step of these limits in the Rezoning Policy for Green Buildings and Vancouver's Building Bylaw along with any synergistic updates to Neighbourhood Energy connection requirements by Q1 2017.

C. THAT Council direct staff to build all new City-owned and Vancouver Affordable Housing Agency (VAHA) projects to be Certified to the Passive House standard or alternate zero emission building standard, and use only low carbon fuel sources, in lieu of certifying to LEED Gold unless it is deemed unviable by Real Estate and Facilities Management, or VAHA respectively, in collaboration with Sustainability and report back with recommendations for a Zero Emissions Policy for New Buildings for all City-owned and VAHA building projects by 2018.

D. THAT Council direct staff, in consultation with industry, to develop a three year, $1.625 million Zero Emissions Home Program for detached and row houses ($325K in 2017 from the Climate Action Rebate Incentive Program Reserve, $650K in 2018 and $650K in 2019 from a funding source to be determined and reported back to Council), and report back to Council with specific recommendations for tools to catalyze leading builders to demonstrate cost effective approaches to building zero emissions homes by 2017.

E. THAT Council direct staff to engage partners, consult with stakeholders, and report back with recommendations in 2017 on the resources and tools required to catalyze leading developers to demonstrate cost effective approaches to building zero emissions multi-unit residential and commercial buildings.

F. THAT Council approves in principle $700,000 over three years ($300K in 2017, $200K in 2018, and $200K in 2019 from the City's 2017 Innovation Fund, subject to Council approval of the 2017 Innovation Fund budget) towards establishing a non-governmental Zero Emissions Building Centre of Excellence with the mission to facilitate the compilation and dissemination of the knowledge and skills required to design, permit, build and operate zero emission buildings in BC, and direct staff to engage partners, secure matching funding, consult with stakeholders and report back with recommendations for implementation in 2017.

G. THAT Council direct staff to review and recommend amendments to the City's bylaws, policies, and guidelines to incorporate "zero emission building related rules" including but not limited to Official Development Plans, the Zoning and Development By-law, Vancouver's Building Bylaw, the Subdivision by-law and all other applicable bylaws, policies and guidelines to remove barriers and facilitate the development of zero emission buildings and provide them with equal weight as other public policy objectives wherever such "zero emission building related rules" confer discretion to a City official or board, and report back with initial recommendations in 2017.

REPORT SUMMARY

This Plan lays out four action strategies to require the majority of new buildings in Vancouver use 100% renewable energy and have no operational greenhouse gas emissions by 2025 and that all new buildings achieve these outcomes by 2030.

These four strategies include:

1. Limits: establish GHG and thermal energy limits by building type and step these down over time to zero
2. Leadership: require City- owned and City managed building projects to demonstrate zero emission building approaches where viable
3. Catalyse: develop tools to catalyse leading private builders and developers to demonstrate effective approaches to zero emission new buildings; and
4. Capacity Building: establish a Centre of Zero Emission Building Excellence to facilitate the removal of barriers, the sharing of knowledge, and the development of the skills required to successfully achieve this goal

These strategies for achieving zero emissions new buildings were developed specifically to ensure comfortable and healthy indoor environments, maximize local economic development, ensure long-term building resilience, protect housing affordability and to facilitate achieving the City's Renewable City Strategy target to have all buildings in Vancouver (including those already built) use only renewable energy by the year 2050.

COUNCIL AUTHORITY/PREVIOUS DECISIONS

In July 2004, Council adopted the *Green Building Strategy*, demonstrating early leadership by setting high environmental standards for the construction of new civic buildings and special development projects such as Southeast False Creek (SEFC). The strategy mandated the use of the LEED Gold Green Building Rating System, and 30% lower energy consumption than current VBBL, with higher targets set for the Olympic Athlete's Village in SEFC. This neighbourhood and development were planned to be a model sustainable community, and by demonstration, contribute to a paradigm shift toward green buildings in private-sector developments across the city.

In June 2008, Council adopted a set of Building By-law amendments directed at reducing the environmental impacts of new one- and two-family dwellings. The amendments made Vancouver's Building By-law the greenest building code for one- and two-family dwellings in North America at the time.

In June 2008, Council also adopted a Building By-Law amendment to require the use of ASHRAE 90.1 2007, to improve the energy efficiency performance of all new Part 3 (large residential, commercial, industrial) buildings.

In July 2010, Council approved the *Green Buildings Policy for Rezonings*, which required all applicable developments applying for rezoning to achieve the LEED standard. In its current revised form, the policy requires meeting LEED Gold with additional energy reductions. This policy was developed to use a well-established City process (rezoning) to help transition industry toward more sustainable building practices.

In January 2011, Council adopted the revised *Greenest City Action Plan 2020* targets, which included the target to have all buildings constructed from 2020 onward will be carbon neutral in operations.

In October 2012, Council approved the *Vancouver Neighbourhood Energy Strategy and Energy Centre Guidelines*, to address the *Greenest City 2020 Action Plan* objective of reducing 120,000 tonnes carbon dioxide per year through the conversion of existing steam heat systems to low carbon energy sources and the deployment of sustainable energy systems for high-density neighbourhoods.

In April 2014, Council adopted a set of progressive Building By-law amendments as part of Vancouver's revised 2014 *Building By-law* that made great strides forward in terms of energy efficiency for one- and two-family dwellings and laneway houses. In sum, the new code required higher energy efficiency for walls, roofs, windows and skylights; energy efficient hot water tanks, boilers and furnaces; and improved air-tightness. As well, commercial and large residential buildings were required to meet the most up-to-date energy standards.

In November 2015, Council approved the *Renewable City Strategy* (RCS), detailing how Vancouver will achieve the target of 100% renewable energy use by 2050 and directed staff to bring forward recommendations for achieving zero emissions new buildings by 2030 and where possible, sooner.

CITY MANAGER'S/GENERAL MANAGER'S COMMENTS

The City Manager supports these recommendations as an effective approach for rapidly transitioning the local building industry towards higher quality and healthier new buildings that are highly energy efficient and rely only on renewable energy.

REPORT

Background/Context

Vancouver's Greenest City Action Plan (GCAP) includes targets to achieve carbon neutral new construction and to reduce emissions from existing buildings and industry by 20% from 2007 levels by 2020.

Changes to the City's Building Bylaw and the introduction of green building requirements for rezonings have successfully begun to transform construction practices in Vancouver. Emissions from newly constructed houses have been reduced by 48% as compared to 2007. Sixty seven large condominium, apartment, and commercial buildings representing over 8.5 million square feet of new development are under construction or have been built to achieve LEED Gold certification. These building are shifting standard construction approaches towards more efficient lighting, heating, and water systems along with improved ventilation system designs and the use of healthier materials for improved indoor air quality.

In addition, the increased production of renewable electricity in BC combined with recent trends towards warmer winters and City/energy utility programs to support and incentivise energy conservation have reduced GHG emissions from existing buildings and industry by 20% as compared to 2007, meeting the GCAP target for 2020.

Building on this success, Council established more aggressive and longer term targets in the fall of 2015 with the adoption of the Renewable City Strategy. This Strategy targets 100% of all energy used in Vancouver come from renewable sources by 2050.

Analysis undertaken in the development of the Renewable City Strategy estimated that of all the buildings (measured by floor space not number of structures) that are anticipated by 2050:

- 30% would be built prior to 2010
- 30% would be built between 2010 and 2020
- 40% would be built after 2020.

If all buildings are to use only renewable energy by 2050, the sooner new buildings achieve near zero emissions, the fewer buildings there will be that require costly and challenging deep energy retrofits to achieve the target.

Consequently, the Renewable City Strategy targeted new buildings to be zero emissions by 2030 by:

- Demonstrating zero emission standards in new City of Vancouver buildings
- Utilizing rezoning policy tools to lead the transition
- Incentivizing and streamlining development of near zero emission buildings
- Establishing and enforcing GHG intensity limits for new development
- Developing innovative financing tools
- Building partnerships to foster industry capacity
- Mandating energy use reporting

In adopting the Strategy, Council directed staff to bring forward a plan to action these measures that was to include recommendations on achieving zero emissions new buildings by 2030 or sooner where possible. This Zero Emissions Building Plan is staff's response to this direction.

Consultation

This is a Plan to fundamentally shift building practice in Vancouver in just under 10 years. It focuses building policy, catalyst tools, and an investment in capacity building on high performing building envelopes and transitioning to100% renewable energy for new buildings.

In order to succeed, it will be essential that other local governments, professional associations, academic institutions, non-governmental agencies, energy utilities and the development industry are aligned with and committed to the success of the shift articulated in this Plan. Consequently, it was developed not only in consultation with these stakeholders but through close collaboration with them.

Concurrent with the development of this Plan, the Province was working with local governments and these same stakeholders to develop recommendations on the structure and targets for a Provincial energy "stretch code" as well as for new actions for their Climate Leadership Plan. To foster alignment between the City's Near Zero Emissions Building Plan and recommendations for these Provincial plans, the City and Province actively shared research and undertook joint consultation exercises.

The full list of organizations actively involved in the development of this Plan is listed in Appendix B but key partners included:

- BC Hydro (co-funded research and consultation)
- Urban Development Institute (collaborated on establishing scope of research work and supported industry consultation to ensure representative voices from the designers, developers, builders, and suppliers for multi-unit residential buildings)
- Greater Vancouver Home Builders Association
- BC Ministry Responsible for Housing, Building and Safety Standards Branch
- BC Ministry of Energy and Mines, Electricity and Alternative Energy Division
- Staff from the cities of Richmond, New Westminster, and Surrey
- BC Housing and the Homeowners Protection Office
- International Building Performance Simulation Association - BC Chapter
- Fenestration Association of BC

- New Buildings Institute (one of the leading U.S. building energy code think tanks)
- Pembina Institute
- Canadian Passive House Institute

The Plan was also shaped and informed by ongoing discussions with the cities of New York and Brussels, whose involvement was made possible through a grant from the Carbon Neutral Cities Alliance.

Strategic Analysis

On average, 82% of new development in Vancouver is residential, 1-2% is office space and the remaining 16% is made up of a wide variety of building types. As per Council's direction in November 2015 when the Renewable City Strategy was adopted, this Plan includes detailed actions to reduce emissions in all new residential and office building to zero by 2025 with the exception of high-rise multi-unit residential buildings which do not go through a rezoning process; these will be required to achieve zero emissions in the Building Bylaw by 2030.

One key factor that will enable Vancouver to achieve this aggressive target is that electricity in BC is legislated to be at least 93% renewable and currently, 97% of electricity is provided from renewable sources. As a result the emphasis in this Plan is to reduce heating energy demand and to transition heating systems in new buildings to renewable energy such as waste heat, electricity, and bio-energy resources recovered from local waste (e.g. bio-methane from composting, clean wood waste).

Further research and analysis will be required before recommending detailed actions for achieving zero emissions in the dozens of other buildings types that make up the remaining 16% of new development in Vancouver as each of these buildings types has very unique energy usage and emissions profiles. Interim approaches for addressing all other building types will be recommended in the Rezoning Policy for Green Building later in 2016.

Past policy approaches to reduce energy use in new buildings combined with a gradual increase in the amount of renewable energy in electricity has resulted in a 33% reduction in greenhouse gas emission intensity (amount of GHG per unit area per year) in new buildings from 2007 requirements.

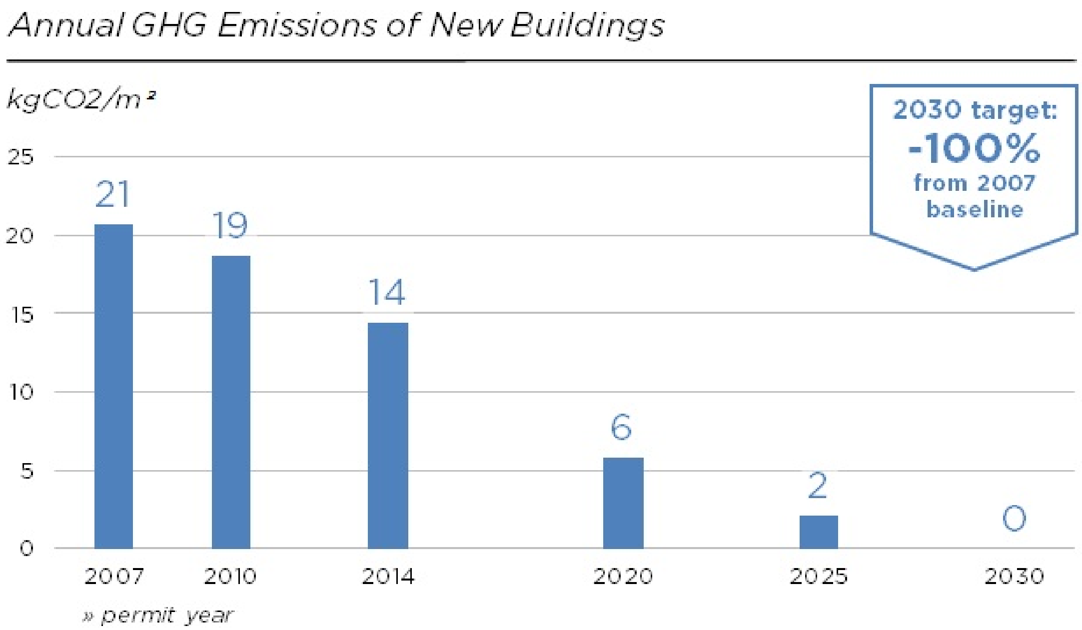

Figure 1: Weighted Average GHG Intensity for New Buildings in Vancouver

In accordance with the Renewable City Strategy, this plan sets a path to achieve significant reductions in energy demand in new buildings and increase the use of renewable energy. Beginning in 2016, new residential buildings will follow one of the following general paths towards achieving real and durable GHG emission reductions for new residential buildings in Vancouver:

1) First Path - Reduce Focused: where Neighbourhood Renewable Energy connections are not available, policy will initially focus on significant reductions in space heating and fresh air heating demand through greatly improved building envelope performance and highly efficient “passive” heat recovery ventilation. Once envelopes have improved significantly, requirements for renewable energy for hot water heating will be introduced in later years.

This Plan leverages the *Passive House* standard and its associated research, tools, training and verification processes to assist industry in successfully transitioning to highly energy efficient building envelope and ventilation system designs. Passive House is the leading global standard for high efficiency building envelopes and is supported by extensive designer and builder training (available locally), building science research, specialized energy modelling, third party design review and validation, and a strong Canadian and North American network of practitioners.

2) Second Path – Renewables Focused: new buildings connecting to a Neighbourhood Renewable Energy System (NRES) will also be required to reduce demand for space heating energy but the emphasis for these buildings will be on providing renewable heat energy for heating, ventilation air, and hot water. Neighbourhood Renewable Energy Systems are often viable in high density neighbourhoods such as Southeast False Creek and enable the use of a wide variety of local and renewable energy sources that are not otherwise feasible for individual buildings. In addition, these systems will make it possible for existing buildings that are already connected or can be connected in the future to transition to 100% renewable energy without requiring expensive and disruptive building renovations. Given the significant investment required to establish this shared infrastructure and the GHG benefits achieved, new buildings connecting to these systems will not be aiming to achieve passive house levels of performance and will require more modest improvements to building envelope performance in order achieve zero emissions. In addition, the City must collaborate with NRES utilities to ensure their continued success.

Office buildings and other building types where heating energy use is a less significant factor than it is in residential buildings will be required to pursue better envelopes while simultaneously transitioning to renewable energy.

The Plan includes four essential areas of action:

1. Limits: establish GHG and thermal energy limits by building type and step these down over time to zero
2. Leadership: require City-owned and city managed building projects to demonstrate zero emission building approaches where viable
3. Catalyse: develop tools to catalyse leading private builders and developers to demonstrate effective approaches to zero emission new buildings; and
4. Capacity Building: establish tools and a Centre of Zero Emission Building Excellence to facilitate the removal of barriers, the sharing of knowledge, and the development of the skills required to successfully achieve this goal

GHG and Thermal Energy Limits

This plan recommends establishing GHG Intensity (GHGI) targets for each major building type and stepping these down over time to zero by 2025, except for high-rise MURBs that do not go through a rezoning process which will be required to achieve zero emissions by 2030 in the Building Bylaw. These are to be complemented by Thermal Energy Demand Intensity (TEDI) targets to ensure real and durable reductions through building envelope performance improvements for all buildings.

These time-stepped GHG intensity reduction targets by building type will result in a 90% reduction in emissions from new buildings as compared to 2007 by 2025 and will ensure all new buildings permitted from 2030 onward will have zero emissions.

These targets are to be reflected as maximum GHGI and TEDI limits in the Rezoning Policy for Green Buildings and the Building Bylaw which are to be updated in 2016/2017, 2020, 2025 and 2030. Furthermore, requirements for buildings to be connectable to a Neighbourhood Energy System will need to be reviewed and updated to reflect only geographical areas where the City has certainty in a renewable energy source for the system supply.

Also note that, the requirements and limits established in the Rezoning Policy become Building Bylaw requirements 4-5 years later. Refer to the Plan (attached as Appendix A) for the specific targets by building type and date.

In summary:

- Detached Houses: Vancouver's 2014 Building Bylaw introduced aggressive new energy efficiency measures and emissions in these buildings have been reduced by 48% since 2007. Aside from establishing a cap on maximum allowed GHG emissions (effectively requiring large new houses to be more efficient than modestly sized ones) no *significant* new regulations will be imposed until 2020 and the immediate focus will be on the provision of catalyst tools and capacity building for early adopters of zero emission building approaches.
- Low-Rise Multi-Unit Residential Buildings (4-6 story MURBs): These buildings have not had significant new requirements imposed recently and provide an ideal form for Passive House levels of performance. Proposed amendments to the Building Bylaw and the Rezoning Policy for this form of development in 2016 will reduce emissions from this building type by nearly 50%, primarily by aligning insulation, window and ventilation system performance requirements with those for detached housing. The Plan targets 2020 updates to the Rezoning Policy to require Passive House performance for this form of development, thus emphasizing the immediate importance of catalyst tools and capacity building for early adopters of zero emission building approaches.
- High-Rise Multi-Unit Residential Buildings (MURBs): This Plan recommends establishing a GHGI limit in 2016 that would result in 64% lower emissions as compared to current rezoning policy outcomes (for buildings not connected to a renewable neighbourhood energy system). The incremental costs of improved envelope and ventilation systems will be offset by the savings from not being required to build a hydronic heated building.

Establishing these limits in policy and regulation will be undermined without also investing in clear and simple compliance processes supported with tools for both staff and industry, such as training, best-practice guides, etc.

City Leadership

In order to transition industry to building zero emissions by 2025 it is essential that the City demonstrate effective approaches in new building projects that it leads or influences so as to:

- inform what approaches work best under what conditions
- identify regulatory, permitting, and financing barriers so that these can be removed
- share real development experiences with private industry
- help catalyze the development of the required professional services, builder skills, and the supply of building components
- create opportunities for the public to experience the health and comfort benefits of these buildings

This Plan commits the City to build all new City facilities to the Passive House standard and certification, and use only low carbon fuel sources, or utilize equivalent near zero emission approach *wherever feasible* and to work with partners on other City influenced developments to assess and pursue opportunities to do the same. Given the magnitude of this shift in design and construction practice, feasibility of these approaches may be curtailed by financial, technical, schedule, and partner limitations that cannot be managed in the immediate term. This experience will enable the City to develop tools and processes to overcome challenges and will be used to inform a detailed policy for all City-led projects within two years.

Catalyst Tools

Rapid and effective transformation of the local building industry will require more than defined GHGI and TEDI reduction targets or City demonstrations of leadership. In order to achieve zero emissions for the majority of new buildings by 2025, the City must begin fostering zero emission design and building experience with numerous private sector leaders immediately. This will also stimulate local production and competition in the supply of highly efficient building elements while also improving the available selection and decreasing costs.

Initially, the development of zero emission new buildings will involve additional real or perceived risks and costs. New tools will be required in order to effectively catalyze private sector building innovation at the scale that will be required to enable zero emission building regulations within 9 years. Design and construction catalyst tools will target whole building performance and/or specific high performing building elements and practices.

The Plan describes key principles to guide the development of effective catalyst tools including appeal, clarity, timeliness to inform decision making, scale for impact, diversity of participants, and consistency of objectives/requirements.

Catalyst Tools for Detached and Row Houses

Given the relatively small size of detached and row house buildings, the fairly modest and reasonably well understood incremental costs of building these to near zero emissions, and a fairly consistent regulatory structure for the majority of these buildings, catalyst tools for this sector can be developed and launched relatively quickly.

The Plan outlines numerous catalyst tools that will be explored in further detail including expedited permitting, permit cost waivers, funding for case studies and design insight sharing, design competitions, and the potential for time limited relaxation of targeted City requirements such as those for minimum subdivision lot sizes or design guidelines for new homes in character neighbourhoods.

Preliminary research of the required costs to develop and provide catalyst tools at an adequate scale was undertaken and it was estimated that an incentive program of $325,000 for the first year and $650,000 for each of the next two years for a total of 1.625 million dollars would provide a meaningful start which could inform, and be re-evaluated in conjunction with, the proposed Building Bylaw updates proposed for 2020.

Catalyst Tools for Low-Rise MURBs

The Plan proposes that the 2020 Rezoning Policy for Green Buildings require 4-6 story MURBs achieve Passive House performance. In order to enable this, significant catalyst tools that can be launched in 2017 are required.

Given the far greater diversity of requirements and existing programs that impact the majority of these buildings, additional research is required to assess the cost to deliver and provide effective catalyst tools for this sector. That said, these same requirements and programs introduce additional opportunities to create meaningful catalyst tools.

In addition to exploring expedited permitting and permit fee waivers, staff will research options for the provision of required parking and potential, synergies with the Rental 100 Program, the Rezoning Policy for Green Buildings, and the green building requirements for large developments sites.

Significant delays in launching a meaningful incentive program may necessitate a delay in introducing the rezoning requirement for these buildings to meet Passive House levels of performance.

Catalyst Tools for High-Rise MURBs
Given their scale and the smaller pool of developers and design professionals who typically get involved in these large scale projects, only a few high-rise MURBs per year striving to attain Passive House like levels of performance would have a meaningful impact on our understanding of what is possible and would begin to lower the incremental costs for key building elements. Similar options as described for low-rise MURB catalyst tools will be explored. In addition to these, opportunities to introduce a design-build competition where entries could be judged on GHG performance, cost effectiveness, and public appeal will also be explored.

For all these incentives, and in particular those for the MURBs, the City should engage and seek support from higher levels of government given the transformative nature that a successful incentive program would have not only for the building industry in Vancouver but across BC and could help inform similar changes in major urban centres across Canada and the US.

Capacity Building
In order to successfully achieve zero emission for the majority of new buildings by 2025, the capacity of the building industry will need to be rapidly increased. This means providing resources and training, encouraging knowledge-sharing and supporting peer-to-peer learning. Capacity building will also include strengthening the relationship between the City and the building industry, with an emphasis on single-family-home builders to ensure that they are engaged and well supported with training and resources.

Not only will an investment in developing industry capacity for zero emissions buildings result in increased local jobs in design, construction, and manufacturing, it will increase business opportunities across North America as other jurisdiction adopt more energy efficient and lower emission building practices.

In developing this plan, staff conducted two workshops with industry stakeholders, held a meeting with leading architects and designers, and met with a number of the key stakeholders individually. Staff also researched leading capacity-building programs around the world, including multiple engagements with staff in Brussels and New York

City. The result of this research and consultation is a set of actions in the Plan aimed at rapidly increasing the capacity of Vancouver's building industry to design and build zero emissions buildings. These actions include:

- Providing funding to designers to share technical case studies and host tours of near-zero emission buildings;
- Requiring energy performance audits to be done after near-zero emission buildings are operating;
- Producing resources, guides to address industry-identified knowledge gaps;
- Hosting panel, exhibits and other networking events;
- Supporting training (primarily delivered by partner organizations) to help the industry gain needed skills, particularly those that are unique to zero-emission buildings;
- Removing barriers identified by the industry, such as permitting challenges;
- Showcasing Vancouver's leading developers, designers and builders through events and awards; and
- Engaging the public through tours and communication materials highlighting the aesthetics and liveability of near-zero emission buildings.

In order to coordinate the delivery of these actions, it is recommended that a neutral, arms-length Zero Emission Building Centre of Excellence be established:

Zero Emission Building Centre of Excellence
The proposed Centre is to be neutral and arms-length as Vancouver will not be acting alone to facilitate the development of zero emission building expertise – numerous other public sector and industry association groups have acknowledged the need for and advantages of establishing such an entity. The Centre will serve as a neutral space where developers, designers and builders can convene to learn, network and identify concerns or barriers to high-performance buildings. In this way, the Centre will help streamline the City's permitting processes.

The proposed Centre of Excellence will partner with professional and industry associations to host training events, courses, panels, and exhibits. In addition, the Centre could administer mission-related programs on behalf of partner organizations, such as energy-efficiency incentive programs. Several leading cities have established similar knowledge-sharing hubs for green buildings (see "New York's Building Energy Exchange") and they've proven to be highly effective in supporting the local building industry.

The Zero Emission Building Centre for Excellence is anticipated to be a physical space, centrally located, with a small staff trained in architecture and building science. Following best practices seen elsewhere, the centre is expected to be operated by an existing third-party organization with expertise in delivering training, education and communication materials and with a proven financial track record. This approach will ensure neutrality and a continued focus on the mission. Staff will be evaluating a number of potential host organizations in the coming months. Should there not be a suitable existing organization staff will consider other alternatives such as establishing a new arm's length non-profit.

Seed funding of $700,000 over the next three years is being requested to establish and begin operating the Centre, contingent upon receiving at least matching funds from external partners. A number of groups have expressed strong interest in partnering with the City, including BC Hydro, BC Construction Association, Wood Works BC, Simon Fraser Community Trust, other local governments, and the provincial government. While specific external funds have not yet been identified, the centre is expected to have impacts beyond the City and as such there are a number of potential funding sources, including but not limited to the Western Diversification Grant, Metro Vancouver Sustainability Grant, and Provincial Innovative Clean Energy funding.

Staff will report back to Council within six months with a detailed organization structure and funding strategy for the centre, including confirmed external funding sources.

Removing Barriers
Some existing City policies, regulations, bylaws, and guidelines make it challenging and more expensive to build to zero emission levels of performance. As the City and private leaders accelerate the development of zero emission buildings, the City will allocate dedicated staff to assess barriers and implement changes to minimize them. Ideally, adjusting how a policy is structured may enable its original public interest to be served while reducing the barrier to zero emission building. In more challenging instances, the benefits of reducing barriers to zero emissions buildings will need to be balanced against other public interests that a policy might be serving.

In addition, given the new, highly efficient approaches that designers and builders are already beginning to pursue, it is also critical that staff are provided with training and that internal processes are adjusted to ensure public safety is maintained while avoiding unnecessary delays in permitting for these buildings.

Implications/Related Issues/Risk (if applicable)

Financial

This report recommends a total of $1,625,000 be allocated over three years ($325,000 in 2017 from the Climate Action Rebate Incentive Program Reserve, $650,000 in 2018 and $650,000 in 2019 from a funding source to be determined and reported back to Council) to develop and provide tools to catalyze private sector leadership in demonstrating effective approaches to near zero emission detached and row housing.

In addition, staff will explore the development of similar catalyst tools multi-unit residential and commercial buildings and will report back to Council with specific resource requests and program recommendations in 2017.

This report also recommends approval in-principle for $700,000, contingent upon securing matching funding, to be allocated over three years with $300,000 in 2017, $200,000 in 2018 and $200,000 in 2019 from the City's 2017 Innovation Fund (subject to Council approval of the 2017 Innovation Fund budget) towards establishing an Zero

Emission Building Centre of Excellence with the mission to facilitate the compilation and dissemination of the knowledge and skills required to design, permit, build and operate zero emissions buildings.

The City's contribution of $700,000 towards a Zero Emission Building Centre of Excellence is expected to leverage at least $700,000 in direct matching funds plus over $100,000/year of in-kind contributions from a wide range of potential partners including, but not limited to: other BC local governments; the Provincial Government; Metro Vancouver; the Federal Government; energy utilities; and charitable foundations with strong commitments to climate protection.

Staff will report back with the sources of matching funding and recommendations for establishment of the Centre of Excellence in early 2017.

Additional financial implications such as those potentially required for new City-led buildings to demonstrate zero emissions as well as to develop and provide tools to catalyze early industry leaders to build zero emission multi-unit residential buildings to will be included in separate Council reports as additional research and consultation are completed.

CONCLUSION

Meeting the City's 2050 target to use only renewable energy will require the majority of new buildings be designed and built to achieve zero emissions by 2025 and all new buildings to achieve this target by 2030. Meeting these aggressive targets and timelines will require a restructuring of the City's policies and tools as well as leadership by the City and industry in demonstrating effective approaches for achieving this goal. It will also require a collaborative approach amongst many stakeholders to share knowledge, remove barriers, and ensure that the required skills are developed and widely available in BC.

This collaborative effort to transform how new buildings are designed and built will not only reduce their GHG emissions but will also make them healthier and more comfortable for their occupants. In addition, this innovation in the building industry will make buildings more resilient to changes in weather, climate and energy prices while providing significant opportunities for local professionals, trades, and industries.

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Zero Emissions Building Plan

7/12/2016

Table of Contents

1 Exec Summary

This Plan lays out four action strategies to require the majority of new buildings in Vancouver to have no operational greenhouse gas emissions by 2025 and that all new buildings have no greenhouse gas emissions by 2030.

These four strategies include:

1. Limits: establish GHG and thermal energy limits by building type and step these down over time to zero
2. Leadership: require City-led building projects to demonstrate zero emission building approaches where viable
3. Catalyse: develop tools to catalyse leading private builders and developers to demonstrate effective approaches to zero emission new buildings; and
4. Capacity Building: build industry capacity through information sharing tools and the development of a Centre of Excellence for Zero Emissions Building to facilitate the removal of barriers, the sharing of knowledge, and the development of the skills required to successfully achieve this goal

These strategies for achieving zero emissions new buildings were developed specifically to ensure comfortable and healthy indoor environments, maximize local economic development, ensure long-term building resilience, protect housing affordability and to facilitate achieving the City's Renewable City Strategy target to have all buildings in Vancouver (including those already built) use only renewable energy by the year 2050.

2 Background

The Greenest City Action Plan includes a target to achieve carbon neutral new construction by 2020. More significantly the Renewable City Strategy targets 100% of all energy used in Vancouver come from renewable sources by 2050. In this Strategy, it was estimated that of all the buildings (measured by floor space not number of structures) that are anticipated by 2050:

- 30% would be built prior to 2010
- 30% would be built between 2010 and 2020
- 40% would be built after 2020.

If all buildings are to use only renewable energy by 2050, the sooner new buildings achieve near zero emissions, the fewer buildings there will be that require costly and challenging deep energy retrofits to achieve the target.

Consequently, the Renewable City Strategy targeted new buildings to be zero emissions by 2030 and where possible sooner.

2.1 New Building Emissions Trends

Operational greenhouse gas emissions from new buildings vary widely by building type, size, the carbon intensity and amount of the energy used, and policy or regulatory limits imposed on the building's design and construction. Building scale greenhouse gas emissions are measured in kg CO2e/m2 per year; since these are emissions per unit area they are referred to as emissions intensity or GHGI.

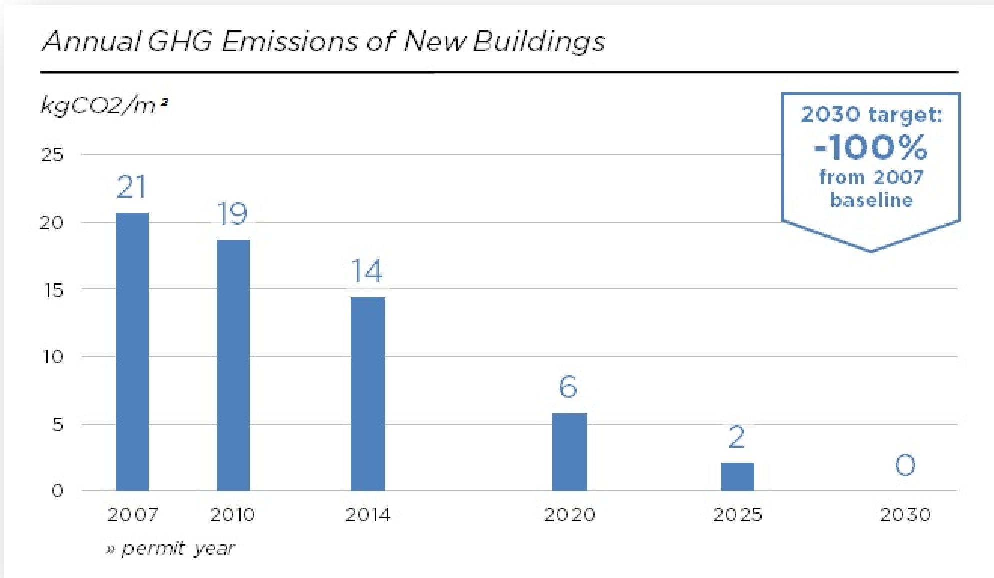

FIGURE 1: Aggregate GHG Emissions of All New Buildings Types

Total annual GHG emissions for a specific building type are calculated based on the modelled energy use of a typical sample building designed to its governing policy and/or regulatory requirements multiplied by the carbon intensity of the specific sources of energy sources used in that building.[1] Aggregate GHG emissions for all buildings types are based on a built area weighted average[2] of the emissions associated with each of the specific building types.

[1] Note that historic emissions for a specific building type are estimates only. Energy efficiency regulations do not *currently* control directly for GHG emissions so historic (and current) emissions by building type are based on modelled outcomes of *typical* design responses to energy efficiency regulations governing a building's design and construction in a given year.

[2] In 2007, only the Building Bylaw stipulated efficiency requirements (with the exception of a very limited number of buildings such as City facilities). Since then, rezoning policies as well as neighbourhood renewable energy system (NRES) connection requirements have introduced additional energy use limitations on large numbers of buildings in specific areas. GHG calculations (by building type) incorporate an estimate of how much new built area is impacted by rezoning conditions and/or NRES connection and therefore have lower GHG emissions than a building only impacted by the Bylaw.

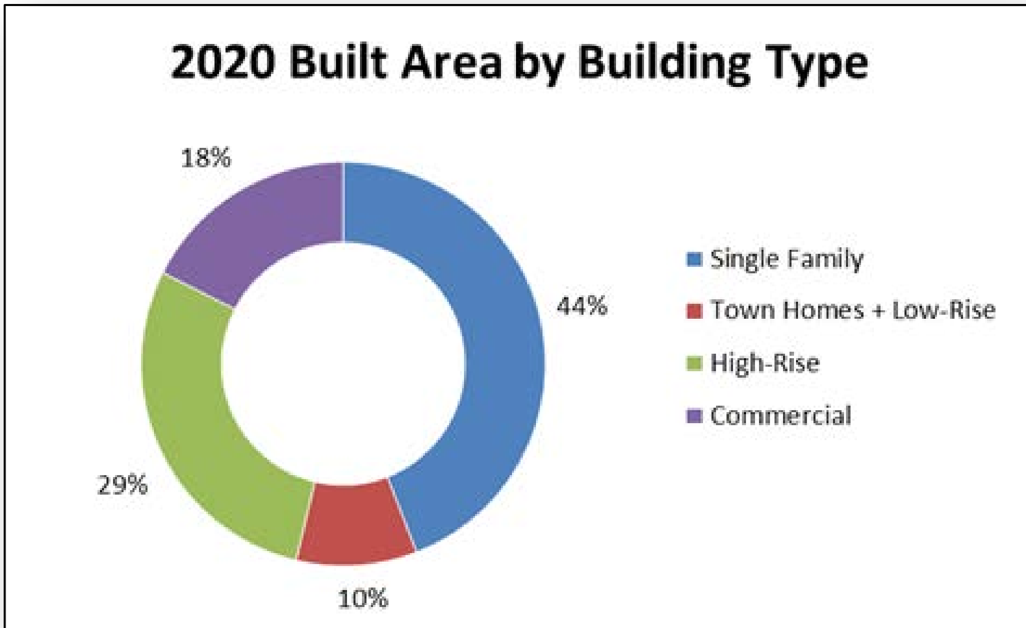

FIGURE 2: Built Area by Building Type

New development in Vancouver is predominantly residential with 82% of new building area being for houses, condominiums and apartments. Detached housing, referred to as "single family" but also including secondary suites, laneway houses and duplexes, represents the category of buildings with the most new development (by total floor area) per year. Even though significant and meaningful reductions in GHGI from new detached houses have been achieved since 2007, the significant amount of new development of this building type means additional improvements in performance must remain an important focus moving forward.

Mid and high-rise multi-unit residential buildings (over 6 stories in height) are the second most significant form representing 29% of new building area. Vancouver's efforts to reduce emissions from new mid and high-rise residential buildings have not been as successful in reducing emissions as they have been for houses and therefore must also be a form of development for particular focus. Fortunately, the expansion of neighbourhood renewable energy systems (NRES) and immediate changes outlined in this plan create two pathways to significantly reduce emissions from this critical form of development.

2.2 Renewable Energy in Vancouver

Unlike most jurisdictions around the world, Vancouver's electricity is already close to 100% renewable; Provincial legislation requires BC's grid to be supplied by a minimum of 93% renewable energy and the current mix is over 97% renewable and therefore has very low GHG emissions associated with its use. As a result, while electricity conservation remains important, the focus of this plan is on reducing the demand for fossil fuel based natural gas used primarily for space heating and hot water and transitioning these functions to renewable sources such as electricity (including heat pumps), bio-gas, and neighbourhood renewable energy systems (NRES).

In addition, because grid provided electricity is almost entirely renewable in BC, this Plan does not focus initially on mandatory building scale renewable energy technologies such as solar photovoltaic (PV) as is the case in a number of other leading jurisdictions. This Plan provides flexibility for builders and owners in determining how best to achieve the targeted GHG emission outcomes. One key element of providing flexibility for solutions is through removing barriers to good technologies and solutions such as solar PV.

When a building is required to achieve zero emissions if the electricity grid is not 100% renewable then the buildings will be obligated to install an on-site renewable energy system (or secure a share of Vancouver-based renewable power systems where on-site systems are not viable) that produces enough renewable energy to offset the small portion of grid power that comes from fossil fuel based generation.

2.3 Passive House

Passive House (also Passiv Haus) is the most rigorous and widely applied global standard that has been developed and refined specifically for ensuring highly energy efficient building envelope and ventilation system design and construction.

This standard is supported by:

- professional and trades training programs;
- customized energy modelling software to ensure strict energy limits are not exceeded, good ventilation is provided, and thermal comfort is maintained;
- third party verification processes (90% of which can be completed prior to construction start); and
- Canadian, North American, and global networks of designers, builders, equipment manufacturers and researchers.

Hundreds of millions of square feet, primarily of residential development but also including many schools, offices, hotels, firehalls, museums, etc., have been built and certified to the standard worldwide.

Throughout this Plan, reference is made to the Passive House standard as near zero emission because buildings meeting the standard’s criteria use virtually no space heating energy, limiting emissions to heating water and electricity use. While there is insufficient local data to conclude that this standard should be applied in its entirety to all building types under all conditions, the standard and its associated tools are seen as a key tool to effectively transform the building industry to greatly improved building envelopes and ventilations system approaches.

3 Stepping Down GHG Emissions to Zero

Zero emissions new buildings will be achieved by incrementally lowering the permitted GHG emissions for new construction in Vancouver`s Building Bylaw over time. Currently, no jurisdiction in North America has building code requirements that establish specific limits on GHG emissions. Experience has revealed that indirect approaches such as regulating energy cost efficiency as compared to a `reference` building (as is the standard approach under the North American building efficiency standard ASHRAE90.1 and in LEED) have not been as effective as anticipated in reducing emissions in Vancouver.

This Plan establishes greenhouse gas intensity (GHGI) targets (GHG emissions per unit area per year) by building type and includes a stepped reduction timeline to reflect these targets as maximum permitted limits in Vancouver`s building policies and Building Bylaw.

> *Clearly defining and quantifying desired outcomes and providing a schedule for performance changes will enable industry to plan appropriately and to focus building design and construction innovation towards achieving these objectives.*

3.1 Stepping Down GHG Emissions to Zero - Reduction Pathways

This Plan establishes two pathways by which GHGI limits for new buildings can be achieved in order to a) ensure reliable and durable emission reductions and to b) maximize co-benefits such as:

- local economic development
- healthy indoor building environments
- maximum occupant comfort
- protecting affordability
- future proofing to enable additional performance improvements post-occupancy
- resilience to climatic changes, extremes, and/or power outages.

3.1.1 Path One: High Performance Building Envelope and Ventilation Systems

A building envelope is like its skin – it includes surface elements such walls, windows, and the roof. Building envelope performance is primarily influenced by the amount and effectiveness of wall, roof and foundation insulation and the amount of windows and their energy efficiency. It is also impacted by how the building is designed to use the low angle of the sun in the winter to provide free heating while using shading strategies to keep out direct sunlight in the summer and avoid the need for air conditioning.

Ventilation `systems` are the means by which fresh air is provided for the building and stale air is exhausted.

Building envelope and ventilation system performance are interdependent. An efficient ventilation system cannot have warm air leaking out of the envelope in the winter (or cool air leaking out of the building during the hot summer) through poorly weather proofed walls and openings. At the same time, a healthy and durable building envelope depends on adequate airflow to avoid moisture accumulation which can lead to rot and mold. Very good draft proofing and the use of a `heat recovery ventilator` (HRV) that uses the energy of warm exhaust air to pre-heat fresh incoming air during the winter and vice versa during the summer are central to an energy efficient ventilation system.

A very efficient heat recovery ventilator (HRV) can pre-heat cold incoming fresh winter air from 0° C to 17 or 18° C just by recovering the heat energy from the exhaust air; because most of the fresh air heating is free, buildings can be well ventilated without concerns about the cost of doing so.

The first pathway to zero emissions buildings focuses on highly efficient building envelopes and ventilation systems because these systems do not depend on sophisticated maintenance staff or specialized contractors to ensure they are performing as designed. Given that 82% of the new development in Vancouver is residential and that most homeowners, strata councils, and apartment building operators are not building energy system experts, keeping the building systems simple is essential to reliable and durable building energy efficiency performance. In addition, these elements of a building are more difficult to upgrade once construction is completed. As the ultimate aim is to have all existing achieve 100% renewable energy or near zero emissions getting the envelope and ventilation systems right at the start are essential as these will be costly and disruptive to improve after the building is completed.

Co-Benefits of High Performing Building Envelopes and Ventilation Systems

High performing building envelopes result in more local jobs as insulation and windows are largely supplied from regional manufacturers. Installing these and weather proofing a building provide greater opportunities for local tradespeople than does the import of advanced energy system such as heat pumps or solar panels.

In addition, this pathway will result in increased occupant comfort and improved indoor air quality; buildings will be less drafty, there will be no chill from poorly performing windows, and a well-sealed and insulated building with triple-paned windows will be much quieter and easier to maintain.

3.1.2 Path Two: Neighbourhood Renewable Energy Systems

Neighbourhood energy systems are shared infrastructure platforms which provide heating and/or cooling for multiple buildings. In dense urban settings (as well as hospital or university campuses), these systems enable entire neighbourhoods to utilize nearly 100% renewable energy sooner than would otherwise be possible because of:

- economies of scale;
- incremental renewable energy technology costs can be amortized by a utility over 25+ years and repaid through operating cost savings due to free or low-cost energy sources such as sewer waste heat or clean wood waste;
- systems are continuously monitored to ensure performance objectives are met

Co-Benefits of Neighbourhood Renewable Energy Systems

- *Establishing and expanding neighbourhood renewable energy systems is essential to effectively reducing emissions from difficult-to-retrofit large occupied buildings; new buildings connecting to these systems help to expand RNES infrastructure and thereby increase the number of existing buildings that can be served with renewable energy*
- *New buildings that connect to a neighbourhood renewable energy system prior to the mandatory requirement for zero emissions new construction will be "zero emissions ready". They will not need to be retrofitted to achieve this objective at a future date because the neighbourhood system they are connected to can increase its mix of renewable energy over time;*
- *These systems foster overall energy resilience by utilizing a diversity of locally available free or waste energy sources such as sewer heat, commercial and industrial waste heat, or clean wood waste; creating a role for local energy or resources that would otherwise be wasted decreases Vancouver's overall dependence on imported sources of energy.*

One advantage of these systems is that they can provide renewable energy to all three building systems that require heat: space heating, ventilation air, and domestic hot water.

This pathway also results in reliable and durable GHG emission reductions by avoiding the need for complex mechanical systems in buildings. While this approach does depend on advanced renewable energy technologies, these systems are not operated or maintained by building owners but by an energy utility with professional and well trained staff. In this Plan, all buildings will be required to provide improved building envelopes and ventilation systems to improve occupant comfort and health but because neighbourhood renewable energy systems significantly reduce GHG emissions, envelope and ventilation system efficiency improvements required for buildings connecting to these systems will be more modest than for other buildings.

Given the importance of these systems in reducing emissions not only from new buildings but also from existing buildings, the City must continue to work with the NRES utilities to ensure these systems are successfully implemented and expanded.

3.2 Stepping Down GHG Emissions to Zero - Metrics

This Plan depends upon three metrics for it to be successful. They are described here in descending order of priority for Vancouver.

3.2.1 Greenhouse Gas Intensity (GHGI - kg CO2e/m2 annually)

Incrementally lowering GHGI limits in policy and regulation is the cornerstone of this Plan. GHGI is determined by the total amount of energy supplied to the building by type (electricity, natural gas, hot water or steam) multiplied by the energy's carbon intensity (a measure of how much greenhouse gas emissions are associated with its use). This overall operational GHG emission total is then divided by the building area to calculate GHGI.

> ***Carbon Accounting***
> *Vancouver follows global best practice for city-level carbon accounting which requires it to use provincially established carbon intensities for energy sources such as electricity, natural gas, and transportation fuels.*
>
> *Provincial changes to the accounting protocols for the carbon intensity of electricity are anticipated in the next year or two. If this occurs, the targets (as well as historic results) for new building GHGI established in this Plan will be revised to reflect this change.*

3.2.2 Thermal Energy Demand Intensity (TEDI kWh/m2 annually)

Thermal energy *demand* intensity is the amount of heat that is required to keep a building comfortably warm regardless of how efficiently or inefficiently that heat is produced. This metric reflects building envelope performance. In order to ensure continually improving envelope efficiencies, specific time-stepped limits for TEDI are required.

3.2.3 Energy Use Intensity (EUI)

Energy *use* intensity is the total amount of externally provided energy to a building including not only for heating, ventilation, and hot water (that are the primary sources of GHG emissions in buildings) but also for air conditioning, fans, pumps, lighting and expected energy use from appliances such as dishwashers and computers (referred to as plug loads). Time-stepped limits for EUI will ensure that even when energy provided to a building is renewable that it is being used efficiently and is not being wasted unnecessarily.

In jurisdictions where electricity is largely non-renewable, reducing overall energy use will effectively drive GHG reductions and is often the focus (directly or indirectly) of energy regulations and policy. As a result, there is significant global effort (public and private) to improve electrical efficiencies and reduce electricity use. Because overall energy use is not central to achieving GHG reductions in Vancouver (where we have more than 93% renewable electricity) and because the global electrical efficiency of lighting, devices and appliances is rapidly improving, it is not essential for Vancouver to drive innovation in this area.

For these same reasons, it is also not productive to establish *future,* time stepped EUI targets in this Plan. In order to ensure that energy is not being wasted, even if it is supplied from a renewable source, EUI limits reflecting established and proven good efficiency practices will be incorporated into rezoning and building bylaw updates at the time these are being developed.

3.3 Stepping Down GHG Emissions to Zero - Embodied Carbon

The City of Vancouver's green building and community-wide greenhouse gas emission reduction targets do not account for embodied (also referred to as upstream) emissions that occur as a result of energy used and GHGs emitted from building material resource extraction, production and transportation. In addition, under current policy and code requirements, the GHG emissions associated with the energy used in the operation of a building are significantly greater than the emissions embedded in the materials required for its construction. As result, this Plan is focused primarily upon reducing operational GHG emissions from new buildings.

That said, as this Plan is successfully implemented and operational emissions from buildings decline rapidly, the relative importance of addressing GHG emissions embodied in building materials will quickly become a significant consideration in efforts to reduce overall GHG emissions associated with buildings. Some building materials, such as wood, which is an abundant local and potentially renewable resource, can actually sequester carbon to reduce GHG emissions.

While historically it was difficult to quantify embodied emissions of building materials, new research and software tools have been developed specifically for the Canadian construction sector. These tools can be used quantify the embodied emissions from buildings on a detailed project basis for all building components and materials. In anticipation of the near term importance of measuring and reducing the embodied emissions of building materials, it is essential that the City begin collecting data from new developments on their estimated embodied carbon in order to inform future incentive, policy, and potentially regulatory mechanisms targeted at reducing the embodied emissions of new buildings as these become an increasingly significant portion of overall building lifecycle emissions.

3.4 Stepping Down GHG Emissions to Zero - Policy and Regulatory Tools

In this Plan, GHGI and TEDI targets are established for each major building type and step down starting in 2016 in roughly 5 year intervals until all buildings achieve zero emissions by 2030, and for many building types, by 2025. The Building Bylaw and the Rezoning Policy for Green Buildings will be updated to reflect these targets as firm limits for the prescribed milestone years. Time stepped EUI targets have not been established in this Plan but will be established to reflect established good electrical efficiency practices for each update to the Policy and Bylaw.

The City currently uses voluntary commitments from developers applying for rezoning to gradually drive improved green building outcomes. In general, GHGI and TEDI limits that will be required in the Rezoning Policy will be reflected in the Building Bylaw five years later. By aligning the limits for rezoning with the limits that will be required of all new construction within 5 years, the Rezoning Policy can help the industry evolve from one bylaw step to the next, and will provide demonstration projects for the building technologies and techniques that will soon be required by the Bylaw. This approach is often called a ‘stretch code’ or ‘reach code’. It has been used effectively by the City of Toronto Green Standard and the Ontario Building Code since 2006 to provide clarity and predictability to industry on upcoming energy code changes.

Prioritize Outcomes and Focus Policy Requirements

In order to enable industry to transform rapidly and successfully towards meeting these aggressive time-stepped GHGI and TEDI targets, it will be important to ensure that the Green Building Policy for Rezonings is structured to enable a focus on these high priority outcomes.

The effectiveness of the green building requirements in the current Rezoning Policy will be evaluated and outcomes will be prioritized. The 2016 update of the rezoning policy will include recommendations for achieving the highest priority green building outcomes.

It also aligns with the approach currently recommended by the BC Provincial Energy Efficiency Working Group, and is a key recommendation of the Pembina Institute for governments seeking to rapidly improve building performance.

3.5 Stepping Down Emissions to Zero - GHG and Energy Targets

Extensive research, energy modelling, and stakeholder consultation was undertaken to understand current building design and construction practices and to inform stepped reduction GHG and thermal energy demand targets for each major building type that were deemed ambitious yet achievable. Detailed construction and operating cost analysis of building changes required to meet the 2016/2017 targets were undertaken to ensure that the new requirements do not increase the cost of housing in Vancouver.

It is anticipated that building practices and the availability of cost competitive building systems will evolve quickly in response to the initial targets. The viability and cost implications of subsequent targets (2020 and later) will be assessed in detail and will be used to inform recommended changes to the targets should it be determined that they are overly aggressive.

The GHG emissions reduction benefit for new buildings connecting to a Neighbourhood Renewable Energy System (NRES) will be recognized if the NRES is City owned, or once the renewable energy supply is secured (e.g. by legally binding agreement or equivalent regulatory approach) even if the implementation of the renewable energy plant is not yet completed. In addition, while the GHG target for all buildings of a specific type are consistent, the thermal energy demand targets for RNES connected buildings will not be as stringent since these buildings will be paying for renewable energy infrastructure through utility rates and achieving reliable GHG reductions through their use of low-carbon energy.

In order to achieve zero emissions in new buildings by 2025 (or in some cases 2030), any portion of non-renewable energy in grid provided electricity will be required to be offset by the installation of an on-site renewable energy system such as photovoltaic solar panels. In the case of high-rise buildings with relatively small roof areas compared to the overall building size, the small portion of non-renewable energy in electricity will be allowed to be offset via a community-scale renewable power system. As grid power is required by legislation to be 93% renewable and is currently 97% renewable, the size of on-site renewable systems to make up the remaining 0-7% required to achieve 100% renewable power will be small in size and will be very modest in cost.

3.5.1 GHG and Energy Targets - Building Energy Performance Modelling

To support the establishment of GHGI and TEDI targets and to facilitate compliance as these targets are introduced to building policy and regulations, energy modeling guidelines have been developed. The intent of the guidelines is to clarify and standardize energy modeling assumptions to align with the parameters used in developing the established performance targets.

The energy modeling guidelines establish a consistent methodology around parameters such as operating schedules, non-regulated loads, air leakage, and others so that proposed building designs are measured in a consistent manner against the policy and code requirements. One key element is that the guidelines establish requirements for how to properly represent envelope heat loss by incorporating thermal bridging that has historically been ignored in code compliance modeling.

It is important to note that actual building energy use and emissions may vary from the modeled results; *energy models results based on standardized assumptions regarding building use are comparative not predictive*. A useful analogy is the fuel efficiency ratings of cars and standardized test conditions (speed, vehicle loading, road conditions etc) used to determine a vehicle's rating. The actual fuel efficiency of the vehicle can differ significantly from the test results given actual driving habits, road conditions, and vehicle usage (towing, number of passengers etc).

It is also important to note that different building energy modelling tools can generate fairly different results. The modelling tools used for detached homes, high rise MURBs and Offices, and for Passive House design are all different and therefore comparison of modeled outcomes between different building types can be misleading. What is important is that modelling tools enable relative comparisons for buildings of the same type to enable target setting and compliance.

As the GHGI and TEDI limits, targets and outcomes get closer to zero emissions, current modelling tools *may* no longer be effective. Research into the appropriateness of different modelling tools will be ongoing through the implementation of this Plan.

3.5.2 GHG and Energy Targets - Detached Housing

Detached houses (including secondary suites, laneway houses, and duplexes) represent the largest amount of new construction in Vancouver accounting for an average of 44% of new development by area. Over 90% of new houses are heated with natural gas and as a result have a significant opportunity to reduce greenhouse gasses by improving the building envelopes. These buildings are exposed to the weather on all sides and tend to have complex shapes, increasing the surface area to volume ratio which increases energy use. Since there are no rezoning for new one and two family homes, the City has historically lacked tools to encourage innovation and "better than code" energy performance.

Despite these challenges, Vancouver significantly reduced emissions and energy use in new homes with the 2014 Building Bylaw by prescriptively requiring better insulation, higher performing windows, increased air tightness requirements, the use of heat recovery ventilators, and requirements for more efficient equipment such as furnaces. As industry adapts to these significant changes, only minor improvements will be introduced between now and 2020.

One minor improvement will be setting a maximum allowed total GHG emission impact for new detached homes. The maximum allowed limit will be based on the average carbon footprint of a new home in Vancouver. Effectively, this will require larger than average homes to pursue greater energy efficiency or the use of additional renewable energy technologies sooner than the rest of the market. All grid connected space heating, domestic hot water heating, fireplaces (indoor and outdoor) and outdoor heating would be considered in setting the average. These larger than average projects will help drive innovation and the adoption of leading practices making improvements in more modest sized houses easier in the future.

While an envelope focus as the pathway towards zero emissions has been initially successful with the most recent changes to the Vancouver Building Bylaw, it is not envisioned that the Building Bylaw will mandate Passive House levels of performance for all new detached houses when zero emissions will be required in 2025. This is because achieving a Passive House level of envelope performance may be very challenging while still maintaining the complex building shapes required to maintain a early 20th Century housing character. A slightly higher TEDI combined with renewable energy based heating equipment, such as air-to-water heat pumps, will allow zero emissions to be achieved while still allowing for significant architectural variety.

Successfully transitioning detached homes to zero emissions will require the development of new incentive tools. This is because, unlike other building forms which have "better than code" requirements for rezoning, the City currently lacks tools to encourage innovations in energy efficiency performance for detached houses. In addition, the Vancouver homebuilding industry in comprised of a large number of small companies, many of them run by immigrants whose first language is not English, being responsible for no more than a few dozen homes out of the 1000 that are built each year. As a result, an ongoing investment in training, peer-to-peer exchanges, and capacity building is essential.

2007 Baseline		Current Bylaw		2020 Bylaw		2025 Bylaw	
GHGI	TEDI	GHGI	TEDI	GHGI	TEDI	GHGI	TEDI
23	113	12	84	7	55	0	30

GHG emissions for new detached houses, representing over 40% of all new development in the City, were significantly reduced as a result of improved envelope and efficiency requirements in the 2014 Building Bylaw; these emissions are almost 50% lower than the 2007 baseline. This Plan does not include any significant new regulatory requirements before 2020 but focuses on the provision of incentives for innovation and an investment in knowledge sharing and training.

3.5.3 GHG and Energy Targets - Low-Rise MURB Targets

Low rise MURB's (including rowhouses and 4-6 story multi-unit residential buildings) in Vancouver are predominantly wood framed, most have punched windows, they include relatively modest amounts of window area, and typically only have one or two sides exposed to the outdoor air. These factors, combined with the early adoption of the Passive House Standard by some rental apartment building developers, create an ideal opportunity to transition rapidly to high performing building envelopes and Passive House levels of performance.

The primary challenge in this transition is that these buildings have not historically been required to achieve high levels of energy efficiency, so success will depend upon immediate incentives for innovation, resources and tools to build the design knowledge and construction skills required. Because of the similarities in construction between 1&2 family homes and low-rise MURBs, aligning the requirements will help facilitate improved availability of high performing building elements such as windows, reduce confusion, and improve enforcement success. In addition, some design relaxations may be required to accommodate extra insulation and enable simplified building shapes.

Requirement Type	Current Bylaw		Current Rezoning		2016 Bylaw Updates		2016 Rezoning Update		2020 Rezoning Update		2025 Bylaw Requirement	
	GHGI	TEDI	GHGI	TEDI	GHGI	TEDI	GHGI	TEDI	GHGI	TEDI	GHGI	TEDI
Bylaw or Rezoning	12.5	50	10.5	42	5.5	35	5	25	4.5	15*	0	15*
NRES Connected							5	35	4.5	35	0	TBD

* Passive House or equivalent performance

> Low-rise multi-unit residential buildings are the ideal building form and construction type for cost effective high performing building envelopes and ventilation systems. This Plan proposes immediate updates to the Building Bylaw targeting a reduction of nearly 50% in GHG emissions for new low-rise residential development and establishes the target for all low-rise MURB developments that are rezoned as of 2020 to achieve Passive House performance.

3.5.4 GHG and Energy Targets - High-Rise MURB Targets

High-rise MURBs represent the most significant challenge for achieving zero emissions given the changes from current design and construction practice required and the fact that it is the second most prevalent form of new development in the City representing 29% of new development floor area. These buildings typically include large amounts of glass and exposed concrete (slab ends and balconies), both of which result in significant heat losses and are leading to a growing reliance on air conditioning. In addition, they have historically used a ventilation approach that results in most of the conditioned air being lost to the outside (such as up the elevator shaft) before it reaches the units, which is very inefficient and can lead to poor indoor air quality. An unintended consequence of the City's 2011 and 2014 Rezoning Policy for Green Buildings is that it forced builders away from inexpensive to install, low carbon electric baseboard heat and led them to more expensive hydronic heating systems that use natural gas.

Despite these challenges, rapid improvements can be made immediately through the restructuring of the rezoning policy to reduce exposed concrete, improve window performance, shift towards direct ventilation and heat recovery ventilators, and allowing the use of electric heat once again. These requirements can each be stepped up while technologies for renewable creation of hot water at the scale required in MURBs are encouraged and then become normal practice.

Where low-carbon energy is available by connecting to a Neighbourhood Renewable Energy System, GHG reductions will be reliably and durably reduced. When starting from a context of low GHG emissions (RNES connection), requiring significant additional investment in the building envelope provides highly diminished return (in the form of additional GHG reductions) for the capital costs involved. As a result, the TEDI limits for these buildings, while require some improvements in the envelope and ventilation systems, will be less aggressive than the TEDI limits for buildings that are not connected.

Requirement Type	Typical Outcome of Current Requirements		2016 Limits		2020 Limits		2025 Limits	
	GHGI	TEDI	GHGI	TEDI	GHGI	TEDI	GHGI	TEDI
Bylaw	20.0	55	20.0*	55*	6.0	32	5	TBD
Rezoning	16.5*	46*	6.0	32	5.0	18	0	TBD
RNES Connected	5.5	46	6.0	40	5.0	40	0	TBD

* Typical outcomes of the Rezoning Policy for Green Buildings which has been in place since 2011 will be reflected in the building bylaw in 2017.

This Plan targets an immediate reduction in GHG emissions of 64% for rezoned high-rise MURBs that are not connected to a RNES. This can be achieved by restructuring and updating of the rezoning policy in the fall of 2016 without increasing the cost of new development. The added expense of improved building envelopes and ventilation systems will be offset by the reduced construction costs cost of not forcing developers to install hydronic heating.

3.5.5 GHG and Energy Targets - Office

Office buildings tend to use more electricity and require less heating than residential buildings resulting in much lower GHGI impacts than high-rise MURBs under current policy requirements. This is due to very low use of hot water, ventilation systems with much lower distribution losses, and higher density of occupants and equipment which both emit heat and thereby lower heating system energy demands.

Despite their already relatively low GHGI, there are immediate opportunities for further improvement. This is due to the fact that office buildings typically have a different ownership structure than residential buildings and incremental constructions costs associated with higher energy efficiency requirements can be recovered through operating costs savings. In addition, office building tenants typical place a higher value on green building performance than residential building purchasers or tenants, possibly as a result of corporate social responsibility and/or recognition that green buildings typically foster more productive working environments. As a result, office developers have been demonstrating innovation in building envelope, heating, and ventilation system design that establish proven if not-yet-common approaches for energy and GHG emissions reductions.

Requirement Type	Typical Outcome of Current Requirements		2016 Limits		2020 Limits		2025 Limits	
	GHGI	TEDI	GHGI	TEDI	GHGI	TEDI	GHGI	TEDI
Bylaw	9.5	40	9.5	40	3.0	27	0	21
Rezoning	7.5	30	3.0	27	1.0	21	0	TBD
RNES Connected	3.0	30	3.0	27	1.0	27	0	TBD

This Plan recommends an immediate 65% reduction in GHG emissions for office buildings. Unlike residential develop, new office buildings already rely upon complex mechanical systems and typically have trained and dedicated operations staff. As a result, improvements in this form of development will result from both improved building envelopes as well as a shift to renewable energy heating systems (either connection to a NRES or the use of heat pump technologies).

3.5.6 GHG and Energy Targets - Other Building Types

All other building types (excluding residential and office) such as food service, hotels, retail, light industrial, hospitals, schools, etc. represent an estimated 13% - 16% of new development by area in an average year. Given the wide diversity of building types, the specific energy use characteristics each type, and the small amount of new development of each type specific GHG and TEDI targets have not yet been developed. As better data becomes available and further research can be completed, specific targets will be proposed. In the interim, rezoning policy and building code updates will rely upon a "% better than" approach as compared to established standards. The most obvious shortfall of this approach will remedied by shifting from the existing energy cost efficiency requirements to energy use efficiency requirements.

3.6 Stepping Down GHG Emissions to Zero – Compliance with Targets

Building codes evolved historically to ensure health and safety outcomes. As a result, most compliance and enforcement tools are oriented to ensuring these outcomes. There is a growing awareness across North America that carefully constructed energy policies and regulation have been undermined by the absence of clear compliance processes and enforcement mechanisms. In addition, there are a number of prescriptive requirements for new buildings that do not directly result in reduced energy use or emissions but are essential to help ensure that design outcomes are actually achieved.

A number of tools will be used at different points in the building lifecycle to encourage and confirm compliance with the policy, as well as to assess whether the policy is delivering the intended outcomes. Compliance and measurement of outcomes should be demonstrated at each phase of the building lifecycle, throughout design, construction, and post-occupancy.

3.6.1 Compliance with Targets - Process and Tools

In order to facilitate compliance with building energy and emission performance policy and regulation, requirements and a process for demonstrating compliance must be clearly established and communicated with industry. This will include need to include clearly defined roles for suppliers, design professionals, commissioning agents, permit processing and inspections staff. Digital tools for submitting documentation and doing initial quality control checks, along with training sessions and videos regarding compliance expectations and process will greatly assist in streamlining this essential work for both applicants and staff.

Compliance of the proposed design with the targets described in the preceding sections will be demonstrated by applicants submitting project information in a standardized form that includes how the modeled intensities compare to the targets, as well as key design values that will allow staff to assess the application for possible anomalies or to seek more detail. Key values will include such metrics as overall ventilation rate, heat recovery effectiveness at rated and design conditions, assembly total effective R-value, window-to-wall ratio, and more. This format will serve as a quality control mechanism for applications for re-zoning, and should be updated at each phase of the permitting process.

In addition to requiring compliance of the design with the performance targets, applicants will be required to demonstrate compliance of the building construction through testing of the building air-barrier, commissioning of the building systems, and measurement and benchmarking of the building energy use once occupied.

3.6.2 Compliance with Targets - Air barrier testing

Air-tightness of the building is a critical factor in creating long-lasting, reliable energy performance. To ensure that buildings are designed and constructed to deliver this performance, a successful air-tightness test of the building will be required prior to occupancy permit being granted. There are different standards available in North America to draw from, including the Seattle standard, which has been in effect for over five years now, and the adoption of which would allow industry and officials to draw on local knowledge and expertise.

The Seattle standard requires whole-building air leakage testing to ASTM E779 with some modifications, and buildings must achieve a maximum air leakage of 2 L/s per m² of façade area, at a pressure of 75 Pascals. To help builders achieve this, there are also requirements for the individual components to meet maximum leakage rates, including windows, elevator doors, loading docks and others.

In the Seattle example, buildings that do not meet the standard are required to be re-inspected and re-sealed. In adopting this standard for Vancouver, additional compliance and enforcement measures could be considered, such as mandatory re-testing or re-training of the builder’s quality control staff.

3.6.3 Compliance with Targets - Commissioning

Commissioning is a quality control process of verifying that a building’s systems operate as intended, and is typically conducted by a third-party

Commissioning Agent. The commissioning agent works for the building owner or developer to verify that the building operates as designed, and validates that the design and operation meet the original requirements set out for the building at the beginning of the project. To do this, the commissioning agent periodically reviews the project during all phases of design, construction, and handover. They will focus particularly on active building systems such as the Heating, Ventilation, and Air-Conditioning (HVAC), plumbing, and lighting systems and their controls, to ensure that they operate as intended under a variety of conditions. This process will often include a follow-up review after the building is occupied in different seasons to ensure both heating and cooling system function correctly. Industry standards for commissioning include ASHRAE Guideline 0-2005 and Guideline 1.1-2007, and use of these guidelines are consistent with the requirements of LEED, as well as the City of Seattle Energy Code and California's Title 24 requirements.

Requiring commissioning be conducted by a Commissioning Agent according to these guidelines will support the policy goal of actually realizing modeled efficiency and reduced carbon performance in new buildings.

3.6.4 Compliance with Targets - Benchmarking

An important tool in measuring outcomes once buildings are built is the benchmarking of building energy use and emissions. Benchmarking involves the measurement and monitoring of key performance indicators of the building including energy use (of each major building system) and emissions, and comparing these metrics against those of other buildings in a common database, such as the US EPA's Energy Star Portfolio Manager. While the City is working with the Province and other interested local governments to develop energy benchmarking reporting regulation for all large existing buildings, updates to the rezoning policy will require energy metering of each major building system for new buildings, a benchmarking service contract is in place to ensure this data is compiled post-occupancy, and that a covenant on the property requires the owner to release non-personal data to the City.

> ***Essential Feedback Mechanism***
> *Modeled energy data is an imperfect tool to achieve real and durable GHG reductions. By metering and reporting the actual performance of new buildings, the outcomes of GHG and energy policies can be directly measured, and adjustments can be made to increase effectiveness and efficiency of the requirements. Equally important is that this data will help inform industry as to what building designs, systems, and construction approaches are most effective in achieving real GHG and energy savings.*

3.7 Carbon Neutral New Buildings

The Greenest City Action Plan includes a target to have all new buildings carbon neutral by 2020. Carbon neutrality is achieved through a combination of energy use reduction, transition to renewable energy sources, and/or by offsetting a building's operational GHG emissions with reductions in emissions elsewhere (typically through the purchase of a carbon offset).

This Plan establishes GHG limits by building type to be reflected in the building bylaw that step down to zero for most new building by 2025 and for all buildings by 2030. The Building Bylaw does not provide the flexibility to have a firm, non-zero carbon limit in 2020 (ie the GHGI limits in this Plan) and to also have a limit of zero that can be achieved through the purchase of an offset.

Staff will explore the potential of having GHGI limits in the rezoning policy, where the City has greater flexibility for establishing expectations for new buildings) along with the requirement for carbon neutrality where the latter might be achieved through the purchase of a carbon reduction credit. Carbon reduction credits could be achieved through City (or City recognized) programs that incrementally reduce GHG emissions in Vancouver. This rezoning requirement and the creation of a Carbon Reduction Credit Program could potentially generate an estimated $700,000/year for City (or City recognized) programs, such as home energy retrofit incentives, to generate the required carbon reductions to achieve carbon neutrality. Such a system could be in place between 2020 (carbon neutral requirement) and 2025 when near zero emissions will required in the building bylaw.

Stepping Down GHG Emissions to Zero - ACTIONS

Establishing and effectively transitioning the building bylaw and other City policies to require new buildings meet specific GHG and energy use targets is the cornerstone of this Zero Emissions Building Plan. This will require the following actions:

- Update the Building Bylaw in the fall of 2016 to reflect the targets described in Section 3.5.3 above for 4-6 story MURBs
- Restructure the Rezoning Policy for Green Buildings in the fall of 2016 to focus on key outcomes and reflect the targets for low-rise MURBs, high-rise MURBs, and office buildings as detailed in 3.5.3, 3.5.4, and 3.5.5 above
- Incorporate requirements for calculating and reporting embodied emissions in the restructured Rezoning Policy for Green Buildings
- Beginning in the fall of 2016, periodically review and revise as required NEU connection requirement zones to only mandate connection in areas where low-carbon outcomes capable of achieving these targets have been secured

- Undertake additional research and consultation and report back with recommendations on changes and approaches for embedding future stepped reductions prior to 2020 and 2025 respectively.
- Ensure that new policy and code requirements are supported with investment in the development of compliance processes, tools, and training for both staff and applicants prior to the requirements taking effect
- Incorporate air barrier testing, building energy system commissioning, and benchmarking in the Rezoning Policy for Green Buildings in the fall of 2016 and seek future opportunities to incorporate these into the building bylaw
- Research and consult with stakeholders on the viability of establishing a carbon reduction credit program for achieving carbon neutral buildings through the Rezoning Policy for Green Buildings and report back to Council with recommendations prior to 2020.

4 City Leadership

Achieving zero emissions for almost all new buildings permitted in Vancouver by 2025 will require early leaders to start demonstrating what is possible immediately. Large complex buildings often take 6 years or more from the initiation of permitting to the availability of occupied and operational building performance data to inform the real world effectiveness of the approaches taken. Building suppliers need local demand and lead time to enable their investment in the development, manufacture, and approvals for new products to meet industry needs in Vancouver. Finally, leading designers and builders must gain practical experience with zero emission buildings under a wide variety of conditions and building uses in order to learn what works (and what doesn't) and refine their approaches.

Similar to requiring LEED Gold for new civic facilities when the City first began to support a shift in the broader market towards green buildings, if the City wants to achieve zero emissions for most buildings by 2025, it is essential that it lead by example now.

City commitment to demonstrate that zero emission buildings are possible will:

- Inform what approaches work best under what conditions
- Identify regulatory, permitting, and financing barriers so that these can be removed
- Build real development experience that can be shown to and shared with private industry
- Help catalyze the development of the professional services, builder skills, and the supply of building components required to achieve zero emissions

- Enable the public to experience the benefits of these buildings beyond their operational cost savings

The City is involved in a wide variety of building projects. Some of these projects are already underway while for others, the design team and program have not yet been established. Some new projects are for City owned and operated facilities like branch libraries and swimming pools while a more significant amount of development involves City owned land or City Owned buildings being led by a development partner as an in-kind amenity for the neighbourhood. In these latter cases, negotiation with the development and operating partners will be required to demonstrate the value and secure their commitments to showcasing a zero emissions building approach.

In addition, some City facilities have the opportunity to connect to neighbourhood renewable energy systems and thereby greatly reduce their GHG emissions via this pathway while others must focus on high performing building envelopes.
This diversity of both building types and the nature of City involvement creates many opportunities to showcase leadership in zero emission buildings but it also creates complexity. In order to enable a focus on transformational change on building GHG emissions, City projects that pursue Passive House or a Zero Emissions approach will not also be mandated to achieve LEED gold certification.

4.1 City Leadership - City Owned and Operated Civic Facilities

City owned, developed, and operated new buildings provide the greatest flexibility for demonstrating zero emissions leadership as there are no partners involved with their own interests and limitations to accommodate. Incremental construction costs can be recouped through operational savings. Passive House Certification will be required for all city owned buildings, as well as the requirement to use only low carbon fuel sources unless both or either is deemed unviable. In the case of specialized facilities where the energy demand is less dominated by building envelope losses (such as outdoor pool), while Passive House Certification will be assessed for its suitability as zero emissions approach, other opportunities may be explored in lieu of Passive House Certification to demonstrate leadership with a method that does not include such a strong focus on the building envelopment improvements.

Fire hall 17, one of the next City owned and operated facilities to be built which is very similar to residential development for much of its programming, is being planned to achieve Passive House Certification, , and use only low carbon fuel sources to the greatest extent possible, in order to show early leadership in achieving near zero emissions.

4.2 City Leadership – In Kind Development Contributions

Developers often volunteer to develop a public amenity on behalf of the City such as rental housing or a day care when seeking to rezone a development; the City will work with these partners to assess the viability of these “in-kind” developments to demonstrate Passive House or another near zero emissions approach. This form of “in-kind” development represents a significant amount of new building area each year but complexity can arise when these developments are not stand-alone buildings but are incorporated into a portion of a larger building. While these building portions may need to share mechanical systems with the larger building and it may not be possible to certify just the City's portion to the Passive House Standard, the City will seek to require these elements to demonstrate zero emissions leadership to the extent possible given these limitations.

4.3 City Leadership - Affordable Housing Leadership

The Vancouver Affordable Housing Agency (VAHA) has a mandate to identify where the greatest impact can be made, and act as a catalyst for innovative housing ideas and models. VAHA sees zero emissions buildings and the Passive House standard in particular as an important opportunity for housing innovation.

VAHA has already incorporated the requirement to assess projects against Passive House standards as part of its RFP process and is assessing proponent team capacity and experience to successfully deliver Passive House projects as part of its proposal review. As a result of this "action while planning" VAHA is already aiming to deliver 3510 Fraser Street, one of its very first projects, as Passive House Certified.

In addition, the City has been working closely with BC Housing in the development of this Plan. BC Housing has been a leader in sustainable affordable housing for over a decade and has over 50 buildings registered with the Canada Green Building Council, 34 of which have achieved certification, almost all to LEED Gold. Given all of the

Passive House for Affordable Housing in the U.S.

As of this year, housing agencies in eleven US states have prioritized Passive House in their applications for affordable housing funding, with twenty four additional states actively working to develop similar programs.
The catalyst for this in 2014 when the Pennsylvania Housing Finance Agency (PHFA) and a group of 25 stakeholders including builders, architects and cities initiated a project with the target of all affordable housing in Pennsylvania be designed and constructed to a Net-Zero-Energy-Capable standard by 2030.

The standard proposed to achieve this was Passive House. By incorporating Passive House into its scoring criteria for the award of limited federal funding (via a 9% tax credit) available for affordable housing, nearly 40% of the 2015 affordable housing proponents in Pennsylvania applied as Passive House Projects. The construction cost premium calculated between Passive House projects and non-Passive House was less than 2%. 8 out of the 39 projects that were awarded 2015 funding were Passive House totaling 422 new affordable housing units.

The first state after Pennsylvania to announce a prioritization of Passive House was New York. This caught the attention of the White House, which has incorporated Passive House into their comprehensive plan to bring renewable energy and energy efficiency to households across the U.S.

sustainable new construction projects they completed, BC Housing has found that those with simple designs that rely primarily on passive elements rather than complex mechanical systems use less energy and are easier and more affordable to maintain. This discovery has led to BC Housing exploring other green building certification options including Passive House. They have targeted Passive House certification as a requirement in RFPs for several of recent new construction projects, and have shortlisted two projects in the City of Vancouver on which to pursue Passive House certification.

BC Housing believes that Passive House has the potential to help create affordable housing that is more energy efficient, and more affordable and easier to operate. Furthermore they have committed to compiling and sharing their experience on all Passive House (and other near zero emission) projects to facilitate capacity building in the BC development industry.

4.4 City Leadership - Procurement Process

Additional City leadership to demonstrate a more cost effective process to achieve high quality, highly energy efficient buildings that the City should explore and pilot is in new building design procurement. Constructing an innovative public building begins with the procurement process. As evidenced in places as diverse as The Netherlands and Edmonton, AB, changing the process by which governments procure their green buildings can have a significant impact on the architectural, lifecycle cost and energy performance outcomes of the buildings constructed. Through comparing the procurement changes that were implemented in jurisdictions seen as leaders in procuring exemplary and innovative buildings, a number of commonalities are present:

- Creating a multi-staged RFP process that creates a design competition focusing on a streamlined set of selection criteria that value architectural excellence, awards, and design;
- Transparently stating the project budget in the RFP and requesting that teams prepare their submissions to best demonstrate near zero emissions allows for greater creativity and typically requires an integrated team approach thereby helping to reduce risks;
- Creating the space for dialog with invited, shortlisted firms following the RFP in order to understand the proposed designs, and potential technical or economic risks; and
- In Europe, using Building Information Models (BIMs) as a requirement for project management and a part of the proposal submission package.

The BC Construction Association launched a “Construction Innovation Project” in 2016, with the goal of facilitating change in industry and government to meet the building and infrastructure needs of the 21st

Century. One component of this is a recommendation for government and industry to launch an Innovative Procurement Initiative, recognizing that the current status quo is stifling, rather than catalyzing innovation.

> *As it stands, the procurement process needs to be fixed. There has to be a shift from a culture of "lowest bid" to focus increasingly on quality and "whole-life" value.* – BC Construction Association, December 2015 [1]

City Leadership ACTIONS

In response to these opportunities and challenges, this Plan commits the City to:

- Build all new City owned facilities, and VAHA developments to be Passive House Certified and use only low carbon fuel sources, or other near zero emissions approach where technically, financially, and operationally feasible
- Require partners undertaking in-kind developments on behalf of the City to pursue Passive House Certification and use only low carbon fuel sources, or other near zero emission outcomes for the entire or City-portion of new developments where viable
- Direct City staff to investigate and pilot new procurement process(es) for City-led Passive House or alternate near zero emissions new development and assess/showcase the value of such a process as a tool for industry change
- Leverage the experience gained from the above actions to inform a more specific policy to define and govern outcomes for "City-led" projects by 2018.

5 Catalyzing Leadership

Rapid and effective transformation of the entire local development and building industry will require more than defined GHGI and TEDI reduction targets and government leadership. New design approaches must be learned, tried and refined. While technologies exist to achieve zero emissions buildings, many of the required elements such as super-efficient windows, prefabricated insulated wall panels, heat recovery ventilators, and air source heat pumps for domestic hot water are not readily available in our local market due to (current)

> *Supporting early innovators will signal market demand for super-efficient building components, support building design evolution, catalyze new training and education initiatives, and build broader industry confidence that zero emissions buildings are achievable.*
>
> *Ultimately, early showcase projects by public and private sector leaders will reduce the incremental costs of zero emission buildings and inform effective, streamlined, and flexible future regulations to ensure all buildings ultimately achieve these outcomes.*

[1] https://www.bccassn.com/media/bcca-report-construction-innovation-2016.pdf

low demand. Finally, it takes time for local industries to research, develop, and get approvals for new building products. In order to be competitive and to flourish; they need local demand for zero emissions buildings now in order to commit to these investments.

In order to achieve zero emissions for most building types by 2025, it is essential that the City develop tools to encourage innovation and offset incremental costs so as to catalyze voluntary leadership by private developers in demonstrating effective approaches for achieving zero emission new buildings as soon as possible.

5.1 Principles for Effective Catalysts

Preliminary staff analysis of effective (and less effective) approaches to catalyzing early leadership indicates that a range of tools tailored to the opportunities and challenges of specific building types will be required. The following principles will guide the development of these catalyst tools:

- Appeal and Clarity – catalyst tools must be tailored to local market conditions and priorities so as to provide clear and measurable appeal to builders and developers

- Timeliness –certainty on whether or not a proponent will qualify for and be able to access the catalyst must be provided in a timely manner in order to influence key project decisions

- Scale – in order to be effective, catalysts must help drive sufficient scale of demand for zero emissions buildings and their components to attract investment and competition to effectively reduce the incremental costs

- Diversity –experience and confidence in effective zero emission buildings must be fostered amongst multiple designers, developers, and builders before zero emissions can be expected for broad segments of the market

- Consistency –criteria and expectations regarding zero emissions buildings must remain fairly consistent from year to year to enable industry to focus on the desired outcomes and optimize their solutions by learning from prior projects

Underlying these principles is the understanding that market transformation does not begin to accelerate until leadership and innovation are supported; it is of paramount importance that effective tools to catalyze zero emission building leadership are made available as soon as possible, even if the catalyst program is not of sufficient initial scale or includes some imperfections. Early and visible success will attract not only participants but partner commitments and program details can be refined over time.

Note that while a catalyst program will be initially developed for zero emission new construction, consideration will be paid to the potential for expanding the partnerships and structures created to also deliver catalyst tools for deep building energy/emission reduction retrofits in the future.

5.2 Catalyst Approaches

Before describing possible catalyst tools (in Section 5.3) that will be considered for to reward private leadership, three general approaches have been identified and should be explored as standalone or a combination of options for each targeted building type.

A. Fixed Criteria: offering a benefit or reward for developers that commit to building to a specified set of criteria (such as Passive House). This approach is very useful when there is a high degree of certainty in viable and optimal outcomes as these can be clearly defined and there are no delays created in determining if a proponent qualifies.

B. Component Offers: offering a benefit or reward for building that utilize a defined building element such as a heat pump for domestic hot water or super-efficient windows. This approach has the benefit of generating high volumes of market demand and industry experience with a given technology to rapidly increase competition in its supply. Driving demand for key zero emission building elements can bring down the cost of a more complete building approach such as Passive House without limiting uptake to those proponents willing to make that full commitment. In addition, component offers can be structured to simultaneously support building energy or emissions retrofits when the same technology could easily be used in existing buildings.

C. Project Competition: offering a prize or benefit for winners of a call for projects competition assessed and judged against defined criteria. This approach can be very powerful when desired and potentially competing outcomes can be generally defined but when win-win solutions or the optimal balance between these outcomes requires testing and experimentation. This approach enables leading designers and builders to demonstrate what is possible (and what is not) to their industry peers and can be used to develop ground-tested, well informed policies with already built showcase projects.

As an additional benefit to this approach, competitions are inherently interesting to the public and would create an opportunity to engage and educate Vancouverites on the appeal and benefits of zero emission buildings. One notable disadvantage of this approach is that it can increase project timelines as proponents go through the call for competition submission, evaluation, and award process.

Brussel's BATEX Program

The Brussel's Region successfully partnered with their building industry to transition new buildings from amongst the least efficient in Europe to having all new residential and office buildings meet Passive House performance in just over seven years. This was achieved through the BATEX or Exemplary Buildings program.

BATEX offered a prize of up to 100 euros per square meter through 6 calls for projects judged to be of exemplary design and fit with their neighbourhood that achieved the highest levels of energy efficiency while remaining cost effective. The program aimed to stimulate innovation and demand for high performing buildings by encouraging private sector leaders to demonstrate what was possible and the best approaches for achieving these aims.

The BATEX program catalyzed private sector leaders to innovate and demonstrate to their peers as well as to the government how best to achieve multiple but clearly defined objectives. 243 projects representing over 6 million square feet of new development participated in the program over a period of seven years. BATEX built sufficient local industry confidence and capacity to deliver beautiful and high performing buildings to enable the introduction of effective legislation requiring all new buildings to achieve passive house performance levels beginning in 2015.

http://document.ibgebim.be/opac_css/elecfile/BRO_BE_Batex_EN_BR.pdf

5.3 Catalyst Tools

A wide range of tools are potentially available to the City to catalyze private leadership in demonstrating cost effective and attractive approaches to zero emission building. These should be explored in the context of the challenges and opportunities presented by specific building types and in consideration of the principles established in Section 5.1:

A. City Charges and Taxes: reducing or waiving City charges such as permit fees, development cost levies, or even property taxes would decrease the overall project costs and could be an effective tool to catalyze zero emission buildings. In considering these tools, administrative costs and the value of lost revenues will need to be addressed.

B. Expedited Permitting: developers and builders have indicated that decreased permitting times would reduce their costs and risks in a project and could be an effective catalyst tool. That said, this approach might be very complex and time consuming to establish as there are many steps to a permit approval and expediting each of these may be impractical; alternatively creating a whole new process could also be challenging especially for a time limited incentive program. In addition, large complex projects such as those going through a rezoning process involve complex back-and-forth negotiations which it may be difficult to expedite with certainty.

C. Public Benefit Negotiations: If the incremental costs for early adopters of Passive House or other zero emissions building approaches could be defined and taken into account when negotiating public benefit expectations for large new developments, the overall project costs and therefore the need for other catalyst tools would be reduced.

D. Parking Requirements: Below grade parking can be expensive to build and for small or unusually shaped sites, meeting the City's parking requirements can sometimes make development unviable. There may be opportunities to allow greater use of existing parking incentives such as those provided for additional bicycle parking or the provision of car sharing vehicles and parking for zero emission buildings.

E. Design Prize: A competition with a cash prize awarded for the winning submission for attractive, cost effective designs that effectively achieve near zero emissions for various building types could be a powerful catalyst tool. Design teams could be motivated by the offered prize and potential prestige to overcome design challenges. In addition designs could be made publicly available to showcase how to design zero emissions building and if the designs are flexible enough to be useful in a variety of contexts, they would reduce the overall cost of building a near zero emission building by avoiding the need for custom design expenses.

F. Exemptions to form of development and land-subdivision requirements: exemptions or partial relaxations of City requirements for land-division or form of development might be an effective catalyst with negligible negative impacts if carefully limited in scale and duration. For example, one builder recently offered to commit to build two Passive House certified homes if permitted to subdivide a 50' lot into two 25' lots (smaller than City standard sizing). In addition, design guidelines protecting neighbourhood character are developed to apply to an entire zoning area, typically in older single family neighbourhoods. These guidelines can result in very complex building shapes which make it more challenging and costly to build highly efficient envelopes such as those required to meet Passive House. A limited number of exemptions to these guidelines for early Passive House showcase buildings might be on avenue gain neighbourhood feedback on new, energy efficient building forms while learning what creative designers and builders can do to address neighbourhood fit.

G. Buildable Area: Allowing even modest amounts of additional buildable area for near zero emission buildings would be a very effective catalyst for private leadership. That said, doing so in an outright fashion would require extensive public engagement, could take a significant time to implement, and could lead to land speculation – a high cost for a temporary incentive. Enabling modest floor space exclusions at the Director of Planning discretion for passive design buildings or features might offer an opportunity to find an effective balance and create a catalyst for zero emission buildings.

5.4 Catalyst Tools for Targeted Building Types

5.4.1 Catalyst Tools - Detached and Row House Developments

The relatively small size and simplicity of detached and row housing make the scale and administrative ease of a permit discount program for early leaders in demonstrating near zero emissions building approaches like Passive House for these buildings viable and could be launched in the near future. For detached housing, it would be beneficial to explore the ideal balance between GHG reduction levels via envelope and simple mechanical solutions, cost, and neighbourhood fit. This form of development would be a good candidate for a design competition with a cash prize. Criteria for judging winners would include envelope performance, GHG reduction, replicability of solution (eg cost effectiveness), and neighbourhood fit.

Targeted technology incentives for domestic hot water heat pumps and highly efficient HRVs and windows may be complementary to the competition based approach. Given Vancouver's concurrent focus on supporting and piloting of incentives for detached home energy retrofits, targeted technology incentives might be supportive of both objectives and should be explored with other levels of government.

Additional opportunities to catalyze zero emission detached and row housing that need to be explored further include: limited and time bound relaxations to lot sub-division restrictions and neighbourhood design guidelines and/or expedited permitting (especially in outright zones).

Especially important in this sector are efforts to engage local builders from ethnic communities to inform the incentives offered for these building types to ensure universal appeal and access considerations are incorporated.

5.4.2 Catalyst Tools - Low-Rise MURBs

Low-rise (4-6 story) MURBs are an ideal building form for achieving Passive House. As this Plan recommends the 2020 update of the Green Building Policy for Rezoning's require these buildings meet the Passive House standard and given the body of global and rapidly developing local knowledge for how to cost effectively do so, catalyst tools for this form should be focused on meeting Passive House outcomes.

In addition to the catalyst tools to be explored for detached housing, the synergies demonstrated between Passive House and low-rise rental MURBs – both in built form and in the business case of their development, mean that opportunities for alignment between tools to catalyze zero emission buildings and the Rental 100 program need to be explored.

> ***Passive House MURBs Underway***
> *Presently there are 3 passive House Multi Family projects (comprising approximately 200 homes) under construction in Vancouver. In addition there are two multifamily projects in permitting comprising another 100 homes. Most projects are rental projects, with one market condo project and one market cohousing project.*

5.4.3 Catalyst Tools - High-Rise MURBs and Offices

Given the predominance of concrete and glass in the construction of high-rise MURBs combined with the limited amount of global data on the incremental costs, code barriers and constructability, establishing firm TEDI outcomes for zero emission buildings beyond those established for 2016 and 2020 will require additional research and pilot projects undertaken in partnership with private developers. A design competition to show case attractive, cost effective, near zero emission high rise building design approaches may be an important tool. In addition, understanding and proving out viable electric and heat pump solutions for domestic hot water in MURBs will be critical in order to achieve zero emissions for new MURBs by 2025.

Supporting early developer leadership will require tools to share in the risk and incremental costs of innovation. In addition to the tools to be described for detached housing, public benefit negotiations for high-rise towers may be a key tool in this sector.

Finally, while an envelope focused solution (beyond what is envisioned for the 2016 rezoning policy update) is less critical for the office sector to achieve zero emissions new buildings, it is also anticipated that the occupant comfort and productivity benefits combined with lower expected incremental costs of achieving Passive House envelope outcomes mean that a more modest incentive may be sufficient to catalyze leadership and innovation in this sector.

5.4.4 Catalyst Tools - Leadership on Special Sites

Some projects and sites in Vancouver present unique opportunities to demonstrate leadership in establishing neighbourhood renewable energy systems or building to Passive House performance outcomes. These are sites where, even though the City may not be leading the development, it is a key partner in the project moving forward or where environmental leadership (beyond general rezoning policy requirements) are already an expectation for the site. In these cases, the City should work collaboratively with the project developer to assess if there are mutually beneficial opportunities for developing the site to the Passive House levels or performance when an NRES is not viable.

Examples where there may be opportunities for the City to partner with a developer to demonstrate leadership might include:

- Vancouver Art Gallery
- Jericho Lands
- Some large development sites along the Cambie Corridor
- Etc

Even if the permitting and development of the site is still a number of years away, there are immediate benefits to committing to zero emissions leadership. Committing or establishing requirements to build to the Passive House standard for a large future development signals to industries such as window and prefabricated wall manufacturers that there will be a strong and ongoing local demand for high performance building products. Given that code and policy requirements will be evolving rapidly, early commitments such as these pose low risks given that by the time development occurs, bylaw or rezoning requirements may require near or zero emissions anyway.

5.4.5 Catalyst Tools – Financing Approaches

A key opportunity to catalyze developers of condominium projects to invest in meeting zero emission buildings before they are required to do so would be the creation of and/or increased use of innovative financing tools.

Smart investments in reduced energy use will pay for themselves over time. The challenge faced by condominium developers is that since they immediately sell the buildings they develop, they cannot recover their incremental capital costs spent on energy efficiency improvements through the resultant operating cost savings.

> ***Energy Efficiency Strata Loan for Condos with City Loan Loss Guarantee***
>
> *An energy efficiency loan program for new condos was first established in North America by the Toronto Atmospheric Fund (TAF) to overcome the energy efficiency split incentive. Condo developers in Toronto were previously unwilling to construct buildings that exceeded minimum energy standards because of the increased sale price due to higher construction costs and the resulting loss of competitiveness with other new developments. These barriers were overcome by TAF loaning the developer an amount equal to the incremental costs to construct a building that exceeds the building code energy performance by a specified percentage. The loan is assigned to the condominium home owners association to repay. Through energy modelling, the energy upgrade measures beyond code requirements were designed so that the monthly energy cost savings would exceed monthly loan repayment. Through marketing and the disclosure documentation required by law, potential buyers were made aware of the energy performance and the anticipated cost savings associated with the measures, as well as the loan that would be required to repay through their monthly condo fees. This tool holds significant potential for the voluntary construction of near zero emission condos in Vancouver, as it:*
>
> - *Removes the split incentive for energy efficiency in new construction;*
> - *Creates a clearer picture of energy costs for the buyer; and*
> - *Makes condo buyers able to afford a higher performing building for the purchase price of a code minimum alternative.*

Innovative tools exist where the incremental costs of efficiency are financed separately from the rest of the development costs. The loan for these costs is transferred to strata which repays this loan through a line item on the strata fees collected from owners.

Catalyst Tool ACTIONS

Developing and testing new design approaches, fostering the skills required to building to achieve zero emissions, and creating demand for new high performing building products to establish local production capability all require time. In order to require most buildings to achieve zero emissions by 2025, it is essential to begin providing catalysts for private sector leaders to demonstrate cost effective approaches to zero emissions building immediately. This will require catalyst tools for detached and row housing as well as multi-unit residential buildings, negotiations with developers of special sites with unique leadership opportunities, and the exploration of innovative financing tools as summarized by the following actions:

- Develop a program to provide catalyst tools such as design competitions, expedited permitting, permit fee reductions, or others for zero emissions detached and row house buildings targeting dozens of units per year for at least three years at which time the program should be reassessed
- Explore and recommend additional catalyst tools such as supplementary incentives for the Rental 100 Program for passive house low-rise multi-unit residential buildings targeting hundreds of units per year between now and 2020
- Explore and recommend catalyst tools for high-rise MURBs and office buildings structured to inform the ideal balance between high-performing building envelopes, renewable energy technologies, and cost effectiveness
- Engage developers of special sites in Vancouver to identify opportunities to develop these sites so that buildings achieve zero or near zero emissions

Explore and recommend required City actions to support the development and availability of innovative financing approaches for zero emissions or near zero emissions condominium buildings so as to decrease the need for other catalyst tools

6 Capacity Building

Designing and constructing near-zero emission buildings requires specialized knowledge and skills. To date, the local building industry has had limited experience in these types of buildings, particularly compared to our counterparts in areas of Europe. The local knowledge and skills that do exist are currently with a small group of early adopters who have pursued Passive House standards on a handful of very recent projects. Similarly, many Vancouver residents are unaware of zero emission buildings and the long-term benefits these buildings provide.

In order to rapidly transition to near-zero emission buildings in Vancouver, the capacity of the building industry will need to be increased. This means providing resources and training, encouraging knowledge-sharing and supporting peer-to-peer learning. Lessons learned by one designer can help another avoid similar pitfalls. Similarly, major energy savings realized on one project can be adopted by others to make similar gains. Capacity building will also include strengthening the relationship between the City and the building industry, with an emphasis on single-family-home builders to ensure that they are well supported with training and resources.

The following section outlines the recommended actions for rapidly increasing capacity in Vancouver's building industry to design, build and operate near-zero emission buildings. These actions recognize and build on the work already being done by various levels of government, industry associations, academic institutions and professional bodies. Many of the capacity-building actions recommended below will be delivered in partnership with other organizations.

6.1 Capacity Building - Generating knowledge

Near-zero emission buildings are already being built in Vancouver. These projects provide ideal quick-start learning opportunities. To maximize the learning potential, it's recommended that funding be offered to "early adopter" designers of near zero-emission buildings to produce written case studies that summarize their design methodology, design outcomes, successes and lessons learned on the project. Leading designers have told us they would be willing to "share their story" so that others can learn from them – replicating and building upon their successes and avoiding similar pitfalls. The specific terms of the case study would be refined through consultation with the design community, but would likely include design methodology, key design details (wall assemblies, mechanical equipment, etc.), challenges encountered, project costs, and modelled energy performance.

In addition to the written case study, designers will be required, as a condition of the design funding, to offer technical tours of their buildings and/or to present their project at a local knowledge-sharing conference or event. A technical tour is an ideal way for other architects, designers and engineers to see a zero emissions building first-hand and ask questions directly to the design team. This tour would look at the nuts-and-bolts of the building and would be geared towards peers in the industry. (Public tours of zero emissions buildings are discussed in Section 6.2).

Secondly, it's recommended that funding be provided to support the creation of new resource guides and training opportunities, to address industry-identified knowledge and skills' gaps. The production of resources such as reports, design details, and construction best practices, would be done through partnerships with existing organizations such as the Homeowner Protection Office, BC Hydro, the Architects Institute of B.C. The BC Construction Association, for example, has indicated that resources aimed at improving procurement practices would lead to more innovation and leading-edge construction. Similarly, this funding would support training that would be delivered through a partner organization (an example would be to offer subsidized rates for Canadian Passive House Institute's certification courses). While some knowledge and skills gaps are known today, it's expected that additional gaps will emerge as more designers and builders begin to tackle near-zero emission buildings. The case studies produced by designers will be specifically required to identify gaps.

Lastly, projects selected under the building incentive program will be required to provide post-occupancy energy performance reports, which will compare measured energy consumption with the modelled energy performance of the buildings. The energy performance report will include an audit, to identify the potential causes of difference between the modelled and actual performance. Through our consultation with the building industry, stakeholders identified actual building performance as a key knowledge gap today as virtually no publicly accessible post-occupancy monitoring information is available. The performance monitoring reports are intended to be public, though there may be some information that is private. The information gained through evaluating the operations of zero emissions buildings will be invaluable in determining if and when new design approaches are effectively in reducing GHG emissions and for refining design approaches going forward.

6.2 Capacity Building - Public Engagement

Stakeholders have told us that there is currently limited market demand for high-performance buildings, largely because of lack of awareness. Further, we've heard that there are persistent "urban myths" about the cost and performance of Passive House-like buildings. These urban myths persist in the public as well as amongst developers. A key piece of capacity building is therefore aimed at sharing information with the public about the real cost and performance of high-efficiency buildings, as well as promoting the other benefits of zero emissions buildings such as improved air quality, quietness and better temperature regulation.

As a condition of receiving design funding (Action 6.1.1), designers will be required to facilitate a public tour of their high-performance buildings. This tour will be geared toward the general public and not technical experts. The intent of the tour will be to showcase the aesthetic quality of the building, its high livability (quietness, natural temperature control, etc.) and its energy performance features.

A strong communication program is critical for engaging the public and raising awareness and demand for zero emissions buildings. Leading jurisdictions such as Brussels have implemented successful campaigns that featured regular high-profile zero emissions building ribbon cutting ceremonies, high-quality photography, glossy journals, and coffee table books to convey the aesthetic quality of Passive House buildings. These programs went beyond simply conveying information--they help build cachet around zero emissions buildings. It is recommended that a similar communications program be developed for the zero emissions building program, customized for the Vancouver market, which would include a variety of forms and mediums.

It's also recommended that innovative and aesthetically pleasing zero emissions buildings in Vancouver be recognized in both public and industry settings. This could be done in conjunction with existing building conferences and awards programs and/or through a dedicated Zero Emissions Award and Recognition Event. These showcases would provide opportunities to recognize leading developers, designers and builders. It would also raise the public profile of high-performance buildings (Wood Works BC's annual Wood Design Awards draws hundreds of attendees). These events could be coordinated to include public tours of the zero emissions buildings.

6.3 Capacity Building - Sharing knowledge

A key piece of the Zero Emissions Building Plan is ensuring that knowledge gained by early adopters is disseminated widely such that the capacity of the industry as a whole can be accelerated. It's particularly important to support designers and builders who in the past may not have been fully engaged. Single-family home builders, for example, will need new tools and training to successfully deliver zero emissions buildings. Focussing specific effort on these builders will mean a smoother transition and ultimately a more skilled workforce.

Peer-to-peer learning has been shown to be a one of the key ways to increasing knowledge in the building industry. For example, New York's Building Energy Exchange (BEEx), a non-profit created and partially supported by the City of New York, has helped build a strong green buildings' network in the city (focussed primarily on architects and designers) and facilitates ongoing peer-to-peer learning events and exhibitions. BEEx has become a hub for the zero emissions building industry in New York. Closer to home, Wood Works BC is a highly successful capacity-model with a strong educational and networking component. Over the past two decades, Wood Works BC has been particularly effective at identifying barriers to wood construction and working with stakeholders to remove those barriers.

Building on these successful models, it is recommended that a Centre of Excellence for Zero Emissions Building be established in Vancouver for near-zero emissions buildings. The Centre of Excellence will a central hub to disseminate case studies and resource guides, host panels and events, facilitate tours, share performance data from demonstration buildings, link with education partners to support and promote training, and identify barriers and knowledge gaps. The centre will serve as a neutral space where developers, designers, and builders can voice their concerns and work with City staff to resolve them. In this way, the centre will act as the "living room" for the local green building community, where relationships can be built. The Centre could also be used to deliver mission-related programs on behalf of the City and/or its partners. There is currently no such venue in Vancouver and this has been identified by stakeholders as a missing piece in the local green building industry.

The centre of excellence is envisioned as an independent entity focused on building industry capacity to design, build, and operate near zero emissions buildings. It would be supported by and serve a coalition of partners with a strong interest in transforming the building industry not just in Vancouver but across BC. A number of stakeholders including BC Hydro, BC Construction Association, Wood Works BC, SFU Properties Trust, BCIT, BC Housing, the provincial government and other local governments have expressed a strong interest in partnering with the City to create and support the ongoing success of a Centre of Excellence for Zero Emissions Building either through providing funding, sharing data, supporting programming and events, or partnering on training and resources. The Centre is expected to offer far-reaching benefits in terms of greenhouse reductions, education and skills training, and economic growth. The purpose, key roles, and organizational structure are outlined below.

Purpose

The Centre of Excellence for Zero Emissions Building will serve the building industry by compiling and sharing knowledge, identifying and facilitating the removal of barriers and building a community, with particular emphasis on groups that may not have been fully engaged in the past.

Key functions

The main functions of the centre of excellence for Zero Emission Building are as follows:

1. To provide a central source of information and resources, including case studies, performance monitoring reports, technical papers, and design details.

2. To ensure industry segments such as multicultural single-family home builders who often do not access new information and training through conventional means are engaged and supported in this transition.

3. To identify knowledge gaps and regulatory/permitting barriers to near-zero emissions building and work with partners to identify and implement solutions.

4. To serve a neutral space to facilitate dialogue between developers, designers, builders and the City and build relationship through networking events, panels, and exhibitions.

5. To showcase zero-emissions buildings to the public through a range of communications, tours, public space activations, and an annual awards event.

6. To administer mission-related programs, such as building incentive programs, on behalf of the City and/or partner organizations.

Organizational Structure

The Centre of Excellence for Zero Emission Building is envisioned as an independent entity accountable to dedicated board of directors for implementing its agreed-upon mission. Ideally, an existing third-party organization will operate the Centre of Excellence to minimize the start-up time required and to leverage existing organisational resources and staffing. The third-party organization will need to have a proven track record in delivering large projects, particularly in work related to sustainability and buildings, and be able to attract funding on an ongoing basis. The Centre will need a dedicated leader and several staff to administer the programming, serve as a knowledge hub, and ensure ongoing funding support. To this end, it is anticipated that an executive manager would be needed with training and experience in the field of architect and green buildings. This manager would oversee the operation of the Centre and guide the overall programming. It is anticipated that the Centre will need at least two additional staff with some background in the field of green buildings and strong communications skills. In order to ensure the centre is well managed, accountable for implemented it agreed to mission, and connected to key private and public sector partners, a separate board of directors or steering committee will be established. The board of directors or steering committee will include representatives from all major funding partners, as well as from key stakeholder groups.

The centre for excellence is intended to be a physical space. The space would provide office space for staff as well as exhibition space, to show green products and technologies related to near-zero emissions buildings as well as host training sessions, dialogues and networking events. Ideally the space would be able to accommodate speakers and small panel discussions. The physical space could be located within a building currently operated by a partner organization or in a building owned by the City. The space should be in a central located easily accessible by practitioners as well as the public (i.e., it should be visible).

In addition to a physical space, the Centre will have a comprehensive website, which will serve as a publicly-accessible repository for case studies, technical report, performance monitoring report and design details. The website would include a calendar of events and training, including courses offered by partner organizations such as AIBC, APEGBC, and HPO. In addition to the website, the Centre would include a variety of social media platforms to communicate with stakeholders and the public.

The organizational structure and financial model for the Centre of Excellence, including the physical space, staffing, board/steering committee, and funding sources, requires significant detailed planning. This planning will be done in partnership with key stakeholders over the next six months, at which time a detailed report will be brought back to Council for consideration.

NYC's Building Energy Exchange

The Building Energy Exchange (BEEx) was established in 2014 by the City of New York as a non-profit. The City provided seed funding and continues to provide office and exhibition space. BEEx currently has four full-time staff and is overseen by a board of directors made up of government and industry representatives and leading professionals.

Be-ex initially focused on lighting retro-fits but has since expanded to energy efficiency, specifically for commercial buildings larger than 50,000 square feet. They focus their capacity-building efforts on architects and designers as these professionals are involved in almost all projects..

Be-ex's capacity building work includes:

- *Hosting exhibits, panel discussions, speakers and networking events*
- *Serve as a resource hub for energy efficiency and lighting*
  - *Courses*
  - *Case studies*
  - *Technical reports*
- *Provide an online calendar of courses and training opportunities, many of which are delivered by partner organizations*
- *Act as a liaison between City and architects/designers*
- *Provide space for stakeholder engagement on City-led initiatives*
- *Establishing formal partnerships with industry stakeholders to share information and resources*

In a relatively short period of time, BEEx has established itself as a recognized hub for the local architectural and design community. They have built a sizable, engaged audience interested in near-zero emission and passive house buildings.

6.4 Capacity Building - Removing Barriers

Existing City of Vancouver regulations, policies, design guidelines, and requirements that establish expectations and requirements for new buildings can create challenges to building zero emission buildings.
For the past 5 years, the City has been working to identify and resolve barriers to higher performing buildings. One example was the provision of a wall thickness exclusion for highly insulated buildings so that they are not penalised with a loss of allowable building area. Recently Council approved amendments for detached houses in RS-1 zones (the majority of single family lots in Vancouver are in RS-1 zones) that provide the Director of Planning discretion to relax height and setback requirements for projects that achieve Certified Passive House to make use of the square footage gained from the wall thickness exclusion.

This approach must be expanded to other zones and building types as slightly thicker walls and higher roofs are required to provide highly efficient building envelopes.

More barriers have already been identified and more will emerge as the City and private sector leaders accelerate the development of near zero emission buildings. Resolving some of these barriers will be straightforward, such as accepting Passive House energy model results to show compliance with policy and bylaws while others will require the careful balancing of several public policy objectives.

Interdepartmental cooperation and accountability will be required to modify policies, bylaws and guidelines and create flexibility to resolve design challenges such as:

- Simple, cubic building forms are most energy efficient (and contribute to the ease of installing insulation and air barrier systems) but can conflict with step back, access to light, and "traditional character" requirements that increase building articulation and therefore roof and wall area as well as complexity
- Orientation for effective solar access and logical location of solar panel mounting can conflict with the form and material guidelines in some district schedules. The main conflict is where the guidelines speak to traditional roof forms and materials as seen from the street view, which may be the only aspect useful for solar installations.
- Policies that require builders to provide access to private outdoor space leads to the proliferation of cantilevered balconies which add cost and create complex heat loss challenges; alternative options for the provision of suitable private or semi-private outdoor spaces must be explored to balance affordability, sustainability and liveability outcomes.

Vancouver's Building By-law can also create barriers to zero emissions buildings. For example, the By-law requires a ducted kitchen exhaust from a range hood regardless of whether the range is gas or electric. In other jurisdictions, the use of a recirculating hood with charcoal filter paired with an electric range and a commissioned heat-recovery-ventilation unit is a permitted approach for maintaining indoor air quality. Similarly, the Bylaw considers wood buildings and some highly energy efficient window framing materials such fibreglass as to be fire hazards in buildings over 4-6 stories in height. There is growing a body of evidence that these materials can be safe if their use is properly regulated. Research into these challenges and alternate approaches is required to inform possible By-law changes.

Finally, the importance of City staff training on Passive House and zero emission building techniques and materials cannot be understated. Removing barriers in our regulations, policies and guidelines hinges upon City staff being able to understand this work and its intent, and feel comfortable implementing it.

Capacity Building ACTIONS

In order to successfully transition the majority of new buildings to zero emissions by 2025 while fostering the greatest opportunities for local economic development, it is essential that the City and other invested stakeholders work together to foster the capacity to design, build, permit, and produce components for zero emissions buildings. This will require investments to generate and share knowledge, increase public awareness, and to remove policy and permitting hurdles as summarized by the following actions:

- Provide funding for designers to prepare case studies and lead technical tours of zero emissions buildings
- Develop resource guides to document effective approaches to common challenges
- Invest in training programs for designers and trades
- Require post-occupancy performance evaluations of zero emissions buildings
- Organize opportunities for the public to learn about and experience the quality of zero emission buildings through the showcasing of beacon buildings, provision of public tours, and by making passive house units available for short term occupancy
- Establish a Centre of Excellence for Zero Emissions Building and website to foster the development and sharing of knowledge and skills regarding effective approaches to zero emissions buildings
- Identify and resolve City policy and process barriers to passive house and other near zero emission buildings
- Provide training and tools for City staff to facilitate permitting of zero emissions buildings

7 CONCLUSIONS

Meeting the City's 2050 target to use only renewable energy will require the majority of new buildings be designed and built to achieve zero emissions by 2025 and all new buildings to achieve this target by 2030. While meeting these aggressive targets and timelines is achievable, especially given that our electricity is almost 100% renewable already, it will require a restructuring of the City's policies and tools as well as leadership by the City and industry to demonstrate effective approaches for achieving this goal. It will also require a collaborative approach amongst many stakeholders to share knowledge, remove barriers, and ensure that the required skills are developed and widely available in BC.

This collaborative effort to transform how new buildings are designed and built will not only reduce their GHG emissions but will also make them healthier and more comfortable for their occupants. In addition, this innovation in the building industry will make buildings more resilient to changes in weather, climate and energy prices while providing significant opportunities for local professionals, trades, and industries.

Organizations Involved in the Development of the Zero Emissions Building Plan

Energy Utilities

- BC Hydro (cofounded research and consultation)
- FortisBC
- Creative Energy
- River District Energy

Industry and Professional Associations

- Urban Development Institute BC
- Greater Vancouver Homebuilders Association
- BC Construction Association
- Architectural Institute of BC
- Association of Professional Engineers and Geoscientists of BC
- International Building Performance Simulation Association – BC Chapter
- Fenestration Association of BC
- RealPAC

Public Sector

- BC Ministry Responsible for Housing, Building and Safety Standards Branch
- BC Ministry of Energy and Mines, Electricity and Alternative Energy Division
- Cities of Richmond, New Westminster, Surrey, Victoria, Burnaby, North Vancouver, New York, Seattle, and Brussels
- Metro Vancouver
- BC Housing and the Homeowners Protection Office

Non-Governmental Associations

- Pembina Institute
- Canadian Passive House Institute
- Building Energy Exchange (New York)
- Wood Works BC
- Canadian Green Building Council
- Lighthouse Sustainable Building Centre

Academic Institutions

- UBC
- SFU Community Trust
- BCIT

Consultant Team

- RDH Engineering
- Integral
- BTY
- EnerSys
- Morrison Herchfield
- New Buildings Institute

<u>Companies</u>

- Recollective
- Perkins and Will Architecture
- Cornerstone Architecture
- Lanefab Design/Build
- Peak Construction
- Insightful Healthy Homes
- Lang Wilson Practice in Architectural Culture
- DLP Architecture
- Brantwood Consulting
- Numerous additional builders, window manufacturers, and building system supply companies

TIMES COLONIST

B.C. ferries will head to Poland for refits

Andrew Duffy / Times Colonist

March 25, 2016 06:01 AM

Spirit of Vancouver Island was built in 1994. Photograph By File, Times Colonist

With shipyards in Vancouver and Victoria both choked with work, B.C. Ferries will for the first time send vessels offshore for refits in 2017.

A Polish shipyard has won a $140-million contract from B.C. Ferries to conduct the mid-life upgrades of the two Spirit-class vessels.

Gdansk-based Remontowa, the largest ship-repair yard in Poland, won the contract after a competitive bidding process.

B.C. Ferries spokeswoman Deborah Marshall confirmed it is the first time the corporation has sent a vessel offshore for refit.

“But this isn’t just a refit, it’s a massive project, not the typical refit that we do,” she said.

The upgrades include converting the Spirit of Vancouver Island and Spirit of British Columbia to dual-fuel so that they can operate on liquefied natural gas in addition to diesel.

Both vessels will also have their safety features — marine-evacuation systems, rescue boats, fire-detection system, public-address system and fire-protection system — upgraded and their navigation and propulsion equipment renewed.

Passenger areas will also get an upgrade, with new designs, washrooms, expanded gift shops and new coffee bars.

Mark Wilson, B.C. Ferries’ vice-president of engineering, said during the last fiscal year, B.C. Ferries spent $118 million on diesel fuel, 16 per cent of which was consumed by the two Spirit-class vessels. “The conversion of the two largest ships in the fleet, along with the three new dual-fuel Salish-class vessels currently under construction, will go a long way to help with fare affordability for our customers, as LNG costs significantly less than marine diesel,” he said.

Wilson said the move will also reduce the corporation's environmental footprint, since using LNG in the two vessels will cut carbon-dioxide emissions by an estimated 12,000 tonnes annually.

Remontowa won the contract after being short-listed for the job alongside Seaspan's Vancouver Shipyard and another site.

Seaspan pulled out of the bidding process, however, since its three shipyards — Vancouver, Victoria and its drydock — are too busy to handle the work.

"We are at capacity at all three yards, and the National Shipbuilding Strategy work we are doing for the federal government is a major priority for us," said Seaspan Shipyards president Brian Carter in a statement. As part of that strategy, Seaspan is building new coast guard, fisheries and non-combat naval vessels.

The first ferry to be upgraded in Poland will be the Spirit of British Columbia, built in 1993. That work will start in fall 2017 and is expected to be completed in spring 2018.

The Spirit of Vancouver Island, built in 1994, will follow in fall 2018, with work expected to be completed in spring 2019.

Both vessels will sail to Poland and back under their own power, though B.C. Ferries will hire a professional ship-delivery company to crew the vessels.

Between 2007 and 2009, B.C. Ferries used Netherlands-based Redwise Global Ship Delivery to move the three Coastal-class vessels and the Northern Expedition to the Island from Germany.

The Spirit-class ferries will go through the Panama Canal, but Marshall said the precise route to Poland and back will be determined by the ship-delivery company.

Marshall said 45 days have been budgeted for the trip to Poland, which includes time to wait out bad weather. Temporary living quarters will be installed on both vessels to house B.C. Ferries staff and the ship-delivery crew.

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Appendix D-24

REFER TO LIVE SPREADSHEET MODELS

(accessible by opening the Attachments Tab in Adobe)

Appendix D-25

REFER TO LIVE SPREADSHEET MODELS

(accessible by opening the Attachments Tab in Adobe)

FORTIS INC.

Barclays CEO Energy-Power Conference

September 5, 2017

Forward-Looking Information

Fortis Inc. ("Fortis" or, the "Corporation") includes "forward-looking information" in this presentation within the meaning of applicable Canadian securities laws and "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995 (collectively referred to as "forward-looking information"). Forward-looking information included in this presentation reflects the expectations of Fortis management regarding future growth, results of operations, performance, business prospects and opportunities. Wherever possible, words such as "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "target", "will", "would" and the negative of these terms and other similar terminology or expressions have been used to identify forward-looking information, which includes, without limitation: the expectation of regulatory stability in the near-term; the Corporation's consolidated and segmented forecast midyear rate base for 2017 and the period 2017 through 2021 and associated compound annual growth rate; targeted average annual dividend growth through 2021; the Corporation's forecast gross consolidated and segmented capital expenditures for 2017 and the period 2017 through 2021; the nature, timing and expected costs of certain capital projects including, without limitation, the ITC Multi-Value Regional Transmission Projects and 34.5kV to 69kV Conversion Project, the Central Hudson Gas Main Replacement Program, the FortisBC Lower Mainland System Upgrade and expansion to Tilbury 1A, the FortisAlberta Pole Management Program, and additional opportunities beyond the base plan including, without limitation, the Lake Erie Connector, the Wataynikaneyap Project and the pipeline expansion to the Woodfibre liquid natural gas site; the expectation that capital expenditures will exceed expectations; and the expected timing of filing of regulatory applications and receipt and outcome of regulatory decisions.

Forward-looking information involves significant risk, uncertainties and assumptions. Certain material factors or assumptions have been applied in drawing the conclusions contained in the forward-looking information. These factors or assumptions are subject to inherent risks and uncertainties surrounding future expectations generally, including those identified from time-to-time in the forward-looking information. Such risk factors or assumptions include, but are not limited to: uncertainty regarding the outcome of regulatory proceedings of the Corporation's utilities and the expectation of regulatory stability; no material capital project and financing cost overrun related to any of the Corporation's capital projects; sufficient human resources to deliver service and execute the capital program; the Board of Directors exercising its discretion to declare dividends, taking into account the business performance and financial conditions of the Corporation; risk associated with the impact of less favorable economic conditions on the Corporation's results of operations; no significant changes in laws and regulations that may materially negatively affect the Corporation and its subsidiaries; currency exchange rates and resolution of pending litigation matters. Fortis cautions readers that a number of factors could cause actual results, performance or achievements to differ materially from the results discussed or implied in the forward-looking information. These factors should be considered carefully and undue reliance should not be placed on the forward-looking information. For additional information with respect to certain of these risks or factors, reference should be made to the continuous disclosure materials filed from time to time by Fortis with Canadian securities regulatory authorities and the Securities and Exchange Commission. Fortis disclaims any intention or obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise.

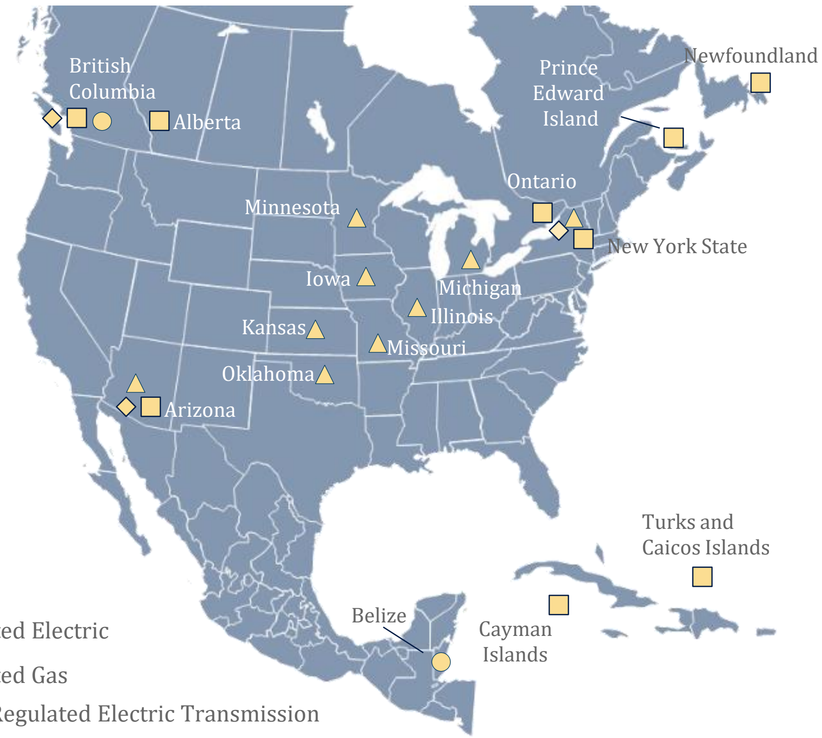
Unless otherwise specified, all financial information referenced is in Canadian dollars.

Fortis Today

- Leader in the North American regulated electric and gas utility business
- ITC provides strong platform in electric transmission sector
- Tremendous economic, geographic and regulatory diversity
- Recent regulatory outcomes provide stability for near term
- Visible growth provided by base 5-year capital program
- Pursuing several additional energy infrastructure opportunities
- Consistent dividend growth and superior long-term returns to shareholders

A Leader in North American Utility Industry

- Regulated utilities
  - 9 U.S. states
  - 5 Canadian provinces
  - 3 Caribbean countries
- ~8,400 employees
- 2017F midyear rate base ~$26B
- ~30% of rate base regulated by FERC (ITC rate base)
- Market cap $19.0B(1)
- Listed on TSX/ NYSE



Regulated Electric

Regulated Gas

FERC-Regulated Electric Transmission

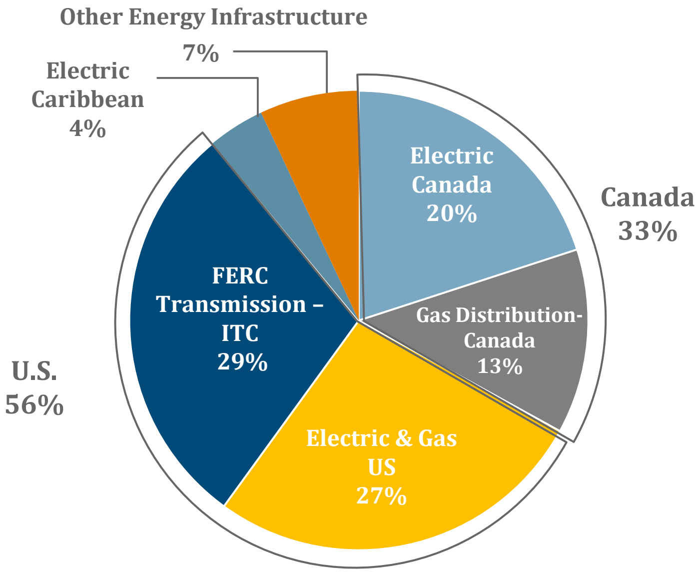
Long-Term Contracted Hydro Generation

(1) Market capitalization as of July 31, 2017.

Highly Diversified:
Economic, Geographic and Regulatory Diversification

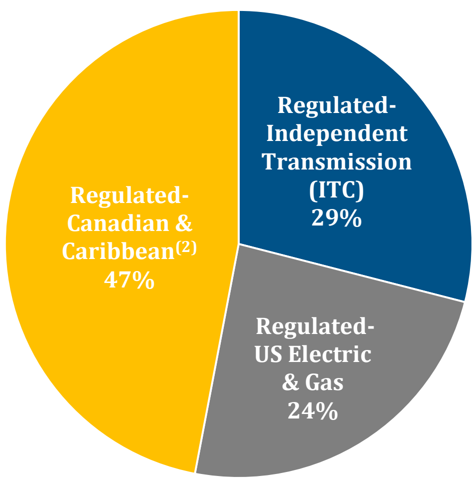
Pro Forma Net Earnings[1]

For the Twelve Months Ended June 30, 2017



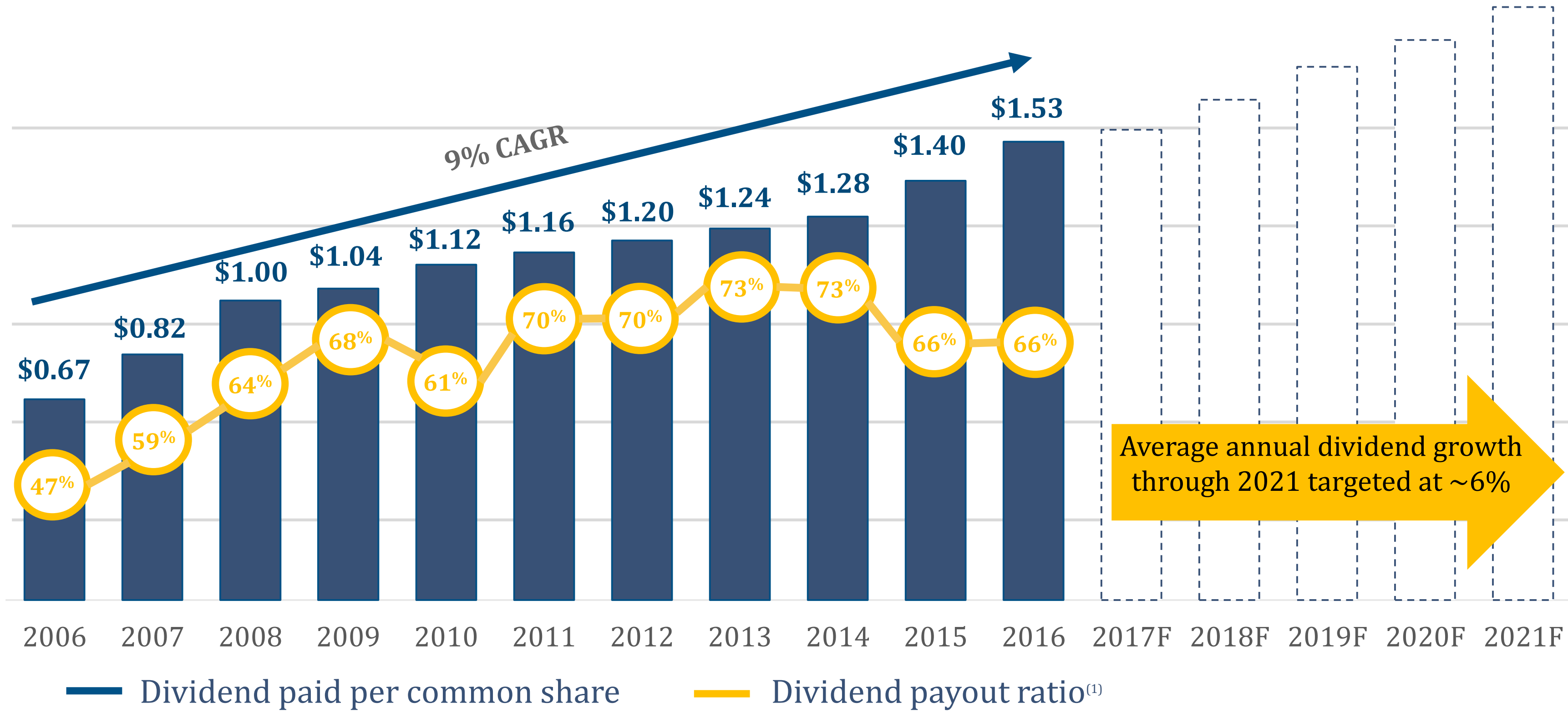
Fortis 2017 Midyear Rate Base[2]

~$26 Billion
Transmission & Distribution represents ~86% of rate base



(1) Excluding ITC's one-time merger-related expenses, "Corporate and Other" segments and intercompany eliminations.
(2) Includes 100% of the Waneta Hydroelectric Expansion of which Fortis has a 51% controlling ownership interest.

Average Annual Dividend Growth Target of ~6% through 2021



43 Consecutive Years of Annual Dividend Payment Increases

(1) Dividend payout ratio for 2011 through 2016 adjusted for non-recurring items

Delivering Superior Shareholder Returns

- Average annualized total shareholder return over last 5 years [(1)]

Fortis	**10.34%**
S&P/TSX Composite Index	8.55%
S&P/TSX Capped Utilities Index	6.69%

(1) For the 5-year period ending July 31, 2017.

FORTIS INC.

Our Strategic Focus Delivers Results

Strategy

Leverage the operating model, footprint of our utilities, operating expertise, reputation and financial strength to develop growth opportunities

Strategic Initiatives

- Execute Utility CAPEX Plan
- Target Additional Energy Infrastructure
- Increase Renewables
- Enhance Customer & Regulatory Relationships
- Unlock LNG Value
- Utility Acquisitions

ITC: Transformational Growth for Fortis

✓ Accretive to EPS

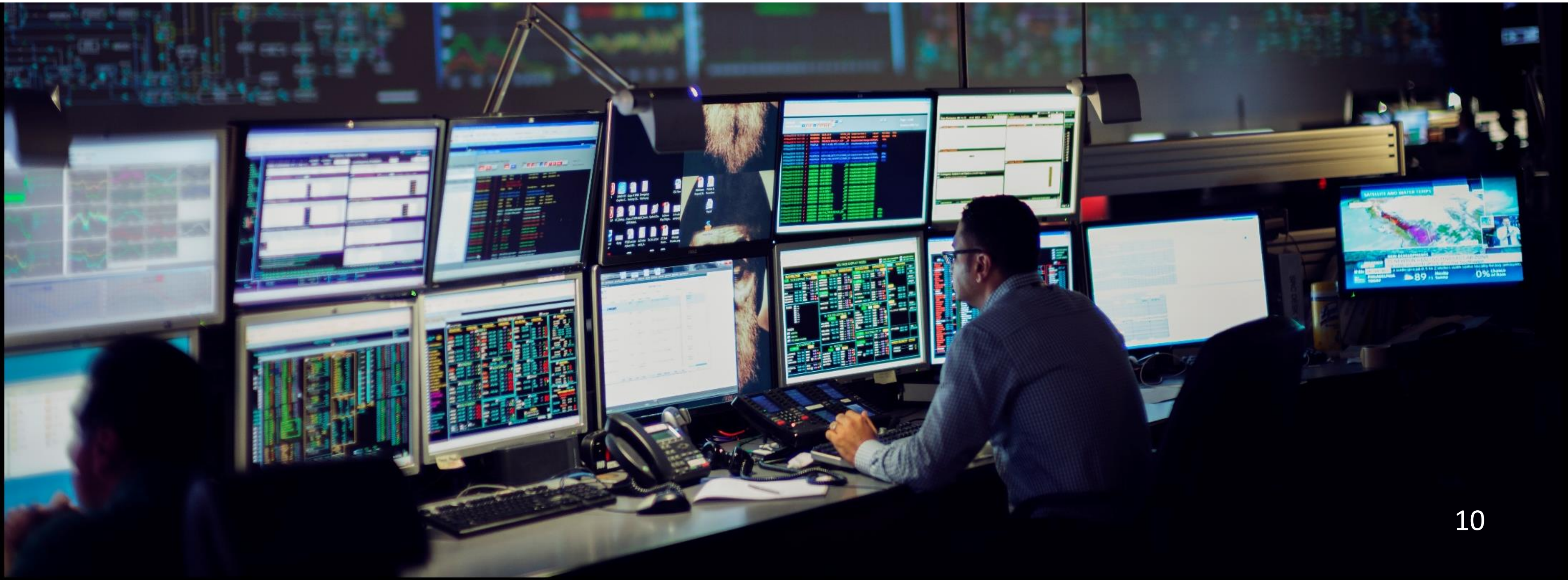
✓ Financing complete

✓ Integration on track
  - Minimal impact on day-to-day operations at ITC
  - ITC's new board of directors formed
  - Linda Apsey appointed President and CEO of ITC during Q4 2016
  - Joe Welch elected to Fortis' Board of Directors in 2017

ITC® A FORTIS COMPANY

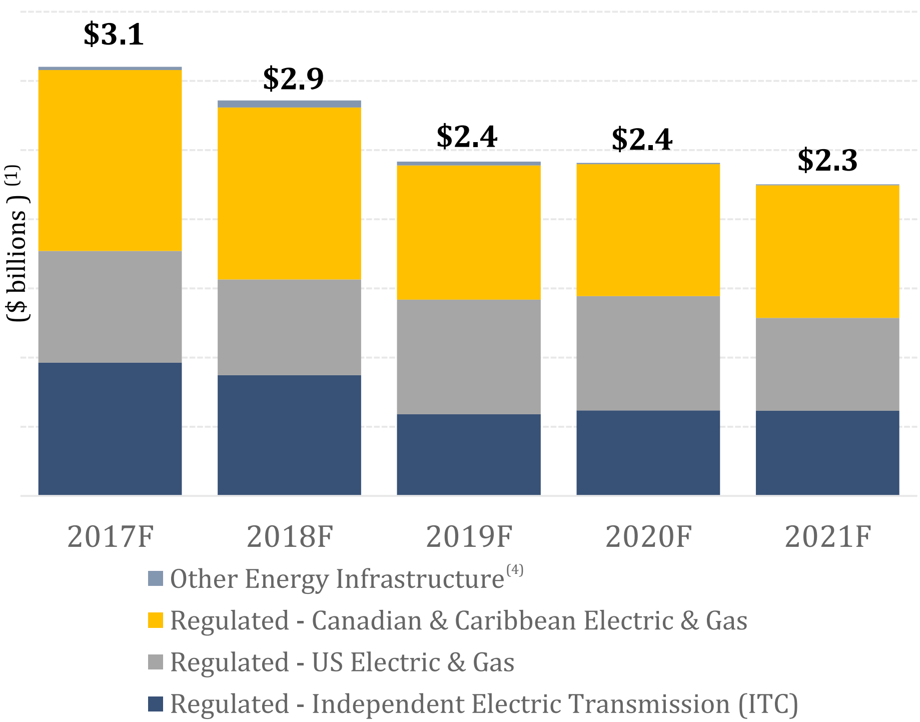
Our Focused Strategy Continues to Yield Strong Results

- ✓ Focused on base growth while making prudent investments to provide safe, reliable and cost effective energy solutions to our customers
- ✓ Benefitting from the acquisition of ITC
- ✓ Maintaining constructive regulatory relationships:
  - UNS rate case settlement
- ✓ Highly executable, low risk capital plan remains on track

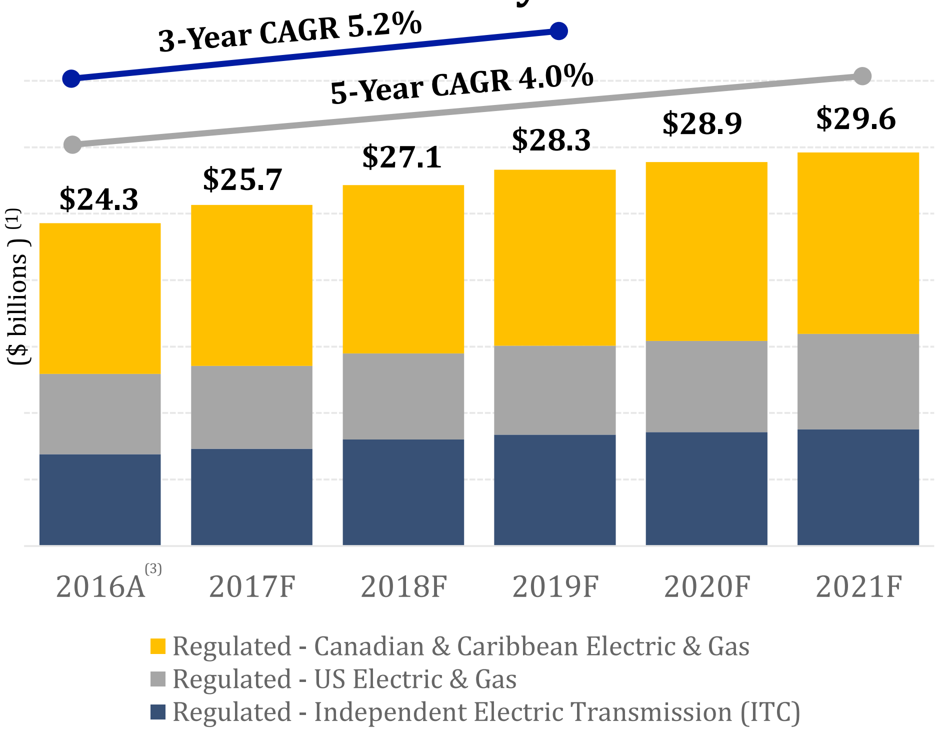


Capital Plan Grows Rate Base to ~$30 Billion in 2021

~$13B Five-Year Capital Program



2016 – 2021 Midyear Rate Base (2)



Midyear Rate Base Sensitivities	3-Year CAGR to 2019	5-Year CAGR to 2021
Capex at ~$3B for all years	+30 bps to 5.5%	+90 bps to 4.9%
Add $1 billion in rate base in the last year	+130 bps to 6.5%	+70 bps to 4.7%

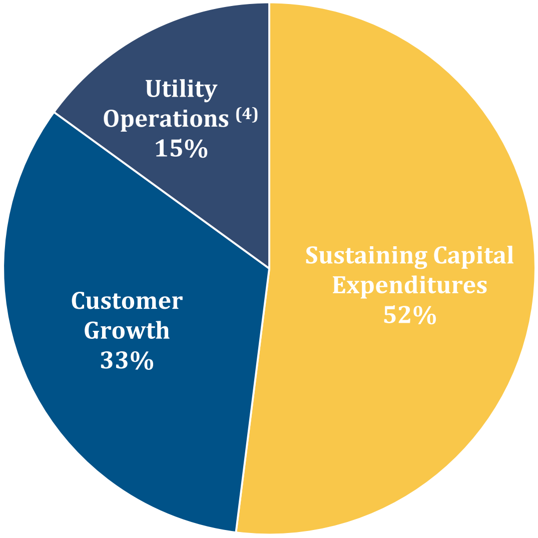
(1) US Dollar-denominated CAPEX and midyear rate base converted at a USD/CAD exchange rate of 1.30 for 2017 through 2021.
(2) Includes the impact of bonus depreciation and excludes construction work in progress.
(3) Reflects actual midyear 2016 rate base compared to the November 2016 forecast of $24.2 billion.
(4) Includes 100% of the Waneta Expansion, of which Fortis has a 51% controlling ownership interest.

Highly Executable Capital Plan

Major Capital Projects

$millions(1) (2)	Forecast 2017	Forecast 2018-2021	Total 2017-2021 Forecast
ITC Multi-Value Regional Transmission Projects (3)	305	244	549
ITC 34.5 kV to 69 kV Conversion Project	89	369	458
FortisBC Lower Mainland System Upgrade	200	182	382
Central Hudson Gas Main Replacement Program	33	169	202
FortisAlberta Pole-Management Program	43	53	96
FortisBC Tilbury LNG Facility Expansion – Tilbury 1A	65	-	65

5-Year Capital Forecast Spending



(1) Represents capital asset expenditures, including both the capitalized debt and equity components of AFUDC, where applicable.
(2) US Dollar denominated CAPEX converted at a USD/CAD exchange rate of 1.30 for 2017 through 2021.
(3) Consists of four separate multi-value projects to create a stronger connection within the Midwestern United States, improve transmission capacity and to connect wind energy.
(4) Includes facilities, equipment, vehicles, information technology and other assets.

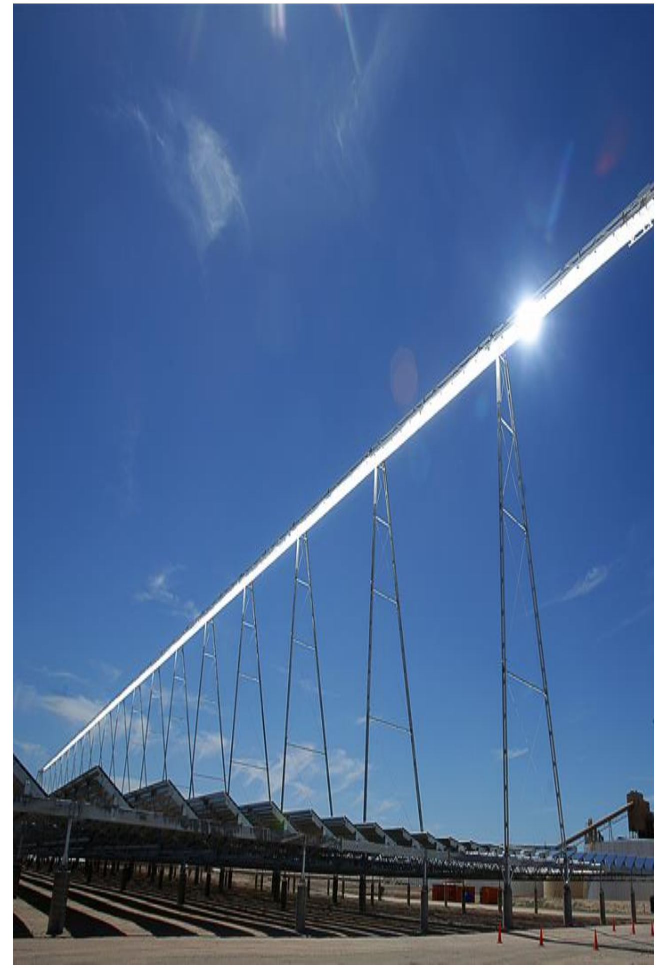
Opportunities Beyond Base Plan

Beyond the Forecast: Development Project Update

FORTIS ONTARIO **Wataynikaneyap Power Project**	✓ Opportunity to connect remote First Nations communities in Northern Ontario to the grid ✓ In Q1 2017, the Ontario Energy Board issued its deferral account approval allowing recovery of spending that occurred since November 2010 ✓ Federal Government announced in August 2017 up to $60 million in funding to connect Pikangikum First Nation to the power grid with construction to commence in October 2017 ✓ Construction will begin following the receipt of permitting, approvals and a cost-sharing agreement between the federal and provincial governments
FORTIS BC **Woodfibre LNG**	✓ Potential pipeline expansion to the Woodfibre LNG export site ✓ Earliest expected in service date is late 2020
ITC A FORTIS COMPANY **Lake Erie Connector**	✓ Proposed 1,000 MW, bi-directional, high-voltage direct current transmission underwater line connecting the Ontario energy grid to the PJM energy market ✓ In May 2017, ITC completed the major permit process in Pennsylvania upon receipt of two required permits from the Pennsylvania Department of Environmental Protection, and in June approval was received from Canada's Governor in Council and the Certificate of Public Convenience and Necessity was issued by the National Energy Board

Poised to Deliver Quality Results

- On track to execute 2017 plan, supported by acquisition of ITC and reasonable rate case outcome at UNS
- Consistent dividend growth
  - 43 years of consecutive dividend increases
  - 6% average annual dividend growth guidance through 2021
- Highly diversified regulated utilities, focused on wires and gas businesses
- Highly executable, risk-adjusted base capital plan
- Regulatory stability
- Strong organic growth potential in existing businesses
- Track record of superior shareholder returns



FORTIS INC.

Barclays CEO Energy-Power Conference

September 5, 2017

Expected Upcoming Events

Expected Earnings Release Dates	
Q3 – 2017	November 3, 2017

Save the Date - 2017 Investor Day	
Toronto	October 16, 2017
New York	October 18, 2017

FORTIS INC.

Diane Roy
Director, Regulatory Services

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March 30, 2016

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Laurel Ross, Acting Commission Secretary and Director

Dear Ms. Ross:

Re: FortisBC Energy Inc. (FEI)

Natural Gas Demand-Side Management (DSM) – 2015 Annual Report

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Attached please find the Natural Gas DSM Program 2015 Annual Report for FEI.

If further information is required, please contact Ken Ross, Manager, Integrated Resource Planning and EEC Reporting at 604-576-7343 or ken.ross@fortisbc.com.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachment

FortisBC Energy Inc.

Natural Gas
Demand-Side Management Programs
2015 Annual Report

March 30, 2016

Table of Contents

List of Tables

1. REPORT OVERVIEW

FortisBC Energy Inc. (FEI or the Company)[1], is committed to delivering a broad portfolio of cost-effective Demand-Side Management[2] (DSM) measures that address the expectations of customers while meeting the requirements for public utilities to pursue cost-effective DSM[3]. In 2015, the company achieved a combined portfolio MTRC[4] of 1.2 on expenditures of $31.9 million, meeting FEI's goal of cost-effective program delivery.

This DSM Annual Report (the Report) outlines the Company's actual results and expenditures for 2015. The Report follows a similar format to the 2014 and other previous Annual Reports, relying on detailed tables to demonstrate Program results and expenditures. The Report compares 2015 activity and results to the Company's 2014-18 DSM Plan, as provided in the FEI's 2014-2018 Performance Based Ratemaking (PBR) Application and approved by the Commission in Order G-138-14. Where the details of individual programs vary substantially from the 2014-2018 Plan, explanations are provided in the applicable Program Area sections of this report.

1.1 Purpose of Report: Transparency, Accountability and Update on Progress

This Report details the Company's activities for the overall DSM portfolio and in each Program Area. Incentive and non-incentive expenditures are reported at the level of each program or measure, as well as at the program area and portfolio levels. Results for the following cost effectiveness test calculations are provided for the overall portfolio and each Program Area in Section 2, and for each program or measure in the respective Program Area sections: Total Resource Cost (TRC), Ratepayer Impact Measure (RIM), Participant Cost Test (PCT), and Utility Cost Test (UCT). In accordance with British Columbia's Demand-Side Measures Regulation, results of the modified TRC (MTRC) calculations (see Section 2.1) are also provided where appropriate.

This Report also demonstrates that the Company is meeting the accountability mechanisms directed by the Commission in Order G-36-09. One such mechanism was the requirement to file DSM Annual Reports, which states:

[1] The three BC Gas utilities formerly known as FortisBC Energy Inc. (FEI), FortisBC Energy (Vancouver Island) Inc. (FEVI) and FortisBC Energy (Whistler) Inc. (FEW) were amalgamated into a single utility - FortisBC Energy Inc. - in 2014. 2015 was the first complete year that the company operated as a single utility, which is reflected throughout this document by eliminating the breakout of separate FEI, FEVI and FEW statistics and results.

[2] Throughout this Annual Report the use of the term Demand-Side Management or "DSM" is intended to refer to demand-side measures in BC as defined in the BC Demand-Side Measures Regulation.

[3] BC Utilities Commission Act, Section 44.1 (2) and Section 44.1(8) (c), and BC Demand-Side Measures Regulation Section 3.

[4] Pursuant to the BC Demand-side Measures Regulation, the portfolio level MTRC is calculated based on costs and benefits of all programs in the portfolio as well as any program area and portfolio level administration costs, and including the benefit adders for those programs for which the MTRC is relied upon to determine cost effectiveness on an individual program basis (i.e. those programs that have been designated as being under the MTRC Cap as presented in Section 2.1 of this report).

A requirement that Terasen [now FEI] submit annually to the Commission, by the end of the first quarter following year-end, for each year of the funding period, a report on all [DSM] initiatives and activities, expenditures and results for TGI and TGVI.

1.2 Organization of the DSM Annual Report

The following describes how each section of the Report presents the results of 2015 DSM activities:

Section 1: Report Overview

- Provides a high-level background for the Report.

Section 2: Portfolio Overview

- Provides a summary and detail regarding the actual 2015 expenditures for DSM activities, along with an explanation of expenditures held in both the DSM deferral account and another deferral account set up for DSM incentive amounts provided to Alternative Energy Services ("AES") projects in which FEI is a participant.
- Section 2.5 discusses any new requirements from the Commission concerning information to be included in the 2015 DSM Annual Report.

Section 3: Funding Transfers

- Provides a discussion on funding transfers.

Section 4: Energy Efficiency and Conservation ("EEC") Advisory Group Activities

- Provides information regarding EEC Advisory Group ("EECAG") activities in 2015, including a summary of meetings and accountability considerations.

Sections 5 - 9 provide information on:

- Residential Energy Efficiency Program Area;
- Low Income Energy Efficiency Program Area;
- Commercial Energy Efficiency Program Area;
- Innovative Technologies Program Area; and
- Industrial Energy Efficiency Program Area.

Each of the above mentioned sections contain a table summarizing the planned and actual expenditures for the respective Program Area in 2015, including incentive and non-incentive spending, annual and NPV gas savings, as well as TRC and other cost-effectiveness test results. Additional tables outline the individual 2015 programs, including program and measure descriptions, program assumptions and sources for these assumptions, and a breakdown of incentive and non-incentive spending. Where applicable, details on program closures or planned programs that were not launched in 2015 are also included in these program detail sections.

Section 10: Conservation Education and Outreach Initiatives

- Provides both a summary and details regarding actual 2015 expenditures for the Conservation Education and Outreach ("CEO") Program Area.

Section 11: Enabling Activities

- Provides both summary and detail regarding actual 2015 expenditures for the Enabling Activities that support the work of the DSM portfolio as a whole.

Section 12: Evaluation

- Provides both summary and detail regarding pending and actual expenditures for 2015 program evaluation activities, as well as summary results from evaluations and studies completed in 2015.

Section 13: Data Gathering, Reporting and Internal Controls Processes

- Provides a summary of the Company's data tracking, process control and reporting for 2015 DSM activities, and a high level description of the Company's internal approval process for programs.

Section 14: 2015 DSM Programs Annual Report Summary

- Summarizes the Report and the Company's 2015 DSM activity.

2. PORTFOLIO OVERVIEW

In this Section, FEI provides its DSM energy savings, expenditures and cost-effectiveness test results at an overall portfolio level for 2015. A summary of the overall portfolio results is provided in Table 2-1, demonstrating that the Company achieved a combined portfolio MTRC of 1.2. DSM expenditures were almost $32 million and recorded natural gas savings were over 434,000 GJ.

Table 2-1: Overall DSM Portfolio Results for 2015

Annual Gas Savings (GJ/yr.)		434,550
NPV of Gas Savings (GJ)		3,238,526
Utility Expenditures, Incentives ($000s)		20,976
Utility Expenditures, Non-Incentives ($000s)		10,889
Utility Expenditures, Total ($000s)		31,865
Benefit/Cost Ratios	TRC	0.7
	MTRC	1.2
	Utility	0.9
	Participant	2.3
	RIM	0.3

Table 2-2 provides the cost-effectiveness test results by Program Area for the overall DSM portfolio.

Table 2-2: Overall DSM Portfolio Level Results by Program Area - 2015

Portfolio Level Results

Portfolio	Annual Gas Savings (GJ/yr.)		NPV Gas Savings (GJ)	Utility Expenditures ($000s)						Benefit/Cost Ratios				
				Incentives		Non-Incentives		All Spending						
	2014-2018 EEC Plan	2015 Actual		2014-2018 EEC Plan	2015 Actual	2014-2018 EEC Plan	2015 Actual	2014-2018 EEC Plan	2015 Actual	TRC	MTRC	Utility	Participant	RIM
Portfolio Level Activities														
Total	No Direct Savings			n/a	n/a	n/a	1200	n/a	1200			No Direct Savings		
Residential Sector														
Total	141,535	121,377	1,160,795	8,086	10,531	3,065	2,204	11,152	12,735	0.5	1.5	0.9	1.3	0.4
Commercial Sector														
Total	304,786	270,933	1,756,471	9,355	8,740	2,218	2,006	11,573	10,746	1.2	n/a	1.4	2.2	0.6
Industrial Sector														
Total	142,349	16,575	132,597	1,686	578	671	412	2,357	989	1.0	n/a	1.1	2.2	0.6
Low Income														
Total	26,920	24,100	171,948	1,520	910	1,303	640	2,822	1,550	1.4	2.2	1.3	3.3	0.6
Conservation Education and Outreach														
Total	No Direct Savings			n/a	n/a	2,400	2,830	2,400	2,830			No Direct Savings		
Innovative Technologies														
Total	72,204	1,564	16,715	438	217	780	409	1,218	626	0.2	n/a	0.2	0.8	0.2
Enabling Activities														
Total	No Direct Savings			n/a	n/a	5,015	1,189	5,015	1,189			No Direct Savings		
TOTAL PORTFOLIOS														
Total	**687,795**	**434,550**	**3,238,526**	**21,086**	**20,976**	**15,452**	**10,889**	**36,537**	**31,865**	**0.7**	**1.2**	**0.9**	**2.3**	**0.3**

Notes:

- Portfolio Level Activities are those activities for which the costs cannot be assigned to individual DSM programs. It should be noted that these activities are distinct from the Enabling Activities specifically listed in Section 9 of the 2014-18 Plan. These distinct Portfolio Level Activities include expenditures such as EECAG activities, DSM Energy Solutions Managers, portfolio level staff labour, staff training and conferences, research and association memberships, portfolio level research studies, and regulatory work including consulting fees .

Throughout this Report, the following general notes also apply to all the program areas:

- In the above table, and in tables throughout the report, any difference in the totals between the Portfolio Overview, Program Area, and individual program tables is due to rounding. Some "zero" values are a reflection of rounding to the $000 expenditure level when expenditures were under $500.
- A "Non-Program Specific Expense" line item has been included for each program area. These expenditures represent the costs attributable to that program area but support multiple programs and, therefore, are not specific to only one program. Generally, these expenditures represent items such as training, travel, marketing collateral and consulting services that support the overall program area.

It is FEI's view that, as with prior annual reports, the savings reported herein continue to be conservative and lower than the savings experienced in the marketplace as a result of the Company's DSM activities, causing the cost-effectiveness test results reported to be lower than they would be otherwise, for the following reasons:

- <u>Net to Gross Ratio</u> - The Net-to-Gross ratio that FEI is using to report energy savings from DSM activity is highly conservative in that it includes the free ridership impact, which serves to reduce reported energy savings, but in most cases does not include the energy savings benefits of spillover[5] effect. FEI intends to continue identifying and incorporating spillover effects into reporting of energy savings impacts from DSM activity on a program-by-program basis, wherever spillover can be supported.
- <u>Attribution from Government Regulation</u> – the introduction of many municipal, provincial and federal minimum equipment and system performance standards is supported by the Company's DSM activity. Until 2014 when FEI claimed energy savings from the Residential New Home Program, the Company had not historically claimed any energy savings from the implementation of these standards. FEI will not be claiming any such energy savings in 2015. The Company continues to believe the claimed savings are conservative and do not represent all of the savings attributable to FEI's codes and standards work. FEI will continue to look for opportunities to claim energy savings from the implementation of these standards.
- <u>Conservation Education and Outreach</u> – CEO activities had expenditures of $2.8 million in 2015. These activities do result in energy savings; however, since these savings remain difficult to quantify, FEI does not currently attribute energy savings to them. Thus, these benefits are not reflected in the TRC. FEI continues to explore approaches to determining energy savings from CEO activities and may account for these energy savings in the future.

[5] Free ridership refers to individuals who participate in a program who would have participated in the absence of an incentive. Spillover refers to individuals that adopt efficiency measures because they are influenced by program-related information and marketing efforts, though they do not actually participate in the program. These can be included in the Net-to-Gross ratio employed in the cost-effectiveness analysis to capture the additive effects of spillover to balance the reductive effects of free ridership.

- Enabling Activities – Enabling Activities similarly had expenditures of $1.2 million in 2015 for work that contributes to energy savings but that cannot currently be quantified. Since these savings are not included in the portfolio TRC calculation, FEI believes the portfolio energy savings benefits are higher than reported.

FEI's DSM activities include a number of specified demand side measures. The *Demand-Side Measures Regulation* defines "specified demand-side measure" as:

a) a demand-side measure referred to in section 3 (c) or (d),
b) the funding of energy efficiency training,
c) a community engagement program,
d) a technology innovation program, or
e) financial or other resources provided
   i. to a standards-making body to support the development of standards respecting energy conservation or the efficient use of energy, or
   ii. to a government or regulatory body to support the development of or compliance with a specified standard or a measure respecting energy conservation or the efficient use of energy in the Province;

Specified demand side measures within FEI's portfolio include the Innovative Technologies programs (see Section 8), education and community engagement programs (see Section 10), and Codes and Standards related DSM activity (see Section 11). The *Demand Side Measures Regulation* defines how the Commission must consider these specified measures. Section 4(4) of the *Regulation* stipulates that the cost effectiveness of specified measures must be determined by the cost effectiveness of the portfolio as a whole. These measures are therefore not subject to the 33% 'MTRC Cap' (see Section 2.1). Additionally, these measures cannot be determined to be "not-cost effective" under the Utility Cost Test.

In summary, FEI's 2015 DSM expenditures, including specified DSM, were cost-effective under the BC *Demand-Side Measures Regulation*.

2.1 Portfolio Level MTRC Calculation and Results

In 2015, FEI met the conditions of the Province's *Demand-Side Measures Regulation*, achieving a portfolio MTRC value of 1.2 with 32 percent of the portfolio enabled by the MTRC cost-effectiveness test. While FEI strives for TRC test results that approach or exceed 1.0 within each program and across all programs, there are benefits to implementing programs that do not meet this threshold. Some of these benefits include making programs available to those customers that would otherwise be underserved (such as low income and residential customers), water savings, increased human health and comfort, and economic benefits such as job creation. These benefits were recognized in 2011 and 2014 amendments to the *Demand-Side Measures Regulation*, which enable the use of an MTRC in determining program and portfolio cost effectiveness. The MTRC uses the long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia as a proxy for the avoided cost of energy and allows for the inclusion of non-energy benefits (NEBs).[6]

Utilities can implement natural gas DSM with TRC values less than 1.0 but that meet an MTRC threshold of 1.0 as long as expenditures on these activities do not exceed 33 percent of the total portfolio expenditure. FEI refers to this 33 percent as the “MTRC Cap”. Table 2-3 shows both the TRC and MTRC of those programs with measures to which the MTRC cost effectiveness test is applied, along with the expenditures[7] related to those measures. Table 2-2 shows that the overall portfolio MTRC is 1.2 in accordance with the *Demand-Side Measures Regulation* and the Commission’s approval to assess cost effectiveness on an overall portfolio basis[8].

Table 2-3: Programs with Measures Subject to MTRC and Proportion of 2015 Portfolio Spend

Program	Program TRC	Program MTRC	Expenditure ($000s) subject to cap	% of Portfolio Spending
EnergyStar Domestic Hot Water	0.4	1.5	2,448	7.7%
Furnace Replacement	0.5	1.4	3,528	11.1%
Domestic Hot Water Conservation * Program / Low Flow Fixtures	2.2	n/a	73	0.2%
EnerGuide 80 New Construction	0.4	1.5	1,296	4.1%
Energy Efficiency Home Performance (HERO)	0.4	1.4	1,709	5.4%
Energy Conservation Assistance Program (ECAP)	0.5	1.8	1,015	3.2%
Total			**$10,069**	**31.6%**

2.2 Meeting Approved Spending Levels

The Company’s DSM expenditures were within the approved levels. FEI filed its 2014-2018 Performance Based Ratemaking (PBR) Application with the British Columbia Utilities

[6] The BC *Demand Side Measures Regulation* was amended in July, 2014 by allowing for the whole cost of the long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia to be used as a proxy for the avoided cost of natural gas in the MTRC cost-effectiveness test. As the DSM Regulation stipulates, the value that the FEI has used for the avoided cost of gas in the MTRC calculation is $100/MWh, or $27.78/GJ, as indicated in BC Hydro’s November 2013 Integrated Resource Plan, Section 9.2.12, “Long Run Marginal Cost” (pgs. 9-51 to 9-55).

[7] The expenditures listed in Table 2-3 are associated with those measures within each program that do not pass the TRC and therefore to which the MTRC avoided cost of energy and NEBs apply when calculating the MTRC portfolio cost effectiveness test. For this reason, expenditures in Table 2-3 may differ from total program expenditures listed elsewhere in this report.
* *The Energy Star Washers and Dryers that are part of the Domestic Hot Water Conservation / Low Flow Fixtures program have individual measure TRC values of 0.6 and 0.4 respectively*.

[8] The Commission approved the assessment of the cost effectiveness using an MTRC of 1 or greater on an overall portfolio basis as part of its decision on the 2012-2013 RRA Decision, Order No. G-44-12, page 174. While this approval is not explicitly stated in the PBR decision (Order No. g-139-14), FEI interprets this approval to be implicit in the approval of the 2014-2018 DSM Plan.

Commission (the Commission) on June 10, 2013. As part of the PBR Application, FEI requested acceptance, pursuant to section 44.2 of the *Utilities Commission Act* (*UCA*) of an expenditure schedule for Energy Efficiency and Conservation expenditures from 2014 to 2018. The Commission approved the PBR application on September 12, 2014 including a 2015 DSM expenditure limit of $36.5 million[9].

In the 2014-2018 PBR application, FEI proposed to maintain the 2012–2013 approved approach that only $15 million of the requested annual DSM budget be added to the DSM rate base each year of the PBR period, with any additional DSM spend being captured in an DSM non-rate base deferral account attracting AFUDC. FEI requested approval to transfer any new amounts accumulated in the non-rate base DSM deferral account to FEI rate base DSM deferral account in the following year. This included approval to transfer the balance in the non-rate base DSM incentive deferral account as of December 31, 2013 to the rate base DSM deferral account on January 1, 2014. In the 2014-2018 PBR Application, it was proposed that the amounts will be amortized over 10 years beginning in 2014 in accordance with the existing approved amortization period for the DSM rate base deferral account. In its decision, the Commission Panel approved FEI's request to (i) continue the DSM accounting treatment approved for 2012–2013 and, (ii) to transfer any new amounts accumulated in the non-rate base DSM deferral account to FEI rate base DSM deferral account in the following year. In accordance with this decision, $16.75 million was transferred to the non-rate based DSM deferral account in 2015.

FEI notes a small difference in the total DSM rate base ($15 million) plus non-rate base deferral account amount ($16.75 million) versus the total 2015 expenditures ($31.87 million) reported in Tables 2-1 and 2-2. This difference is due to some program activity that occurred in late 2015 but for which the payments were not processed prior to the 2015 year-end.

FEI has managed its 2015 DSM activity within the funding limits approved by the Commission. Section 3 discusses funding transfers between program areas in 2015 within the overall DSM funding envelope and within rules for transferring funds between program areas as set out by the Commission.

2.3 DSM Incentives for AES/TES Projects

Commission Order G-44-12 directed FEI to hold all DSM incentives that are provided for Alternative Energy Services (AES) or Thermal Energy Services (TES) technologies for projects in which the FEI is a participant in a separate deferral account. Up until 2015, FEI reported on the amounts being added to this deferral account in its DSM Annual Report. In 2015, by Order G-86-15, the Commission approved both the transfer of these amounts to the rate base deferral account and the discontinuation of the AES/TES deferral account. As such, FEI will no longer be reporting on these amounts.

[9] BCUC Order G-138-14, page 277 of the Decision.

2.4 Meeting Adequacy Requirements of the Demand-Side Measures Regulation

The *Demand-Side Measures Regulation* has the following requirements for a utility's portfolio of DSM activity to be considered adequate:

> A public utility's plan portfolio is adequate for the purposes of Section 44.1 (8) c of the Act only if the plan portfolio includes all the following:
>
> a) A demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption;
> b) If the plan portfolio is introduced on or after June 1, 2009, a demand-side measure intended specifically to improve the energy efficiency of rental accommodations;
> c) An education program for students enrolled in schools in the public utility's service area;
> d) If the plan portfolio is submitted on or after June 1, 2009, an education program for students enrolled in post-secondary institutions in the public utility's service area.

FEI has met all the requirements for adequacy. There are a number of programs for low income customers, which are discussed in their own section (see Section 6). Although there are a number of Commercial and Low Income energy efficiency programs intended for use by owners of rental buildings, including the Energy Specialist Program (see Section 7), FEI applied and received approval for the Rental Apartment Efficiency Program (RAP) pursuant to Commission Directive 148 from the 2014-2018 PBR decision, Order G-138-14. That order required FEI to file one or more DSM programs intended specifically to address the unique market barriers to energy efficiency faced by renters. The RAP program, launched in late 2015, spans both the Residential and Commercial Program Areas. The expenditure details for RAP are presented and discussed in each of the respective Program Area sections (Sections 5 and 7) and a full program overview for RAP is presented in Section 7.2.1.

In terms of education programs, FEI's School Education Program, Commercial and Residential customer education programs and other energy efficiency and conservation outreach initiatives are presented in Section 10.

2.5 Addressing BCUC Directives from the FEI 2014-18 Performance Based Ratemaking Decision

FEI filed its 2014-18 EEC Plan and associated funding request to the BCUC with the FEI 2014-18 Performance Based Ratemaking Application. There were a number of Commission directives from that Decision that are specific to the 2014-18 EEC Plan. Many of these directives were required to be addressed in the 2014 Annual Report and as such do not need to be addressed again in this or subsequent Annual Reports. In this section, FEI addresses the BCUC directive regarding labour costs that applies to the overall 2015 DSM Portfolio. Program specific directives are addressed in the applicable program area sections of this report.

2.5.1 LABOUR COSTS

The Commission Panel directed FEI to allocate 'labour costs coded to DSM' to its DSM programs during the 2014-2018 expenditure approval period, with the exception of costs related to Evaluation, Measurement & Verification.

As with the 2014 Annual Report, FEI has included labour cost coded to each DSM program in the reported "Administration" expenditures for each program. This information is included in the specific Program tables included in each DSM Program Area section of this report (Sections 5-11). FEI Notes that while the 2014 – 2018 DSM Plan was approved by the Commission as set out in FEI's application, program and program area costs were not re-cast with labour included at the program level. This change therefore impacts the direct comparison of actual program and program area spending to planned spending. The inclusion of Labour costs at the Program level can cause program area expenditures to appear higher than the approved amounts even though non-labour costs are within approved amounts. Actual spending in the "Enabling Activities" program area will also be lower than planned since a substantial amount of labour costs planned for this program area are being reported within other program areas. This issue is also discussed in Section 3 on funding transfers.

2.6 Collaboration & Integration

FEI continues to collaborate and integrate DSM programming among BC's largest energy utilities, as well as with other entities such as governments and industry associations. The Company recognizes that doing so will maximize program efficiency and effectiveness. Collaborative activity is captured in the individual Program Area sections and program descriptions found in Sections 5 through 11.

FEI and BC Hydro continued to expand on their program and project collaborations through their voluntary Memorandum of Understanding (MOU), the purpose of which is to develop enhanced utility integration in support of government legislation, policy and direction. The two utilities agreed to extend the MOU for a further three year period covering August 2015 through August 2018. In 2015, the electric utility FortisBC Inc. (hereafter referred to as FBC) also joined the collaboration and signed the MOU.

FEI and BC Hydro again conducted a joint review of incremental cost efficiencies created as a direct result of the partnership over the April 1, 2014 to March 31, 2015 time period (BC Hydro fiscal year). This review examined the costs incurred for each program and project collaboration that was in place over that time period and determined that FEI and BC Hydro combined had total incremental cost efficiencies of approximately $5.4 million as a result of working together. FEI, FBC and BC Hydro also continue to experience additional benefits from their collaboration efforts, including streamlined application processes for customers, extended program reach and consistent and unified messaging resulting in improved energy literacy.

2.7 Summary

FEI's DSM portfolio met the goal of cost effectiveness with a MTRC value of 1.2 in 2015. The Company is of the view that both energy savings accounted for in the portfolio and the resulting TRC are conservative. Benefits from additional activities, such as CEO, play a very important role in supporting the development and delivery of programs, while creating a culture of conservation in British Columbia. FEI expects that with a more complete approach to the Net-to-Gross ratio, the incorporation of energy savings from CEO and with the recent changes to the Demand-Side Measures Regulation, the DSM portfolio will be continue to be cost effective.

3. FUNDING TRANSFERS

Two Program Areas – Residential and CEO – incurred actual program expenditures that were greater than their respective approved Program Area funding amounts[10]. In the case of CEO, exceedance of the approved Program Area funding level was the result of reporting labour expenditures at the program level as directed by the Commission[11]. The approved 2014 - 2018 EEC Plan was based on labour being reported at the portfolio level, and planned Program Area expenditure levels were not re-cast subsequent to the Commission's decision regarding the reporting of labour costs. Therefore, the approved Program Area funding limits do not include labour. Since the expenditures for CEO as shown in Table 2-2 include labour, and since the approved CEO funding level would not be exceeded if labour costs were removed, no funding transfer is required.

For the Residential Program Area, expenditures other than labour costs exceed the approved funding level by $1,241,000 as a result of the success of the residential programs. To accommodate these additional expenditures in the Residential Program area, $827,000 of available funding within the Commercial Program Area and $414,000 of available funding in the Industrial Program Area have been transferred to the Residential Program Area. None of these amounts exceed 25% of the respective program area approved funding levels[12].

[10] Order G-138-14.
[11] Directive 145, Order G-138-14
[12] According to Directive 151, Order G-138-14, funding transfers in excess of 25% of program area approved funding levels require prior approval from the Commission.

4. EEC ADVISORY GROUP ACTIVITIES

4.1 Overview

The Energy Efficiency and Conservation Advisory Group (EECAG) provides insight and feedback on FEI's portfolio of DSM activities and related issues. This includes: DSM program and portfolio performance, development and design; funding transfers; policy and regulations that may impact DSM activities; and other issues and activities as they may arise.

Members may be appointed based on their relevant subject matter expertise, representation of a common interest shared by stakeholders, or representation of a particular organization/group and/or interest. This includes, but is not limited to, governments, regions, First Nations organizations, customers, suppliers, industries, non-governmental organizations, research institutes and other groups that have historically intervened in the FEI's regulatory proceedings.

Since the formation of the EECAG in 2009, FEI has had the opportunity to gain valuable insight on DSM program design and implementation and develop positive working relationships with stakeholders. EECAG input continues to be instrumental as FEI moves forward with DSM activities, helping to ensure that efforts are aligned with the interests and suggestions of stakeholders.

4.2 Summary of the 2015 Workshop

EECAG workshops provide a forum for stakeholders to learn about DSM programs and engage in constructive dialogue with FEI. Since FEI was in the second year of an approved plan for DSM activities and because both the regulatory framework and market dynamics for DSM programming has remained stable during this time, a single workshop in 2015 was sufficient to update EECAG members and seek their input on programming issues. The EECAG workshop was held on November 4th in Vancouver and was well attended by EEGAG members or their alternate delegates. The EECAG Independent Facilitator was engaged in workshop design and facilitation of the workshop. Copies of materials and minutes for these meetings were distributed to EECAG members and other workshop attendees.

At the November workshop, FEI provided:

- Program area updates and highlights for 2015;
- An update and discussion on the Conservation Potential Review, an in-progress study being undertaken to examine available technologies and determine their conservation potential, which includes the amount of energy savings that can be achieved over the study period for each of the four largest utilities in BC (FEI, FBC, BC Hydro and Pacific Northern Gas);
- An overview of newly approved programs and an Innovative Technologies Pilot project (Condensing Make-up Air Unit Pilot);

- Plenary sessions, led by the independent facilitator, to discuss two specific issues that FEI is currently experiencing in its DSM programming and gather feedback from the group on potential solutions:

    1. Claiming and accounting for energy savings from Conservation, Education and Outreach (CEO) activities that encourage the implementation of energy efficiency measures or that change behavior to conserve energy use.

    2. The application of measurement and verification (M&V) approaches to industrial projects to address the challenge of high M&V costs and administrative burden on smaller industrial projects.

- An opportunity for EECAG members to share their own initiatives and insights on energy efficiency and conservation efforts in their own organizations or areas of influence.

With respect to the plenary sessions, the following key discussion points and feedback were raised:

CEO Activities:

FEI believes that CEO activities do result in energy savings, however, the majority of these savings are difficult to track and report since they are often behavioral in nature and involve events where energy efficiency messaging is delivered to large audiences with no way to track the subsequent energy consumption behavior of each individual. In this session, FEI presented three CEO initiatives (in-store rebates, Empower Me Energy Savings Kits and employee promotions) for which activity could be tracked and a conservative estimate of savings developed.

EECAG members were generally in favour of identifying and claiming the savings for these three initiatives where good data exists with which to determine the savings. A number of ideas for additional information sources on tracking and calculating savings on behavioral programs were offered by group members. FEI explained that they were seeking a summer student to further explore methodologies for determining behavioral energy savings. Such savings have not been claimed for 2015 but may be claimed in future annual reports.

Industrial M&V Approach:

A review of the industrial market segment and industrial programming was provided to EECAG members along with a refresher on M&V practice as it currently applies to FEI's Industrial Optimization program. FEI staff explained using examples that M&V costs are currently very similar across projects at around \$20,000 (external, 3rd party costs based on projects completed to date) and typically require a similar level of effort, regardless of the magnitude of natural gas savings or cost of the project. For smaller projects, this level of cost and effort could cause a project to fail current cost effectiveness tests and therefore be a barrier to implementing energy efficiency measures. FEI sought feedback from the EECAG on alternatives to the current M&V approach to industrial projects.

EECAG members sought clarification on the types of projects supported by industrial DSM incentives, variables contributing to the level of confidence in M&V results and savings persistence. Members also put forward ideas on how to reduce M&V costs for smaller projects. A range of approach suggestions and a few examples from industrial customers were provided by EECAG members for consideration by FEI. Scaling M&V practices based on project size, project savings and/or the level of risk inherent were common themes.

In addition to the plenary feedback sessions discussed above, FEI and EECAG members discussed the following key points throughout the workshop:

- FEI continues to maintain good relationships with the contractor community, and is now expanding industry relationships to include equipment manufacturers and distributors.
- Members would like to receive a mid-year update on annual portfolio progress.
- Members are interested in what role the utility could play on regulatory and building code compliance.
- Members would like to see more focus, if possible, on behavioral programs in the CPR study than there has been in past studies.
- It was clarified that the CPR does not make recommendations on program design such as identifying more low income programs, but rather examines available measures and their cost effectiveness which becomes an input into utility program design.
- The benefits of reaching out to renovators as well as contractors in the residential market in order to improve program awareness and energy literacy.
- The potential benefits of and barriers to deeper retrofits in the residential sector.
- The idea of developing a repository of energy efficiency technologies, housed at an educational facility.

To close the workshop, members discussed a range of initiatives and studies related to energy efficiency and conservation that are being taken by their own organizations or members. A number of follow up action items were identified and included in the workshop minutes for follow-up by various parties.

4.3 Feedback & Lessons Learned

In addition to input on specific topics presented, EECAG members are encouraged to provide general feedback on the workshops, membership or any other issues. This feedback is typically voiced during the workshops or submitted to FEI via evaluation forms distributed at each workshop. The results from these evaluation forms are compiled and all comments are considered when planning future workshops.

In an ongoing effort to improve EECAG interaction, results from feedback are considered in collaboration with the EECAG Independent Facilitator, to help design future EECAG sessions and workshops. Feedback received during the 2015 workshop indicated that adjustments made to the workshops based on prior feedback were helpful and that degree of consultation in 2015 was appropriate. FEI's efforts to share with EECAG members how their input was being used was appreciated and a good balance has been struck between providing informational sessions and facilitating sessions designed to obtain feedback on important topics.

5. RESIDENTIAL ENERGY EFFICIENCY PROGRAM AREA

5.1 Overview

The Residential Energy Efficiency Program Area was successful in reducing annual natural gas consumption by 121,000 GJ and achieving an overall TRC/MTRC of 1.5. Over $12.7 million was invested in Residential Energy Efficiency upgrades in 2015, and 82 percent of this investment was customer incentive spending.

Table 5-1 summarizes the projected and actual expenditures for the Residential Energy Efficiency Program Area in 2015, including incentive and non-incentive spending, annual and NPV gas savings, as well as TRC/MTRC and other cost-effectiveness test results.

Residential programs serve over 870,000 homes in the FEI service territories. For DSM purposes, these customers predominantly include end-use customers living in residential single-family homes, row houses, townhomes or mobile homes.[13] Some in-suite measures in Multi-unit residential buildings ("MURBS") are also included in this funding envelope. These measures may include low flow fixtures and a small number of fireplaces and water heaters in MURBS or individually metered units. Residential programs serve retrofit and new home applications. In combination with FEI's education and outreach activities, these programs play an important role in driving the culture of conservation in British Columbia.

Table 5-1: Residential Energy Efficiency Program Area Results Summary

Program	Annual Gas Savings (GJ/yr.)		Actual NPV Gas Savings (GJ)	Utility Expenditures ($000s)						Benefit/Cost Ratios				
				Incentives		Non-Incentives		All Spending						
	2014-2018 EEC Plan	2015 Actual		2014-2018 EEC Plan	2015 Actual	2014-2018 EEC Plan	2015 Actual	2014-2018 EEC Plan	2015 Actual	TRC	MTRC	Utility	Participant	RIM
Non Program Specific Expenses														
Total	No Direct Savings			0	0	540	396	540	396	No Direct Savings				
Energy Efficiency Home Performance (HERO)														
Total	40,846	15,508	165,673	1,065	1,397	423	312	1,488	1,709	0.4	1.4	0.9	0.8	0.4
Furnace Replacement Program														
Total	31,413	31,261	314,454	2,984	3,228	356	300	3,340	3,528	0.5	1.4	1.2	1.0	0.4
Enerchoice Fireplace Program														
Total	15,485	30,123	274,355	1,040	1,826	321	383	1,361	2,209	2.4	n/a	1.1	7.4	0.4
Appliance Service Program														
Total	No Direct Savings			356	535	100	81	456	616	No Direct Savings				
ENERGY STAR® Domestic Hot Water "DHW" Technologies														
Total	16,918	24,885	237,337	1,353	2,319	119	370	1,472	2,688	0.4	1.5	0.8	1.0	0.4
Domestic Hot Water Conservation Program /Low Flow Fixtures														
Total	12,826	9,483	67,288	190	99	100	126	290	226	2.2	n/a	2.5	6.6	0.6
New Home Program														
Total	8,347	7,126	80,670	848	1,096	188	199	1,036	1,296	0.4	1.5	0.6	1.2	0.3
New Technologies Program														
Total	1,450	0	0	191	0	97	0	287	0	No Direct Savings				
Rental Apt Efficiency (RAP)* *Residential Portion*														
Total	0	2,992	21,017	0	31	0	35	0	66	n/a	n/a	n/a	n/a	n/a
Customer Engagement Tool for Conservation Behaviours														
Total	14,250	0	0	0	0	706	0	706	0	No Direct Savings				
On-Bill Financing														
Total	No Direct Savings			59	0	115	0	174	0	No Direct Savings				
ALL PROGRAMS														
Total	**141,535**	**121,377**	**1,160,795**	**8,086**	**10,531**	**3,065**	**2,204**	**11,152**	**12,735**	**0.5**	**1.5**	**0.9**	**1.3**	**0.4**

[13] Programs for Multifamily Dwellings served under Rate Schedule 2 or 3 are included in the Commercial Energy Efficiency Program Area (please refer to Section 7) with a few exceptions as noted in text.

Notes:

- ∗ The Rental Apartment Efficiency Program (RAP) includes a combination of residential and commercial measures, each funded from their respective Program Areas. The *Residential Portion* details of this program included in Table 5-1 shows only those Residential Program Area expenditures. These expenditures are associated with the direct install of residential fixtures, and a portion of the communication and evaluation costs. Commercial Program Area expenditures that are part of RAP are presented in Tables 7-1 and 7-10. Cost effectiveness values for only the *Residential Portion* of RAP are not provided as they do not represent a complete program view. Please refer to Table 7-11 for a complete program view and further program details including program cost effectiveness results.

5.2 Residential TRC and MTRC Results

FEI's DSM Program Principles state that programs should be universal, offering access to programs for all residential and commercial customers. Although many Residential programs are challenged in meeting a conventional TRC test in a low gas cost environment, these programs, with their broad reach, are cost-effective when considering broader societal benefits and a greenhouse gas (GHG) emissions reduction perspective. This was recognized in the 2011 and 2014 amendments to the Demand-Side Measures Regulation that enabled the inclusion of lower TRC programs through the application of the MTRC. The overall 2015 Residential Program Area TRC was 0.5 with a blended TRC/MTRC result of 1.5.

5.3 2015 Residential Energy Efficiency Programs

Tables 5-2 through 5-9 outline the specific Residential Energy Efficiency programs undertaken in 2015, including program and measure descriptions and a breakdown of non-incentive spending.

Table 5-2: Energy Efficient Home Performance Program -Home Energy Rebate Offer (HERO)

Program Description	This collaborative program promotes energy-efficient home upgrades while educating homeowners on the value of whole home performance. Utility partners administer the program. Federal, provincial and local governments co-promote this program and other related initiatives including capacity building for the trades, home labeling and the introduction of NRCan's Home Energy Rating System in spring of 2016.						
Target Market	Residential customers						
New vs Retrofit	Retrofit						
Partners	BC Hydro, FortisBC (Electric), BC Ministry of Energy and Mines, Natural Resources Canada and local governments						
Eligible Measures	Draftproofing	Attic Insulation	Basement Insulation	Wall Insulation	$750 Bonus Offer		
Incremental Measure Cost	$989	$1,880	$1,463	$1,953	N/A		
Incentive Amount	Up to $500	Up to $600	Up to $1000	Up to $1200	$750		
Savings Per Participant	6.6 GJ	8.9 GJ	6.1 GJ	5.6 GJ	N/A		
Measure Life & Source	9 years for Draftproofing, 25 years for Insulation Consultations with BC Hydro, Habart & Hood, 2010 Conservation Potential Review and Dunsky Energy Consulting.						
Free Rider Rate & Source	20% average assumed based on past program analysis and NRCan evaluation. *Final Report: Analysis of Net-to-gross Survey Results for the ecoENERGY Retrofit for Homes Program.* Bronson Consulting Group. August, 2010						
Sources of Assumptions	Habart and Hood, Hot 2000 Energy Modeling Reports 2010, 2011 2010 Conservation Potential Review Dunsky Energy Consulting, Hot 2000 Modeling 2012, 2013, 2015 2012 Residential End Use Study, FortisBC BC Hydro PowerSmart, Evaluation of the LiveSmart BC Efficiency Incentive Program F2009-F2011						
Participants	2015	Projected	Actual				
	Total	3,276	2,010				
Expenditures ($,000s)			Non-Incentive Expenditures				
	2015	Incentives	Industry Support	Admin	Communication	Research & Evaluation	Total
	Total	1,397	51	176	45	40	1,709

Notes:

- This program is a collaboration between FEI, FBC and BC Hydro with support from BC Ministry of Energy and Mines and Natural Resources Canada
- Energy savings estimates were provided by Dunsky Energy Consulting through the evaluation of HERO participant records in comparison to LiveSmart BC measure uptake, BC Hydro Evaluation of the LiveSmart BC Efficiency Incentive Program and Hot 2000 modeling estimates.
- Measure costs were based on HERO participant records and market analysis provided by Dunsky Energy Consulting.
- Industry support includes application support fees to energy advisors and FEI's contribution to Year One establishment of the Home Performance Stakeholder Council "HPSC", The HPSC is an industry led group comprised of key industry players tasked with addressing the fragmented interests, opportunities and challenges that exist in BC's nascent home performance industry which is continuously evolving. The HPSC is supported by a three year funding agreement between FEI, FBC, BC Hydro and Ministry of Energy and Mines.

Table 5-3: Furnace Replacement Program

Program Description	The Furnace and Boiler Replacement program targets customers with functioning furnaces (standard or mid-efficiency) or boilers and, through a combination of marketing, incentives and industry outreach, encourages them to replace the equipment immediately, rather than waiting for it to fail at some point in the future.						
Target Market	Residential customers						
New vs Retrofit	Retrofit						
Partners	N/A						
Eligible Measures	Standard efficiency	Mid - Efficiency	Boilers				
Incremental Measure Cost	$2,115	$2,115	$3,560				
Incentive Amount	$800	$800	$800				
Contractor Incentive	$50	$50	$50				
Savings Per Participant	8.5 GJs	6.0 GJs	9.3 GJs				
Measure Life & Source	Furnace - 18 years and Boiler - 18 years -Navigant Consulting report, BC Hydro Power Smart QA Standard, NRCan						
Free Rider Rate & Source	Early Replacement Methodology						
Sources of Assumptions	2012 and 2013 Furnace Replacement Pilot Program Evaluation - by Habart and Associates Furnace Replacement Program - Billing Analysis of 2012 Participant Savings. Sampson Research Inc. 2012 FortisBC Residential End Use Study 2015 Analysis of Program Participants						
Participants	2015	Projected	Actual				
	Total	3,276	4,035				
Expenditures ($,000s)			Non-Incentives				
	2015	Incentives	Dealer Incentives	Admin	Communication	Research & Evaluation	Total
	Total	3,228	193	82	22	4	3,528

Notes:

- The Furnace & Boiler Replacement program continues to be run outside of heating season to reduce the incidence of emergency replacements.
- The program is successful in terms of participation targets, contractor feedback and energy savings per unit. However, cost effectiveness tests have been challenged by the following factors:
  - Over time the proportion of old standard efficiency replacements (8.5 GJs savings) to mid-efficiency replacements (6.0 GJ savings) has declined resulting in decreased energy savings overall. In 2013, standard replacements comprised 76% of total program participants while in 2015 standard replacements comprised only 66% of total participants. This is consistent with trends of the installed base of furnaces observed in the 2012 Residential End Use Study indicating that the proportion of standard efficiency furnaces has declined from 44% in 2008 to 23% in 2012.
  - The incremental cost (economic cost as developed through Early Replacement Methodology) of furnaces increased by 15% and boilers by 13% in 2015 over 2014 which adversely affects cost effectiveness. This is likely due to the declining Canadian dollar.
  - Cost effectiveness was favoured in that contractor estimates of furnace remaining life averaged 5.0 years in 2015 and 4.1 years in 2014.
- Contractor incentives of $50 per participant are allocated to the administration portion of non-incentive spend.

Table 5-4: EnerChoice Fireplace Program

Program Description	This program promotes the purchase and installation of energy-efficient EnerChoice fireplaces for zone heating. The program educates consumers and dealers about the EnerChoice label and the benefits of selecting natural gas fireplaces based on energy-efficiency and heating attributes rather than just decorative features. Program awareness and participation was promoted through a combination of customer and dealer incentives and promotional activities.						
Target Market	Residential customers						
New vs Retrofit	Both						
Partners	N/A						
Eligible Measures	EnerChoice Fireplace						
Incremental Measure Cost	EnerChoice Fireplace (Retrofit): $150, EnerChoice Fireplace (New Construction): $300						
Customer Incentive Contractor Incentive	$300 $50 (Retrofit only)						
Savings Per Participant	7.8 GJ						
Measure Life & Source	15 years- Data from prior program participants, Impact of Terasen Gas Pilot Fireplace Program (2004) by Habart and Associates, 2010 Conservation Potential Review, 2012 FortisBC Residential End Use Study						
Free Rider Rate & Source	40% - Retrofit and 15% New Construction - indicates market transformation of the EnerChoice brand						
Sources of Assumptions	Data from prior program participants Impact of Terasen Gas Pilot Fireplace Program (2004) by Habart and Associates, 2010 Conservation Potential Review 2012 FortisBC Residential End Use Study 2015 FortisBC Enerchoice Fireplace Program Impact Evaluation by Sampson Research Inc.						
Participants		Projected	Retrofit Total	New Construction Total	2015 Total		
	Total	3,468	5,113	975	6,088		
Expenditures ($,000s)			Non-Incentives				
	2015	Incentives	Dealer Incentives	Admin	Communication	Research & Evaluation	Total
	Total	1,826	253	59	42	29	2,209

Notes:

- The EnerChoice Fireplace Program Impact Evaluation and Market Effects Study demonstrated the need to redefine the EnerChoice eligible products directory to improve minimum efficiency standards. Therefore the EnerChoice program was temporarily suspended to undertake industry and government consultation for 2016 program design. The 2016 program is expected to be in market in Q2 2016.
- Contractor incentives of $50 per participant are allocated to the administration portion of non-incentive spend.

Table 5-5: Appliance Service Program

Program Description	This program will provide customer education related to the importance of regular appliance maintenance to ensure efficient operation of natural gas appliances. This program will also create opportunities for contractors to dialogue with customers about upgrading appliances to more efficient models.					
Target Market	Residential customers					
New vs Retrofit	Retrofit					
Partners	N/A					
Eligible Measures	Furnace Service (69%), Fireplace Service (31%)					
Incremental Measure Cost	N/A					
Incentive Amount	$33					
Savings Per Participant	N/A					
Measure Life & Source	N/A					
Free Rider Rate & Source	N/A					
Participants (no. of services)	2015	Projected	Actual			
	Total	0	21,380			
Expenditures ($,000s)			Non-Incentives			
	2015	Incentives	Admin	Communication	Research & Evaluation	Total
	Total	535	54	28	0	616

Notes:

- The incentive amount of $33 represents the average incentive awarded per participant based upon a portion of the participants having both a furnace and fireplace serviced at $25 (incentive) per service.

Table 5-6: ENERGY STAR® Water Heater Program

Program Description	This program promotes the replacement of standard efficiency water heaters with efficient ENERGY STAR® models. As part of a longer term market transformation strategy, the program introduced 0.67 EF storage tank water heaters and new technologies with energy factors (EF) greater than 0.80. The new technologies include condensing and non-condensing tankless water heaters, hybrids and condensing storage tanks. The program is available to both retrofit and new construction markets. The program supports upcoming federal and provincial Minimum Efficiency Act Standards for natural gas- and propane-fired water heaters.
Target Market	Residential customers
New vs Retrofit	Both
Partners	N/A

Eligible Measures	ESTAR 0.67 EF Storage Tank	Non-Condensing Tankless	Condensing Tankless	Hybrids	Condensing Storage Tank
Incremental Measure Cost					
Retrofit	$250	$1,510	$2,359	$2,219	$2,030
New Construction	$100	$425	$825	$1,478	$2,771
Incentive Amount	$200	$400	$500	$500	$1,000
Savings Per Participant	3.0 GJ	6.5 GJ	8.3 GJ	7.3 GJ	5.0 GJ

Measure Life & Sources	17.2 years Weighted average - Manufacturers and other utilities; ACEEE Emerging Hot Water Technologies and Practices for Energy Efficiency as of 2011. October 2011. Report Number A112. Sachs, H., Jacob Talbot and Nate Kaufman; Canadian Residential Water Heater Market Assessment. 2009. Caneta Research Inc. 2012
Free Rider Rate & Source	10%- ACEEE Emerging Hot Water Technologies and Practices for Energy Efficiency as of 2011. October 2011. Report Number A112. Sachs, H., Jacob Talbot and Nate Kaufman; Program Participant Feedback. 2012 Residential End Use Study.
Sources of Assumptions	ACEEE Emerging Hot Water Technologies and Practices for Energy Efficiency as of 2011. October 2011. Report Number A112. Sachs, H., Jacob Talbot and Nate Kaufman; 2014 and 2015 Program Participant Feedback. A Canadian high efficiency natural gas water heater pilot project. Project # 417311. Natural Gas Technologies Centre. Prepared by Adam Neale. 2012 FortisBC Residential End Use Study. 2010 Conservation Potential Review.

Participants	2015	Projected Total	Actual							
			ESTAR 0.67 EF Storage Tank		Non-Condensing Tankless		Condensing Tankless & Hybrids		Condensing Storage Tank	
			Retrofit	New Const.	Retrofit	New Const.	Retrofit	New Const.	Retrofit	New Const.
	Total	3,900	3,237	45	162	106	1,304	312	378	224

Expenditures ($,000s)	2015	Incentives	Non- Incentives				Total
			Dealer Incentives	Admin	Comm.	Research & Evaluation	
	Total	2,319	261	64	45	0	2,688

Notes:

- The Canadian high efficiency natural gas water heater pilot project conducted by Natural Gas Technologies Centre based on sub-metering analysis of 38 homes confirmed that the stated energy savings estimates are valid with overall energy savings of about 37% across new technologies over the base line 0.62 EF storage tank water heater. This study was published in 2014.
- Based on data from 2015 program participants, incremental costs for water heaters was unchanged or slightly decreased over 2014, unlike the cost increase noted for furnaces and boilers in 2015.

Table 5-7: Domestic Hot Water Conservation - Low Flow Fixtures and Washer Promotions

Program Description	The objective of this program is to reduce hot water consumption in houses, row houses and MURBS through partnerships with utilities or government. Initiatives include the installation of low-flow fixtures and ENERGY STAR washers and dryers.
Target Market	Residential customers
New vs Retrofit	Retrofit
Partners	BC Hydro, FBC, Non-Governmental Organizations (NGOs), and Municipalities
Eligible Measures	Low-Flow Fixtures; ENERGY STAR® Washers and Dryers
Low Flow Fixtures:	
Incremental Measure Cost	N/A in this direct install program
Incentive Amount	N/A in this direct install program
Savings Per Participant	Bathroom fixtures 0.8 GJ / Kitchen fixtures 0.8 GJ/ Shower 1.3 GJ
Measure Life & Source	10 years- 2010 Conservation Potential Review (ultra low-flow shower head, 1.25 GPM)
Free Rider Rate & Source	10%- City Green Report: Tap by Tap, January 10, 2012
ENERGY STAR Washers:	
Incremental Measure Cost	$102
Incentive Amount	• $50 rebate (FEU contributes $25) on qualifying ENERGY STAR® clothes washers - IMEF of 2.76 to 2.93, and WF of 3.5 to 3.3 • $100 rebate (FEU contributes $75) on qualifying ENERGY STAR clothes washers - IMEF of 2.94 or higher, WF of 3.2 or less
Savings Per Participant	1.0 GJ Natural Gas plus 0.25 GJ electric - BC Hydro
Measure Life & Source	14 years- 2010 Conservation Potential Review and Ontario Power Authority "2010 Prescriptive Measures and Assumptions: Release 1"
Free Rider Rate & Source	20%- BC Hydro based on market share of eligible washers

Participants	2015	Projected	Actual Low Flow Fixtures	Actual ENERGY STAR Washers		
	Total	N/A	10,116	501		
Expenditures ($,000s)		**Incentives**	**Non-Incentives**			**Total**
			Admin	Communication	Research & Evaluation	
	Total	99	71	18	37	226

Notes:

- The Low Flow Fixtures project in Table 5-6 summarizes 2015 activity for the Tap by Tap project on Vancouver Island and the BC Hydro MURB project for municipalities in the Lower Mainland. This pilot has been replaced in market by the Rental Apartment Program outlined in Table 5-9.
- The Washer promotion was a collaboration with BC Hydro for a spring promotion in May-June and fall promotion in September-October. In addition FEI collaborated with FBC from May 2015 through December 2015.

Table 5-8: New Home Program

Program Description	This program provides education and financial incentives to support energy-efficient building practices for the Residential sector. 2015 expenditures are related to a wrap-up of projects with 2014 building permits that qualified for the 2014 EG80 program. This program supported efficiency updates to the BC Building Code (effective Dec. 2014). In June 2015, the utilities launched ENERGY STAR® for New Homes as the new whole home performance standard. As new builds take time for completion, there are no applications to date.					
Target Market	Builders of residential properties – single family homes and townhomes and homeowner builders					
New vs Retrofit	New Construction					
Partners	BC Hydro and FBC					
Eligible Measures	EG80 Single Family Dwellings		EG80 Townhome/Rowhome		Boilers	
Incremental Measure Cost	$3,912		$1,166		$1,350	
Incentive Amount	$2,000		$200		$1,000	
Savings Per Participant	16.3 GJs		4.4 GJs		8.4 GJs	
Measure Life & Source	25 years- New Construction Costs and Savings and Life Cycle Costs, First published in 2011 and updated in 2014, Cooper and Habart, and Dunsky Energy Consulting					
Free Rider Rate & Source	15% for EnerGuide 80 and 40% for Boilers					
Participants	2015	Projected	Actual			
			EG80 SFD	EG80 Rowhome	Boiler	Total
	Total	191	407	0	295	702
Expenditures ($,000s)	2015		Non-Incentive Expenditures			
		Incentives	Admin	Communication	Research & Evaluation	Total
	Total	1,096	127	48	24	1,296

Notes:

- FEI has collaborated with BC Hydro Power Smart and FBC on this program.
- Energy savings and participant costs were derived from a 2013 study, BC Building Code (2014) & New Homes Program, by Cooper and Habart. This study was co-developed with FBC and BC Hydro.
- In 2014, the FEI's attribution for energy savings for the advancement of Codes and Standards as a direct result of the New Home Program included an estimate of 2015 program participants. The program advanced Codes and Standards by way of helping builders, developers and contractors become more knowledgeable in building more energy efficient homes and enabling the market transformation to more stringent codes. As such, this work in part enabled the introduction of the new BC Building code effective December 2014 and the 2014 Vancouver Building By-Law (VBBL) effective January 1, 2015. Both of these new building codes set a higher energy efficiency standard for residential homes that include single family homes and row homes/townhouses over the current version of the respective building codes. For more information please refer to the 2014 EEC Annual Report Section 5.3, Table 5-8 New Home Program.

Table 5-9: Rental Apartment Efficiency (RAP) – *Residential Portion* (New Program)

Program Description	There are three components to the RAP program. The first component is to provide direct install in-suite energy efficiency upgrades to building owners or property management companies of rental properties (hereinafter referred to as Participant(s)). These devices will be installed by an agent of FortisBC into each individual rental suite. The second component is to simultaneously provide those Participants with energy assessments recommending building-level energy efficiency upgrades such as condensing boilers, high efficiency water heaters and lighting upgrades. The last component is to provide the Participant with support in implementing those energy efficiency recommendations and applying for rebates. Expenditures associated with the energy assessment, implementation support, boiler/water heater rebates as well as a portion of the communication and evaluation costs are covered by the Commercial Program Area.				
Target Market	Purpose-Built Rental Apartment Buildings				
New vs Retrofit	Retrofit				
Partners	FortisBC Inc.				
Eligible Measures	1.3 GPM Showerheads, 1.3 GPM Handheld Showerheads, 0.8 GPM Bathroom Aerators, 0.8 GPM Kitchen Aerators				
Incremental Measure Cost	Varies				
Incentive Amount	Full cost				
Savings Per Participant	Varies				
Measure Life & Source	Varies				
Free Rider Rate & Source	Varies				
Participants	2015	Projected	Actual		
	Total	0	3,078		
Expenditures ($,000s)			Non-Incentives		
	2015	Incentives	Admin	Communication	Research & Evaluation	Total
	Total	31	24	5	6	66

Notes:

- Expenditures associated with direct install activities and a portion of the communication and evaluation costs are covered by the Residential Program Area. Expenditures associated with the energy assessment, implementation support, boiler/water heater rebates as well as the remaining portion of communication and evaluation costs are covered by the Commercial Program Area.
- Full program details including both residential and commercial activity and cost effectiveness results are available in Section 7, Table 7-11.
- Below is a list of the 2015 measure participant counts that are covered under the Residential Program Area.

Installed Measure Type	Installed #
1.5GPM Bathroom Aerators (Gas)	1023
1.5GPM Handheld Showerhead (Gas)	153
1.5GPM Kitchen Aerators (Gas)	995
1.5GPM Showerheads (Gas)	907

5.4 2015 Residential Energy Efficiency Programs Planned But Not Launched

5.4.1 CUSTOMER ENGAGEMENT TOOL

FEI developed the business case and released an RFP for vendor selection in 2014. A Customer Engagement Tool (CET) relies heavily on social norms, i.e. a customer's energy usage is compared to the average of their neighbours in order to prompt behavioural change, i.e., energy savings. The CET is being reviewed to ensure that customer data exchanged with the vendor is secure and is in compliance with the Personal Information Protection Act and corporate privacy policies. The project will be re-evaluated in 2016.

5.4.2 ON-BILL FINANCING

On-bill financing pilots were found to be expensive and administratively burdensome for utilities. Pilot implementations were unsuccessful with very low uptake rates. However, in 2014 FortisBC partnered with CIBC to offer a competitive financing package through the Trade Ally Network. Partnerships with additional financial institutions, such as VanCity, were developed in collaboration with BC Hydro and promoted through the Home Energy Rebate Offer.

5.4.3 NEW TECHNOLOGIES

FEI continues to explore New Technologies through the Innovative Technologies Program. There were no new technologies ready for deployment in 2015. Combination heat and water heating systems are currently under evaluation and a pilot was launched in early 2015. Pilot implementation learnings will be used to assess the business case, which if cost effective will be presented to BCUC for consideration for a 2017 program.

5.5 Summary

Residential Energy Efficiency Program Area activity in 2015 resulted in over 121,377 GJ/year of natural gas savings. Residential Energy Efficiency programs enabled customers to upgrade appliances and capture energy savings, supported the introduction of new provincial regulations and continued to build on relationships with the trades for education and program awareness. The combination of financial incentives, policy support, contractor outreach and effective marketing is instrumental to the ongoing success of these programs in generating natural gas savings and fostering market transformation in the residential sector.

Universality is a key guiding principle for FEI's DSM initiatives. Amendments to the Demand-Side Measures Regulations have enabled more programs to be developed, resulting in significant energy savings benefits for residential customers. The Province, in turn, benefits from the resulting GHG emissions reductions in the residential building sector.

6. LOW INCOME ENERGY EFFICIENCY PROGRAM AREA

6.1 Overview

In 2015, FEI saw continued success with the Energy Savings Kit (ESK) Program and the Energy Conservation Assistance Program (ECAP). The Company also implemented another successful Residential Energy Efficiency Works (REnEW) session, and developed three new Low Income Programs (described under 6.3 2015 Low Income Programs Planned But Not Launched).

In addition to FEI's own Low Income programs, progress continues to be made on investing the $5.2 million in funds granted to FEI by the Ministry of Energy, Mines and Natural Gas in 2009 to enable energy efficiency in low income households. In 2015, the Company invested $377 thousand of this funding primarily on retrofits in low income homes, partnership funding of the REnEW program, development of a building operator online training system, and an energy advisor position focused on the non-profit building sector. None of these investments are included in the spending amounts shown in Table 6-1. The remaining granted funds will be invested over the next 1-2 years.

Table 6-1 summarizes the planned and actual expenditures for the Low Income Program Area in 2015, including incentive and non-incentive spending, annual and NPV gas savings, as well as the cost-effectiveness test results. The TRC and MTRC for low income programs uses a value of 140% of the benefits in accordance with July 2014 amendments to Section 4(2)(b) of the Demand-Side Measures Regulation. This amendment effectively increases the deemed cost effectiveness of the Low Income programs.

Table 6-1: 2015 Low Income Program Results Summary

Program	Annual Gas Savings (GJ/yr.)		Actual NPV Gas Savings (GJ)	Utility Expenditures ($000s)						Benefit/Cost Ratios				
				Incentives		Non-Incentives		All Spending						
	2014-2018 EEC Plan	2015 Actual		2014-2018 EEC Plan	2015 Actual	2014-2018 EEC Plan	2015 Actual	2014-2018 EEC Plan	2015 Actual	TRC	MTRC	Utility	Participant	RIM
Non Program Specific Expenses														
Total	No Direct Savings			0	0	305	89	305	89	No Direct Savings				
Energy Saving Kit (ESK)														
Total	9,312	18,463	129,673	86	236	57	128	143	364	5.0	n/a	4.1	7.8	0.9
Energy Conservation Assistance Program (ECAP)														
Total	7,569	5,638	42,275	1,101	674	743	342	1,844	1,015	0.5	1.8	0.5	1.7	0.3
Residential Energy Efficiency Works (REnEW)														
Total	No Direct Savings			0	0	81	72	81	72	N/A				
*Low Income Space-Heat Top-Ups														
Total	2,569	0	0	71	0	15	3	86	3	N/A				
*Low Income Water-Heating Top-Ups														
Total	751	0	0	12	0	5	3	16	3	N/A				
*Non-Profit Custom Program														
Total	6,718	0	0	249	0	98	3	348	3	N/A				
ALL PROGRAMS														
Total	**26,920**	**24,100**	**171,948**	**1,520**	**910**	**1,303**	**640**	**2,822**	**1,550**	**1.4**	**2.2**	**1.3**	**3.3**	**0.6**

6.2 2015 Low Income Programs

Tables 6-2 through 6-4 outline the specific Low Income programs undertaken in 2015, including program and measure descriptions and a breakdown of non-incentive spending.

Table 6-2: Energy Saving Kit (ESK) Program

Program Description	The goal of this program is to reach a broad audience of low income customers and enable them to take some simple steps towards saving energy by installing a bundle of easy-to-install items that are delivered to their door. Promotional activities include bill inserts, event promotions such as food banks, targeted digital campaigns and partnerships with government ministries and non-profits that serve the low income population.					
Target Market	Low Income Residential Customers					
New vs Retrofit	Retrofit					
Partners	BC Hydro and FortisBC Inc. (FBC)					
Eligible Measures	Bundle of measures, including high efficiency water fixtures, water heater pipe wrap, draft proofing tape, outlet gaskets, window film, etc.					
Incremental Measure Cost	$ 22.44 Average based on the full cost of the gas measures included in the ESK and pro-rated by the proportion of participants that use natural gas for space or water heating.					
Incentive Amount	$ 22.44 Since the program is free to participants, the incentive equals the incremental cost.					
Savings Per Participant	2.4 GJ per year					
Measure Life & Source	10 years - Average based on the individual gas measures included in the Energy Saving Kit					
Free Rider Rate & Source	27% - Based on 2010 BC Hydro participant survey.					
Participants	2015	2015 Projected	2015 Actual			
	Total	6,379	10,538			
Expenditures ($,000s)	2015	Incentives	Admin	Communication	Research & Evaluation	Total
	Total	236	60	67	1	364

Table 6-3: Energy Conservation Assistance Program (ECAP)

Program Description	This program enables deep energy savings in low income customer homes that have moderate to high energy consumption. Promotional activities include bill inserts, customer endorsements, outreach, promotion at events and conferences, and partnerships with government ministries, housing providers, and other organizations that serve the low income population.
Target Market	Low Income Residential Customers
New vs Retrofit	Retrofit
Partners	BC Hydro and FBC
Eligible Measures	Bundle of customized measures, which may include low-flow fixtures, water heater pipe wrap, professional draft proofing, outlet gaskets, window film, insulation, improved ventilation, CO detectors, and furnaces.
Incremental Measure Cost	$516 Based on average cost of the customized bundle of measures installed. Includes the full cost of the gas measures installed in gas heated homes.
Incentive Amount	$516 Since the program is free to participants, the incentive equals the incremental cost.
Savings Per Participant	4.5 GJ per year
Measure Life & Source	11 years - Average based on the individual gas measures installed.
Free Rider Rate & Source	4% (Source: Primarily third-party studies)
Participants	2015 Total — 2015 Projected: 1,359; 2015 Actual: 1,305
Expenditures ($,000s)	2015 Total — Incentives: 674; Admin: 160; Communication: 71; Research & Evaluation: 110; Total: 1,015

Table 6-4: Residential Energy Efficiency Works (REnEW) Program

Program Description	The goal of this program is to enhance the energy efficiency trade sector in BC in a manner that also enhances communities. This program targets individuals facing barriers to employment and provides training in energy efficiency retrofitting. The training is delivered by industry experts at no costs to participants.
Target Market	Low income individuals facing barriers to employment
New vs Retrofit	N/A
Partners	N/A
Eligible Measures	N/A
Incremental Measure Cost	N/A
Incentive Amount	N/A
Savings Per Participant	N/A
Measure Life & Source	N/A
Free Rider Rate & Source	N/A
Participants	2015 Total — 2015 Projected: 20; 2015 Actual: 13
Expenditures ($,000s)	2015 Total — Incentives: 0; Admin: 71; Communication: 1; Research & Evaluation: 0; Total: 72

6.3 2015 Low Income Programs Planned But Not Launched

In 2015 FEI developed three new Low Income Programs: Low Income Space Heat Top-Up Program, Low Income Water Heater Top-Up Program, and the Non-Profit Custom Program. These three new programs have since been approved by the BCUC and will launch in 2016.

Each are described briefly below. Results of these new programs will be reported on in the 2016 Annual Report.

Table 6-5: Low Income Space Heat Top Up

Program Description	The existing Commercial Space Heat Program offers rebates to commercial customers for the installation of high efficiency space heating equipment in commercial applications. The Low Income Space Heat Top Up Program will piggyback on the existing Commercial Space Heat Program and offer an additional incentive over and above the commercial rebate if the customer meets the eligibility criteria. Promotional activities will include partnerships with BC Housing, BC Non-Profit Housing Association (BCNPHA), and the provincial and regional BCNPHA conferences, trade shows and educational seminars.				
Target Market	The Low Income Space Heat Top Up Program is primarily focused on apartment buildings that are owned or operated by a First Nations band, a non-profit housing provider, or a housing co-operative.				
New vs Retrofit	Both				
Partners	N/A				
Eligible Measures	Condensing boilers and mid-efficiency boilers.				
Incremental Measure Cost	$7,500 per appliance (Business case assumptions. No participants in 2015.)				
Incentive Amount	$6/MBH (Business case assumptions. No participants in 2015.)				
Savings Per Participant	168 GJ/yr per appliance (Business case assumptions. No participants in 2015.)				
Measure Life & Source	20 Years				
Free Rider Rate & Source	18%				
Participants	Service Region	2015 Projected	2015 Actual		
	Total	22	0		
Expenditures ($,000s)	2015	Incentives	Admin	Communication	Research & Evaluation	Total
	Total	0	3	0	0	3

Table 6-6: Low Income Water Heating Top Up

Program Description	The existing Commercial Water Heater Program was launched in 2010 and it offers rebates to commercial customers for the installation of high efficiency water heating equipment in commercial applications. The Low Income Water Heater Top Up Program will piggyback on the existing Commercial Water Heater Program and offer an additional incentive over and above the commercial rebate if the customer meets the eligibility criteria. Promotional activities will include partnerships with BC Housing, BC Non-Profit Housing Association (BCNPHA), and the provincial and regional BCNPHA conferences, trade shows and educational seminars.
Target Market	The Low Income Water Heater Top Up Program is primarily focused on apartment buildings that are owned or operated by a First Nations band, a non-profit housing provider, or a housing co-operative.
New vs Retrofit	Both
Partners	N/A
Eligible Measures	High Efficiency Storage Tanks, High Efficiency Domestic Hot Water Boilers, High Efficiency Tankless Domestic Hot Water
Incremental Measure Cost	$6,678 per appliance (Business case assumptions. No participants in 2015.)
Incentive Amount	$1.67/MBH (Business case assumptions. No participants in 2015.)
Savings Per Participant	$76 GJ/year per appliance (Business case assumptions. No participants in 2015.)
Measure Life & Source	12 Years
Free Rider Rate & Source	5%

Participants		2015 Projected	2015 Actual			
	2015 Total	20	0			
Expenditures ($,000s)	**2015**	**Incentives**	**Admin**	**Communication**	**Research & Evaluation**	**Total**
	Total	0	3	0	0	3

Table 6-7: Low Income Non-Profit Custom

Program Description	This program will encourage non-profit housing societies to replace inefficient equipment and systems with high-efficiency solutions. This program will involve an energy study and will provide incentives based on the recommendations of the study. Incentives under this program will cover all or most of the incremental cost of the cost-effective measures. The proposed program is built around three components: 1) An energy study: FEI will initially contribute up to 50% of the costs for the initial energy study for all eligible participants. Where appropriate, the Company will also provide funding so that the energy study provider can write a scope of work. 2) A capital cost incentive, equal to the incremental cost of the energy efficient measure, will be paid after the measure is installed. 3) A completion bonus: Upon implementation of at least one priority measure recommended by the energy study and deemed as eligible for incentives, the Company will contribute the remaining 50% cost of the energy study. Promotional activities will include partnerships with BC Housing, BC Non-Profit Housing Association (BCNPHA), and the provincial and regional BCNPHA conferences, trade shows and educational seminars.
Target Market	The Non-Profit Custom Program is primarily focused on apartment buildings that are owned or operated by First Nations bands, non-profit housing providers, or housing co-operatives.
New vs Retrofit	Both
Partners	N/A
Eligible Measures	Eligible measures are expected to include mechanical equipment (i.e. boilers, ventilation systems, water heat/storage, etc.) and heating controls (i.e. zone controls, temperature set back controls, etc.). In addition there will be other more customized scenarios that will be assessed for savings and incentive potential as the opporutnities arise.
Incremental Measure Cost	Energy Study: $13 thousand, Capital Incentive: $38.2 thousand (Business case assumptions. No participants in 2015.)
Incentive Amount	Energy Study: $13 thousand, Capital Incentive: $38.2 thousand (Business case assumptions. No participants in 2015.)
Savings Per Participant	831GJ/year (Business case assumptions. No participants in 2015.)
Measure Life & Source	14 Years (Business case assumptions. No participants in 2015.)
Free Rider Rate & Source	5%

Participants			
2015	2015 Projected	2015 Actual	
Total	10	0	

Expenditures ($,000s)	Incentives	Admin	Communication	Research & Evaluation	Total
2015 Total	0	3	0	0	3

6.4 Summary

The Low Income Program Area has been an important priority for the Company since the initial creation of the DSM Program Principles. The goal of creating programs that are accessible to all has been achieved through the continuation of the ESK Program, the REnEW Program and ECAP and will be further enhanced by the addition of the three new Low Income programs in 2016.

7. COMMERCIAL ENERGY EFFICIENCY PROGRAM AREA

7.1 Overview

In 2015, Commercial Energy Efficiency programs continued to encourage commercial customers to reduce their overall consumption of natural gas and their associated energy costs. The Commercial Energy Efficiency Program Area reduced annual natural gas consumption by over 270,000 GJs and achieved an overall TRC of 1.2. Nearly $11 million was invested in Commercial Energy Efficiency, of which 81% was incentive spending.

Table 7-1 summarizes the projected and actual expenditures for the Commercial Energy Efficiency Program Area in 2015, including incentive and non-incentive spending, annual and NPV gas savings, as well as TRC and other cost-effectiveness test results.

Table 7-1: 2015 Commercial Energy Efficiency Program Results Summary

Program	Annual Gas Savings (GJ/yr.)		Actual NPV Gas Savings (GJ)	Utility Expenditures ($000s)						Benefit/Cost Ratios				
				Incentives		Non-Incentives		All Spending						
	2014-2018 EEC Plan	2015 Actual		2014-2018 EEC Plan	2015 Actual	2014-2018 EEC Plan	2015 Actual	2014-2018 EEC Plan	2015 Actual	TRC	MTRC	Utility	Participant	RIM
Non Program Specific Expenses														
Total	No Direct Savings			0	0	1,100	635	1,100	635	No Direct Savings				
Space Heating Program														
Total	53,081	91,688	971,341	1,722	4,002	109	248	1,831	4,249	1.9	n/a	2.1	3.0	0.6
Water Heating Program														
Total	13,833	14,251	113,189	220	282	59	137	279	419	1.0	n/a	2.3	1.6	0.7
Commercial Food Service Program														
Total	13,350	13,698	108,802	294	414	137	229	431	643	1.1	n/a	1.4	2.4	0.5
Customized Equipment Upgrade Program														
Total	57,575	18,395	155,074	2,473	1,009	222	410	2,696	1,419	0.8	n/a	1.0	1.6	0.5
EnerTracker Program														
Total	31,154	30,937	30,937	394	221	148	62	543	283	0.8	n/a	0.7	2.2	0.4
Continuous Optimization Program														
Total	134,793	72,958	299,142	1,983	995	202	18	2,185	1,013	1.2	n/a	2.3	1.9	0.7
Commercial Energy Assessment Program														
Total	0	16,229	16,229	379	67	87	26	466	93	1.4	n/a	1.1	3.5	0.4
Energy Specialist Program														
Total	0	9,414	58,394	1,890	1,716	144	200	2,034	1,916	n/a	n/a	n/a	n/a	n/a
Mechanical Insulation Pilot														
Total	1,000	0	0	0	0	8	0	8	0	n/a	n/a	n/a	n/a	n/a
Rental Apt Efficiency (RAP)* *Commercial Portion*														
Total	0	3,363	3,363	0	34	0	41	0	76	n/a	n/a	n/a	n/a	n/a
ALL PROGRAMS														
Total	**304,786**	**270,933**	**1,756,471**	**9,355**	**8,740**	**2,218**	**2,006**	**11,573**	**10,746**	**1.2**	**n/a**	**1.4**	**2.2**	**0.6**

Notes:

- ∗ The Rental Apartment Efficiency Program includes a combination of residential and commercial measures, each funded from their respective Program Areas. The *Commercial Portion* details of this program included in Table 7-1 and 7-10 show only those Commercial Program Area expenditures. These expenditures are associated with the commercial energy assessment, implementation support, boiler/water heater rebates as well as a portion of the communications and evaluation costs. Residential Program Area expenditures that are part of the RAP program are presented in Tables 5-1 and 5-9. Cost effectiveness values for only the *Commercial Portion* of RAP are not provided as they do not represent a complete program view. Please refer to Table 7-11 for a complete program view and further program details including program cost effectiveness results.

7.2 2015 Commercial Energy Efficiency Programs

The following tables outline the specific Commercial Energy Efficiency programs undertaken in 2015, including program and measure descriptions and a breakdown of non-incentive spending.

Table 7-2: Space Heat Program

Program Description	This program provides rebates for the installation of high efficiency space heating equipment in commercial applications. Currently only rebates for high efficiency boilers are offered. Rebates for condensing rooftop units may also be offered via the program in 2016.					
Target Market	Commercial					
New vs Retrofit	Both					
Partners	N/A					
	Retrofit	New Construction				
Incremental Measure Cost	$19,279	$35,751				
Incentive Amount	$14,233	$27,669				
Savings Per Participant	418 GJ	438 GJ				
Measure Life & Source	20 years - ASHRAE Handbook and Conservation Potential Review					
Free Rider Rate & Source	18% - Efficient Boiler Program Impact Evaluation, June 12, 2003					
Participants	2015	Projected	Actual			
	Total	143	267			
Expenditures ($,000)	2015	Incentives	Admin	Communication	Research & Evaluation	Total
	Total	4,002	222	15	11	4,249

Table 7-3: Water Heating Program

Program Description	This program provides rebates for the installation of high-efficiency commercial water heaters with thermal efficiencies greater than or equal to 84%.					
Target Market	Commercial					
New vs Retrofit	Both					
Partners	N/A					
	Retrofit	New Construction				
Incremental Measure Cost	$6,235	$9,366				
Incentive Amount	$1,892	$3,493				
Savings Per Participant	115 GJ	108 GJ				
Measure Life & Source	12 years -2010 Conservation Potential Review, Navigant Consulting (16 April 2009) Measures and Assumptions for Demand Side Management Planning Appendix C: Substantiation Sheets Ontario Energy Board pp. 210-226.					
Free Rider Rate & Source	5% - Navigant Consulting (16 April 2009), Measures and Assumptions for Demand Side Management Planning, Appendix C: Substantiation Sheets, Ontario Energy Board, pp. 210-226.					
Participants	2015	Projected	Actual			
	Total	115	132			
Expenditures ($,000)	2015	Incentives	Admin	Communication	Research & Evaluation	Total
	Total	282	89	35	14	419

Table 7-4: Commercial Food Service Program

Program Description	This program offers a suite of rebates for the installation of high-efficiency cooking appliances and it may also provide other incentives relevant to commercial food service participants such as low-flow pre-rinse spray valve or faucet aerator installs.					
Target Market	Commercial					
New vs Retrofit	Both					
Partners	N/A					
		Retrofit	New Construction			
Incremental Measure Cost		$5,309	$7,270			
Incentive Amount		$2,598	$3,880			
Savings Per Participant		125 GJ	184GJ			
Measure Life & Source	12 Years - Foodservice Incentive Program Study 2012, Fisher-Nickel Inc., Marbek Conservation Potential Review (2010) and Database for Energy Efficiency Resources (DEER). San Francisco, CA, California Public Utilities Commission, 2011.					
Free Rider Rate & Source	20% - Foodservice Incentive Program Study 2012, Fisher-Nickel Inc.					
Participants	2015	Projected	Actual			
	Total	368	126			
Expenditures ($,000)	2015	Incentives	Admin	Communication	Research & Evaluation	Total
	Total	414	114	116	0	643

Notes:

- During Q3/Q4 2014, as part of the Commercial Food Service Program, FEI in partnership with BC Hydro and the City of Vancouver participated in a program to install low-flow pre-rinse spray valves and faucet aerators in Vancouver food service establishments. All spray valves and aerators were installed in 2014, thus the participants, energy savings and incremental costs were included in the 2014 Energy Efficiency and Conservation Annual Report. The Implementation Contractor's final report and invoice were not received by FEI until 2015 however; therefore, the incentive expenditure has been included in the 2015 program incentive expenditure without associated participants, energy savings and incremental costs.

Table 7-5: Customized Equipment Upgrade Program

Program Description	This program provides eligible customers with funding towards the completion of a detailed Energy Study, to identify energy saving opportunities specific and customized to their facilities, and subsequent capital incentive funding to encourage the implementation of any cost effective measures identified therein. The program seeks to capture energy savings associated with measures that are otherwise difficult to incent as part of a prescriptive program because they are complex, and one project may include multiple measures with interactive effects. The expected energy savings, measures, capital cost, incentives etc, will necessarily vary depending on the customer, though each project is submitted to a TRC test and must be approved by the utility.					
Target Market	Commercial customers					
New vs Retrofit	Both					
Partners	BC Hydro (New Construction)					
Eligible Measures	Utility funded energy study, and utility incented Energy Saving Measures as identified in the energy study and approved by the utility. Energy Saving Measures are variable.					
Incremental Measure Cost	Variable. Dependent upon participant's proposed Energy Saving Measures.					
Incentive Amount	If TRC ≥ 1.0 then $5 / discounted GJ saved over 50% of the Energy Measure Life (EML), up to 10 yrs.					
Savings Per Participant	Variable. Dependent upon participant's proposed Energy Saving Measures.					
Measure Life & Source	Variable. Dependent upon participant's proposed Energy Saving Measures.					
Free Rider Rate & Source	Variable. Dependent upon participant's proposed Energy Saving Measures.					
	FEW	0	0			
	Total	87	56			
Expenditures ($,000s)						
	Labour	0	57	0	0	57
	Total	149	68	3	0	220
Expenditures ($,000s)						
	Labour	0	196	0	0	196
	Total	860	339	0	0	1,198

Notes:

- The Customized Equipment Upgrade Program is complex in nature and has variable measure savings, costs, incentives and/or cash flows which, unlike in prescriptive programs, occur over a period of years. Consequently, providing results for this program within an annual report format is challenging. In general, the savings in this program occur in later years after the participants have had the time to implement customized Energy Conservation Measures, while some program incentives and costs are payable at the outset. Please refer to the notes provided below for additional details.
- New Construction:
    - Participation in this program can last for approximately 5 years. This is broken down into approximately 12 months to prepare the required whole building energy simulation, followed by up to 48 months to build the proposed building. The program incurs incentive expenditures upon the successful completion of the energy simulation, as well as upon completion of the building, while natural gas savings are only obtained upon completion of the proposed building.
    - This program is in partnership with BC Hydro. Participants are recorded when the energy simulations or the new buildings are complete, and the incentive becomes payable.
    - The '2015 Actual' participants include 6 completed energy simulations, and 2 completed buildings with implemented measures. The associated natural gas savings from these 2 projects is approximately 3,875 GJ/year.

- Retrofit Program:
  - Participation in this program can last for approximately 2 years. This is broken down into approximately 6 months to prepare the required energy study, followed by 18 months to implement the proposed Energy Conservation Measures. The program incurs incentive expenditures upon the successful completion of the energy study, as well as upon installation of the approved Energy Conservation Measures, while natural gas savings are only obtained upon installation of the approved Energy Conservation Measures. As such, in years where a high number of energy studies are completed but few projects complete installation, the program's benefit/cost ratios will be impacted as incentive expenses will be incurred without obtaining natural gas savings to offset them.
  - The '2015 Actual' participants includes 41 completed energy studies, and 7 projects where Energy Conservation Measures were installed. The associated natural gas savings from these 7 projects is approximately 23,177 GJ/year.
  - The increased number of completed energy studies in 2015 versus 2014, along with the low number of completed Measure installations, has contributed to a lower TRC ratio compared to last year. Customers have continued to demonstrate interest in the program, leading to an increase in energy studies completed in 2015. However, since the majority of energy studies completed in 2014 were completed in the latter part of the year, these projects are still within their 18-month implementation stage of the program, and will not complete installation of their Measures until after the 2015 reporting year has closed. Projects that completed energy studies in 2015 and are eligible for capital incentive funding are expected to complete implementation in 2016/2017.

Table 7-6: EnerTracker Program

<table>
<tr><td>Program Description</td><td colspan="6">This pilot program is a subset of the continuous optimization (C.Op) program. It provides participants who are otherwise unable or unwilling to participate in the full C.Op program with access to an Energy Management Information System (EMIS). EMIS software provides customers with a detailed picture of their natural gas consumption in "near time". Timely access to this information is expected to speed up fault detection, thereby enabling more rapid corrective action to avoid wasted gas consumption, and to assist in the identification of additional natural gas conservation measures.</td></tr>
<tr><td>Target Market</td><td colspan="6">Commercial customers with existing AMR devices (FEI only)</td></tr>
<tr><td>New vs Retrofit</td><td colspan="6">Retrofit</td></tr>
<tr><td>Partners</td><td colspan="6">N/A</td></tr>
<tr><td>Eligible Measures</td><td colspan="6">Energy Management Information System</td></tr>
<tr><td>Incremental Measure Cost</td><td colspan="6">$938/yr (Average)</td></tr>
<tr><td>Incentive Amount</td><td colspan="6">$938/yr (Average)</td></tr>
<tr><td>Savings Per Participant</td><td colspan="6">2% of annual natural gas consumption -- Proof of concept study</td></tr>
<tr><td>Measure Life & Source</td><td colspan="6">1 year -- Measure Life is based on annual EMIS software subscription</td></tr>
<tr><td>Free Rider Rate & Source</td><td colspan="6">6.4% -- Proof of concept study</td></tr>
<tr><td rowspan="2">Participants</td><td>2015</td><td>Projected</td><td>Actual</td><td></td><td></td><td></td></tr>
<tr><td>Total</td><td>540</td><td>236</td><td></td><td></td><td></td></tr>
<tr><td rowspan="2">Expenditures ($,000s)</td><td>2015</td><td>Incentives</td><td>Admin</td><td>Communication</td><td>Research & Evaluation</td><td>Total</td></tr>
<tr><td>Total</td><td>221</td><td>19</td><td>0</td><td>43</td><td>283</td></tr>
</table>

Notes:

- As there is currently insufficient AMR (Automated Meter Reader) infrastructure in the Vancouver Island service territory to support the rollout of this pilot, program availability is limited to the Lower Mainland and Interior service territories.
- Note that participation in the program is cumulative, meaning that a participant is enrolled for multiple years, claiming savings and incurring costs on an annual basis for the duration of the EMIS software license.
- An Evaluation of the pilot is underway but was not completed in time for this annual report. Findings will be included in the 2016 Annual Report and will be used to determine what role the EnerTracker Program will play in the Commercial Energy Efficiency Program portfolio moving forward.

Table 7-7: Continuous Optimization Program

Program Description	The Continuous Optimization Program (C.Op) is designed to help commercial building owners identify and correct energy wasting operation faults, and continuously monitor building performance to help maintain and improve energy efficiency, resulting in reduced operating costs. C.Op is offered in partnership with BC Hydro. In the FortisBC electric service territory, C.Op is offered in partnership with FortisBC Inc. as the Building Optimization Program (B.Op). The program funds re-commissioning services to study the participant's building and recommend energy efficiency improvements, as well as access to an energy management information system (EMIS) to assist in tracking the building's performance after the re-commissioning work is complete. In return, participants must implement, at their costs, measures identified by the re-commissioning study that when combined have a payback period of two years or less.					
Target Market	Commercial customers with buildings >50,000 ft^2 who consume an average of 7,500 GJ of natural gas per year or natural gas is 40% of their building's total energy consumption.					
New vs Retrofit	Retrofit					
Partners	BC Hydro					
Eligible Measures	RE/Retro-commissioning study, employee training, and "near time" energy consumption monitoring.					
Incremental Measure Cost	Average nominal program duration incremental cost (7 years): $41,275 2015 observed average implemented incremental cost: $26,096					
Incentive Amount	Average nominal program duration incentive amount (7 years): $15,915 2015 observed average implemented incentive amount: $14,213					
Savings Per Participant	Average expected annual natural gas savings: 1,465 GJ/year 2015 observed average implemented natural gas savings: 1,042 GJ/year					
Measure Life & Source	5 years - the duration of utility support for the energy management information system, plus one year.					
Free Rider Rate & Source	0% - BC Hydro					
Participants	2015	Projected	Actual	Participants Implementing in 2015	Cumulative Program Participants	
	Total	270	0	70	420	
Expenditures ($,000s)	2015	Incentives	Admin	Communication	Research & Evaluation	Total
	Total	995	18	0	0	1,013

Notes:

- The C.Op. Program is conducted in partnership with BC Hydro and FEI. BC Hydro and FEI act as the primary administrators of program activities, with FEI providing financial and process support.
- Participation in these programs lasts for approximately 7 years for a typical participant. The 7 years are composed of approximately: 12 months of baseline data collection; 24 months of re-commissioning study work, plus the implementation of a recommended bundle of energy conservation measures; and, 48 months of monitoring and continuous improvement.
- Participants are recorded as soon as they are accepted into the program; however, natural gas savings do not occur until they have completed the implementation of a recommended bundle of energy conservation measures, approximately 36 months later. As such, the program incurs incentive expenses (for the upgrading of meter equipment, re-commissioning costs and EMIS costs) before natural gas savings are obtained.
- The average nominal program duration incremental cost represents the total incremental cost expected to be incurred when an average participant completes the full 7 year run in the program. The 2015 observed average implemented incremental cost represents the incremental costs incurred specifically in 2015 divided by the total number of participants who implemented in 2015.
- The average nominal program duration incentive amount represents the total incentive expected to be paid when an average participant completes the full 7 year run in the program. The 2015 observed average implementation incentive amount represents the incentive paid specifically in 2015 divided by the total number of participants who implemented in 2015. Due to the nature of the program, the incentive amount paid is not solely attributable to those who implemented in 2015.
- The average expected annual natural gas savings represent the expected annual natural gas savings per participant after they have completed the implementation of a recommended bundle of energy conservation measures. The 2015 observed average implemented natural gas savings represent natural gas savings attributed to customers who have completed the implementation of a recommended bundle of energy conservation measures specifically in 2015 divided by the total number of participants who implemented in 2015.

Participant count clarification:

- 2015 Actual represents the number of new participants who were approved in 2015. There were no new participants because the program has been closed to new participants since September 2013..
- Participants implementing in 2015 represents the number of participants who have successfully completed implementing the bundle of energy conservation measures in 2015.
- Cumulative Program Participants represent the total number of approved program participants from the entire multi-year duration. Program participants have the option to discontinue participation in the program during the multi-year duration. Since the 2014 Annual Report was finalized, 13 participants chose to discontinue participation, resulting in a lower cumulative participation number in 2015 versus last year.

Table 7-8: Commercial Energy Assessment Program

Program Description	This program identifies inefficiencies at the participant's facilities via an on-site walkthrough assessment by an energy-efficiency consultant. The consultant then produces a report that describes the observed inefficiencies, outlines proposed solutions, and identifies any applicable incentive programs. FortisBC then forwards the report to the participant. Simple measures, such as low-flow faucet aerators and pre-rinse spray valves, are provided to the participant at no charge.				
Target Market	Medium commercial and small industrial customers with an average annual consumption between 1,500 and 10,000 GJ.				
New vs Retrofit	Retrofit				
Partners	FortisBC Inc.				
Incremental Measure Cost	$1,550				
Incentive Amount	$1,375				
Savings Per Participant	502 GJ				
Measure Life & Source	1.07 Years - Conservative estimate based on the implementation of low-cost, simple recommendations (such as operational adjustments) from the energy assessment report, past spray valve program data and database for Energy Efficiency Resources (DEER). San Francisco, CA, California Public Utilities Commission, 2011.				
Free Rider Rate & Source	34% - 2010 Friuch Energy Assessment Evaluation				
Participants	2015	Projected	Actual		
	Total	523	49		
Expenditures ($,000s)	2015	Incentives	Admin	Communication	Research & Evaluation	Total
	Total	67	26	0	0	93

Notes:

- At the time of writing the 2014-2018 EEC Plan, the FEI were unsure whether the Provincial Government's Business Energy Advisor ("BEA") program would continue or not. A contingency measure was planned for this program to ensure small businesses had access to energy analysis had the BEA program been discontinued. Participation from small business customers was foreseen in the 2014-2018 EEC Plan. As the BEA program was continued the scope of the Commercial Energy Assessment Program was not expanded to include small businesses and the number of participants in 2015 is significantly less than was estimated in the 2014-2018 EEC Plan. Of the 523 participants projected in the Plan, 72% were part of the small business market.

Table 7-9: Energy Specialist Program

<table>
<tr><td>Program Description</td><td colspan="6">This program funds Energy Specialist positions within customers' organizations, up to $60,000 based on an annual contract. Funded Energy Specialists' key priority is to identify and implement opportunities for their organization to participate in FortisBC's DSM programs, while also identifying and implementing non-program specific opportunities to use natural gas more efficiently. This program is funded as an enabling program.</td></tr>
<tr><td>Target Market</td><td colspan="6">Large Commercial and Institutional Customers</td></tr>
<tr><td>New vs Retrofit</td><td colspan="6">Retrofit</td></tr>
<tr><td>Partners</td><td colspan="6">BC Hydro</td></tr>
<tr><td>Eligible Measures</td><td colspan="6">Energy Specialist position</td></tr>
<tr><td>Incremental Measure Cost</td><td colspan="6">$60,000</td></tr>
<tr><td>Incentive Amount</td><td colspan="6">$60,000</td></tr>
<tr><td>Savings Per Participant</td><td colspan="6">Total 2015 verified (non-EEC program) annual natural gas savings = 9,414 GJs/year</td></tr>
<tr><td>Measure Life & Source</td><td colspan="6">N/A</td></tr>
<tr><td>Free Rider Rate & Source</td><td colspan="6">7% weighted average against the verified savings - Evaluation of 2015 Energy Specialist Program completed projects.</td></tr>
<tr><td rowspan="2">Participants</td><td>2015</td><td>Projected</td><td>Actual</td><td></td><td></td><td></td></tr>
<tr><td>Total</td><td>32</td><td>32</td><td></td><td></td><td></td></tr>
<tr><td rowspan="2">Expenditures ($,000s)</td><td>2015</td><td>Incentives</td><td>Admin</td><td>Communication</td><td>Research & Evaluation</td><td>Total</td></tr>
<tr><td>Total</td><td>1,716</td><td>134</td><td>0</td><td>66</td><td>1,916</td></tr>
</table>

Notes:

- The Energy Specialist Program continues to experience success as an enabling program. In 2015, organizations with Energy Specialists were responsible for 43% of the gross natural gas savings and 43% of the incentives paid out by the Commercial DSM programs that Energy Specialists can directly participate in, not including the Energy Specialist Program itself. This is in addition to the Conservation Education and Outreach, Innovative Technologies, Low Income, and Residential programs and incentives that Energy Specialists promoted and utilized in 2015.
- Some organizations had Energy Specialists for part of the year only.
- The energy savings listed only apply to third party verified natural gas projects completed by Energy Specialists in 2015 that did not directly receive incentive funding from another DSM program.
- In 2015, FEI continued to co-fund six Business Energy Advisors (BEAs) with BC Hydro which was increased to eight part way through the year at BC Hydro's expense. FortisBC is a minority funding contributor in this arrangement, contributing $60,000 per funding year for all eight Business Energy Advisors combined. This is equivalent to the funding of one Energy Specialist. Business Energy Advisors are tasked with the same objectives as Energy Specialists but target small to medium sized businesses. As a collective they are expected to achieve FortisBC DSM program participation results similar to that of one Energy Specialist. Hence, this has been counted as one participant in the participant total for the Energy Specialist Program.

Table 7-10: Rental Apartment Efficiency (RAP) – *Commercial Portion* (New Program)

Program Description	There are three components to the RAP program. The first component is to provide direct install in-suite energy efficiency upgrades to building owners or property management companies of rental properties (hereinafter referred to as Participant(s)). These devices will be installed by an agent of FortisBC into each individual rental suite. The second component is to simultaneously provide those Participants with energy assessments recommending building-level energy efficiency upgrades such as condensing boilers, high efficiency water heaters and lighting upgrades. The last component is to provide the Participant with support in implementing those energy efficiency recommendations and applying for rebates.
Target Market	Purpose-Built Rental Apartment Buildings
New vs Retrofit	Retrofit
Partners	FortisBC Inc.
Eligible Measures	Walkthrough Energy Audits, Implementation Support, Condensing Boilers, Energy Efficiency Water Heaters
Incremental Measure Cost	Varies
Incentive Amount	Varies
Savings Per Participant	Varies
Measure Life & Source	Varies
Free Rider Rate & Source	Varies
Participants	2015 / Projected / Actual Total / 0 / 26
Expenditures ($,000s)	2015 / Incentives / Admin / Communication / Research & Evaluation / Total Total / 34 / 29 / 7 / 5 / 76

Notes:

- The Participant number listed under Table 7-10 represents the number of Energy Assessments conducted. Incentives for implementation support and building-level upgrades such as condensing boilers and high efficiency water heaters were not realized in 2015 due to the program's entry into the market late in the year and the time required for the Participants to make building-level upgrade decisions.

7.2.1 2015 PROGRAMS WITH JOINT PROGRAM AREA BUDGETS – FULL PROGRAM OVERVIEW

Table 7-11: Rental Apartment Efficiency (RAP)

Program	Annual Gas Savings (GJ/yr.)		Actual NPV Gas Savings (GJ)	Utility Expenditures ($000s)						Benefit/Cost Ratios				
				Incentives		Non-Incentives		All Spending						
	2014-2018 EEC Plan	2015 Actual		2014-2018 EEC Plan	2015 Actual	2014-2018 EEC Plan	2015 Actual	2014-2018 EEC Plan	2015 Actual	TRC	MTRC	Utility	Participant	RIM
Rental Apt Efficiency (RAP) - Commercial Portion														
Total	0	3,363	3,363	0	34	0	41	0	76	0.3	n/a	0.3	3.4	0.2
Rental Apt Efficiency (RAP) - Residential Portion														
Total	0	2,992	21,017	0	31	0	35	0	66	2.6	n/a	2.6	8.8	0.6
Overall Program														
Total	**0**	**6,356**	**24,380**	**0**	**65**	**0**	**77**	**0**	**142**	**1.5**	**n/a**	**1.4**	**6.5**	**0.5**

Notes:

- The Rental Apartment Efficiency Program was launched in October 2015 in response to Commission directive 148 of Order G-138-14 and Commission approval of Order G-138-14. This Table provides a complete Program View of expenditures and savings for both the Residential and Commercial Program Areas. Please refer to Table 5-9 and Table 7-10 for more details regarding the Rental Apartment Efficiency Program specific to each Program Area. Expenditures associated with the direct install activities and a portion of the communication and evaluation costs are covered by the Residential Program Area. Expenditures associated with the energy assessment, implementation support, boiler/water heater rebates as well as a portion of the communication and evaluation costs are covered by the Commercial Program Area. The higher non-incentive expenditures for the Commercial activities relative to the energy savings result in a TRC of 0.3 while the TRC for the Residential activities is 2.6. The TRC for the Rental Apartment Efficiency Program (Overall) which includes both the Commercial and Residential activity expenditures is 1.5.

7.3 2015 Commercial Energy Efficiency Programs Planned But Not Launched

7.3.1 MECHANICAL INSULATION PILOT PROGRAM

This pilot program had originally been set to launch in 2013 but was subsequently cancelled as FEI was unable to conclude a satisfactory agreement with a 3rd party contractor to deliver the project. FEI is not presently pursuing this pilot further.

7.4 Summary

Commercial Energy Efficiency Program Area activity in 2015 successfully achieved 270,933 GJ of annual natural gas savings and a positive TRC of 1.2. The Space Heat program continues act as the corner stone program as it invests more in natural gas efficiency projects than the other commercial programs. However all programs continue to experience growth in participation, incentive spend and natural gas savings. The Commercial Food Service Program in particular experienced significant growth in 2015, helping food service establishments in British Columbia reduce natural gas consumption and costs. Moving forward, the programs will continue to generate natural gas savings and foster market transformation in the commercial sector.

8. INNOVATIVE TECHNOLOGIES PROGRAM AREA

8.1 Overview

A primary objective of the Innovative Technologies Program Area is to identify market-ready technologies that are not yet widely adopted in British Columbia, and which are suitable for the development of or inclusion in the portfolio of ongoing DSM programs in other Program Areas. This is accomplished through pilot and demonstration projects, pre-feasibility studies and the use of Industry Standard Evaluation, Measurement and Verification (EM&V) protocols to validate manufacturers' claims related to equipment and system performance. Results from Innovative Technologies activities are used in making future DSM programming decisions and technology inclusions.

Just as important as identifying new technologies that should be incorporated into the DSM portfolio are findings that indicate which technologies should not. Section 8.3 summarizes how the activities and processes for the Innovative Technologies Program Area were successful in identifying proposed projects that should not proceed to full pilot phase or further.

All 2015 activities undertaken in this Program Area meet the definition of technology innovation programs as set out in the *Demand-Side Measures Regulation*. It should be noted that Innovative Technologies are considered a "specified demand-side measure,"[14] meaning that the Program Area or the measures therein are not subject to a cost-effectiveness test. Instead the cost-effectiveness of these expenditures will be evaluated as part of the DSM portfolio as a whole.[15] Innovative Technologies expenditures are also not subject to the 33 percent cap on programs for which the MTRC is utilized as a cost-effectiveness measure according to Section 4 (4) of the *Demand-Side Measures Regulation*.[16]

Table 8-1 summarizes the projected and actual expenditures for the Innovative Technologies Program Area in 2015, including incentive and non-incentive spending, annual and NPV gas savings, as well as TRC and other cost-effectiveness test results where applicable.

Table 8-1: 2015 Innovative Technologies Program Area Results Summary

Program	Annual Gas Savings (GJ/yr.)		Actual NPV Gas Savings (GJ)	Utility Expenditures ($000s)						Benefit/Cost Ratios				
				Incentives		Non-Incentives		All Spending						
	2014-2018 EEC Plan	2015 Actual		2014-2018 EEC Plan	2015 Actual	2014-2018 EEC Plan	2015 Actual	2014-2018 EEC Plan	2015 Actual	TRC	MTRC	Utility	Participant	RIM
Non-Program Specific Expenses														
Total	No Direct Savings			n/a	0	n/a	200	n/a	200	No Direct Savings				
Pilot/Demonstration Projects														
Total	n/a	1,564	16715	438	217	780	194	1,218	411	0.2	n/a	0.4	0.8	0.2
Studies														
Total	No Direct Savings			n/a	0	n/a	15	n/a	15	No Direct Savings				
ALL PROGRAMS														
Total	**n/a**	**1,564**	**16,715**	**438**	**217**	**780**	**409**	**1,218**	**626**	**0.2**	**n/a**	**0.2**	**0.8**	**0.2**

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14 BCUC Log No. 36730, Request for Clarification of Order G-44-12 and Decision on the 2012 – 2013 Revenue Requirements Application and Natural Gas Rates Application.

15 Subsection 4(4) of the Demand-Side Measures Regulation, and the Decision on the 2012 – 2013 Revenue Requirements Application and Natural Gas Rates Application, page 175.

16 BCUC Log No. 36730, Request for Further Clarification of Order G-44-12 and Decision on the 2012 – 2013 Revenue Requirements Application and Natural Gas Rates Application and the Commission's May 11, 2012 letter.

Notes:

- Innovative Technologies are considered a "specified demand-side measure," meaning that the Program Area or the measures therein are not subject to a cost-effectiveness test. Instead the cost-effectiveness of these expenditures will be evaluated as part of the DSM portfolio as a whole.

8.2 2015 Innovative Technologies Activities

Tables 8-2 to 8-3 outline the specific Innovative Technologies activities undertaken in 2015, including program and measure descriptions and a breakdown of non-incentive spending[17].

Table 8-2: Pilots

Program Description	The Pilot Program focused on evaluating market-ready technologies and conducting small scale pilots to gather data to validate manufacturers' claims about measure system performance and energy savings. The data from pilots can also be used to help improve the quality and installation of future systems, and to understand and reduce market barriers. Technologies that successfully emerge from the Innovative Technologies Program will be considered for inclusion in the various program areas within the larger EEC portfolio.					
Target Market	Variable					
New vs Retrofit	Retrofit					
Pilots						
Condensing Make-up Air Unit (CMUA) Pilot	Objectives of the program are to validate energy savings claims, assess customer acceptance rates, and identify technical issues associated with the installation and operation of condensing gas-fired ventilation units in British Columbia commercial buildings. These results were completed in Q3 2015 and handed off to the Commercial Program Area.					
	2015 Total	Participants 0				
Apartment Fireplace Efficiency Retrofit (AFER) Pilot	Objectives of the pilot are to verify energy savings from replacing older decorative style "B" vented fireplaces with Direct Vent EnerChoice level heating style fireplaces in Multi Unit Residential Buildings (MURB'S). The results will be used to determine the feasibility of launching a rebate program for high efficient EnerChoice direct vent fireplaces in MURB's or to extend the existing fireplace rebate offers to MURB'S. Results are expected Q2 2016.					
	2015 Total	Participants 33				
Combination Space and Water Heating System (CURP) Pilot	Objectives of the pilot are to identify field-validated energy performance of each combination system type, technical issues, field-validated incremental costs, customer acceptance and the effective marketing channels for promoting a combination system retrofit rebate. The results will provide insight into a cost-effective rebate program for residential customers to upgrade their existing space and water heating equipment to combination systems. Results are expected Q2 2016.					
	2015 Total	Participants 78				
Participants	2015 Total	Projected n/a	2015 Actual 111			
Expenditures ($,000s)	2015	Incentives	Non-Incentive Expenditures: Admin	Non-Incentive Expenditures: Communication	Non-Incentive Expenditures: Research & Evaluation	Total
	Total	217	68	14	113	411

[17] As Innovative Technologies activities are considered pilots rather than EEC programs, they were not presented in individual program tables as in other Program Area sections in this report.

Table 8-3: Studies

Description	Studies are used to assess the market opportunity, technical characteristics and projected energy savings of commercially available DSM technologies. The results can be used to determine the feasibility of launching a pilot or to make future program area inclusion decisions.					
Target Market	Variable					
New vs Retrofit	N/A					
Studies						
Combination Unit Space and Water Heating Performance Assessment	Study facilitated through the Canadian Gas Association and in partnership with Natural Resources Canada to assess the Combo performance in a lab controlled environment, identifying the different sources of energy loss followed by a comparison of the performance to the base-case system. The final report is expected to be completed for Q2 of 2016.					
Expenditures ($,000s)			Non-Incentive Expenditures			
	2015	Incentives	Admin	Communication	Research & Evaluation	Total
	Total	0	15	0	0	15

8.3 Summary

Innovative Technologies represent a key component of FEI's overall commitment to DSM activities by identifying viable technologies and projects that have the potential to support the development of new programs within the larger DSM portfolio.

In 2015, the Company received outcomes from the .67 EF Water Heater pilot that were used to inform program decisions for the ENERGY STAR water heater program and internal statistics of relative DHW loads. The Measurement and Verification study (M&V) was conducted over a 2 year period from November 2012 to December 2014. Based on the M&V results, the 0.67 EF Energy Star water heater resulted an average of 6 GJ or 15% of energy savings in residential use across the nine M&V participants. The M&V results confirmed that it's more cost-effective to upgrade from a standard efficiency water heater to a 0.67 EF Energy Star water heater if the rate of the Domestic Hot Water use per day is very high.

Additionally, in 2015 FEI received outcomes from the Condensing Make-up air unit ("CMUA") pilot that resulted in those technologies being included as eligible measures within the Commercial Program Area. Condensing Make up air units extract a portion of the latent heat available in the combustion products through condensation of the flue gas, boosting the nameplate efficiency from 80% to 90% or greater. The M&V was conducted over a 2 year period from January 2013 to July 2015. Based on the M&V results, the CMUA's indicated natural gas savings of 28% relative to pre-existing make up air units and 17% relative to new 80% efficient make up air units.

Furthermore, the Innovative Technologies Program Area were successful in identifying technologies that should not proceed to full pilots at the time of writing or not to be included as an eligible measure within an existing program. In 2015, FEI received outcomes from the Coil Cleaning Pilot that resulted in excluding it as an eligible measure within the Commercial Program Area. The intake air of an air handling unit (AHU) is filtered and conditioned through the heating and cooling coil before entering the occupant space for space heating and ventilation. The intake filters are only effective to a certain degree in cleaning the intake air which causes the downstream heating and cooling coils to plug up. Cleaning of the heating and cooling coil was expected to save natural gas due to increased heat transfer on the heating coil. The analysis of the measurement data shows that the average normalized energy consumption at the heating coils (BTU/°C/cfm) are marginally different between the two systems. The marginal difference in heating coil effectiveness, expressed as units of BTU to raise one cfm by one °C, between the two systems does not provide a conclusive natural gas energy savings result.

Overall, the Innovative Technologies initiatives successfully achieved results in evaluating the feasibility of new technologies and providing insights used towards the design of future DSM programs. The Innovative Technologies Program Area continues to use consistent criteria to ensure the greatest potential for screening technologies for further development as full programs in other areas of the DSM portfolio.

9. INDUSTRIAL ENERGY EFFICIENCY PROGRAM AREA

9.1 Overview

In 2015, the Industrial Energy Efficiency Program Area continued to encourage industrial customers to consume natural gas more efficiently and achieved an overall TRC of 1.0, with a combined net natural gas savings of 16,575 GJ/yr.

2015 Industrial Optimization Program activities resulted in seven new Technology Implementation funding agreements being executed and five projects being commissioned. In addition, eight energy audit reports were completed and identified energy conservation measures with the potential to provide natural gas savings of over 200,000 GJ/yr.

Table 9-1 summarizes the projected and actual expenditures for the Industrial Energy Efficiency Program Area in 2015, including incentive and non-incentive spending, annual and NPV gas savings, as well as TRC and other cost-effectiveness test results.

Table 9-1: 2015 Industrial Energy Efficiency Program Results Summary

Program	Annual Gas Savings (GJ/yr.)		Actual NPV Gas Savings (GJ)	Utility Expenditures ($000s)						Benefit/Cost Ratios				
				Incentives		Non-Incentives		All Spending						
	2014-2018 EEC Plan	2015 Actual		2014-2018 EEC Plan	2015 Actual	2014-2018 EEC Plan	2015 Actual	2014-2018 EEC Plan	2015 Actual	TRC	MTRC	Utility	Participant	RIM
Non Program Specific Expenses														
Total	No Direct Savings			0	0	262	130	262	130	No Direct Savings				
Industrial Optimization Program														
Total	104,103	16,575	132,597	1,368	578	328	282	1,696	860	1.1	n/a	1.3	2.2	0.6
Specialized Industrial Process Technology Program														
Total	38,246	0	0	318	0	81	0	399	0	No Direct Savings				
ALL PROGRAMS														
Total	**142,349**	**16,575**	**132,597**	**1,686**	**578**	**671**	**412**	**2,357**	**989**	**1.0**	**n/a**	**1.1**	**2.2**	**0.6**

Notes:

- For the purpose of cost-effectiveness tests, 16,575 GJ in savings have been claimed for 2015. As a project's total incentive can be made across multiple years, the annual natural gas savings reported for each project are pro-rated based on the proportion of the project's total incentive that is made in any given year. Please refer to the Industrial Optimization Program description below for further details on this methodology and 2015 application.
- Please refer to section 9.3.1 below for Specialized Industrial Process Technology Program details.

9.2 2015 Industrial Energy Efficiency Programs

The following table outlines the Industrial Energy Efficiency Program Area activity undertaken in 2015, including program and measure descriptions and a breakdown of non-incentive spending.

Table 9-2: Industrial Optimization Program

Program Description	The program includes measures that allow customers to identify, assess, and implement customized cost-effective energy efficiency projects for industrial processes using natural gas as process heat or an energy source.					
Target Market	Medium and large industrial facilities					
New vs Retrofit	Both					
Eligible Measures	Variable. Natural gas measures with a TRC ≥ 1.0					
Incremental Measure Cost	Dependent upon participant's proposed energy conservation measures					
Incentive Amount	Varies by measure. If TRC ≥ 1.0 then approximately $5 / GJ saved over 3 years					
Savings Per Participant	Variable					
Measure Life & Source	Variable. Dependent upon participant's proposed energy conservation measures					
Free Rider Rate & Source	10% Technology Implementation; 20% Industrial Energy Audit, Plant Wide Audit, Feasibility Study. Source: Best estimate.					
Participants	2015	Projected	Actual			
	Total	26	13			
Expenditures ($,000s)	2015	Incentives	Admin	Communication	Research & Evaluation	Total
	Total	578	206	8	68	860

Notes:

- The Industrial Optimization Program includes measures that allow industrial customers to identify, investigate, and implement natural gas energy efficiency projects. Measures include Plant Wide Audit, Feasibility Study, Industrial Energy Audit and Technology Implementation. The Plant Wide Audit and Feasibility Study measures were introduced in 2015 and are designed as a high level, facility wide audit and a detailed system or process specific study respectively. These two new measures replace the Industrial Energy Audit measure. As such, Industrial Energy Audit applications are no longer being accepted and it is expected that the last participant will complete their energy audit in 2016.
- The Industrial Energy Audit, Plant Wide Audit and Feasibility Study measures do not include direct savings as the incentives are aimed only at identifying energy saving opportunities and the participant is not bound to implement energy conservation measures identified in the audit process. The Industrial Optimization Program claims 16,575 GJ of net natural gas savings in 2015 which are attributable to Technology Implementation projects.
- Depending on the size of the incentive, Technology Implementation project incentive payments are either paid fully on project commissioning or are paid across the first three years after commissioning and based on the natural gas saving performance in each year. Hence, for larger incentives, only a portion of the incentive is paid on project commissioning. For consistency in performing cost benefit analyses, only a prorated portion of the natural gas savings and project costs are included in the determination of the cost benefit ratios (e.g. if 25% of the incentives were paid in 2015, only 25% of the project cost and only the NPV of 25% of the project's savings would be used as inputs). This approach was adopted in 2013.
- In the 2012 EEC Annual Report, the cost-effectiveness ratios for the only project commissioned under the Technology Retrofit Program were calculated using the NPV of the total estimated natural gas savings, the total estimated project cost, but only twenty five percent of the calculated incentive. As such, the incentive paid in 2015 towards this project was necessarily included as an input to the 2015 cost-effectiveness ratios, though any energy savings, project costs, and participant count were not, as these had been recorded in full in 2012. Any subsequent incentives paid for this project will be included in future reports, without any corresponding costs,

benefits, and participant counts until such time as the full value of the incentive commitment has been accounted for.

- The time between Technology Implementation funding agreement execution and project commissioning can span across multiple annual reporting periods due to the lead times associated with energy conservation measure procurement and the often limited and predetermined maintenance shutdown windows in industrial facilities. To provide greater insight into program activity, seven funding agreements were executed under the Technology Implementation measure in 2015 and are estimated to result in 80,438 GJ/yr of net natural gas savings. Five projects were commissioned in 2015.

9.3 2015 Industrial Energy Efficiency Programs Planned But Not Launched

9.3.1 SPECIALIZED INDUSTRIAL PROCESS TECHNOLOGY PROGRAM

The Commission's Decision to FEI's Multi-Year Performance Based Ratemaking Plan for 2014-2018 requested that detailed plans for the program were to be approved by the Commission prior to incurring expenditures. FEI developed plans associated with the Specialized Industrial Process Technology Program more fulsomely in 2015. Detailed plans of this program were submitted to and approved by the Commission in early 2016.

9.4 2015 Industrial Energy Efficiency Program Closures

There were no program closures for the Industrial Energy Efficiency Program Area in 2015.

9.5 Summary

The Industrial Energy Efficiency Program Area activity in 2015 resulted in 16,575 GJ/yr of net natural gas savings and a TRC of 1.0. The Industrial Optimization Program was enhanced by introducing the Plant Wide Audit and Feasibility Study measures and participation in the program continued to grow. The conversion rate from the energy study component to the implementation component of the program increased in 2015 and is demonstrated by the number of projects initiated and commissioned throughout the year. These projects will lead to significant additional natural gas savings in the years to come.

In 2016, FEI will look to further refine and enhance the Industrial Optimization Program to encourage continued growth in participation and implementation of natural gas energy efficiency projects. In addition, FEI has recently received the Commission's approval of the Specialized Industrial Process Technology Program business case and will be launching this program into market.

10. CONSERVATION EDUCATION AND OUTREACH INITIATIVES

10.1 Overview

The CEO portfolio continues to support the DSM portfolio goals of energy conservation in a variety of ways. In order to foster a culture of conservation, several programs and campaigns were undertaken in 2015, giving the team new learnings and new insights into behaviour change and customer attitudes on efficiency. Educating all types of customers including residential, commercial and students – remains a strong priority and we are continuing to ensure steps are taken to make the information relevant and timely for these customers.

Continued collaboration with the FBC was executed in an effort to maximize efficiencies across both teams. In 2015 costs were shared on school outreach, community outreach, retail campaigns, communications pieces and various event materials. Steps were also taken to further partner with BC Hydro in the CEO portfolio in 2015, leading to a new collaboration with the Workplace Conservation Awareness (WCA) Program focusing on post-secondary institutions. Our ethnic outreach program, Empower Me continued to reach out to our Punjabi and Chinese communities through a community based social marketing approach. BC Hydro and FortisBC worked closely together in that development and continued to support the program expansion into new regions and new audiences. New retail and point-of-sale opportunities were also explored in partnership with BC Hydro in 2015.

CEO continued to provide information to customers and the general public on natural gas conservation and energy literacy and sought out new opportunities to reach customers, both face-to-face and online. FortisBC won Chartwell's 2015 Best Practices Bronze Award in Program Marketing for our behavior change digital tool The Conserver Club. FortisBC also continues to support various training seminars and educational workshops in collaboration with such organizations as the Greater Vancouver Home Builders Association and other industry associations. In addition, our first annual Efficiency in Action awards were held to recognize those commercial organizations that have most effectively utilized FEI's DSM programs.

As these are not incentive-based programs, FEI has not attributed direct savings to them in 2015. The following tables do not contain information about eligible measures, incentive amounts, savings levels, free-ridership, spillover or participation levels. CEO costs are included at the portfolio level and incorporated into the overall DSM portfolio cost-effectiveness results. Although there were no energy savings attributed to the CEO Program Area in 2015, it should be noted that the FEI continues to explore ways to identify and confirm energy savings from CEO activities.

Table 10-1 summarizes the projected and actual expenditures for the CEO Program Area in 2015. The approved spending for 2015 was $2.4 million and actual spending in 2015 was $2.8 million.

Table 10-1: 2015 CEO Initiative Results Summary

Program	Annual Gas Savings (GJ/yr.)		Actual NPV Gas Savings (GJ)	Utility Expenditures ($000s)						Benefit/Cost Ratios				
				Incentives		Non-Incentives		All Spending						
	2014-2018 EEC Plan	2015 Actual		2014-2018 EEC Plan	2015 Actual	2014-2018 EEC Plan	2015 Actual	2014-2018 EEC Plan	2015 Actual	TRC	MTRC	Utility	Participant	RIM
Non-Program Specific Expenses														
Total	No Direct Savings			0	0	240	145	240	145	No Direct Savings				
Residential Education Program														
Total	No Direct Savings			0	0	990	1,795	990	1,795	No Direct Savings				
Commercial Education Program														
Total	No Direct Savings			0	0	450	282	450	282	No Direct Savings				
School Education Program														
Total	No Direct Savings			0	0	720	609	720	609	No Direct Savings				
Street Team														
Total	No Direct Savings			0	0	0	0	0	0	No Direct Savings				
ALL PROGRAMS														
Total	**No Direct Savings**			**0**	**0**	**2,400**	**2,830**	**2,400**	**2,830**	**No Direct Savings**				

10.2 2015 CEO Programs

Tables 10-2 through 10-4 outline the CEO initiatives undertaken in 2015. This includes program descriptions as well as a breakdown of spending, all of which is classified as "non-incentive spending".

Table 10-2: Residential Education Program

Program Description	This program provides information to Residential customers and the general public on natural gas conservation and energy literacy by seeking opportunities to engage with customers directly (either face-to-face or through online programs). This audience also included low income and ethnic customers. Promotional activities in 2015 included print and online communications and engagement campaigns as well as educational seminars, development of online tools and participation in home shows and community events. The Program also included the cost of production of materials for events and prizing for audience engagement that are utilized at events targeting Residential customers and children. In addition, continuing partnerships with the regional Canadian Home Builders' Associations and local sports organizations expanded outreach opportunities to engage with Residential customers. Furthermore, FEI continued to focus on behavioural change opportunities that resulted in energy savings.
Target Market	Residential customers and general public
New vs Retrofit	Both
Expenditures ($,000s)	see below

Expenditures ($,000s)			Non-Incentive Expenditures			
	2015	Incentives	Admin	Communication	Research & Evaluation	Total
	Total	0	1,092	659	44	1,795

Table 10-3: Commercial Education Program

Program Description	This program provides ongoing communication and education about energy conservation initiatives as well as encourages behavioural changes that help Commercial customers reduce their organization's energy consumption. The Commercial sector is made up of small and large businesses in a variety of sub sectors such as retail, offices, multi-family residences, schools, hospitals, hospitality services and municipal/institutions. Promotional activities for 2015 included print and online communications, event support of industry trade shows, industry association meetings, award events, and development of tools to assist with education and engagement. In addition, the Companies furthered partnerships with organizations such as the Business Improvement Associations of BC (BIABC) and Climate Smart, who all work with small to medium-sized businesses. This program area continued to guide and support behaviour education campaigns delivered by energy specialists (or an energy manager) in their respective organizations. Collaborations between internal departments, as well as with other utilities, were pursued to achieve cost efficiencies in the budget, in particular on advertising and outreach events.
Target Market	Commercial customers, multi-family, energy specialists, energy management staff
New vs Retrofit	Retrofit
Expenditures ($,000s)	

		Non-Incentive Expenditures			
2015	Incentives	Admin	Communication	Research & Evaluation	Total
Total	0	227	50	5	282

Table 10-4: School Education Program

Program Description	This program responds to section 44.1 (8) (c) of the Utilities Commission Act, R.S.B.C 1996, c.473, s.125.1 (4) (e), where a public utility's plan portfolio is adequate if it includes an education program for students enrolled in [K-12] schools and post-secondary schools in the Company's service area. Activities included building partnerships and funding support for a variety of in-class and online programs related to conserving energy for K-12 students, delivered both internally and externally by third parties such as non-profit organizations or local sports teams. Some of the activities included were: Energy is Awesome, Green Bricks, Energy Champion assembly presentations and Beyond Recycling. Some of these activities also included distribution or education of low-flow fixtures, colouring books, mood pencils, and educational playing cards as part of the program. Partnerships and funding support for post-secondary activities included in-residence and on-campus education campaigns.
Target Market	Students
New vs Retrofit	Retrofit
Expenditures ($,000s)	

		Non-Incentive Expenditures			
2015	Incentives	Admin	Communication	Research & Evaluation	Total
Total	0	523	6	79	609

10.3 Summary

All of the Conservation Education and Outreach initiatives described above are designed to foster a culture of energy conservation in BC. This portfolio is immensely important to FEI's overall DSM effort and helps to keep the program information and energy conservation message top-of-mind with all of our customers. By changing attitudes and behaviours, the Company will help communities reach their goals, help customers save energy and money, increase participation in DSM programs and ultimately support the shared goals of FEI and the Provincial Government. This portfolio will continue to explore new ways and seek out new opportunities and channels to connect with our customers to ultimately grow that culture of energy conservation.

11. ENABLING ACTIVITIES

11.1 Overview

In 2015, Enabling Activities continued to support and supplement FEI's DSM program development and delivery, advancing energy efficiency in British Columbia. This included:

- the ongoing Trade Ally Network program;
- work completed in advancing national and provincial building codes, appliance/ equipment standards, and regulations;
- maintenance on the Company's DSM program tracking system;
- work on a new Conservation Potential Review; and,
- continued funding to support post-secondary energy management programs.

While these activities play a very important role in FEI's portfolio of DSM activities by advancing the delivery of all Program Areas, the Company has not claimed any energy savings in 2015 for work completed in this area.

While no energy savings will be claimed for Enabling Activities in 2015, FEI developed an acceptable methodology for measuring and attributing energy efficiency savings from Codes and Standards work for the 2014 Residential New Home program (see Table 5-8, page 32 of the 2014 Annual Report). Attribution savings were not available to be claimed in 2015 as there were no changes to energy efficiency regulation in the BC Building code energy efficiency that came into effect in 2015. FEI will continue to examine and, where appropriate, adopt methodologies for claiming energy savings from Codes and Standards for future programs.

Table 11-1 summarizes the projected and actual expenditures for the Enabling Activities in 2015.

Table 11-1: 2015 Enabling Activities Results

Program	Annual Gas Savings (GJ/yr.)		Actual NPV Gas Savings (GJ)	Utility Expenditures ($000s)						Benefit/Cost Ratios				
				Incentives		Non-Incentives		All Spending						
	2014-2018 EEC Plan	2015 Actual		2014-2018 EEC Plan	2015 Actual	2014-2018 EEC Plan	2015 Actual	2014-2018 EEC Plan	2015 Actual	TRC	MTRC	Utility	Participant	RIM
Trade Ally Network														
Total	No Direct Savings			n/a	n/a	500	643	500	643	No Direct Savings				
Codes and Standards														
Total	No Direct Savings			n/a	n/a	35	182	35	182	No Direct Savings				
TrakSmart Maintenance														
Total	No Direct Savings			n/a	n/a	80	126	80	126	No Direct Savings				
Conservation Potential Review														
Total	No Direct Savings			n/a	n/a	500	137	500	137	No Direct Savings				
Energy Management Education Funding														
Total	No Direct Savings			n/a	n/a	150	101	150	101	No Direct Savings				
ALL PROGRAMS														
Total	**No Direct Savings**			**n/a**	**n/a**	**1,265**	**1,189**	**1,265**	**1,189**	**No Direct Savings**				

11.2 2015 Enabling Activities by Program

The following tables outline the specific Enabling Activities undertaken in 2015 by activity, including activity descriptions along with a breakdown of spending. Note that all spending under Enabling Activities is considered non-incentive spending.

Table 11-2: Trade Ally Network

Program Description	This program develops and manages a contractor network to promote DSM programs and energy-efficiency messaging. FEI identifies trade allies as equipment manufacturers, service contractors, distributors and retailers, and recognizes the influence these industry groups have with the end-use Residential, Commercial and Industrial customers who make energy-efficiency decisions. This program also supports funding energy efficiency training as outlined in the DSM Regulation.				
Expenditures ($,000s)	2015	Admin	Communication	Research & Evaluation	Total
	Total	265	378	0	643

Table 11-3: Codes and Standards

<table>
<tr><td>Program Description</td><td colspan="5">Utilities have a unique understanding of energy supply and customer demand cycles, which can be of assistance in the development of codes and standards. The content and timing of code implementation directly affects market transformation in all program areas. FEI’s level of regulatory involvement typically includes one of three involvement classifications: monitoring, stakeholder engagement and developing regulations. The Codes & Standards area “supports the development of or compliance with specified standard or a measure respecting energy conservation or the efficient use of energy” as referred to in the definition of “specified demand-side measures” in the DSM Regulation.</td></tr>
<tr><td>Policy Initiatives consultation process</td><td colspan="5">Evaluation, analysis and review of national, provincial and municipal initiatives for energy efficiency.</td></tr>
<tr><td>Industry consultation process</td><td colspan="5">Collaboration with entities like BC Hydro and the Home Owner Protection Office (HPO) for the development of industry training and guidelines on implementation of new energy efficiency measures. Participation with the BC Safety Authority Gas Technology Committee industry stakeholder group.</td></tr>
<tr><td>Involvement with supporting projects</td><td colspan="5">Active participation for supporting projects like: the Natural Resources Canada new EnerGuide rating system and Leadership in Energy Efficiency Partnerships (LEEP).</td></tr>
<tr><td>Codes and Standards Strategy</td><td colspan="5">Active participation on the Canadian Standards Association (CSA) Strategic Steering Committee on Fuel Burning Equipment. This committee is the highest level committee in the fuel sector at CSA and oversees all committees and sub-committees in the fuel burning sector. Consultation with the Canadian Gas Association (CGA), Canadian Institute of Plumbing and Heating (CIPH), Heating Refrigeration and Air-conditioning Institute (HRAI) and the Canadian Home Builders Association (CHBA) on codes and regulations that are common to our industries.</td></tr>
<tr><td>Codes and Standards Maintenance</td><td colspan="5">Active participation on the CSA Technical Committee on Energy Efficiency and Related Performance of Fuel-Burning Appliances and Equipment. This committee oversees all of the eleven existing performance standards for gas-fired equipment and is looking to develop new needed standards for equipment. Participation in the Standards Council of Canada, committee on Domestic gas cooking appliances ISO/TC 291.</td></tr>
<tr><td>Internal awareness of Code and Regulatory changes</td><td colspan="5">Development of internal documents and updates for relevant program areas and personnel.</td></tr>
<tr><td>Standards library</td><td colspan="5">Purchase of up to date standards for reference.</td></tr>
<tr><td rowspan="2">Expenditures ($,000s)</td><td>2015</td><td>Admin</td><td>Communication</td><td>Research & Evaluation</td><td>Total</td></tr>
<tr><td>Total</td><td>181</td><td>1</td><td>0</td><td>182</td></tr>
</table>

Table 11-4: TrakSmart Maintenance

Program Description	Ongoing IT license and maintenance costs related to the portfolio DSM tracking system.				
Expenditures ($,000s)	2015	Admin	Communication	Research & Evaluation	Total
	Total	126	0	0	126

Notes:

- Spending on TrakSmart maintenance was higher than Plan (see Table 11-1 for Plan amount) as a result of enhancements completed to improve incentive application processing time. These enhancements were not anticipated when the 2014-2018 Plan was prepared.

Table 11-5: Conservation Potential Review

Program Description	FEI considers the CPR to be an important tool for use in developing, supporting, and assessing current and future DSM expenditure applications, as well as for directional input into program development. The purpose of a CPR study is to examine available technologies and determine their conservation potential, which includes the amount of energy savings that can be achieved through energy-efficiency and conservation programs over the study period. This project is being worked on in collaboration with BC Hydro, Pacific Northern Gas and FortisBC Electric. Core work on the CPR began 2015. As of end-2015 the CPR project was approximately one third complete.				
Expenditures ($,000s)	2015	Admin	Communication	Research & Evaluation	Total
	Total	137	0	0	137

Table 11-6: Energy Management Education Funding

Program Description	Funding to support post-secondary energy management programs such as the UBC Masters in Clean Energy and the BCIT Sustainable Energy Management Advanced Certificate.				
Expenditures ($,000s)	2015	Admin	Communication	Research & Evaluation	Total
	Total	101	0	0	101

11.3 2015 Enabling Activities Planned But Not Launched

11.3.1 Home Energy Efficiency Web Portal

This project concept was to develop a home energy-efficiency web portal with content, energy saving tips, online calculators, and a “one-stop rebate shop” for the entire Province of BC.

Partners were to include the provincial government, BC Hydro and FBC. The budget was to cover building the site communications to launch the site, and ongoing support. This project has been delayed while utilities address branding issues and customer information privacy concerns associated with a joint web portal. These funds may be accessed in 2016 as utility partners assess options for online forms and administrative functionality of the Home Energy Rebate Offer.

11.4 Summary

Enabling Activities are critical initiatives that support and supplement DSM program development and delivery. The success of the Residential Furnace Replacement program (see Section 5, Table 5-3), which was promoted through the contractor network, demonstrates the value of the Trade Ally Network program. Communications were immediate and responsive through the network and at the end of the program, 73% per cent of the program's participants used contractors who were members of the Trade Ally Network.

FEI's involvement in codes and standards work in 2015 continued to encompass varying degrees of activities including monitoring, reviewing and responding to existing and proposed regulatory changes and direct participation in various working groups that explore the development of future targets, codes and standards. For the first time, BC Hydro, Pacific Northern Gas, FEI and FBC began collaboration on a Conservation Potential Review study. The Conservation Potential Review project contract was awarded in 2015 and was well underway by the end of the year.

12. EVALUATION

FEI continued to advance their evaluation activities in 2015 by conducting evaluation studies[18] on a program by program basis. In alignment with the Company's Evaluation Measurement & Verification (EM&V) Framework and industry standard practice, program evaluation activities are assessed at different stages of each program's lifecycle. Based on this ongoing assessment, all programs are evaluated when appropriate. The 2015 evaluation activities presented here reflect the number of programs in market, the different stages of their lifecycle, and the type of evaluation activities required to provide program feedback. The evaluation activities conducted in 2015 are in accordance with the evaluation principles presented in the Company's EM&V Framework.

12.1 2015 Program Evaluation and Evaluation Research Activities

In 2015, FEI's various evaluation activities included quantifying energy savings, assessing participant awareness and satisfaction, identifying barriers to participation, assessing the effectiveness of education initiatives, and conducting industry research. Measurement and Verification (M&V) activities were focused on identifying and verifying project and measure level savings assumptions and understanding any issues associated with equipment installation in the field.

Table 12-1 presents an inventory of all program evaluation and evaluation research related activities undertaken in 2015. Expenditures for these activities have been accounted for within the applicable program or Program Area, non-incentive costs included in previous sections, but are also reported here in order to provide a concise, easy-to-view summary of evaluation activities. Included in the table are: a list of all the 2015 evaluation activities; the Program Area each activity occurred in; the general type of evaluation activity undertaken; the Company's actual 2015 evaluation expenditures; and, a status update on each activity. The total expenditure for program evaluation and research activities in 2015 was $459,000.

[18] Types of evaluation activities include: Communication evaluations, which focus on advertising and media outreach; Evaluation studies, where quality assurance or inspection is conducted to gain more insight on the incented measure; Process evaluations, where surveys and interviews are used to assess customer satisfaction and program success; Impact evaluations, to measure the achieved energy savings attributable from the program; and, Measurement & Verification, to monitor real time energy savings associated with energy conservation measures.

Table 12-1: Inventory of DSM Program Evaluation and Evaluation Research Activities Conducted in 2015[19]

Evaluation Name	Program Area	Type of Evaluation	Years the program has been running [20]	Evaluation Partnership	Actual Evaluation Expenditure (000's)	Evaluation Status [21]
FortisBC Communications Tracking: Energy Efficiency and Conservation	C&EM Portfolio	Communication	ongoing	none	$10	Customer engagement and awareness of C&EM activities. **Completed December 2015 by TNS**
Residential Outreach Program - Empower Me	Conservation Education and Outreach	Process	2	FortisBC Inc. and BC Hydro	$20	Mentor and Champion survey conducted for the program evaluation. **Expected completion by Q3 2016**
Furnace Replacement Pilot Program - Contractor Survey (2014 Contractors)	Residential	Process	3	none	$3	Contractor Survey for 2014 program year. **Completed January 2015 by TNS**
EnerChoice Fireplace Evaluation - Participant Survey & Billing Analysis	Residential	Process & Impact	3	none	$5	Customer survey and billing analysis conducted for program evaluation. **Completed April 2015 by Samspon Research Inc.**
EnerChoice Fireplace Evaluation - Market Study	Residential	Market Analysis	3	none	$24	Analysis of the program's influence on the fireplace market. **Expected completion by Q2 2016**
Home Energy Rebate Offer (HERO) - Participant Survey	Residential	Process	1	FortisBC Inc. and BC Hydro	$15	Customer survey conducted for the program evaluation. **Expected completion by Q3 2016**
Home Energy Rebate Offer (HERO) - Quality Study of Insulation	Residential	Evaluation Study	1	FortisBC Inc. and BC Hydro	$13	On-site visit of homes with insulation and draft proofing measures **Expected completion by Q3 2016**
Home Energy Rebate Offer (HERO) - Quantitative Analysis	Residential	Evaluation Study	1	FortisBC Inc. and BC Hydro	$12	HERO participant analysis to determine inputs for cost effectiveness tests and feedback on 2016 program design. **Completed December 2015 by Dunsky Energy Consulting**
Rental Apartment Efficiency Program (RAP)	Residential / Commercial	Evaluation Study	new	none	$1	Ongoing performance testing for RAP participants. This test uses a flow meter bag measuring device to measure the flow timed to one minute of pressure/flow per suite before and after the installation of the in-suite water-efficient devices. Flow testing will be conducted on 5 units within each participating building location.
Rental Apartment Efficiency Program (RAP)	Residential / Commercial	Process	new	none	$10	Building owner and Tenant survey for program evaluation. **Expected completion by Q4 2016**
Energy Conservation Assistance Program (ECAP)	Conservation for Affordable Housing	Evaluation Study	5	BC Hydro	$45	Ongoing Quality Assurance to ensure all products are installed according to vetted installation policies and procedures.
Energy Savings Kit (ESK)	Conservation for Affordable Housing	Process	5	BC Hydro	$1	Ongoing BC Hydro participant survey to assess customer satisfaction and program awareness.

[19] Table 12-1 does not include Prefeasibility Studies. Please refer to the Innovative Technologies section (Section 8) for details.
[20] Measurement & Verification studies require time to conduct the M&V activities which include but not limited to project commissioning and coordination, installing and removal of monitoring equipment, data collection and, data analysis and reporting. The column 'Years the program has been running' will refer to the time required to conduct the M&V activities. M&V activities align with the International Performance Measurement and Verification Protocol (IPMVP). Concepts and Options for Determining Energy and Water Savings. Prepared by the Efficiency Valuation Organization. www.evo-world.org. January 2012.
[21] M&V completion refers to the time period where the actual monitoring and data collection ends. Analysis and reporting will require additional time

Table 12-1: Inventory of DSM Program Evaluation and Evaluation Research Activities Conducted in 2015[19] (continued)

Evaluation Name	Program Area	Type of Evaluation	Years the program has been running [20]	Evaluation Partnership	Actual Evaluation Expenditure (000's)	Evaluation Status [21]
Energy Specialist Program Energy Savings Audit (Update for 2015)	Commercial	Impact	6	none	$40	The study is an update to the Energy Savings Audit to verify energy savings for projects completed in 2014. **Completed June 2015 by Prism Engineering Ltd and ClearLead Consulting Ltd.**
Energy Specialist Program Energy Savings Audit (Update for 2016)	Commercial	Impact	6	none	$25	The study is an update to the Energy Savings Audit to verify energy savings for projects completed in 2015. **Expected completion by Q2 2016**
EnerTracker Pilot Program - Impact Evaluation	Commercial	Impact	3	none	$43	Billing analysis of the program participants' energy usage. **Expected completion by Q2 2016**
Commercial Water Heating Program	Commercial	Impact	5	none	$13	Customer survey and billing analysis conducted for program evaluation. **Expected completion by Q2 2016**
Condensing Gas-Fired Ventilation Units (CMUA)	Innovative Technologies	Measurement & Verification	2	none	$44	M&V and Final report completed - **November 2015 by Fresco Building Efficiency and SES Consulting**
Apartment Fireplace Efficiency Pilot (AFER)	Innovative Technologies	Measurement & Verification	1	none	$57	Completion of M&V Plan, purchase and installation of monitoring equipment, and baseline monitoring started December 2014. **Expected completion of M&V + Final Report by Q3 2016**
Combination Space/Water Heating Units Pilot	Innovative Technologies	Evaluation Study & Measurement & Verification	1	none	$11	Implementation of a participant survey. **Expected completion of M&V + Final Report by Q1 2017**
Industrial Optimization Program	Industrial	Measurement & Verification	4	none	$68	There were 12 projects requiring M&V activity in 2015. The M&V activities include the completion of an M&V plan, commissioning validation site visits, and M&V reports. Expected M&V completion dates by project: 2016 - 2 projects 2017 - 2 projects 2018 - 4 projects 2019 - 4 projects

1 Table 12-2 contains a summary of all program evaluation studies and pilot program reports completed in 2015 and includes a brief
2 description of the methodologies and key findings.

3 **Table 12-2: Summary of Key Findings and Methodology for 2015 Completed DSM Program Evaluation Studies and Pilot Program**
4 **Reports**

Evaluation Name	Program Area	Type of Evaluation	Methodology	Outcome from Key Findings
FortisBC Communications Tracking: Energy Efficiency and Conservation	C&EM Portfolio	Communication	Online interviews conducted over two waves with 1,200 (600 per wave) British Columbia adults living within the FortisBC service territory.	**Results**: The percentage of participants had aided awareness of at least one of the three main energy efficiency activities undertaken by FortisBC improved from 53% in 2014 to 64% in 2015. Overall, half of the participants surveyed were classified as being at least somewhat engaged with energy efficiency. The level of engagement improved significantly during the second wave. **Outcome of Key Findings:** Continue to emphasize the overarching energy efficiency activities rather than individual programs to build awareness.
Furnace Replacement Pilot Program - Contractor Survey (2014 Contractors)	Residential	Process	102 telephone interviews were conducted between November 24 and November 30, 2015 with Contractors who participated in the program.	**Results:** The key findings are: 1) 54% of contractors stated that over 80% of all furnaces sold / installed during the 2014 program period received a rebate from the program which increased from 23% in the 2013 program. 2) Contractors are very satisfied with the amount of the rebates and the selection of furnaces that qualify for the program. They also noted that the information made available regarding the program has improved. 3) Contractors suggest FortisBC could provide more program promotion, maintain the program for a longer duration or a different seasonal timing. **Outcome from Key Findings:** Continue to work closely with industry on program design and communication efforts.

5

Table 12-2: Summary of Key Findings and Methodology for 2015 Completed DSM Program Evaluation Studies and Pilot Program Reports (continued)

Evaluation Name	Program Area	Type of Evaluation	Methodology	Outcome from Key Findings
EnerChoice Fireplace Evaluation - Participant Survey & Billing Analysis	Residential	Process & Impact	A combination of an online participant survey (n=1,559), estimation of net-to gross factors including free ridership and participant spillover, and a fixed effects billing analysis (n=591) were used to evaluated the 2011 to 2013 program years.	**Results:** 1) 93% of participants were satisfied with the overall program and 89% satisfied with the selection of program qualifying fireplaces. 2) 45% of participants surveyed replaced an inefficient gas fireplace and the remaining replaced either a wood or electric fireplace, or a new install. 3) The average increase in annual gas consumption for wood-to-gas, electric-to-gas, and new installations was estimated at 13.1 GJ. 4) The average increase in annual gas consumption for retrofits was estimated at 8.6 GJ which is attributed to the increase hours of use in the post-program period. **Outcome from Key Findings:** Internal decision was made to put the program on hold while we collaborated with industry stakeholders on program design to continue to raise the minimum efficiency standards for fireplaces. Further analysis and research are to be conducted to provide support for program design.
Home Energy Rebate Offer (HERO) - Quantitative and Qualitative Analysis	Residential	Evaluation Study	Quantitative and qualitative analysis of the overall program. Analysis included a review of the following: n=3,110 program participants (54% natural gas, 46% electric), contractor survey n= 68, stakeholder interviews, comparison to LiveSmart BC for energy savings, overall program performance and program design recommendations.	**Results:** Assumptions for cost effectiveness tests are provided in Section 5.3. Contractor feedback is favorable overall. Program design recommendations include increasing wall and basement insulation amounts and raising insulation maximum payouts as a means of increasing multi-measure uptake. **Outcome from Key Findings:** Updated program offer will be introduced into market in 2016 Q2 or Q3. Contractor engagement is key to reduce application declines and improve quality of workmanship.

Table 12-2: Summary of Key Findings and Methodology for 2015 Completed DSM Program Evaluation Studies and Pilot Program Reports (continued)

Evaluation Name	Program Area	Type of Evaluation	Methodology	Outcome from Key Findings
Energy Specialist Program Energy Savings Audit (Update for 2016)	Commercial	Impact	The methodology remains consistent with the Energy Savings Audit -2015 Update. A total of 28 completed projects were reviewed by Prism Engineering Ltd. Each Energy Specialist was required to complete a project-specific questionnaire and provide detailed project calculations and information for review. Project savings were verified on a project by project basis. Energy Specialist gas savings projects verified were those that did not take advantage of an existing FortisBC incentive program.	**Results:** A total of 28 completed projects for 2015 were reviewed to represent savings in 2015. The total verified savings of these 28 projects is 9,414 GJ/year. NPV gas savings equate to 58,394 GJ which is calculated using a methodology to account for the potential that projects may not persist over the anticipated measure life. **Outcome of Key Findings:** Continue to provide the Energy Specialists with support where required to properly document estimated energy savings.
Condensing Gas-Fired Ventilation Units (CMUA)	Innovative Technologies	Measurement & Verification	**The M&V Plan:** Complies with the International Performance Measurement & Verification Protocol. The selected IPMVP option and measurement boundary was Option B[22] **M&V:** M&V was conducted on 8 commercial sites within the Lower Mainland and Victoria regions. Baseline data was collected and measured for 3 months during the heating season and for 12 month post-retrofit of the CMUA.	**Results:** The M&V results indicated natural gas savings of; 28% relative to pre-existing make up air units, 17% relative to new 80% efficient make up air units. **Outcome from Key Findings:** Data to be used to justify inclusion of CMUA as an eligible measure in the Commercial Custom Design Program. Will also be used for inclusion as a prescriptive measure under the Commercial Space Heat program.
ENERGY STAR© 0.67 Storage Tank Water Heater Pilot	Innovative Technologies	Measurement & Verification	**The M&V Plan:** Complies with the International Performance Measurement & Verification Protocol. The selected IPMVP option and measurement boundary was Option B[22] **M&V:** M&V was conducted and monitored for hot water usage, and natural gas and electricity consumption by the water heaters for 9 residential homes within a 15 month period.	**Results:** Based on the M&V results, the 0.67 EF Energy Star water heater resulted an average of 6 GJ or 15% of energy savings in residential use across the nine M&V participants. The M&V results confirmed that it's more cost-effective to upgrade from a standard efficiency water heater to a 0.67 EF Energy Star water heater if the rate of the Domestic Hot Water use per day is very high. **Outcome from Key Findings:** Transitioned 0.67 Water Heater Pilot results to Residential Program Team. Data to be used to inform program decisions and internal statistics on relative Domestic Hot Water loads.

[22] IPMVP Option A - Measurement of key parameters governing energy use to assess consumption. www.evo-world.org

12.2 Evaluation Collaboration

The FEI have continued to seek opportunities to increase collaboration activities with FBC, BC Hydro, and other entities to conduct program evaluation for DSM programs. The number of collaboration activities depends on the timing of the activity, program participants, legal and privacy concerns and, available budget to conduct the study. Tables 12-1 and 12-2 provide information on program evaluation activities conducted in partnership with other organizations. Three jointly funded evaluation projects were initiated in 2015 as a result of the collaboration efforts between FEI and BC Hydro; Residential Outreach Program – Empower Me Participant Survey, Home Energy Rebate Offer (HERO) – Participant Survey, and Home Energy Rebate Offer (HERO) – Quality Study of Insulation. In addition, BC Hydro and FEI continue to collaborate in the evaluation projects for the Energy Conservation Assistance Program (ECAP) and the Energy Savings Kit Program (ESK).

Collaboration efforts on evaluation have been further enhanced by the Memorandum of Understanding (MOU) on collaboration discussed in Section 2.6. The FEU and BC Hydro evaluation staff held update meetings to review the evaluation plans and discuss future evaluation activities. Evaluation staff from FEI, FBC and BC Hydro continue to hold update meetings and explore opportunities for future collaboration on program evaluations.

13. DATA GATHERING, REPORTING AND INTERNAL CONTROLS PROCESSES

13.1 Overview

The following section demonstrates that FEI has business practices in place to ensure DSM activities and associated spending are in compliance with Commission Orders and the Company's internal control processes. In its 2009 Decision, the Commission directed the FEI to include a discussion in the DSM Annual Report of the Company's internal data gathering, monitoring and reporting control practices. FEI continues to provide this information. This section addresses that directive by providing general information on data gathering and on FEI's business practices related to program development and application processing.

13.2 Program Tracking, Evaluation and Reporting Functions

FEI staff responsible for tracking, evaluation and reporting of DSM activities continue to report to a different Director than staff responsible for program development and implementation in order to:

- conduct independent evaluation activities;
- maintain an independent library of inputs into cost effectiveness calculations; and
- centralize reporting processes.

13.3 Robust Business Case Process Applied to All Programs

Before a new DSM pilot or program can be implemented, a business case must first be developed. FEI is committed to putting each pilot or program through the appropriate level of internal scrutiny before moving ahead, and believe doing so ensures an increased chance of pilot or program effectiveness.

Business cases include information about program rationale and purpose, as well as a description of the target audience, assumptions, cost-benefit tests and proposed evaluation methods. Cost effectiveness analysis is performed using the California Standard Tests (CST) as outlined in the California Standard Practice Manual. FEI uses an in-house cost-benefit modeling tool developed in partnership with expert industry consultants[23] to apply the program costs and benefits in each of the four standard cost-effectiveness tests based on the California Standard Practice Manual (Rate Impact Measure [RIM], Utility, Participant, and TRC) and the MTRC in accordance with British Columbia Demand-Side Measures Regulation.

The results from this modelling are used as inputs for the business cases, which are approved in accordance with FEI's policy on financial authorization levels.

In addition to the internal business case process, the Commission, in its' 2014-2018 PBR decision, has directed FEI to submit a written request and business plan for any new programs

[23] Willis Energy Services Ltd. and The Cadmus Group Inc. provided input into this in-house cost-benefit modelling.

they want to implement that have not previously been identified within the approved DSM Plan. Such requests must demonstrate the new program results in a net improvement to the Portfolio effectiveness or is needed to ensure balanced access to DSM programming among different customer groups. In 2015, business plans were submitted to the Commission for the new RAP program, the Low Income Top-up Programs and the Specialized Industrial Process Technology Program. Each program submission received Commission approval and is discussed in each of the relevant Program Area sections above.

13.4 Incentive Applications Vetted for Compliance with Program Requirements

Ensuring that all customer applications are compliant with program eligibility requirements as laid out in program terms and conditions is also part of the internal control process. FEI has a number of mechanisms in place to ensure DSM incentive funding applications are in compliance with program requirements. The verification process is specific to each program and is dependent on the type of program, its complexity, the financial value of the incentive and other parameters. The general principles applied are as follows:

- Each application is reviewed for completeness and accuracy;
- Applications must meet the criteria outlined in the terms and conditions of the program put forward through the approval process;
- Once approved, incentives are distributed to participants; and
- Copies of application and supporting documents are filed and stored for seven years in case of an audit.

13.5 Internal Audit Services

FEI regularly engages the Company's own Internal Audit Services (IAS) group to review the internal controls associated with the DSM activities. The IAS utilize the most recently completed year of operation on which to conduct their audit (In this case, the 2014 Audit covers the 2013 year. This is consistent with past reports). This audit has been conducted annually up until 2015. In 2015, the IAS group determined that since each of its previous audits determined that FEI's DSM activities were satisfactorily in compliance, the frequency of the audits would be reduced. Therefore, this internal audit was not conducted in 2015. FEI expects the next audit to be completed in late 2016 or early 2017.

13.6 Summary

FEI is committed to strong internal controls in all aspects of the DSM programs. As demonstrated in this section, the Company's business practices related to program development, application processing and ongoing monitoring are all sound and subject to continuous improvement.

14. 2015 DSM PROGRAMS ANNUAL REPORT SUMMARY

In 2015, FEI's DSM portfolio expenditures reached 87% of Plan with 66% of actual DSM program spending going toward customer incentives. With more than 434,000 GJ of annual savings, DSM programming continued to contribute options for customers to reduce their energy use. The FEI cost-effectively delivered these programs within the spending limits approved by the Commission, and in accordance with the BC Demand-Side Measures Regulation. FEI believes that they have made every reasonable effort to ensure DSM programs are operating in compliance with the Company's own DSM Guiding Principles and are meeting provincial requirements for adequacy. FEI also continues to implement good internal data gathering, monitoring and reporting control practices.

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March 31, 2017

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Mr. Patrick Wruck, Commission Secretary and Manager, Regulatory Support

Dear Mr. Wruck:

Re: FortisBC Energy Inc. (FEI)

Natural Gas Demand-Side Management (DSM) – 2016 Annual Report

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Attached please find the Natural Gas DSM Program 2015 Annual Report for FEI.

If further information is required, please contact Ken Ross, Manager, Integrated Resource Planning and DSM Reporting at 604-576-7343 or ken.ross@fortisbc.com.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

FortisBC Energy Inc.

Natural Gas
Demand-Side Management Programs
2016 Annual Report

March 31, 2017

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List of Tables

1. REPORT OVERVIEW

FortisBC Energy Inc. (FEI or the Company),[1] is committed to delivering a broad portfolio of cost effective Demand-Side Management[2] (DSM) measures that address the expectations of customers while meeting the requirements for public utilities to pursue cost effective DSM. In 2016, the company achieved a combined portfolio MTRC[3] of 1.2 on expenditures of $32.165 million, meeting FEI's goal of cost effective program delivery.

This DSM Annual Report (the Report) outlines the Company's actual results and expenditures for 2016. The Report follows a similar format to the 2015 and other previous Annual Reports, relying on detailed tables to demonstrate Program results and expenditures. The Report compares 2016 activity and results to the Company's 2014-2018 DSM Plan, as provided in the FEI's 2014-2018 Performance Based Ratemaking (PBR) Application and approved by the Commission in Order G-138-14. Where the details of individual programs vary substantially from the 2014-2018 DSM Plan, explanations are provided in the applicable Program Area Sections of this report.

1.1 PURPOSE OF REPORT: TRANSPARENCY, ACCOUNTABILITY AND UPDATE ON PROGRESS

This Report details the Company's activities for the overall DSM portfolio and in each Program Area. Incentive and non-incentive expenditures are reported at the level of each program or measure, as well as at the program area and portfolio levels. Results for the following cost effectiveness test calculations are provided for the overall portfolio and each Program Area in Section 2, and for each program or measure in the respective Program Area sections: Total Resource Cost (TRC) Ratepayer Impact Measure (RIM), Participant Cost Test (PCT), and Utility Cost Test (UCT). In accordance with British Columbia's *Demand-Side Measures Regulation* (DSM Regulation), results of the modified TRC (MTRC) calculations (see Section 2.1) are also provided where appropriate.

This Report also demonstrates that the Company is meeting the accountability mechanisms directed by the British Columbia Utilities Commission (BCUC or the Commission) in Order G-36-09. One such mechanism was the requirement to file DSM Annual Reports, which states:

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1 The three BC Gas utilities formerly known as FortisBC Energy Inc. (FEI), FortisBC Energy (Vancouver Island) Inc. (FEVI) and FortisBC Energy (Whistler) Inc. (FEW) were amalgamated into a single utility - FortisBC Energy Inc. - in 2014. 2015 was the first complete year that the company operated as a single utility, which is reflected throughout this document by eliminating the breakout of separate FEI, FEVI and FEW statistics and results.

2 Throughout this Annual Report the use of the term Demand-Side Management or "DSM" is intended to refer to demand-side measures in B.C. as defined in the B.C. *Demand-side Measures Regulation* (DSM Regulation).

3 Pursuant to the DSM Regulation, the portfolio level MTRC is calculated based on costs and benefits of all programs in the portfolio as well as any program area and portfolio level administration costs, and including the benefit adders for those programs for which the MTRC is relied upon to determine cost effectiveness on an individual program basis (i.e. those programs that have been designated as being under the MTRC Cap as presented in Section 2.1 of this report).

> A requirement that Terasen [now FEI] submit annually to the Commission, by the end of the first quarter following year-end, for each year of the funding period, a report on all [DSM] initiatives and activities, expenditures and results for TGI and TGVI.

Use of Report:

The energy savings and cost effectiveness results presented in this report are strictly those resulting from FEI's annual DSM activities as calculated according to industry accepted methods. This information should not be interpreted as the total energy savings from all natural gas conservation initiatives in the FEI service territory, nor the total savings an individual customer may experience. Examples of energy savings not reported here because they are achieved through mechanisms other than FEI's DSM activity include natural conservation through ongoing advancements in equipment efficiency and building envelope construction and initiatives funded by individuals or entities other than FEI.

1.2 *ORGANIZATION OF REPORT*

The following describes how each section of the Report presents the results of 2016 DSM activities:

Section 1: Report Overview

- Provides a high-level background for the Report.

Section 2: Portfolio Overview

- Provides a summary and detail regarding the actual 2016 expenditures for DSM activities.
- Section 2.5 discusses any new requirements from the Commission concerning information to be included in the 2016 DSM Annual Report.

Section 3: Funding Transfers

- Provides a discussion on funding transfers between program areas.

Section 4: Energy Efficiency and Conservation ("EEC") Advisory Group Activities

- Provides information regarding EEC Advisory Group ("EECAG") activities in 2016, including a summary of meetings and accountability considerations.

Sections 5 - 9 provide information on:

- Residential Energy Efficiency Program Area;
- Low Income Energy Efficiency Program Area;
- Commercial Energy Efficiency Program Area;
- Innovative Technologies Program Area; and

- Industrial Energy Efficiency Program Area.

Each of the above mentioned sections contain a table summarizing the planned and actual expenditures for the respective Program Area in 2016, including incentive and non-incentive spending, annual and NPV gas savings, as well as TRC and other cost effectiveness test results. Additional tables outline the individual 2016 programs, including program and measure descriptions, program assumptions and sources for these assumptions, and a breakdown of incentive and non-incentive spending. Where applicable, details on program closures or planned programs that were not launched in 2016 are also included in these program detail sections.

Section 10: Conservation Education and Outreach Initiatives

- Provides both a summary and details regarding actual 2016 expenditures for the Conservation Education and Outreach (CEO) Program Area.

Section 11: Enabling Activities

- Provides both summary and detail regarding actual 2016 expenditures for the Enabling Activities that support the work of the DSM portfolio as a whole.

Section 12: Evaluation

- Provides both summary and detail regarding pending and actual expenditures for 2016 program evaluation activities, as well as summary results from evaluations and studies completed in 2016.

Section 13: Data Gathering, Reporting and Internal Control Processes

- Provides a summary of the Company's data tracking, process control and reporting for 2016 DSM activities, and a high level description of the Company's internal approval process for programs.

Section 14: 2016 DSM Annual Report Summary

- Summarizes the Report and the Company's 2016 DSM activity.

2. PORTFOLIO OVERVIEW

In this Section, FEI provides its DSM energy savings, expenditures and cost effectiveness test results at an overall portfolio level for 2016. A summary of the overall portfolio results is provided in Table 2-1, demonstrating that the Company achieved a combined portfolio MTRC of 1.2. DSM expenditures were almost $32.2 million and recorded natural gas savings were over 438,827 GJ.

Table 2-1: Overall DSM Portfolio Results for 2016

Indicator - 2016 Results		Total
Annual Gas Savings (GJ/yr.)		438,827
NPV of Gas Savings (GJ)		3,682,160
Utility Expenditures, Incentives ($000s)		21,045
Utility Expenditures, Non-Incentives ($000s)		11,120
Utility Expenditures, Total ($000s)		32,165
Benefit/Cost Ratios	TRC	0.7
	MTRC	1.2
	Utility	1.0
	Participant	1.5
	RIM	0.5

Table 2-2 provides the cost effectiveness test results by Program Area for the overall DSM portfolio.

Table 2-2: Overall DSM Portfolio Level Results by Program Area 2016

Portfolio	Annual Gas Savings (GJ/yr.)		NPV Gas Savings (GJ)	Utility Expenditures ($000s)						Benefit/Cost Ratios				
				Incentives		Non-Incentives		All Spending						
	2014-2018 EEC Plan	2016 Actual		2014-2018 EEC Plan	2016 Actual	2014-2018 EEC Plan	2016 Actual	2014-2018 EEC Plan	2016 Actual	TRC	MTRC	Utility	Participant	RIM
Portfolio Level Activities														
Total	No Direct Savings			n/a	n/a	n/a	1,167	n/a	1,167			No Direct Savings		
Residential Sector														
Total	137,884	121,860	1,230,595	7,872	10,291	3,238	2,240	11,110	12,531	0.5	1.5	0.9	1.2	0.5
Commercial Sector														
Total	192,360	255,408	1,942,328	8,934	8,560	2,038	2,077	10,972	10,637	1.1	n/a	1.6	1.7	0.7
Industrial Sector														
Total	168,173	18,349	157,454	1,925	529	737	474	2,662	1,003	1.0	n/a	1.4	1.9	0.7
Low Income														
Total	27,747	36,918	270,705	1,654	1,597	1,387	679	3,042	2,277	1.2	2.3	1.4	3.0	0.7
Conservation Education and Outreach														
Total	No Direct Savings			n/a	n/a	2,400	2,415	2,400	2,415			No Direct Savings		
Innovative Technologies														
Total	18,937	6,292	81,078	636	67	597	690	1,233	757	0.8	n/a	1.0	6.3	0.5
Enabling Activities														
Total	No Direct Savings			n/a	n/a	4,420	1,378	4,420	1,378			No Direct Savings		
TOTAL PORTFOLIOS														
Total	**546,000**	**438,827**	**3,682,160**	**21,020**	**21,045**	**14,818**	**11,120**	**35,839**	**32,165**	**0.7**	**1.2**	**1.0**	**1.5**	**0.5**

Notes:

- Portfolio Level Activities are those activities for which the costs cannot be assigned to individual DSM programs. It should be noted that these activities are distinct from the Enabling Activities specifically listed in Section 9 of the 2014-18 Plan. These distinct Portfolio Level Activities include expenditures such as EECAG activities, DSM Energy Solutions Managers, portfolio level staff labour, some staff training and conferences, research and association memberships, and portfolio level research studies.

Throughout this Report, the following general notes also apply to all the program areas:

- In the above table, and in tables throughout the report, any difference in the totals between tables in the Portfolio Overview or Program Area Sections, and individual program tables is due to rounding. Some "zero" values are a reflection of rounding to the $000 expenditure level when expenditures were under $500.
- A "Non-Program Specific Expense" line item has been included for each program area. These expenditures represent the costs attributable to that program area but support multiple programs and, therefore, are not specific to only one program. Generally, these expenditures represent items such as training, travel, marketing collateral and consulting services that support the overall program area.

It is FEI's view that, as with prior annual reports, the savings reported herein continue to be conservative and lower than the savings experienced in the marketplace as a result of the Company's DSM activities, causing the cost effectiveness test results reported to be lower than they would be otherwise, for the following reasons:

- Net-to-Gross-Ratio - The Net-to-Gross ratio that FEI is using to report energy savings from DSM activity is highly conservative in that it includes the free ridership impact, which serves to reduce reported energy savings, but in most cases does not include the energy savings benefits of spillover[4] effect, which serves to increase energy savings.
- Attribution from Government Regulation –The Company continues to believe the claimed savings reported in this report do not represent all of the savings attributable to FEI's codes and standards work, due to limitations in the rules for reporting these savings.
- Conservation Education and Outreach – CEO activities had expenditures of $2.4 million in 2016. These activities do result in energy savings; however, since these savings remain difficult to quantify, FEI does not currently attribute energy savings to them.
- Enabling Activities – Enabling Activities similarly had expenditures of $1.4 million in 2016 for work that contributes to energy savings but that cannot currently be quantified. Since these savings are not included in the portfolio TRC calculation, the Company believes the portfolio energy savings benefits are higher than reported.

FEI's DSM activities include a number of specified demand side measures. The DSM Regulation stipulates that the cost effectiveness of specified measures must be determined by the cost effectiveness of the portfolio as a whole. These measures are therefore not subject to the 33 percent 'MTRC Cap' (see Section 2.1). Additionally, these measures cannot be determined to be not-cost effective under the UCT.

[4] Free ridership refers to individuals who participate in a program who would have participated in the absence of an incentive. Spillover refers to individuals that adopt efficiency measures because they are influenced by program-related information and marketing efforts, though they do not actually participate in the program. These can be included in the Net-to-Gross ratio employed in the cost effectiveness analysis to capture the additive effects of spillover to balance the reductive effects of free ridership.

In summary, FEI's 2016 DSM expenditures, including specified DSM, were cost effective under the BC DSM Regulation.

2.1 PORTFOLIO LEVEL MTRC CALCULATION AND RESULTS

In 2016, FEI met the conditions of the Province's DSM Regulation, achieving a portfolio MTRC value of 1.2 (see Table 2-2). While FEI strives for TRC test results that approach or exceed 1.0 within each program and across all programs, there are benefits to implementing programs that do not meet this threshold. Some of these benefits include making programs available to those customers that would otherwise be underserved (such as low income and residential customers), water savings, increased human health and comfort, and economic benefits such as job creation. These benefits are recognized in the DSM Regulation, which enable the use of an MTRC in determining program and portfolio cost effectiveness. The MTRC uses the long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia as a proxy for the avoided cost of natural gas and allows for the inclusion of non-energy benefits (NEBs).[5]

Utilities can implement DSM with TRC values less than 1.0 but that meet an MTRC threshold of 1.0[6] as long as expenditures on these activities do not exceed 33 percent of the total portfolio expenditure. FEI refers to this 33 percent as the "MTRC Cap". Table 2-3 shows both the TRC and MTRC of those programs to which the MTRC cost effectiveness test is applied and confirms that these programs make up 30.7 percent of FEI's 2016 DSM portfolio spending.

Table 2-3: Programs Subject to MTRC and the Relative Proportion of 2016 Portfolio Spending

Program	Program TRC	Program MTRC	Expenditure ($000s) subject to cap	% of Portfolio Spending
Energy Star Domestic Hot Water	0.3	1.5	2,685	8.3%
Furnace Replacement	0.4	1.3	3,294	10.2%
EnerGuide 80 New Construction	0.3	1.1	50	0.2%
Energy Efficiency Home Performance (HERO)	0.4	1.6	2,282	7.1%
Domestic Hot Water Conservation Program/Low Flow fixtures	0.5	1.2	2	0.0%
Energy Conservation Assistance Program (ECAP)	0.5	1.9	1,553	4.8%
Total			**$9,864**	**30.7%**

5 The DSM Regulation was amended in July, 2014 by allowing for the whole cost of the long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia to be used as a proxy for the avoided cost of natural gas in the MTRC cost effectiveness test. As the DSM Regulation stipulates, the value that the FEI has used for the avoided cost of gas in the MTRC calculation is $100/MWh, or $27.78/GJ, as indicated in BC Hydro's November 2013 Integrated Resource Plan, Section 9.2.12, "Long Run Marginal Cost" (pgs. 9-51 to 9-55).

6 The Commission approved the assessment of the cost effectiveness using an MTRC of 1 or greater on an overall portfolio basis as part its decision on the 2012-2013 RRA, page 174. While this approval was not explicitly stated in the most recent 2014-2018 PBR application decision, FEI interprets this approval to be implicit in the approval of the 2014-2018 DSM Plan.

2.2 *MEETING APPROVED SPENDING LEVELS*

FEI's 2016 DSM expenditure limit of $35.8 million was approved on September 12, 2014, as part of the Commission's decision on the Company's 2014-2018 PBR Application[7], pursuant to section 44.2 of the *Utilities Commission Act*. The Company's DSM expenditures were within the approved levels and have increased from 2015 spending of just under $32 million. As part of the Commission's decision, FEI was granted approval to add $15 million of the requested annual DSM budget to rate base each year of the PBR period, with any additional DSM spend being captured in a DSM non-rate base deferral account attracting AFUDC. Any new amounts accumulated in the non-rate base DSM deferral account are then transferred to the FEI rate base DSM deferral account in the following year. The Commission also approved the amortization of these amounts over 10 years. In accordance with the Commission's decision $16.4 million was placed in the non-rate based DSM deferral account in 2016.

FEI notes a difference in the total DSM rate base ($15 million) plus non-rate base deferral account amount ($16.4 million) versus the total 2016 expenditures ($32.2 million) reported in Tables 2-1 and 2-2. This difference is due to funding from the Provincial government in support of residential and low income programs in partnership with the Utility and on a few cases of amounts being reported in the annual report in one year and processed in the FEI accounting system in the next at year-end.

FEI has managed its 2016 DSM activity within the funding limits approved by the Commission. Section 3 discusses funding transfers between program areas in 2016 within the overall DSM funding envelope and within rules for transferring funds between program areas as set out by the Commission.

2.3 *MEETING ADEQUACY REQUIREMENTS OF THE DEMAND-SIDE MEASURES REGULATION*

The DSM Regulation has the following requirements for a utility's portfolio of DSM activity to be considered adequate:

> A public utility's plan portfolio is adequate for the purposes of Section 44.1 (8) c of the Act only if the plan portfolio includes all the following:
>
> a) A demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption;
> b) If the plan portfolio is introduced on or after June 1, 2009, a demand-side measure intended specifically to improve the energy efficiency of rental accommodations;
> c) An education program for students enrolled in schools in the public utility's service area;

[7] BCUC Order G-138-14, page 277 of the Decision.

d) If the plan portfolio is submitted on or after June 1, 2009, an education program for students enrolled in post-secondary institutions in the public utility's service area.

The Company has met all the requirements for adequacy. There are a number of programs for low income customers, which are discussed in Section 6. FEI operates a Rental Apartment Efficiency Program specifically to address the unique market barriers to energy efficiency faced by renters in addition to a number of Commercial and Low Income energy efficiency programs intended for use by owners of rental buildings. In 2016, the Rental Apartment Efficiency Program ("RAP") program has been expanded to include incentives as part of the Low Income Program Area.

In terms of education programs, FEI's School Education Program, Commercial and Residential customer education programs and other energy efficiency and conservation outreach initiatives are presented in Section 10.

2.4 ADDRESSING BCUC DIRECTIVES FROM THE FEI 2014-2018 PERFORMANCE BASED RATEMAKING DECISION

The Company filed their 2014-2018 DSM Plan and associated funding request to the BCUC with the FEI 2014-2018 PBR Application. There were a number of Commission Directives from that Decision that are specific to the 2014-2018 DSM Plan. In this section, FEI addresses Directives relevant to the overall 2016 DSM Portfolio. Program specific directives are addressed in the applicable program area sections of this report.

2.4.1 Labour Costs

As with the 2015 Annual Report, FEI has included labour cost coded to each DSM program in the reported "Administration" expenditures for each program as directed by the Commission in the FEI PBR[8] approval. This information is included in the specific Program tables included in each DSM Program Area section of this Report (Sections 5-11). FEI notes that while the 2014–2018 DSM Plan was approved by the Commission as set out in FEI's application, program and program area costs were not re-cast with labour included at the program level. This change therefore impacts the direct comparison of actual program and program area spending to plan. The inclusion of Labour costs at the Program level can cause program area expenditures to appear higher than the approved amounts even though non-labour costs are within approved amounts. Actual spending in the "Enabling Activities" program area will also be lower than planned since a substantial amount of labour costs planned for this program area are being reported within other program areas. This issue is also discussed in Section 3 on funding transfers.

[8] Order G-138-14.

2.5 *COLLABORATION & INTEGRATION*

The Company continues to collaborate and integrate DSM programming among B.C.'s largest energy utilities - FEI, FortisBC Inc. (FBC) and BC Hydro and Power Authority (BC Hydro), or together the "BC Utilities" - as well as with other entities such as governments and industry associations. The Company recognizes that doing so will maximize program efficiency and effectiveness. Collaborative activity is captured in the individual Program Area sections and program descriptions found in Sections 5 through 11.

The BC Utilities continued collaborating on a wide range of programs and projects in 2016 through their voluntary Memorandum of Understanding ("MOU"), the purpose of which is to develop enhanced utility integration in support of government legislation, policy and direction. The BC Utilities are currently working under a collaborative MOU covering August 2015 through August 2018.

2.6 *SUMMARY*

The Company's DSM portfolio met the goal of cost effectiveness with a MTRC value of 1.2 in 2016. The Company is of the view that both energy savings accounted for in the portfolio and the resulting TRC remain conservative. Benefits from additional activities, such as CEO, play a very important role in supporting the development and delivery of programs, while creating a culture of conservation in British Columbia.

3. FUNDING TRANSFERS

Two program areas – Residential and CEO – incurred actual program expenditures that were greater than their respective approved Program Area funding amounts. In the case of CEO, exceedance of the approved Program Area funding level was the result of reporting labour expenditures at the program level as directed by the Commission[9]. The approved 2014-2018 DSM Plan was based on labour being reported at the portfolio level, and planned Program Area expenditure levels were not re-cast subsequent to the Commission's decision regarding the reporting of labour costs. Therefore, the approved Program Area funding limits do not include labour. Since the expenditures for CEO as shown in Table 2-2 include labour, and since the approved CEO funding level would not be exceeded if labour costs were removed, no funding transfer is required.

For the Residential Program Area, expenditures including labour and other costs exceed the approved funding level by $1,421,000 as a result of the success of the residential programs. This amount can be drawn from a combination of funds remaining in other program areas without exceeding 25 percent of the respective program areas' approved funding levels[10], notwithstanding the inclusion of labour in actual program area expenditures, but not in approved plan expenditures for those program areas.

[9] Order G-138-14, Directive 145

[10] According to Order G-128-14, Directive 151, funding transfers in excess of 25 percent of program area approved funding levels require prior approval from the Commission.

4. EEC ADVISORY GROUP ACTIVITIES

4.1 *OVERVIEW*

The Energy Efficiency and Conservation Advisory Group (EECAG) provide insight and feedback on FEI's portfolio of DSM activities and related issues. This includes: DSM program and portfolio performance, development and design; funding transfers; policy and regulations that may impact DSM activities; and other issues and activities as they may arise.

Members may be appointed based on their relevant subject matter expertise, representation of a common interest shared by stakeholders, or representation of a particular organization/group and/or interest. This includes, but is not limited to, governments, regions, First Nations organizations, customers, suppliers, industries, non-governmental organizations, research institutes and other groups that have historically intervened in FEI's regulatory proceedings.

Since the formation of the EECAG in 2009, FEI has had the opportunity to gain valuable insight on DSM program design and implementation and develop positive working relationships with stakeholders. EECAG input continues to be instrumental as FEI moves forward with DSM activities, helping to ensure that efforts are aligned with the interests and suggestions of stakeholders.

4.2 *SUMMARY OF THE 2016 WORKSHOP*

EECAG workshops provide a forum for stakeholders to learn about DSM programs and engage in constructive dialogue with FEI. Since FEI was in the third year of an approved plan for DSM activities and both the regulatory framework and market dynamics for DSM programming has remained stable during this time, a single workshop in 2016 was sufficient to update EECAG members and seek their input on programming issues. The EECAG workshop was held on November 23, 2016 in Vancouver and was well attended by EEGAG members or their alternate delegates. The EECAG Independent Facilitator was engaged in workshop design and facilitation of the workshop. Copies of materials and minutes for these meetings were distributed to EECAG members and other workshop attendees.

The design and outcomes of the November EECAG workshop recognized that FEI is currently operating its portfolio of DSM activities in a stable period of programming and DSM funding. This stability offered an opportunity for the EECAG to reflect on milestones achieved and lessons learned over the past several years of DSM program implementation. The group also examined what future trends and issues might impact the Company's DSM programming going forward as FEI begins planning the preparation of its next DSM Plan for submission to the BCUC. At the workshop, EECAG Members:

- Updated the rest of the group on initiatives related to energy efficiency that they have been either following or directly involved with;
- Identified concerns around implementing upcoming step code changes, including a potential shortage of trades people and contractors to implement changes;

- Identified challenges in reaching target audiences with key messages and resources needed to implement energy efficiency;
- Presented considerations and ideas for working with indigenous communities to improve and implement energy efficiency programs;
- Suggested potential new partnerships and areas to strengthen existing partnerships;
- Identified opportunities to improve communications with customers and other industry players;
- Suggested alternatives for resourcing initiatives and communication efforts;
- Provided alternate view points on how customers might respond to various energy efficiency initiatives;
- Provided comparisons with other initiatives (recycling programs, for example) from which to draw ideas,
- Suggested alternative incentive approaches for consideration, and
- Identified a number of trends / opportunities to watch / explore.

The purpose of these discussions was to identify potential ways that FEI DSM programs might help to overcome barriers and challenges to implementing energy efficiency, as well as identify potential opportunities for future DSM programming so that this information can be considered as FEI prepares its next DSM Plan for 2019 and beyond.

5. RESIDENTIAL ENERGY EFFICIENCY PROGRAM AREA

5.1 *OVERVIEW*

The Residential Energy Efficiency Program Area was successful in reducing annual natural gas consumption by 121,860 GJ and achieving an overall blended TRC/MTRC of 1.5. Over $12.5 million was invested in Residential Energy Efficiency programs in 2016, and 82 percent of this investment was customer incentive spending.

Table 5-1 summarizes the projected and actual expenditures for the Residential Energy Efficiency Program Area in 2016, including incentive and non-incentive spending, annual and NPV gas savings, as well as TRC/MTRC and other cost effectiveness test results.

Residential programs serve over 890,000 customers in the FEI service territories. For DSM purposes, these customers predominantly include those living in single-family homes, row houses, townhomes or mobile homes.[11] Some in-suite measures, such as low flow fixtures and a small number of fireplaces and water heaters in multi-unit residential buildings are also included in this funding envelope. Residential programs serve retrofit and new home applications. In combination with the Company's education and outreach activities, these programs play an important role in driving the culture of conservation in British Columbia.

Table 5-1: 2016 Residential Energy Efficiency Program Area Results Summary

Program	Annual Gas Savings (GJ/yr.)		Actual NPV Gas Savings (GJ)	Utility Expenditures ($000s)						Benefit/Cost Ratios				
				Incentives		Non-Incentives		All Spending						
	2014-2018 EEC Plan	2016 Actual		2014-2018 EEC Plan	2016 Actual	2014-2018 EEC Plan	2016 Actual	2014-2018 EEC Plan	2016 Actual	TRC	MTRC	Utility	Participant	RIM
Non Program Specific Expenses														
Total		No Direct Savings		0	0	540	396	540	396			No Direct Savings		
Energy Efficiency Home Performance (Home Renovation Rebate Program)														
Total	41,894	19,803	243,551	1,092	2,231	450	433	1,542	2,663	0.4	1.6	0.9	0.8	0.5
Furnace Replacement Program														
Total	31,104	26,885	294,180	2,984	3,294	356	349	3,340	3,642	0.4	1.3	0.7	0.9	0.4
EnerChoice Fireplace Program														
Total	14,670	24,338	238,552	986	1,536	312	360	1,298	1,896	2.1	n/a	1.1	7.1	0.5
Appliance Service Program														
Total		No Direct Savings		356	494	100	83	456	577			No Direct Savings		
ENERGY STAR® Domestic Hot Water "DHW" Technologies														
Total	12,997	23,081	244,284	1,078	2,332	137	393	1,215	2,725	0.3	1.5	0.8	0.8	0.4
Domestic Hot Water Conservation Program /Low Flow Fixtures														
Total	12,825	1,034	9,691	190	50	100	8	290	57	0.5	1.2	1.2	1.7	0.5
New Home Program														
Total	8,347	427	5,533	848	50	188	99	1,036	149	0.3	1.1	0.3	1.5	0.3
New Technologies Program														
Total	1,798	No Direct Savings		237	0	74	0	310	0			n/a		
Rental Apt Efficiency (RAP) *Residential Portion*														
Total	0	26,292	194,803	0	306	0	116	0	422			n/a		
Customer Engagement Tool for Conservation Behaviours														
Total	14,250	No Direct Savings		0	0	848	2	848	2			n/a		
On-Bill Financing														
Total		No Direct Savings		102	0	133	0	235	0			n/a		
ALL PROGRAMS														
Total	**137,884**	**121,860**	**1,230,595**	**7,872**	**10,291**	**3,238**	**2,240**	**11,110**	**12,531**	**0.5**	**1.5**	**0.9**	**1.2**	**0.5**

[11] Programs for Multifamily Dwellings served under Rate Schedule 2 or 3 are included in the Commercial Energy Efficiency Program Area (please refer to Section 7) with a few exceptions as noted in text.

Notes:

- RAP includes a combination of residential and commercial measures for both low income qualified and the able to pay rental apartment market, each funded from their respective program areas. RAP expenditures shown here are related only to the residential portion of RAP. Full RAP details are provided in Section 7.3.1 Table 7-10.
- Cost effectiveness values for the *Residential Portion* of RAP are not provided as they do not represent a complete program view. Please refer to Table 7-10 for the programs cost effectiveness results.

5.2 RESIDENTIAL TRC AND MTRC RESULTS

FEI's DSM Program Principles state that programs should be universal, offering access to programs for all residential and commercial customers. Although many Residential programs are challenged in meeting a conventional TRC test where gas costs are relatively low, these programs, with their broad reach, are cost effective when considering broader societal benefits, including greenhouse gas (GHG) emissions reductions. This is recognized in the DSM Regulation which enables the inclusion of lower TRC programs through the application of the MTRC. The overall 2016 Residential Program Area TRC was 0.5 with a blended TRC/MTRC result of 1.5.

5.3 2016 RESIDENTIAL ENERGY EFFICIENCY PROGRAMS

Tables 5-2 through 5-8 outline the specific Residential Energy Efficiency programs undertaken in 2016, including program and measure descriptions and a breakdown of non-incentive spending.

Table 5-2: Energy Efficient Home Performance Program -Home Renovation Rebate (formerly known as Home Energy Rebate Offer "HERO")

Program Description	This collaborative program promotes energy-efficient home upgrades while educating homeowners on the value of whole home performance. Utility partners administer the program. Federal, provincial and local governments co-promote this program and other related initiatives, including capacity building for the trades, home labeling and the introduction of NRCan's updated Home Energy Rating System in the spring of 2016.						
Target Market	Residential customers						
New vs Retrofit	Retrofit						
Partners	BC Hydro, FortisBC (Electric), BC Ministry of Energy and Mines, Natural Resources Canada and local governments						
Eligible Measures	Draftproofing	Attic Insulation	Basement Insulation	Wall Insulation	$750 Bonus Offer		
Incremental Measure Cost	$100	$1,147	$1,463	$1,953	N/A		
Incentive Amount	Up to $500	Up to $600	Up to $1,000	Up to $1,200	$750		
Savings Per Participant	2.4 GJ	8.9 GJ	6.1 GJ	5.6 GJ	N/A		
Measure Life	6 years for Draftproofing, 25 years for Insulation Consultations with BC Hydro, Habart & Hood, 2010 Conservation Potential Review and Dunsky Energy Consulting.						
Free Rider Rate	20% average assumed based on past program analysis and NRCan evaluation. *Final Report: Analysis of Net-to-gross Survey Results for the ecoENERGY Retrofit for Homes Program.* Bronson Consulting Group. August, 2010						
Sources of Assumptions	2010 Conservation Potential Review Dunsky Energy Consulting, Hot 2000 Modeling 2012, 2013, 2015 2012 Residential End Use Study, FortisBC BC Hydro PowerSmart, Evaluation of the LiveSmart BC Efficiency Incentive Program F2009-F2011 BC Hydro, DSM Standard - Effective Measure Life and Persistence - Revision 10 (June 2016) Analysis of program participants and data						
Participants	2016	Projected	Actual				
	Total	3,360	2,251				
Expenditures ($,000s)			Non-Incentives				
	2016	Incentives	Industry Support	Admin	Communication	Research & Evaluation	Total
	Total	2,231	65	252	67	49	2,663

Notes:

- In 2016, the Home Energy Rebate Offer was renamed Home Renovation Rebate Program as this title more accurately describes the program for customers.
- This program is a collaboration between FEI, FBC and BC Hydro with support from BC Ministry of Energy and Mines and Natural Resources Canada
- Industry support includes application support fees to energy advisors and FEI's contribution to Year-two support of the Home Performance Stakeholder Council "HPSC". The HPSC is an industry led group comprised of key industry players tasked with addressing the fragmented interests, opportunities and challenges that exist in B.C.'s nascent home performance industry which is continuously evolving.

Table 5-3: Furnace and Boiler Replacement Program

Program Description	The Furnace and Boiler Replacement program targets customers with functioning furnaces (standard or mid-efficiency) or boilers. Through a combination of marketing, incentives and industry outreach, the program encourages customers to replace the equipment immediately, rather than waiting for it to fail at some point in the future.						
Target Market	Residential customers						
New vs Retrofit	Retrofit						
Partners	N/A						
Eligible Measures	Standard efficiency	Mid - efficiency	Boilers				
Incremental Measure Cost	$1,899	$1,899	$3,756				
Incentive Amount	$800	$800	$800				
Contractor Incentive	$50	$50	$50				
Savings Per Participant	7.0 GJs	5.1 GJs	9.0 GJs				
Measure Life	Furnace & boilers - 18 years						
Free Rider Rate	Early Replacement Methodology						
Sources of Assumptions	2012 and 2013 Furnace Replacement Pilot Program Evaluation - Habart and Associates Furnace Replacement Program - Billing Analysis of 2012 Participant Savings - Sampson Research Inc. 2012 FortisBC Residential End Use Study Navigant Consulting report BC Hydro Power Smart QA Standard NRCan Analysis of program participants and data						
Participants	2016	Projected	Actual				
	Total	3,730	4,117				
Expenditures ($,000s)			Non-Incentive Expenditures				
	2016	Incentives	Dealer Incentives	Admin	Communication	Research & Evaluation	Total
	Total	3,294	211	72	66	0	3,642

Notes:

- As in previous years, the Furnace & Boiler Replacement program pre-qualification period was run outside of heating season to reduce the incidence of emergency replacements.
- Contractor incentives of $50 per participant are allocated to the administration portion of non-incentive spend.
- Based on industry feedback received during 2016, FEI is considering some program design updates.

Table 5-4: EnerChoice Fireplace Program

Program Description	This program promotes the purchase and installation of energy-efficient EnerChoice fireplaces for zone heating. The program educates consumers and dealers about the EnerChoice label and the benefits of selecting natural gas fireplaces based on energy-efficiency and heating attributes, rather than just decorative features. Program awareness and participation was promoted through a combination of customer and dealer incentives and promotional activities. The program was out of market from January 1 to April 30, 2016, to re-evaluate the eligible models directory and reintroduced May 1, 2016.
Target Market	Residential customers
New vs Retrofit	Both
Partners	N/A
Eligible Measures	EnerChoice Fireplace
Incremental Measure Cost	$132
Customer Incentive	$300
Contractor Incentive	$50 (Retrofit only)
Savings Per Participant	EnerChoice Fireplace (Retrofit): 7.8GJ EnerChoice Fireplace (New Construction): 5.0GJ
Measure Life	15 years
Free Rider Rate	2015 program participants - 30% based upon participant questionnaire responses 2016 program participants - 38% based upon participant questionnaire responses
Sources of Assumptions	Impact of Terasen Gas Pilot Fireplace Program (2004) by Habart and Associates 2010 Conservation Potential Review 2012 FortisBC Residential End Use Study 2013 FortisBC Fireplace Upgrades Pre-Feasibility Study 2015 FortisBC EnerChoice Fireplace Program Impact Evaluation 2016 FortisBC EnerChoice Market Effects Study 2016 FortisBC Apartment Fireplace Efficiency Pilot Gas Fireplace Regulatory Proposal - BC Ministry of Energy and Mines, Energy Efficiency Branch (September 2016) Analysis of program participants and data

Participants	2016	Projected Total		Retrofit	New Construction	Total
			2015 Program	2,832	0	2,832
			2016 Program	1,270	1017	2,287
	Total	3,285		4,102	1,017	5,119

Expenditures ($,000s)			Non-Incentives				
	2016	Incentives	Dealer Incentives	Admin	Communication	Research & Evaluation	Total
	Total	1,536	203	82	75	0	1,896

Notes:

- 2016 EnerChoice fireplace program was out of market from Jan through April, while FEI developed a new eligible products directory.
- The EnerChoice Fireplace Program evaluation suggested the need to update the EnerChoice eligible products directory to improve minimum efficiency standards. Therefore the EnerChoice retrofit program was temporarily suspended to undertake industry and government consultation for 2016 program design. The 2016 program was launched May 1, 2016 with a new eligible products directory as the key program enhancement.
- Models included in the FEI eligible EnerChoice fireplace directory must be direct-vented and not have a standing pilot. These requirements support the B.C. Building Code and provincial policy. In addition, the models must be modulating as reported in the Natural Resources Canada fireplace models directory.
- Contractor incentives of $50 per participant are allocated to the administration portion of non-incentive spend.

- In 2016, the Energy Efficiency Branch of the B.C. Government introduced a regulatory proposal to increase the standard of efficiency for fireplaces sold in B.C. that will take effect in 2018. This announcement presents an opportunity for FEI to claim savings, pursuant to the DSM Regulation, as a result of advancing a standard. FEI is assessing the benefits of this advancement for inclusion in the 2017 portfolio results.

Table 5-5: Appliance Service Program

Program Description	This program provides customer education related to the importance of regular appliance maintenance to ensure efficient operation of natural gas appliances. This program also creates opportunities for contractors to dialogue with customers about upgrading appliances to more efficient models.					
Target Market	Residential customers					
New vs Retrofit	Retrofit					
Partners	N/A					
Eligible Measures	Furnace Service (62%), Fireplace Service (33%), Boiler (5%)					
Incremental Measure Cost	N/A					
Incentive Amount	$25 incentive per service; Average of $31 per participant					
Savings Per Participant	N/A					
Measure Life	N/A					
Free Rider Rate	N/A					
Participants (no. of services)	2016	Projected	Actual			
	Total	14,250	19,743			
Expenditures ($,000s)			Non-Incentives			
	2016	Incentives	Admin	Communication	Research & Evaluation	Total
	Total	494	51	32	0	577

Table 5-6: ENERGY STAR® Water Heater Program

Program Description	This program promotes the replacement of standard efficiency water heaters with efficient ENERGY STAR® models. As part of a longer term market transformation strategy, the program introduced 0.67 EF storage tank water heaters and new technologies with energy factors (EF) greater than 0.80. The new technologies include condensing and non-condensing tankless water heaters, hybrids and condensing storage tanks. The program is available to both retrofit and new construction markets. The program supports upcoming federal and provincial Minimum Efficiency Act Standards for natural gas- and propane-fired water heaters.									
Target Market	Residential customers									
New vs Retrofit	Both									
Partners	N/A									
Eligible Measures	**ESTAR 0.67 EF Storage Tank**	**Non-Condensing Tankless**	**Condensing Tankless**	**Condensing Storage Tank**						
Incremental Measure Cost										
Retrofit	$333	$1,705	$2,496	$2,113						
New Construction	$200	$472	$866	$2,113						
Incentive Amount	$200	$400	$500	$1,000						
Savings Per Participant	3.0 GJ	6.5 GJ	8.3 GJ	5.0 GJ						
Measure Life	17.2 years (Weighted average - Manufacturers and other utilities)									
Free Rider Rate	25%									
Sources of Assumptions	ACEEE Emerging Hot Water Technologies and Practices for Energy Efficiency as of 2011. (Report Number A112) Sachs, H., Jacob Talbot and Nate Kaufman Canadian Residential Water Heater Market Assessment. 2009. Caneta Research Inc. 2012 A Canadian high efficiency natural gas water heater pilot project. Project # 417311. Natural Gas Technologies Centre. Prepared by Adam Neale. 2012 FortisBC Residential End Use Study 2010 Conservation Potential Review Analysis of program participants and data									
Participants	2016	Projected	Actual							
		Total	ESTAR 0.67 EF Storage Tank		Non-Condensing Tankless		Condensing Tankless & Hybrids		Condensing Storage Tank	
			Retrofit	New Const.	Retrofit	New	Retrofit	New Const.	Retrofit	New Const.
	Total	3,159	3,042	96	135	90	1,404	635	438	157
Expenditures ($,000s)	2016	Incentives	Non-Incentives				Total			
			Dealer Incentives	Admin	Comm.	Research & Evaluation				
	Total	2,332	242	76	75	0	2,725			

Table 5-7: Domestic Hot Water Conservation - Low Flow Fixtures and Washer Promotions

Program Description	The objective of this program is to reduce hot water consumption in houses, row houses and MURBS through partnerships with utilities or government. Initiatives include the installation of low-flow fixtures and ENERGY STAR washers and dryers.
Target Market	Residential customers
New vs Retrofit	Retrofit
Partners	BC Hydro, FBC, Non-Governmental Organizations (NGOs), and Municipalities
Eligible Measures	Low-Flow Fixtures; ENERGY STAR® Washers and Dryers
ENERGY STAR Washers:	
Incremental Measure Cost	$77
Incentive Amount	**Partnership with BC Hydro:** • $50 rebate (FEU contributes $25) on qualifying ENERGY STAR® clothes washers - IMEF of 2.82 to 2.91, and WF of 3.50 or less • $100 rebate (FEU contributes $75) on qualifying ENERGY STAR clothes washers - IMEF of 2.92 or higher, WF of 3.20 or less **Partnership with FBC:** • $50 rebate (FEU contributes $25) on qualifying ENERGY STAR® clothes washers - IMEF of 2.74 to 2.91, and IWF of 3.50 or less • $100 rebate (FEU contributes $75) on qualifying ENERGY STAR clothes washers - IMEF of 2.92 or higher, IWF of 3.20 or less
Savings Per Participant	1.0 GJ Natural Gas plus 0.25 GJ electric - BC Hydro
Measure Life	14 years
Free Rider Rate	20%- BC Hydro based on market share of eligible washers
Low Flow Fixtures:	
Incremental Measure Cost Incentive Amount Savings Per Participant Measure Life Free Rider Rate	*No applicants in 2016 - activity was undertaken in the Rental Apartment Efficiency Program
Sources of Assumptions	Ontario Power Authority "2010 Prescriptive Measures and Assumptions: Release 1" 2010 Conservation Potential Review BC Hydro, DSM Standard - Effective Measure Life and Persistence - Revision 10 (June 2016) Analysis of program participants and data

Participants	2016	Projected	Actual
	Total	N/A	1,273

Expenditures ($,000s)	2016	Incentives	Non-Incentives			Total
			Admin	Communication	Research & Evaluation	
	Total	50	8	0	0	57

Table 5-8: New Home Program

Program Description	This program provides education and financial incentives to support energy-efficient building practices for the Residential sector. This program supports efficiency updates to the BC Building Code (effective Dec. 2014). In June 2015, the utilities launched ENERGY STAR® for New Homes as the new whole home performance standard.					
Target Market	Builders of residential properties – single family homes and townhomes and homeowner builders					
New vs Retrofit	New Construction					
Partners	BC Hydro and FBC					
Eligible Measures	**ENERGY STAR Single Family Dwellings**				**ENERGY STAR Townhome/Rowhome**	
Incremental Measure Cost	$3,007				*No applicants to date	
Incentive Amount	$2,000					
Savings Per Participant	20.1 GJs					
Measure Life	25 years					
Free Rider Rate	15% for ENERGY STAR					
Sources of Assumptions	New Construction Costs and Savings and Life Cycle Costs, First published in 2011 and updated in 2014, Cooper and Habart, and Dunsky Energy Consulting Analysis of program participants and data					
Participants	2016	Projected	Actual			
				ENERGY STAR SFD		Total
	Total	1,520		25		25
Expenditures ($,000s)	2016		Non-Incentives			
		Incentives	Program Administration	Communication	Research & Evaluation	Total
	Total	50	40	57	2	149

Notes:

- FEI has collaborated with BC Hydro Power Smart and FBC on this program in past years. As of January 2016, BC Hydro removed their incentives although they continue to collaborate with FEI in providing education to builders and energy advisors and support policy regarding High Performance Homes in the province.
- The participant counts in this table are for the ENERGY STAR whole home component of the program. Incentives for natural gas water heaters and fireplaces installed in new home construction are noted under their respective program tables.

5.4 *2016 RESIDENTIAL ENERGY EFFICIENCY PROGRAMS PLANNED BUT NOT LAUNCHED*

5.4.1 Customer Engagement Tool

The Customer Engagement Tool pilot, being developed in partnership with FBC, was postponed to ensure that customer data exchanged with the service provider is secure and in compliance with the *Personal Information Protection Act* (PIPA) and corporate privacy policies. Work is currently underway to further develop and move forward with this pilot.

5.4.2 On-Bill Financing

On-bill financing pilots were found to be expensive and administratively burdensome for utilities. Pilot implementations were unsuccessful with very low uptake rates. However, in 2016 FEI continued to partner with CIBC to offer a competitive financing package through the Trade Ally Network. Partnerships with additional financial institutions, such as Vancity, also continued through 2016 in collaboration with BC Hydro and marketed through the Home Renovation Rebate Program.

5.4.3 New Technologies

FEI continues to explore New Technologies through the Innovative Technologies Program. There were no new technologies introduced in 2016. A combination space and water heating system program is under consideration based on results from the combination space and water heating system pilot (refer to Table 8-2).

5.5 SUMMARY

Residential Energy Efficiency Program Area activity in 2016 resulted in over 120,000 GJs/year of natural gas savings. These programs enabled customers to upgrade appliances and capture energy savings, and continued to build on relationships with the trades for education and program awareness. The combination of financial incentives, policy support, contractor outreach and effective marketing in these programs is instrumental to their ongoing success in generating natural gas savings and fostering market transformation in the residential sector.

6. LOW INCOME ENERGY EFFICIENCY PROGRAM AREA

6.1 *OVERVIEW*

Investments in Low Income DSM programs increased by more than 46 percent in 2016 over 2015. FEI saw the highest participation in Energy Saving Kit (ESK) since 2011, the highest participation in Energy Conservation Assistance Program (ECAP) since the program inception, maintained the Residential Energy Efficiency Works (REnEW) session, and launched three new programs: Low Income Space Heat Top Up, Low Income Water Heating Top Up and the Non-Profit Custom Program.

In addition to FEI's own Low Income programs, progress continues to be made on investing the $5.155 million in funds granted to FEI by the Ministry of Energy, Mines and Natural Gas in 2009 to enable energy efficiency in low income households. In 2016, the Company invested $499 thousand of this funding primarily on retrofits in First Nations bands, Low Income households, outreach focused on the ECAP program, partnership funding of the REnEW program, development of a building operator online training system, and an energy advisor position focused on the non-profit building sector. None of these investments are included in the spending amounts shown in Table 6-1. The remaining granted funds, $867 thousand, will be invested in 2017.

Table 6-1 summarizes the planned and actual expenditures for the Low Income Program Area in 2016, including incentive and non-incentive spending, annual and NPV gas savings, as well as the cost effectiveness test results. The TRC and MTRC for low income programs use a value of 140 percent of the benefits in accordance with July 2014 amendments to Section 4(2)(b) of the DSM Regulation. This amendment effectively increases the deemed cost effectiveness of the Low Income programs.

Table 6-1: 2016 Low Income Program Results Summary

Program	Annual Gas Savings (GJ/yr.)		Actual NPV Gas Savings (GJ)	Utility Expenditures ($000s)						Benefit/Cost Ratios				
				Incentives		Non-Incentives		All Spending						
	2014-2018 EEC Plan	2016 Actual		2014-2018 EEC Plan	2016 Actual	2014-2018 EEC Plan	2016 Actual	2014-2018 EEC Plan	2016 Actual	TRC	MTRC	Utility	Participant	RIM
Non Program Specific Expenses														
Total	No Direct Savings			0	0	305	106	305	106	No Direct Savings				
Energy Saving Kit (ESK)														
Total	8,381	22,145	164,078	78	254	51	115	129	369	5.3	n/a	5.0	9.2	0.9
Energy Conservation Assistance Program (ECAP)														
Total	8,324	8,199	69,268	1,211	1,216	822	336	2,033	1,553	0.5	1.9	0.5	1.6	0.4
Residential Energy Efficiency Works (REnEW)														
Total	No Direct Savings			0	0	81	74	81	74			n/a		
Low Income Space-Heat Top Up														
Total	2,827	1,164	13,499	78	62	16	2	94	64	2.7	n/a	2.6	3.5	0.8
Low Income Water-Heating Top Up														
Total	826	105	890	13	6	5	1	17	7	1.9	n/a	1.5	3.3	0.7
Non-Profit Custom Program														
Total	7,389	0	0	274	0	108	31	383	31			n/a		
Rental Apt Efficiency (RAP) *Low Income Portion*														
Total	0	5,305	22,970	0	59	0	14	0	73			n/a		
ALL PROGRAMS														
Total	**27,747**	**36,918**	**270,705**	**1,654**	**1,597**	**1,387**	**679**	**3,042**	**2,277**	**1.2**	**2.3**	**1.4**	**3.0**	**0.7**

Notes:

- The Space-Heat Top Up, Water-Heating Top Up and Non-Profit Custom Programs are new programs launched in 2016, following BCUC approval.
- During implementation of the Non-Profit Custom Program, FEI determined that some program objectives could be more easily met by extending RAP eligibility to low-income customers. Hence the introduction of the Low-Income RAP line item in Table 6-1.
- RAP includes a combination of residential and commercial measures for both low income-qualified and the able-to-pay rental apartment market, each funded from their respective program areas. RAP expenditures shown here are related only to the Low Income portion of RAP. Full RAP details are provided in Section 7.3.1, Table 7-10
- Cost effectiveness values for *the Low Income Portion* of RAP are not provided as they do not represent a complete program view. Please refer to Table 7-10 for the program's cost effectiveness results.

6.2 *2016 LOW INCOME PROGRAMS*

Tables 6-2 through 6-7 outline the specific Low Income programs undertaken in 2016, including program and measure descriptions and a breakdown of non-incentive spending.

Table 6-2: Energy Saving Kit (ESK) Program

Program Description	The goal of this program is to reach a broad audience of Low Income customers and enable them to take some simple steps towards saving energy by installing a bundle of easy-to-install items that are delivered to their door. Promotional activities include bill inserts, event promotions such as food banks, targeted digital campaigns and partnerships with government ministries and non-profits that serve the low income population.
Target Market	Low Income Residential Customers
New vs Retrofit	Retrofit
Partners	BC Hydro and FortisBC Inc. (FBC)
Eligible Measures	Bundle of measures including high efficiency water fixtures, draft proofing tape, outlet gaskets, window film, etc.
Incremental Measure Cost	$ 20.10 Average based on the full cost of the gas measures included in the ESK.
Incentive Amount	$ 20.10 Since the program is free to participants, the incentive equals the incremental cost.
Savings Per Participant	2.7 GJ per year
Measure Life & Source	10 years - Average based on the individual gas measures included in the Energy Saving Kit
Free Rider Rate & Source	27% - Based on 2010 BC Hydro participant survey.
Participants	2016 / Projected / Actual Total / 5,740 / 12,640
Expenditures ($,000s)	2016 / Incentives / Admin / Communication / Research & Evaluation / Total Total / 254 / 53 / 62 / 0 / 369

Table 6-3: Energy Conservation Assistance Program (ECAP)

Program Description	This program enables deep energy savings in low income customer homes that have moderate to high energy consumption. Promotional activities include bill inserts, customer endorsements, outreach, promotion at events and conferences, and partnerships with government ministries, housing providers, and other organizations that serve the low income population.
Target Market	Low Income Residential Customers
New vs Retrofit	Retrofit
Partners	BC Hydro and FortisBC Inc. (FBC)
Eligible Measures	Bundle of customized measures, which may include low-flow fixtures, water heater pipe wrap, professional draft proofing, outlet gaskets, window film, insulation, improved ventilation, CO detectors, and furnaces.
Incremental Measure Cost	$627 Based on average cost of the customized bundle of measures installed. Includes the full cost of the gas measures installed in gas heated homes.
Incentive Amount	$627 Since the program is free to participants, the incentive equals the incremental cost.
Savings Per Participant	4.4 GJ per year
Measure Life & Source	12 years - Average based on the individual gas measures installed.
Free Rider Rate & Source	4% (Source: Primarily third-party studies)
Participants	2016 / Projected / Actual Total / 1,495 / 1,941
Expenditures ($,000s)	2016 / Incentives / Admin / Communication / Research & Evaluation / Total Total / 1,216 / 191 / 63 / 82 / 1,553

Table 6-4: Residential Energy Efficiency Works (REnEW) Program

Program Description	The goal of this program is to enhance the energy efficiency trade sector in BC in a manner that also enhances communities. This program targets individuals facing barriers to employment and provides training in energy efficiency retrofitting. The training is delivered by industry experts at no cost to participants.				
Target Market	Low income individuals facing barriers to employment				
New vs Retrofit	N/A				
Partners	Ministry of Energy and Mines, FortisBC Inc. (FBC)				
Eligible Measures	N/A				
Incremental Measure Cost	N/A				
Incentive Amount	N/A				
Savings Per Participant	N/A				
Measure Life & Source	N/A				
Free Rider Rate & Source	N/A				
Participants	2016	Projected	Actual		
	Total	20	13		
Expenditures ($,000s)	2016	Incentives	Admin	Communication	Research & Evaluation	Total
	Total	0	72	2	0	74

Table 6-5: Low Income Space Heat Top Up

Program Description	The existing Commercial Space Heat Program offers rebates to commercial customers for the installation of high efficiency space heating equipment in commercial applications. The Low Income Space Heat Top Up Program is an add-on to the existing Commercial Space Heat Program and offers an additional rebate over and above the commercial rebate if the customer meets the eligibility criteria. Promotional activities include partnerships with BC Housing, BC Non-Profit Housing Association (BCNPHA), and the provincial and regional BCNPHA conferences, trade shows and educational seminars.					
Target Market	The Low Income Space Heat Top Up Program is primarily focused on apartment buildings that are owned or operated by a First Nations band, a non-profit housing provider, or a housing co-operative.					
New vs Retrofit	Both					
Partners	N/A					
Eligible Measures	Condensing boilers and mid-efficiency boilers.					
Incremental Measure Cost	$7,683 per appliance					
Incentive Amount	Condensing: $6/MBH Mid-efficiency: $3/MBH					
Savings Per Participant	129 GJ/yr					
Measure Life & Source	20 years - ASHRAE Handbook and Conservation Potential Review					
Free Rider Rate & Source	18% - Efficient Boiler Program Impact Evaluation, June 12, 2003					
Participants	2016	Projected	Actual			
	Total	27	11			
Expenditures ($,000s)	2016	Incentives	Admin	Communication	Research & Evaluation	Total
	Total	62	2	0	0	64

Note:

- The Low Income Space Heat Top Up program was launched mid-year which led to fewer participants than planned. It's expected that participation will grow in 2017.

Table 6-6: Low Income Water Heating Top Up

<table>
<tr><td>Target Market</td><td colspan="6">The existing Commercial Water Heating Program offers rebates to commercial customers for the installation of high efficiency water heating equipment in commercial applications. The Low Income Water Heating Top Up Program is an add-on to the existing Commercial Water Heating Program and offers an additional rebate over and above the commercial rebate if the customer meets the eligibility criteria.

Promotional activities include partnerships with BC Housing, BC Non-Profit Housing Association (BCNPHA), and the provincial and regional BCNPHA conferences, trade shows and educational seminars.</td></tr>
<tr><td>New vs Retrofit</td><td colspan="6">Both</td></tr>
<tr><td>Partners</td><td colspan="6">N/A</td></tr>
<tr><td>Eligible Measures</td><td colspan="6">High Efficiency Storage Tanks, High Efficiency Domestic Hot Water Boilers, High Efficiency Tankless Domestic Hot Water</td></tr>
<tr><td>Incremental Measure Cost</td><td colspan="6">$4890 per appliance</td></tr>
<tr><td>Incentive Amount</td><td colspan="6">Storage tank water heater: $2/MBH
Hot water supply boiler (84%-89.9% thermal efficiency): $1/MBH
Hot water supply boiler (90%+ thermal efficiency): $2/MBH
High-efficiency tankless water heater: $1/MBH</td></tr>
<tr><td>Savings Per Participant</td><td colspan="6">34 GJ/year per appliance</td></tr>
<tr><td>Measure Life & Source</td><td colspan="6">12 years -2010 Conservation Potential Review, Navigant Consulting (16 April 2009) Measures and Assumptions for Demand Side Management Planning Appendix C: Substantiation Sheets Ontario Energy Board pp. 210-226.</td></tr>
<tr><td>Free Rider Rate & Source</td><td colspan="6">38% - Efficient Commercial Water Heater Evaluation 2016, Prism Engineering</td></tr>
<tr><td rowspan="2">Participants</td><td>2016</td><td>Projected</td><td>Actual</td><td></td><td></td><td></td></tr>
<tr><td>Total</td><td>22</td><td>5</td><td></td><td></td><td></td></tr>
<tr><td rowspan="2">Expenditures ($,000s)</td><td>2016</td><td>Incentives</td><td>Admin</td><td>Communication</td><td>Research & Evaluation</td><td>Total</td></tr>
<tr><td>Total</td><td>6</td><td>1</td><td>0</td><td>0</td><td>7</td></tr>
</table>

Note:

- The Low Income Water Heating Top Up program was launched mid-year which lead to fewer participants than planned. It’s expected that participation will grow in 2017.

Table 6-7: Non-Profit Custom Program

Program Description	This program is designed to encourage social housing apartment buildings to replace inefficient equipment and systems with high-efficiency solutions. The program is built around three components: 1) An energy study: Currently there are two avenues available to non-profit housing providers to receive a free energy audit and study. Most participants are having their energy study performed by BC Non-Profit Housing Association (BCNPHA). Some participants are opting to go through the RAP Low Income program for these services. 2) Implementation support: Currently the implementation support is available through the RAP Low Income program. There is additional work still under development for this component of the program. Future implementation support could be offered to housing providers that have used BCNPHA for their energy study. 3) Incentives for Measures: At this point, it is only the Space Heat Top Up and the Water Heater Top Up measures that are available. Analysis is currently being performed on additional measures to offer additional incentives for.					
Target Market	The Non-Profit Custom Program is primarily focused on apartment buildings that are owned or operated by First Nations bands, non-profit housing providers, or housing co-operatives.					
New vs Retrofit	Both					
Partners	N/A					
Eligible Measures	Eligible measures include boilers and water heaters. Additional measures may in the future include items such as heating controls (i.e. zone controls, temperature set back controls, etc.) and potentially building envelope measures.					
Incremental Measure Cost	N/A					
Incentive Amount	N/A					
Savings Per Participant	N/A					
Measure Life & Source	N/A					
Free Rider Rate & Source	N/A					
Participants	2016	Projected	Actual			
	Total	11	0			
Expenditures ($,000s)	2016	Incentives	Admin	Communication	Research & Evaluation	Total
	Total	0	23	0	8	31

Notes:

- Before FEI could bring this program to market several things changed that caused FEI to consider a modified path to achieving the program objectives. These changes include:
  - a desire to ensure that there is no confusion between existing FEI programs (e.g..RAP) and the Non-Profit Custom Program
  - the energy audits that were envisioned to be included in the Non-Profit Custom Program are now being performed by staff at BCNPHA (two of which are FEI-funded Energy Specialists); and
  - RAP is open to low income buildings and thus there are some low income buildings that have participated in RAP Low Income. Please refer to Table 7-10 for the cost effectiveness results for the RAP Low Income Portion and Table 7-11 for program details.
- FEI believes that it is on a path to achieving many of the objectives outlined in the Non-Profit Custom Program through a phased approach that began in 2016 by allowing Low Income Non-Profit Housing Providers to be eligible for RAP.

6.3 *SUMMARY*

The Low Income Program Area has been an important priority for the Company since the initial creation of the DSM Program Principles. In 2016 all historical Low Income programs were operating at their highest levels to date and three new programs were introduced.

7. COMMERCIAL ENERGY EFFICIENCY PROGRAM AREA

7.1 OVERVIEW

In 2016, Commercial Energy Efficiency programs continued to encourage commercial customers to reduce their overall consumption of natural gas and their associated energy costs. The Commercial Energy Efficiency Program Area reduced annual natural gas consumption by approximately 255,400 GJs and achieved an overall TRC of 1.1. $10.637 million was invested in Commercial Energy Efficiency, of which 80 percent was incentive spending.

Table 7-1 summarizes the projected and actual expenditures for the Commercial Energy Efficiency Program Area in 2016, including incentive and non-incentive spending, annual and NPV gas savings, as well as TRC and other cost effectiveness test results.

Table 7-1: 2016 Commercial Energy Efficiency Program Results Summary

Program	Annual Gas Savings (GJ/yr.)		Actual NPV Gas Savings (GJ)	Utility Expenditures ($000s)						Benefit/Cost Ratios				
				Incentives		Non-Incentives		All Spending						
	2014-2018 EEC Plan	2016 Actual		2014-2018 EEC Plan	2016 Actual	2014-2018 EEC Plan	2016 Actual	2014-2018 EEC Plan	2016 Actual	TRC	MTRC	Utility	Participant	RIM
Non Program Specific Expenses														
Total	No Direct Savings			0	0	1,100	474	1,100	474	No Direct Savings				
Space Heating Program														
Total	61,824	82,890	961,647	2,053	3,208	75	265	2,128	3,473	1.6	n/a	2.5	2.2	0.9
Water Heating Program														
Total	15,389	10,608	89,625	245	319	38	191	283	510	0.6	n/a	1.5	1.0	0.7
Commercial Food Service Program														
Total	14,107	14,107	125,910	319	385	155	236	473	622	1.1	n/a	1.8	1.9	0.7
Customized Equipment Upgrade Program														
Total	51,817	56,124	507,620	2,226	2,017	215	466	2,441	2,483	1.1	n/a	1.6	1.7	0.6
EnerTracker Program														
Total	0	12,707	12,707	0	204	13	26	13	230	0.7	n/a	0.4	2.0	0.3
Continuous Optimization Program														
Total	173,381	36,116	152,715	1,553	390	171	28	1,724	418	0.9	n/a	2.9	1.4	0.8
Commercial Energy Assessment Program														
Total	0	8,687	8,687	379	36	108	29	487	65	0.8	n/a	0.9	2.8	0.5
Energy Specialist Program														
Total	0	6,257	6,257	2,160	1,634	162	147	2,322	1,780	n/a				
Rental Apt Efficiency (RAP) *Commercial Portion*														
Total	0	27,911	77,159	0	367	0	215	0	581	n/a				
ALL PROGRAMS														
Total	**192,903**	**255,408**	**1,942,328**	**8,934**	**8,560**	**2,038**	**2,077**	**10,972**	**10,637**	**1.1**	**n/a**	**1.6**	**1.7**	**0.7**

Notes:

- RAP includes a combination of residential and commercial measures for both low income-qualified and the able to pay rental apartment market, each funded from their respective program areas. RAP expenditures shown here are related only to the commercial portion of RAP. Full RAP details are provided in Section Table 7-10.
- Cost effectiveness values for the *Commercial Portion* of RAP are not provided as they do not represent a complete program view. Please refer to Section 7.3.1, Table 7-10 for the program's cost effectiveness results.

7.2 2016 COMMERCIAL ENERGY EFFICIENCY PROGRAMS

The following tables outline the specific Commercial Energy Efficiency programs undertaken in 2016, including program and measure descriptions and a breakdown of non-incentive spending.

Table 7-2: Space Heat Program

Program Description	This program provides rebates for the installation of high efficiency space heating equipment in commercial applications. Currently only rebates for high efficiency boilers are offered. Rebates for condensing rooftop units may also be offered via the program in 2017.					
Target Market	Commercial					
New vs Retrofit	Both					
Partners	N/A					
	Retrofit	New Construction				
Incremental Measure Cost	$21,777	$24,436				
Incentive Amount	$13,111	$20,142				
Savings Per Participant	402 GJ	757 GJ				
Measure Life & Source	20 years - ASHRAE Handbook and Conservation Potential Review					
Free Rider Rate & Source	18% - Efficient Boiler Program Impact Evaluation, June 12, 2003					
Participants	2016	Projected	Actual			
	Total	204	234			
Expenditures ($,000)	2016	Incentives	Admin	Communication	Research & Evaluation	Total
	Total	3,208	232	33	0	3,473

Table 7-3: Water Heating Program

Program Description	This program provides rebates for the installation of high-efficiency commercial water heaters with thermal efficiencies greater than or equal to 84%.					
Target Market	Commercial					
New vs Retrofit	Both					
Partners	N/A					
	Retrofit	New Construction				
Incremental Measure Cost	$9,274	$13,199				
Incentive Amount	$2,028	$4,222				
Savings Per Participant	119 GJ	188 GJ				
Measure Life & Source	12 years -2010 Conservation Potential Review, Navigant Consulting (16 April 2009) Measures and Assumptions for Demand Side Management Planning Appendix C: Substantiation Sheets Ontario Energy Board pp. 210-226.					
Free Rider Rate & Source	38% - Efficient Commercial Water Heater Evaluation 2016, Prism Engineering					
Participants	2016	Projected	Actual			
	Total	128	128			
Expenditures ($,000)	2016	Incentives	Admin	Communication	Research & Evaluation	Total
	Total	319	117	22	52	510

Table 7-4: Commercial Food Service Program

Program Description	This program offers a suite of rebates for the installation of high-efficiency cooking appliances and it may also provide other incentives relevant to commercial food service participants such as low-flow pre-rinse spray valve or faucet aerator installations.					
Target Market	Commercial					
New vs Retrofit	Both					
Partners	N/A					
	Retrofit	New Construction				
Incremental Measure Cost	$1,968	$6,793				
Incentive Amount	$1,050	$3,224				
Savings Per Participant	47 GJ	160 GJ				
Measure Life & Source	13 Years - Foodservice Incentive Program Study 2012, Fisher-Nickel Inc., Marbek Conservation Potential Review (2010) and Database for Energy Efficiency Resources (DEER). San Francisco, CA, California Public Utilities Commission, 2011.					
Free Rider Rate & Source	20% - Foodservice Incentive Program Study 2012, Fisher-Nickel Inc. and Database for Energy Efficiency Resources (DEER). San Francisco, CA, California Public Utilities Commission, 2011.					
Participants	2016	Projected	Actual			
	Total	398	307			
Expenditures ($,000)	2016	Incentives	Admin	Communication	Research & Evaluation	Total
	Total	385	122	104	10	622

Notes:

- In 2016 as part of the Commercial Food Service Program, FEI in partnership with The City of Richmond and The City of Victoria offered a program to install low-flow pre-rinse spray valves and faucet aerators in food service establishments.
- The savings, participation and incremental costs for these measures are included in the average values for the retrofit market. The low cost and savings of these measures has resulted in comparatively low average incentives, savings and incremental costs for retrofit participants.

Table 7-5: Customized Equipment Upgrade Program

Program Description	This program provides eligible customers with funding towards the completion of a detailed Energy Study, to identify energy saving opportunities specific and customized to their facilities, and subsequent capital incentive funding to encourage the implementation of any cost effective measures identified therein. The program seeks to capture energy savings associated with measures that are otherwise difficult to incent as part of a prescriptive program because they are complex, and one project may include multiple measures with interactive effects. The expected energy savings, measures, capital cost, incentives etc., will necessarily vary depending on the customer, though each project is submitted to a TRC test and must be approved by the utility.				
Target Market	Commercial customers				
New vs Retrofit	Both				
Partners	BC Hydro (New Construction) FortisBC (New Construction and Retrofit programs - Program development/testing stage)				
Eligible Measures	Utility funded energy study, and utility incented Energy Saving Measures as identified in the energy study and approved by the utility. Energy Saving Measures are variable.				
Incremental Measure Cost	Variable. Dependent upon participant's proposed Energy Saving Measures.				
Incentive Amount	If TRC ≥ 1.0 then $5 / discounted GJ saved over 50% of the Energy Measure Life (EML), up to 10 yrs.				
Savings Per Participant	Variable. Dependent upon participant's proposed Energy Saving Measures.				
Measure Life & Source	Variable. Dependent upon participant's proposed Energy Saving Measures.				
Free Rider Rate & Source	Variable. Dependent upon participant's proposed Energy Saving Measures.				
Participants	2016	Projected	Actual		
	Total	78	64		
Expenditures ($,000s)	2016	Incentives	Admin	Communication	Research & Evaluation	Total
	Total	2,017	432	17	17	2,483

Notes:

- The Customized Equipment Upgrade Program is complex in nature and has variable measure savings, costs, incentives and/or cash flows which, unlike in prescriptive programs, occur over a period of years. Consequently, providing results for this program within an annual report format is challenging. In general, the savings in this program occur in later years after the participants have had the time to implement customized Energy Conservation Measures, while some program incentives and costs are payable at the outset. Please refer to the notes provided below for additional details.
- New Construction Program:
  - Participation in this program can last for approximately 5 years. This is broken down into approximately 12 months to prepare the required whole building energy simulation, followed by up to 48 months to build the proposed building. The program incurs incentive expenditures upon the successful completion of the energy simulation, as well as upon completion of the building, while natural gas savings are only obtained upon completion of the proposed building.
  - Participants are recorded when the energy simulations or the new buildings are complete, and the incentive becomes payable.
  - The 2016 Actual participants include 14 completed energy simulations, and 3 completed buildings with implemented measures. The associated gross natural gas savings from these 3 projects is approximately 25,269 GJ/year.

- Retrofit Program:
  - Participation in this program can last for approximately 2 years. This is broken down into approximately 6 months to prepare the required energy study, followed by 18 months to implement the proposed Energy Conservation Measures. The program incurs incentive expenditures upon the successful completion of the energy study, as well as upon installation of the approved Energy Conservation Measures, while natural gas savings are only obtained upon installation of the approved Energy Conservation Measures.
  - The '2016 Actual' participants included 23 completed energy studies, and 24 projects where Energy Conservation Measures were installed. The associated gross natural gas savings from these 24 projects is approximately 56,756 GJ/year.

Table 7-6: EnerTracker Program

Program Description	This pilot program is a subset of the continuous optimization (C.Op) program. It provides participants who are otherwise unable or unwilling to participate in the full C.Op program with access to an Energy Management Information System (EMIS). EMIS software provides customers with a detailed picture of their natural gas consumption in "near time". Timely access to this information is expected to speed up fault detection, thereby enabling more rapid corrective action to avoid wasted gas consumption, and to assist in the identification of additional natural gas conservation measures.					
Target Market	Commercial customers with existing AMR devices (FEI only)					
New vs Retrofit	Retrofit					
Partners	N/A					
Eligible Measures	Energy Management Information System					
Incremental Measure Cost	$799/yr (Average)					
Incentive Amount	$799/yr (Average)					
Savings Per Participant	2% of annual natural gas consumption -- Proof of concept study					
Measure Life & Source	1 year -- Measure Life is based on annual EMIS software subscription					
Free Rider Rate & Source	65% - EnerTracker Pilot Program Evaluation 2016, Prism Engineeering					
Participants	2016	Projected	Actual			
	Total	0	255			
Expenditures ($,000s)	2016	Incentives	Admin	Communication	Research & Evaluation	Total
	Total	204	14	7	5	230

Notes:

- An Evaluation of the pilot was completed in 2016. As described therein the program was not found to be particularly effective, and is thus discontinued after 2016.
- As there is currently insufficient AMR (Automated Meter Reader) infrastructure in the Vancouver Island service territory to support the rollout of this pilot, program availability was limited to the Lower Mainland and Interior service territories.
- Note that participation in the program is cumulative, meaning that a participant is enrolled for multiple years, claiming savings and incurring costs on an annual basis for the duration of the EMIS software license.

Table 7-7: Continuous Optimization Program

Program Description	The Continuous Optimization Program (C.Op) is designed to help commercial building owners identify and correct energy wasting operation faults, and continuously monitor building performance to help maintain and improve energy efficiency, resulting in reduced operating costs. C.Op is offered in partnership with BC Hydro. In the FortisBC electric service territory, C.Op is offered in partnership with FortisBC Inc. as the Building Optimization Program (B.Op). The program funds re-commissioning services to study the participant's building and recommend energy efficiency improvements, as well as access to an energy management information system (EMIS) to assist in tracking the building's performance after the re-commissioning work is complete. In return, participants must implement, at their costs, measures identified by the re-commissioning study that when combined have a payback period of two years or less.					
Target Market	Commercial customers with buildings >50,000 ft^2 who consume an average of 7,500 GJ of natural gas per year or natural gas is 40% of their building's total energy consumption.					
New vs Retrofit	Retrofit					
Partners	BC Hydro FortisBC					
Eligible Measures	RE/Retro-commissioning study, employee training, and "near time" energy consumption monitoring.					
Incremental Measure Cost	Average nominal program duration incremental cost (7 years): $41,275 2016 observed average implemented incremental cost: $28,435					
Incentive Amount	Average nominal program duration incentive amount (7 years): $15,915 2016 observed average implemented incentive amount: $10,834					
Savings Per Participant	Average expected annual natural gas savings: 1,465 GJ/year 2016 observed average implemented natural gas savings: 1,033 GJ/year					
Measure Life & Source	5 years - the duration of utility support for the energy management information system, plus one year.					
Free Rider Rate & Source	0% - BC Hydro					
Participants	2016	Projected	Participants Implementing in 2016	Cumulative Program Participants		
	Total	467	36	395		
Expenditures ($,000s)	2016	Incentives	Admin	Communication	Research & Evaluation	Total
	Total	390	10	19	0	418

Notes:

- The C.Op Program is conducted in partnership with BC Hydro and FBC. BC Hydro and FBC Inc. act as the primary administrators of program activities, with CEM providing financial and process support.
- Participation in this program lasts for approximately 7 years for a typical participant. The 7 years are composed of approximately: 12 months of baseline data collection; 24 months of re-commissioning study work, plus the implementation of a recommended bundle of energy conservation measures; and, 48 months of monitoring and continuous improvement.
- Participants are recorded as soon as they are accepted into the program; however, natural gas savings do not occur until they have completed the implementation of a recommended bundle of energy conservation measures, approximately 36 months later. As such, the program incurs incentive expenses (for the upgrading of meter equipment, re-commissioning costs and EMIS costs) before natural gas savings are obtained.

- The average nominal program duration incremental cost represents the total incremental cost expected to be incurred when an average participant completes the full 7 year run in the program. The 2016 observed average implemented incremental cost represents the incremental costs incurred specifically in 2016 divided by the total number of participants who implemented in 2016.
- The average nominal program duration incentive amount represents the total incentive expected to be paid when an average participant completes the full 7 year run in the program. The 2016 observed average implementation incentive amount represents the incentive paid specifically in 2016 divided by the total number of participants who implemented in 2016. Due to the nature of the program, the incentive amount paid is not solely attributable to those who implemented in 2016.
- The average expected annual natural gas savings represent the expected annual natural gas savings per participant after they have completed the implementation of a recommended bundle of energy conservation measures. The 2016 observed average implemented natural gas savings represent natural gas savings attributed to customers who have completed the implementation of a recommended bundle of energy conservation measures specifically in 2016 divided by the total number of participants who implemented in 2016.

Participant count clarification:

- "2016 Actual" represents the number of new participants who were approved in 2016. There were no new participants because the program is currently closed to new participants.
- “Participants Implementing in 2016" represents the number of participants who have successfully completed implementing the bundle of energy conservation measures in 2016.
- “Cumulative Program Participants" represent the total number of approved program participants from the entire multi-year duration. Program participants have the option to discontinue participation in the program during the multi-year duration. A number of program participants chose to discontinue participation in 2016 which, combined with the program being closed to new participants, resulted in a lower cumulative participation number than the previous year.

Table 7-8: Commercial Energy Assessment Program

Program Description	This program identifies inefficiencies at the participant's facilities via an on-site walkthrough assessment by an energy-efficiency consultant. The consultant then produces a report that describes the observed inefficiencies, outlines proposed solutions, and identifies any applicable incentive programs. FortisBC then forwards the report to the participant. Simple measures, such as low-flow faucet aerators and pre-rinse spray valves, are provided to the participant at no charge.					
Target Market	Medium commercial and small industrial customers with an average annual consumption between 1,500 and 10,000 GJ.					
New vs Retrofit	Retrofit					
Partners	FortisBC Inc.					
Incremental Measure Cost	$1,548					
Incentive Amount	$1,347					
Savings Per Participant	495.3 GJ					
Measure Life & Source	1.17 Years - Conservative estimate based on the implementation of low-cost, simple recommendations (such as operational adjustments) from the energy assessment report, past spray valve program data and database for Energy Efficiency Resources (DEER). San Francisco, CA, California Public Utilities Commission, 2011.					
Free Rider Rate & Source	35% - 2010 Friuch Energy Assessment Evaluation, past spray valve program data					
Participants	2016	Projected	Actual			
	Total	524	27			
Expenditures ($,000s)	2016	Incentives	Admin	Communication	Research & Evaluation	Total
	Total	36	26	3	0	65

Notes:

- At the time of writing the 2014-2018 DSM Plan, the FEI were unsure whether the Provincial Government's Business Energy Advisor ("BEA") program would continue or not. A contingency measure was planned for this program to ensure small businesses had access to energy analysis had the BEA program been discontinued. Participation from small business customers was foreseen in the 2014-2018 DSM Plan. As the BEA program was continued the scope of the Commercial Energy Assessment Program was not expanded to include small businesses and the number of participants in 2016 is significantly less than was estimated in the 2014-2018 DSM Plan. In addition, a significant number of multi-family apartment customers now receive their energy assessments through RAP.

Table 7-9: Energy Specialist Program

Program Description	This program funds Energy Specialist positions within customers' organizations, up to $60,000 based on an annual contract. Funded Energy Specialists' key priority is to identify and implement opportunities for their organization to participate in FortisBC's DSM programs, while also identifying and implementing non-program specific opportunities to use natural gas more efficiently. This program is funded as an enabling program.					
Target Market	Large Commercial and Institutional Customers					
New vs Retrofit	Retrofit					
Partners	BC Hydro					
Eligible Measures	Energy Specialist position					
Incremental Measure Cost	$60,000					
Incentive Amount	$60,000					
Savings Per Participant	Total 2016 verified (non-C&M program) annual natural gas savings = 6,257 GJs/ year					
Measure Life & Source	N/A					
Free Rider Rate	0% - Internal Engineering review					
Participants	2016	Projected	Actual			
	Total	36	27			
Expenditures ($,000s)	2016	Incentives	Admin	Communication	Research & Evaluation	Total
	Total	1,634	122	0	25	1,780

Notes:

- The Energy Specialist Program continues to experience success as an enabling program. In 2016, organizations with Energy Specialists were responsible for 28 percent of the natural gas savings and 33 percent of the incentives paid out by Commercial C&EM programs. This is in addition to the Conservation Education and Outreach, Innovative Technologies, Low Income, and Residential programs and incentives that Energy Specialists promoted and utilized in 2016.
- Some organizations had Energy Specialists for part of the year only.
- The energy savings listed only apply to natural gas projects completed by Energy Specialists in 2016 that did not directly receive incentive funding from another C&EM program. These energy savings are only reported and have not been included in the calculations for the benefit/cost tests, as the required inputs are not available.
- In July 2016, BC Hydro discontinued funding for the Business Energy Advisors (BEAs). Prior to this FEI had been co-funding eight BEAs with BC Hydro. FEI was a minority funding contributor in this arrangement, contributing $60,000 per funding year for all eight BEAs combined. This is equivalent to the funding of one Energy Specialist. BEAs were tasked with the same objectives as Energy Specialists but targeted small to medium sized businesses. As a collective they were expected to achieve FEI C&EM program participation results similar to that of one Energy Specialist. Hence, this has been counted as one participant in the participant total for the Energy Specialist Program.

7.3 *2016 PROGRAMS WITH JOINT PROGRAM AREA BUDGETS*

7.3.1 Rental Apartment Efficiency Program (RAP)

RAP includes a combination of residential and commercial measures for both the low income and the able to pay rental apartment market, each funded from their respective program areas. This program is specifically designed to overcome barriers to adopting energy efficiency measures otherwise experienced by rental building owners and their tenants, and includes expenditures from each of the residential, low income and commercial program areas. The expenditures and related savings for this program attributable to each program area are provided in Table 7-10 and correspond to the RAP expenditures shown in the Program Area Summary Tables for each of the three program areas.

Table 7-10: Rental Apartment Efficiency (RAP) – Full Program Summary

Program	Annual Gas Savings (GJ/yr.)		Actual NPV Gas Savings (GJ)	Utility Expenditures ($000s)						Benefit/Cost Ratios				
				Incentives		Non-Incentives		All Spending						
	2014-2018 EEC Plan	2016 Actual		2014-2018 EEC Plan	2016 Actual	2014-2018 EEC Plan	2016 Actual	2014-2018 EEC Plan	2016 Actual	TRC	MTRC	Utility	Participant	RIM
Rental Apt Efficiency (RAP) - Commercial Portion														
Total	0	27,911	77,159	0	367	0	214	0	581	0.9	n/a	1.1	2.5	0.9
Rental Apt Efficiency (RAP) - Low Income Portion														
Total	0	5,305	22,970	0	59	0	14	0	73	3.5	n/a	3.5	5.0	2.3
Rental Apt Efficiency (RAP) - Residential Portion														
Total	0	26,292	194,803	0	306	0	116	0	422	3.2	n/a	3.9	7.1	0.7
Overall Program														
Total	**0**	**59,508**	**294,931**	**0**	**731**	**0**	**345**	**0**	**1,076**	**1.9**	**n/a**	**2.4**	**4.5**	**0.8**

Notes:

- RAP was launched in October 2015 and addresses Commission directive 148 of Order G-138-14.

Table 7-11: Rental Apartment Efficiency (RAP)

Program Description	There are three components to the RAP program. The first component is to provide direct install in-suite energy efficiency upgrades to building owners or property management companies of rental properties (hereinafter referred to as Participant(s)). These devices will be installed by an agent of FortisBC into each individual rental suite. The second component is to simultaneously provide those Participants with energy assessments recommending building-level energy efficiency upgrades such as condensing boilers, high efficiency water heaters and lighting upgrades. The last component is to provide the Participant with support in implementing those energy efficiency recommendations and applying for rebates. Expenditures for RAP are covered by 3 program areas based on the in-suite versus the common area expenses and the able-to-pay versus the low income rental apartment customer. For the able-to-pay rental customer, all the in-suite related expenses associated with the direct install activities are covered by the Residential Program Area, while the common area related expenses are covered by the Commercial Program Area. This includes expenditures associated with the energy assessment, implementation support, and boiler/water heater rebates. For the low income rental customer all expenditures related to both the in-suite and common area expenses are covered by the Low Income Program Area.
Target Market	Purpose-Built Rental Apartment Buildings
New vs Retrofit	Retrofit
Partners	FortisBC Inc.
Eligible Measures	1.5 GPM Showerheads, 1.5 GPM Handheld Showerheads, 0.8 GPM Bathroom Aerators, 0.8 GPM Kitchen Aerators Walkthrough Energy Audits, Implementation Support, Condensing Boilers, Energy Efficiency Water Heaters
Incremental Measure Cost	Varies
Incentive Amount	Varies
Savings Per Participant	Varies
Measure Life & Source	Varies
Free Rider Rate & Source	Varies

Participants

2016	Total	Commercial	Low Income	Residential
Projected	23397	0	0	23397
Actual	30190	219	2752	27219

Participants by Measure Type

	Commercial	Low Income	Residential
Non-SST 1.5 Showerhead		606	8191
Non-SST 1.5 GPM Handheld		278	843
Non-SST 1.5 GPM Bathroom Aerator		927	9142
Non-SST 1.5 GPM Kitchen Aerator		919	9043
Energy Assessment Reports	177	20	
Implementation Support Partial	15	1	
Implementation Support Full	4		
Boiler Top Ups (40% of the rebate)		1	
Condensing Boilers	23		
Total	219	2,752	27,219

Expenditures ($,000s)

2016	Incentives	Non-Incentives			Total
		Admin	Communication	Research & Evaluation	
Commercial	367	202	7	5	581
Low Income	59	14	0	0	73
Residential	306	104	4	8	422
Total	731	320	11	14	1,076

7.4 2016 COMMERCIAL ENERGY EFFICIENCY PROGRAM CLOSURES

7.4.1 EnerTracker Program

Since inception the EnerTracker pilot has not achieved a TRC 1.0 or better, nor is it expected to do so moving forward. Further, the evaluation revealed that although some participants utilized the EMIS tool consistently, a significant portion of participants (25 percent) had not logged into the provided software since starting the program. Moreover, program participants who actively used the provided EMIS tool were found to have reduced natural gas consumption by no more than those participants who did not use the provided EMIS or indeed any energy management software. This program was closed as of December 31, 2016.

7.5 *Summary*

Commercial Energy Efficiency Program Area activity in 2016 successfully achieved approximately 255,400 GJ of annual natural gas savings and a positive TRC of 1.0. The Space Heat program continues to act as the cornerstone program as it invests more in natural gas efficiency projects than the other commercial programs. On the other hand all programs continue to experience growth in participation, incentive spend and natural gas savings. The Commercial Custom Design Program in particular experienced significant growth in 2016, investing over $2 million in energy saving measures that would not otherwise be able to obtain incentives via a prescriptive rebate program. Moving forward, the programs will continue to focus on generating natural gas savings and fostering market transformation in the commercial sector.

8. INNOVATIVE TECHNOLOGIES PROGRAM AREA

8.1 *OVERVIEW*

A primary objective of the Innovative Technologies Program Area is to identify market-ready technologies that are not yet widely adopted in British Columbia, and which are suitable for the development of or inclusion in the portfolio of ongoing DSM programs in other program areas. This is accomplished through pilot and demonstration projects, pre-feasibility studies and the use of Industry Standard Evaluation, Measurement and Verification (EM&V) protocols to validate manufacturers' claims related to equipment and system performance. Results from Innovative Technologies activities are used in making future DSM programming decisions.

Just as important as identifying new technologies to be incorporated into the DSM portfolio are findings that indicate which technologies to not include. Section 8.3 summarizes how the activities and processes for the Innovative Technologies Program Area were successful in identifying proposed projects that should not proceed to full pilot phase or further.

All 2016 activities undertaken in this Program Area meet the definition of technology innovation programs as set out in the DSM Regulation. It should be noted that Innovative Technologies are considered a "specified demand-side measure,"[12] meaning that the Program Area or the measures therein are not subject to a cost effectiveness test. Instead the cost effectiveness of these expenditures will be evaluated as part of the DSM portfolio as a whole.[13] Innovative Technologies expenditures are also not subject to the 33 percent cap on programs for which the MTRC is utilized as a cost effectiveness measure according to Section 4 (4) of the DSM Regulation.[14]

Table 8-1 summarizes the projected and actual expenditures for the Innovative Technologies Program Area in 2016, including incentive and non-incentive spending, annual and NPV gas savings, as well as TRC and other cost effectiveness test results where applicable.

Table 8-1: 2016 Innovative Technologies Program Area Results Summary

Program	Annual Gas Savings (GJ/yr.)		Actual NPV Gas Savings (GJ)	Utility Expenditures ($000s)						Benefit/Cost Ratios				
				Incentives		Non-Incentives		All Spending						
	2014-2018 EEC Plan	2016 Actual		2014-2018 EEC Plan	2016 Actual	2014-2018 EEC Plan	2016 Actual	2014-2018 EEC Plan	2016 Actual	TRC	MTRC	Utility	Participant	RIM
Non Program Specific Expenses														
Total	No Direct Savings			n/a	0	n/a	209	n/a	209	No Direct Savings				
Pilot/Demonstration Projects														
Total	18,937	6,292	81,078	636	67	597	229	1,233	296	1.7	n/a	2.6	6.3	0.7
Studies														
Total	No Direct Savings			n/a	0	n/a	252	n/a	252	No Direct Savings				
ALL PROGRAMS														
Total	**18,937**	**6,292**	**81,078**	**636**	**67**	**597**	**690**	**1,233**	**757**	**0.8**	**n/a**	**1.0**	**6.3**	**0.5**

[12] BCUC Letter Log No. 36730, Request for Clarification of Order G-44-12 and Decision on the 2012 – 2013 Revenue Requirements Application and Natural Gas Rates Application

[13] Subsection 4(4) of the DSM Regulation, and the Decision on the 2012 – 2013 Revenue Requirements Application and Natural Gas Rates Application, page 175.

[14] BCUC Letter Log No. 36730, Request for Further Clarification of Order G-44-12 and Decision on the 2012 – 2013 Revenue Requirements Application and Natural Gas Rates Application and the Commission's May 11, 2012 letter.

Notes:

- Innovative Technologies are considered a "specified demand-side measure," meaning that the Program Area or the measures therein are not subject to a cost effectiveness test. Instead the cost effectiveness of these expenditures will be evaluated as part of the DSM/C&EM portfolio as a whole.

8.2 *2016 INNOVATIVE TECHNOLOGIES ACTIVITIES*

Tables 8-2 to 8-3 outline the specific Innovative Technologies activities undertaken in 2016, including program and measure descriptions and a breakdown of non-incentive spending[15].

[15] Innovative Technologies activities are distinct from C&EM programs and are not presented in individual program tables as in other Program Area sections in this report.

Table 8-2: Pilots

Program Description	The Pilot Program focused on evaluating market-ready technologies and conducting small scale pilots to gather data to validate manufacturers' claims about measure system performance and energy savings. The data from pilots can also be used to help improve the quality and installation of future systems, and to understand and reduce market barriers. Technologies that successfully emerge from the Innovative Technologies Program will be considered for inclusion in the various program areas within the larger C&EM portfolio.
Target Market	Variable
New vs Retrofit	Retrofit
Heat Reflector (HRP) Pilot	To assess energy savings, costing and customer acceptance data related to the installation of a Reflector Panel behind a perimeter heating system in rental MURBs. Energy saving details will be achieved through analysis of billing consumption data on a building level, costing data from the completion of 30 installations and customer acceptance from surveying all building managers at the end of the heating season. Results are expected Q2 2017. 2016 — Participants Total — 30
Apartment Fireplace Efficiency Retrofit (AFER) Pilot	Objectives of the pilot are to verify energy savings from replacing older decorative style "B" vented fireplaces with Direct Vent EnerChoice level heating style fireplaces in Multi Unit Residential Buildings (MURB'S). The results will be used to determine the feasibility of launching a rebate program for high efficient EnerChoice direct vent fireplaces in MURB's or to extend the existing fireplace rebate offers to MURB'S. Results were handed off to the Residential program team in Q4 2016. 2016 — Participants Total — 32
Combination Space and Water Heating System (CURP) Pilot	Objectives of the pilot are to identify field-validated energy performance of each combination system type, technical issues, field-validated incremental costs, customer acceptance and the effective marketing channels for promoting a combination system retrofit rebate. The results will provide insight into a cost-effective rebate program for residential customers to upgrade their existing space and water heating equipment to combination systems. Results are expected Q1 2017. 2016 — Participants Total — 19
Participants	2016 — Projected — Actual Total — n/a — 81

Expenditures ($,000s)			Non-Incentive Expenditures			
2016	Incentives	Admin	Communication	Research & Evaluation	Total
	Total	67	104	0	125	296

Notes:

- Final results from the Apartment Fireplace Efficiency Pilot (AFER) were received in 2016, the findings of which will inform future program design for the Residential Program area. The primary purpose of the study was to compare sub metered gas consumption and run-time on existing natural gas B-vent style fireplaces with EnerChoice natural gas vertical direct-vent fireplaces in apartments. Please refer to Section 12 Evaluation, Table 12-2 for more information on the AFER pilot.

Table 8-3: Studies

Description	Studies are used to assess the market opportunity, technical characteristics and projected energy savings of commercially available DSM technologies. The results can be used to determine the feasibility of launching a pilot or to make future program area inclusion decisions.
Target Market	Variable
New vs Retrofit	N/A
Drain Water Heat Recovery Prefeasibility Study	Drain Water Heat Recovery (DWHR) systems recover part of the energy from the warm drain water to preheat the cold mains water that enters the domestic hot water heating system. DWHR units usually consist of copper piping that is tightly wrapped around a vertical section of a copper drainpipe. The objective of the study is to assess the technical characteristics, market opportunity, and projected energy savings of installing DWHR systems in both new construction and retrofit applications for all suitable residential building types. The study is expected to be completed by Q1 2017.
LEEP BC Climate Zone 5 Study	BC Housing and its BC Partners have defined the target for selection of innovative technologies for new homes to be at 25% reduction in annual space heating energy use from applicable building code, bylaw or green rezoning policy requirements for Climate Zone 5 (Southern Interior and Island North) and Climate Zone 6-8 (Central and Northern BC). NRCan, through the Innovative and Energy Technology Sector (IETS) will lead a series of Local Energy Efficiency Partnership (LEEP) builder group meetings to assess, screen and report on technologies based on their suitability and marketability. The project is expected to be completed by Q4 2017.
LEEP Low Use Homes Study	The objective of this project is to support the home building industry's ability to find and apply new and existing gas based mechanical systems for the growing market share of homes with design heating loads of up to 30,000 BTUs. A companion guide will be developed to support builders and their mechanical designers as they make decisions together on the type of natural gas fuelled mechanical system they want to use in homes with low space heating loads. Some of the technologies considered are drain water heat recovery systems, combined space and water heating units and direct vent wall furnaces. Workshops for the first 2 markets are expected to be conducted by Q4 2017 and workshops for the remaining 6 markets by Q2 2018.
Residential HVAC Zoning Prefeasibility Study	Forced-air zoning systems allow central heating ventilation and air conditioning (HVAC) equipment to be controlled by multiple thermostats or sensors, each serving specific zones of the home. This strategy allows for programmed or occupancy-based temperature set-back or set-forward by zone. The objective of the study is to conduct a technology, market and energy savings assessment of Residential HVAC zone controls for force aired systems. The scope of the study is limited to residential HVAC zoning controls and equipment in single family homes/duplexes, and row/townhouses for all applicable building vintages. The study is expected to be completed in Q1 2017.
Steam Trap Market Characterization Study	Steam traps are installed inline in steam distribution pipe systems, and are used to remove steam condensate from pipes. Improving steam trap maintenance practices provides an opportunity for natural gas energy savings, as failed steam traps are a source of steam losses. The objective of the Steam Trap Market Characterization study was to identify the process of steam trap system surveys and the process of maintaining the steam traps in an attempt to understand why steam traps are not being replaced at the point of failure in the Industrial sector. The study was concluded in Q3 2016.

Table 8-3: Studies Continued

Direct Vent Wall Furnace Study Prefeasibility Study	Direct Vent Wall Furnaces are compact self-contained combustion units that are installed on exterior walls so that combustion by-products are discharged outside through a vent. Direct Vent Wall Furnaces can be a good alternative to central heating systems, especially if a home does not have existing ducting or is built on a concrete slab. The objective of the study is to investigate Direct Vent Wall Furnaces that can be installed to replace lower efficiency space heating systems and lower efficiency fireplaces in both new construction and retrofit applications for all suitable residential building types. The study is expected to be completed in Q2 2017.
Net Zero Homes study	A recent significant research project done through Natural Resources Canada and with builders across Canada has demonstrated the feasibility of net zero energy homes in five Canadian cities. The main objective of this project is to identify the barriers and opportunities for the natural gas industry in a net zero energy home context. The report aims to define a net zero energy home case and to provide sufficient information for the selection of an all-electric scenario and a natural gas and electric combination scenario. The project is expected to be completed in Q3 2017.
Gas fired Heat Pump Prefeasibility Study	Gas heat pumps extract heat from air, ground, or water sources using thermally-driven cycles (engines or absorption), and can achieve high efficiencies in low temperature operation. The objective of the study is to conduct a technology, market and energy savings assessment of all relevant Gas Heat Pump technologies for space and water heating being installed in both Commercial and Residential buildings for all applicable vintages. The study is expected to be completed in Q2 2017.

Expenditures ($,000s)			Non-Incentive Expenditures			
	2016	Incentives	Admin	Communication	Research & Evaluation	Total
	Total	0	252	0	0	252

Notes:

- Outcomes from the Steam Trap Market Assessment study were received in 2016, resulting in steam trap replacements and audits to be considered as future eligible measures under the Industrial Program Area. The goal of the study was to better understand the operator decision making process and whether certain elements that prevent replacement can be mitigated through utility programming intervention. Insights gained from steam trap market characterization enhanced FEI's understanding of steam trap use and maintenance practices within industrial facilities.

8.3 SUMMARY

Innovative Technologies represent a key component of FEI's overall commitment to DSM activities by identifying viable technologies and projects that have the potential to support the development of new programs within the larger DSM portfolio. Overall, the Innovative Technologies initiatives successfully achieved results in evaluating the feasibility of new technologies and providing insights used towards the design of future DSM programs. The Innovative Technologies Program Area continues to use consistent criteria to ensure the greatest potential for screening technologies for further development as full programs in other areas of the DSM portfolio.

9. INDUSTRIAL ENERGY EFFICIENCY PROGRAM AREA

9.1 OVERVIEW

In 2016, the Industrial Energy Efficiency Program Area continued to encourage industrial customers to consume natural gas more efficiently and achieved an overall TRC of 1.0, with a combined net natural gas savings of 18,349 GJ per year.

Table 9-1 summarizes the projected and actual expenditures for the Industrial Energy Efficiency Program Area in 2016, including incentive and non-incentive spending, annual and NPV gas savings, as well as TRC and other cost effectiveness test results.

Table 9-1: 2016 Industrial Energy Efficiency Program Results Summary

Program	Annual Gas Savings (GJ/yr.)		Actual NPV Gas Savings (GJ)	Utility Expenditures ($000s)						Benefit/Cost Ratios				
				Incentives		Non-Incentives		All Spending						
	2014-2018 EEC Plan	2016 Actual		2014-2018 EEC Plan	2016 Actual	2014-2018 EEC Plan	2016 Actual	2014-2018 EEC Plan	2016 Actual	TRC	MTRC	Utility	Participant	RIM
Non Program Specific Expenses														
Total	No Direct Savings			0	0	262	75	262	75	No Direct Savings				
Industrial Optimization Program														
Total	117,575	17,740	150,395	1,545	511	394	356	1,939	867	1.0	n/a	1.5	2.0	0.7
Specialized Industrial Process Technology Program														
Total	50,597	608	7,059	380	18	81	44	461	62	0.8	n/a	1.1	1.0	0.9
ALL PROGRAMS														
Total	**168,173**	**18,349**	**157,454**	**1,925**	**529**	**737**	**474**	**2,662**	**1,003**	**1.0**	**n/a**	**1.4**	**1.9**	**0.7**

Notes:

- For the purpose of cost effectiveness tests, 18,349 GJ in savings have been claimed for 2016. As a project's total incentive can be made across multiple years, the annual natural gas savings are pro-rated based on the proportion of the project's incremental cost that is reported in that year. Please refer to the Industrial Optimization Program description below for further details on this methodology.

9.2 2016 INDUSTRIAL ENERGY EFFICIENCY PROGRAMS

The following tables outline the Industrial Energy Efficiency Program Area activity undertaken in 2016, including program and measure descriptions and a breakdown of non-incentive spending.

Table 9-2: Industrial Optimization Program

Program Description	The program includes measures that allow customers to identify, assess, and implement customized cost-effective energy efficiency projects for industrial processes using natural gas as process heat or an energy source.				
Target Market	Medium and large industrial facilities				
New vs Retrofit	Both				
Eligible Measures	Variable. Natural gas measures with a TRC ≥ 1.0				
Incremental Measure Cost	Dependent upon participant's proposed energy conservation measures.				
Incentive Amount	Variable. Dependent on project characteristics.				
Savings Per Participant	Variable. Dependent on project characteristics.				
Measure Life & Source	Variable. Dependent upon participant's proposed energy conservation measures				
Free Rider Rate & Source	10% Technology Implementation; 20% Industrial Energy Audit, Plant Wide Audit, Feasibility Study. Source: Best estimate.				
Participants	2016	Projected	Actual		
	Total	29	14		
Expenditures ($,000s)	2016	Incentives	Admin	Communication	Research & Evaluation	Total
	Total	511	279	18	59	867

Notes:

- The Industrial Optimization Program includes measures that allow industrial customers to identify, investigate, and implement natural gas energy efficiency projects. Participation in the program can span multiple years due to the timescales associated with completing an energy study, procuring and installing an energy conservation measure, and multi-year measurement and verification analysis.
- Measures include Industrial Energy Audit, Plant Wide Audit, Feasibility Study, and Technology Implementation. FEI is no longer accepting applications for the Energy Audit measure as this was replaced by the Plant Wide Audit and Feasibility Study measures in 2015. Energy Audit participants that completed energy studies and received incentives in 2016 are reported herein.
- The net natural gas savings reported in 2016 are solely attributable to projects implemented through the Technology Implementation measure. The other measures are aimed only at identifying energy saving opportunities and the participant is not bound to implement energy conservation measures identified in the energy study process.
- In 2016, three energy audits, one plant wide audit and four feasibility studies were completed. Five projects progressed to Technology Implementation measure and are expected to save 75,802 GJ per year of natural gas once installed.
- Depending on the size of the incentive, Technology Implementation project incentive payments are either paid fully on project commissioning or are paid across several years after commissioning and based on the natural gas saving performance. Hence, for larger incentives, only a portion of the incentive is paid on project commissioning. For consistency in performing cost benefit analyses, only a prorated portion of the natural gas savings and project costs are included in the determination of the cost benefit ratios. In 2016, FEI reviewed and revised the proration methodology adopted in 2013. The revised methodology results in a more accurate reflection of program cost effectiveness by mitigating the risk of not fully reporting a project's incremental cost and more accurately presenting natural gas savings in a given year. The revised approach has been adopted for the 2016 reporting period.

- In the 2012 DSM Annual Report, the cost effectiveness ratios for the project commissioned under the Technology Retrofit Program were calculated using the NPV of the total estimated natural gas savings, the total estimated project cost, but only twenty five percent of the calculated incentive. As such, the incentive paid in 2016 towards this project was necessarily included as an input to the 2016 cost effectiveness ratios, though any energy savings, project costs, and participant count were not, as these had been recorded in full in 2012. Any subsequent incentives paid for this project will be included in future reports, without any corresponding costs, benefits, and participant counts until such time as the full value of the incentive commitment has been accounted for.

Table 9-3: Specialized Industrial Process Technology Program

<table>
<tr><td>Program Description</td><td colspan="6">This program provides prescriptive incentives to Industrial customers to encourage the implementation of specific technologies and best practices targeted at particular industrial processes using natural gas as process heat or an energy source.</td></tr>
<tr><td>Target Market</td><td colspan="6">Small, Medium and Large Industrial Facilities</td></tr>
<tr><td>New vs Retrofit</td><td colspan="6">Both</td></tr>
<tr><td>Incremental Measure Cost</td><td colspan="6">Variable. Dependent on measure.</td></tr>
<tr><td>Incentive Amount</td><td colspan="6">Variable. Dependent on measure.</td></tr>
<tr><td>Savings Per Participant</td><td colspan="6">Variable. Dependent on measure.</td></tr>
<tr><td>Measure Life & Source</td><td colspan="6">Variable. Dependent on measure.</td></tr>
<tr><td>Free Rider Rate & Source</td><td colspan="6">20% - steam trap audit and replacement; 18% - hot water process boilers; 20% - steam boiler upgrades; 20% pipe insulation; 20% other measures. Source: Specialized Industrial Process Technology Program business case</td></tr>
<tr><td rowspan="2">Participants</td><td>2016</td><td>Projected</td><td>Actual</td><td></td><td></td><td></td></tr>
<tr><td>Total</td><td>11</td><td>1</td><td></td><td></td><td></td></tr>
<tr><td rowspan="2">Expenditures ($,000s)</td><td>2016</td><td>Incentives</td><td>Admin</td><td>Communication</td><td>Research & Evaluation</td><td>Total</td></tr>
<tr><td>Total</td><td>18</td><td>21</td><td>16</td><td>6</td><td>62</td></tr>
</table>

Notes:

- The Commission approved FEI's detailed plans for the Specialized Industrial Process Technology Program under Order G-11-16 in January 2016.
- FEI launched the hot water process boiler measure in Q2 2016. Applications for this measure are administered through the Commercial Program Area's Space Heating Program for efficiency, however, incentives, non-incentives, participation counts, incremental costs, and natural gas savings are reported under the Specialized Industrial Process Technology Program.
- Incentive structure, natural gas savings methodology, and free ridership rates used for the hot water process boiler measure are sourced from the Commercial Program Area's Space Heating Program.
- Development of the steam trap audit and replacement, steam boiler upgrades, and pipe insulation measures continued in 2016 but were not released to market.

9.3 *SUMMARY*

The Industrial Energy Efficiency Program Area activity in 2016 resulted in 18,349 GJ per year of net natural gas savings and a TRC of 1.0. Enhancements to the Industrial Optimization Program have resulted in increased participation and greater natural gas savings in 2016 relative to 2015. Launching the Specialized Industrial Process Technology Program into market is a significant milestone as it represents the first time FEI has been able to support a customer consuming less than 10,000 GJ per year to implement high efficiency equipment for their industrial processes. This showcases FEI's commitment to supporting energy efficiency in the province regardless of sector or size.

FEI looks forward to continuing its support of industrial sector energy efficiency in British Columbia in 2017 and expects growth in program participation and implementation of natural gas energy efficiency projects.

10. CONSERVATION EDUCATION AND OUTREACH INITIATIVES

10.1 *Overview*

The CEO portfolio continues to support the DSM portfolio goals of energy conservation in a variety of ways. In order to foster a culture of conservation, several programs and campaigns were undertaken in 2016, giving the team new information and new insights into behaviour change and customer attitudes on efficiency. Educating all types of customers including residential, commercial and students – remains a strong priority and FEI continues to ensure steps are taken to make the information relevant and timely for these customers.

Collaboration with FBC continued in an effort to maximize efficiencies across both teams. Costs continue to be shared on school, residential and commercial outreach as applicable. The second annual Efficiency in Action awards were held recognizing both electric and gas commercial organizations that have most effectively utilized C&EM programs. FEI's partnership with BC Hydro continued in 2016. This included collaboration on the Energy Wise Network Program for commercial customers (formerly known as the Workplace Conservation Awareness Program) which led to 40 natural gas behavior change projects being submitted by participating commercial customers in 2016. The ethnic outreach program, Empower Me continued to reach new Canadians in 8 languages through a community based social marketing approach. BC Hydro and FEI worked closely together in that development and continued to support the program expansion into new audiences. Empower Me received an honourable mention for its public sector collaboration at the 2016 Community Energy Association Climate & Energy Action Awards.

CEO continued to provide information to customers and the general public on natural gas conservation and energy literacy and sought out new opportunities to reach customers, both face-to-face and online. FEI launched its curriculum-connected online resource program called Energy Leaders for B.C. elementary and secondary school teachers. Currently in the pilot phase, teachers can download bias-balanced lesson plans to assist them with the energy related sections of the curriculum. FEI also continues to support various training seminars and educational workshops in collaboration with such organizations as the Greater Vancouver Home Builders Association and other industry associations.

As these are not incentive-based programs, FEI has not attributed direct savings to them in 2016. The following tables do not contain information about eligible measures, incentive amounts, savings levels, free-ridership, spillover or participation levels. CEO costs are included at the portfolio level and incorporated into the overall DSM portfolio cost effectiveness results. Although there were no energy savings attributed to the CEO Program Area in 2016, it should be noted that FEI continues to explore ways to identify and confirm energy savings from CEO activities. In late 2016 through the Clean Energy Research Centre a University of British Columbia student completed a research paper on FEI's behalf to further examine energy savings attributed to the CEO Program Area. The results from this paper will be reviewed and considered in 2017.

Table 10-1 summarizes the projected and actual expenditures for the CEO Program Area in 2016. The approved spending for 2016 was $2.400 million and actual spending in 2016 was $2.415 million.

Table 10-1: 2016 CEO Initiative Results Summary

Program	Annual Gas Savings (GJ/yr.)		Actual NPV Gas Savings (GJ)	Utility Expenditures ($000s) Incentives		Non-Incentives		All Spending		Benefit/Cost Ratios				
	2014-2018 EEC Plan	2016 Actual		2014-2018 EEC Plan	2016 Actual	2014-2018 EEC Plan	2016 Actual	2014-2018 EEC Plan	2016 Actual	TRC	MTRC	Utility	Participant	RIM
Non-Program Specific Expenses														
Total	No Direct Savings			0	0	240	101	240	101	No Direct Savings				
Residential Education Program														
Total	No Direct Savings			0	0	990	1,495	990	1,495	No Direct Savings				
Commercial Education Program														
Total	No Direct Savings			0	0	450	277	450	277	No Direct Savings				
School Education Program														
Total	No Direct Savings			0	0	720	541	720	541	No Direct Savings				
ALL PROGRAMS														
Total	No Direct Savings			**0**	**0**	**2,400**	**2,415**	**2,400**	**2,415**	**No Direct Savings**				

10.2 *2016 CEO PROGRAMS*

Tables 10-2 through 10-4 outline the CEO initiatives undertaken in 2016. This includes program descriptions as well as a breakdown of spending, all of which is classified as "non-incentive spending".

Table 10-2: Residential Education Program

Program Description	This program provides information to Residential customers and the general public on natural gas conservation and energy literacy by seeking opportunities to engage with customers directly (either face-to-face or through online programs). This audience also included low income and ethnic customers. Promotional activities in 2016 included print and online communications and engagement campaigns as well as educational seminars and participation in home shows and community events. The Program also included the cost of production of materials for events and prizing for audience engagement that are utilized at events targeting Residential customers and children. In addition, continuing partnerships with the regional Canadian Home Builders' Associations and local sports organizations expanded outreach opportunities to engage with Residential customers. Furthermore, FEI continued to focus on behavioural change opportunities that resulted in energy savings.
Target Market	Residential customers and general public
New vs Retrofit	Both
Expenditures ($,000s)	

2016	Incentives	Non-Incentive Expenditures Admin	Communication	Research & Evaluation	Total
Total	0	1,036	460	0	1,495

Table 10-3: Commercial Education Program

Program Description	This program provides ongoing communication and education about energy conservation initiatives as well as encourages behavioural changes that help Commercial customers reduce their organization's energy consumption. The Commercial sector is made up of small and large businesses in a variety of sub sectors such as retail, offices, multi-family residences, schools, hospitals, hospitality services and municipal/institutions. Promotional activities for 2016 included print and online communications, event support of industry trade shows, industry association meetings, award events, and development of tools to assist with education and engagement. In addition, the Companies furthered partnerships with organizations such as the Business Improvement Associations of BC (BIABC) and Climate Smart, who all work with small to medium-sized businesses. This program area continued to guide and support behaviour education campaigns delivered by energy specialists (or an energy manager) in their respective organizations. Collaborations between internal departments, as well as with other utilities, were pursued to achieve cost efficiencies in the budget, in particular on advertising and outreach events.
Target Market	Commercial customers, multi-family, energy specialists, energy management staff
New vs Retrofit	Retrofit
Expenditures ($,000s)	

		Non-Incentive Expenditures			
2016	Incentives	Admin	Communication	Research & Evaluation	Total
Total	0	134	143	0	277

Table 10-4: School Education Program

Program Description	This program responds to section 44.1 (8) (c) of the Utilities Commission Act, R.S.B.C 1996, c.473, s.125.1 (4) (e), where a public utility's plan portfolio is adequate if it includes an education program for students enrolled in [K-12] schools and post-secondary schools in the Company's service area. The program area now has an online resource for teachers directly linking to the K-9 curriculum. Other activities included building partnerships and funding support for a variety of in-class and online programs related to conserving energy for K-12 students, delivered both internally and externally by third parties such as non-profit organizations or local sports teams. Some of the activities included were: Energy is Awesome, Green Bricks, Energy Champion assembly presentations and Beyond Recycling. Some of these activities also included distribution or education of energy-efficient fixtures, colouring books, mood pencils, and educational playing cards as part of the program. Partnerships and funding support for post-secondary activities included in-residence and on-campus education campaigns.
Target Market	This program responds to section 44.1 (8) (c) of the Utilities Commission Act, R.S.B.C 1996, c.473, s.125.1 (4) (e), where a public utility's plan portfolio is adequate if it includes an education program for students enrolled in [K-12] schools and post-secondary schools in the Company's service area.
New vs Retrofit	Retrofit
Expenditures ($,000s)	

		Non-Incentive Expenditures			
2016	Incentives	Admin	Communication	Research & Evaluation	Total
Total	0	141	70	330	541

10.3 *Summary*

All of the initiatives described in CEO outreach are designed to foster a culture of energy conservation in B.C. This portfolio is immensely important to the overall C&EM message and helps to keep the program information and energy conservation message top-of-mind with all customers. By changing attitudes and behaviours, the Company will help communities reach their goals, help customers save energy and money, increase participation in DSM programs and ultimately support the shared goals of FEI and the Provincial Government. This portfolio will continue to explore new ways and seek out new opportunities and channels to connect with customers and grow the culture of energy conservation.

11. ENABLING ACTIVITIES

11.1 OVERVIEW

In 2016, Enabling Activities continued to support and supplement FEI's DSM program development and delivery, advancing energy efficiency in British Columbia. This included:

- the ongoing Trade Ally Network program;
- work completed in advancing national and provincial building codes, appliance/equipment standards, and regulations;
- maintenance on the Company's DSM program tracking system;
- work on a new Conservation Potential Review; and
- continued funding to support post-secondary energy management programs.

While these activities play a very important role in FEI's portfolio of DSM activities by advancing the delivery of all program areas, the Company has not claimed any energy savings in 2016 for work completed in this area.

FEI has developed an acceptable method for measuring and attributing energy efficiency savings from Codes and Standards work for the 2014 Residential New Home program (see Table 5-8, page 32 of the 2014 Annual Report). FEI used the same method to examine potential for attributing efficiency standards advancement in the Residential Fireplace Program (See Notes to Table 5-4) and will continue to examine and, where appropriate, claim energy savings from Codes and Standards advancement.

Table 11-1 summarizes the projected and actual expenditures for the Enabling Activities in 2016.

Table 11-1: 2016 Enabling Activities Results

Program	Annual Gas Savings (GJ/yr.)		Actual NPV Gas Savings (GJ)	Utility Expenditures ($000s)						Benefit/Cost Ratios				
				Incentives		Non-Incentives		All Spending						
	2014-2018 EEC Plan	2016 Actual		2014-2018 EEC Plan	2016 Actual	2014-2018 EEC Plan	2016 Actual	2014-2018 EEC Plan	2016 Actual	TRC	MTRC	Utility	Participant	RIM
Trade Ally Network														
Total	No Direct Savings			n/a	n/a	500	723	500	723	No Direct Savings				
Codes and Standards														
Total	No Direct Savings			n/a	n/a	35	96	35	96	No Direct Savings				
TrakSmart Maintenance														
Total	No Direct Savings			n/a	n/a	80	111	80	111	No Direct Savings				
Conservation Potential Review														
Total	No Direct Savings			n/a	n/a	n/a	345	n/a	345	No Direct Savings				
Energy Management Education Funding														
Total	No Direct Savings			n/a	n/a	150	102	150	102	No Direct Savings				
ALL PROGRAMS														
Total	No Direct Savings			**n/a**	**n/a**	**765**	**1,378**	**765**	**1,378**	No Direct Savings				

Note:

- The 2014-2018 DSM Plan had budgeted a one-time cost of $500,000 for the CPR and anticipated that this would take place in the year 2015. The CPR was started in 2015 but the majority of the expenditures for the project were incurred in 2016.

11.2 2016 ENABLING ACTIVITIES BY PROGRAM

The following tables outline the specific Enabling Activities undertaken in 2016 by activity, including activity descriptions along with a breakdown of spending. Note that all spending under Enabling Activities is considered non-incentive spending.

Table 11-2: Trade Ally Network

Program Description	This program develops and manages a contractor network to promote DSM programs and energy-efficiency messaging. FEI identifies trade allies as equipment manufacturers, service contractors, and distributors, and recognizes the influence these industry groups have with the end-use Residential and Commercial customers who make energy-efficiency decisions. This program also supports funding energy efficiency training as outlined in the DSM Regulation.				
Expenditures ($,000s)	2016	Admin	Communication	Research & Evaluation	Total
	Total	263	461	0	723

Table 11-3: Codes and Standards

Program Description	Utilities have a unique understanding of energy supply and customer demand cycles, which can be of assistance in the development of codes and standards. The content and timing of code implementation directly affects market transformation in all program areas. FEI's level of regulatory involvement typically includes one of three involvement classifications: monitoring, stakeholder engagement and developing regulations. The Codes & Standards area "supports the development of or compliance with specified standard or a measure respecting energy conservation or the efficient use of energy" as referred to in the definition of "specified demand-side measures" in the DSM Regulation.
Policy Initiatives consultation process	Evaluation, analysis and review of national, provincial and municipal initiatives for energy efficiency.
Industry consultation process	Collaboration with entities like BC Hydro and the Home Owner Protection Office (HPO) for the development of industry training and guidelines on implementation of new energy efficiency measures. Participation with the BC Safety Authority Gas Technology Committee industry stakeholder group.
Involvement with supporting projects	Active participation for supporting projects like: the Natural Resources Canada new EnerGuide rating system and Leadership in Energy Efficiency Partnerships (LEEP).
Codes and Standards Strategy	Active participation on the Canadian Standards Association (CSA) Strategic Steering Committee on Fuel Burning Equipment. This committee is the highest level committee in the fuel sector at CSA and oversees all committees and sub-committees in the fuel burning sector. Consultation with the Canadian Gas Association (CGA), Canadian Institute of Plumbing and Heating (CIPH), Heating Refrigeration and Air-conditioning Institute (HRAI) and the Canadian Home Builders Association (CHBA) on codes and regulations that are common to our industries.
Codes and Standards Maintenance	Active participation on the CSA Technical Committee on Energy Efficiency and Related Performance of Fuel-Burning Appliances and Equipment. This committee oversees all of the eleven existing performance standards for gas-fired equipment and is looking to develop new needed standards for equipment. Participation in the Standards Council of Canada, committee on Domestic gas cooking appliances ISO/TC 291.
Internal awareness of Code and Regulatory changes	Development of internal documents and updates for relevant program areas and personnel.
Standards library	Purchase of up to date standards for reference.
Expenditures ($,000s)	

2016	Admin	Communication	Research & Evaluation	Total
Total	95	1	0	96

Table 11-4: TrakSmart Maintenance

Program Description	Ongoing IT license and maintenance costs related to the portfolio DSM tracking system.
Expenditures ($,000s)	

2016	Admin	Communication	Research & Evaluation	Total
Total	111	0	0	111

Table 11-5: Conservation Potential Review

Program Description	FEI considers the CPR to be an important tool for use in developing, supporting, and assessing current and future DSM expenditure applications, as well as for directional input into program development. The purpose of a CPR study is to examine available technologies and determine their conservation potential, which includes the amount of energy savings that can be achieved through energy-efficiency and conservation programs over the study period. This project is being worked on in collaboration with BC Hydro, Pacific Northern Gas and FortisBC Electric. Core work on the CPR began in 2015. As of end-2016 the CPR project was close to being completed.
Expenditures ($,000s)	

2016	Admin	Communication	Research & Evaluation	Total
Total	345	0	0	345

Table 11-6: Energy Management Education Funding

Program Description	Funding to support post-secondary energy management programs such as the UBC Master of Engineering Leadership Program in Clean Energy Engineering and the BCIT Sustainable Energy Management Advanced Certificate.
Expenditures ($,000s)	

2016	Admin	Communication	Research & Evaluation	Total
Total	102	0	0	102

11.3 *2016 ENABLING ACTIVITIES PLANNED BUT NOT LAUNCHED*

11.3.1 Home Energy Efficiency Web Portal

Funds allocated to the Home Energy Efficiency Web Portal were not accessed in 2016 as the main focus of the Home Renovation Rebate Program (formerly known as Home Energy Rebate Offer) was customer experience, contractor engagement, and municipal home energy coaching pilots. In 2017, utility partners will continue to assess options for online resources and tools to support enhanced customer, contractor and administrative services.

11.3.2 Residential End Use Study (REUS)

The REUS provides a snapshot of the FEI Residential customer base. It provides information about the building characteristics, the fuel choice for heating, cooling and cooking, the types and ages of appliances installed, energy-use behaviours, and customer attitudes towards energy issues. The REUS also includes a billing analysis to determine natural gas consumption by appliance type. This study is shared with other FEI departments. Initial scoping for the study was started in 2016 but no expenditures will be incurred until 2017.

11.4 *SUMMARY*

Enabling Activities are critical initiatives that support and supplement DSM program development and delivery. The success of the Residential Furnace and Boiler Replacement Program (see Section 5.3, Table 5-3), which was promoted through the contractor network, demonstrates the value of the Trade Ally Network program. Communications were immediate and responsive through the network and at the end of the program, 71 per cent of the program's participants used contractors who were members of the Trade Ally Network.

FEI's involvement in codes and standards work in 2016 continued to encompass varying degrees of activities including monitoring, reviewing and responding to existing and proposed regulatory changes and direct participation in various working groups that explore the development of future targets, codes and standards. Work also continued on the Conservation Potential Review study which is a collaboration between BC Hydro, Pacific Northern Gas and both FEI and FBC. The Technical and Economic Potential portions of the Conservation Potential Review project were nearing conclusion.

12. EVALUATION

FEI continued to advance their evaluation activities in 2016 by conducting evaluation studies[16] on a program by program basis. In alignment with the Company's Evaluation Measurement & Verification (EM&V) Framework and industry standard practice, program evaluation activities are assessed at different stages of each program's lifecycle. Based on this ongoing assessment, all programs are evaluated when appropriate. The 2016 evaluation activities presented here reflect the number of programs in market, the different stages of their lifecycle, and the type of evaluation activities required to provide program feedback. The evaluation activities conducted in 2016 are in accordance with the evaluation principles presented in the Company's EM&V Framework.

12.1 *2016 PROGRAM EVALUATION AND EVALUATION RESEARCH ACTIVITIES*

In 2016, FEI's various evaluation activities included quantifying energy savings, assessing participant awareness and satisfaction, identifying barriers to participation, assessing customer usability and engagement with various FEI DSM outreach activities, and conducting industry research. Measurement and Verification (M&V) activities were focused on identifying and verifying project and measure level savings assumptions and understanding any issues associated with equipment installation in the field.

Table 12-1 presents an inventory of all program evaluation and evaluation research related activities undertaken in 2016. Expenditures for these activities have been accounted for within the applicable program or Program Area as part of the non-incentive costs, but are also reported here in order to provide a concise, easy-to-view summary of evaluation activities. Included in the table are: a list of all the 2016 evaluation activities; the Program Area each activity occurred in; the general type of evaluation activity undertaken; the Company's actual 2016 evaluation expenditures; and, a status update on each activity. The total expenditure for program evaluation and research activities in 2016 is $518,000 which is an increase from 2015.

[16] Types of evaluation activities include: Communications evaluations, which focus on advertising and media outreach; Evaluation studies, where quality assurance or inspection is conducted to gain more insight on the incented measure; Process evaluations, where surveys and interviews are used to assess customer satisfaction and program success; Impact evaluations, to measure the achieved energy savings attributable from the program; Market Analysis, to characterized the industry and the program's effect on market penetration and, Measurement & Verification, to monitor real time energy savings associated with energy conservation measures.

Table 12-1: Inventory of DSM Program Evaluation and Evaluation Research Activities Conducted in 2016[17]

Evaluation Name	Program Area	Type of Evaluation	Years the program has been running [18]	Evaluation Partnership	Actual Evaluation Expenditure (000's)	Evaluation Status [19]
FortisBC Communications Tracking: Energy Efficiency and Conservation	C&EM Portfolio	Communication	ongoing	none	$13	Customer engagement and awareness of C&EM activities. **Completed November 2016 by TNS**
C&EM Rebates UX Testing - Phase I and II	C&EM Portfolio	Communication	ongoing	none	$2	Usability testing of the rebates section of FortisBC.com website. **Completed July and December 2016 by Participant Research**
Home Energy Rebate Offer (HERO) - Participant Survey	Residential	Process	2	FortisBC Inc. and BC Hydro	-$2	Customer survey conducted for the program evaluation. Partnership funding received in 2016 which resulted in a negative expenditure for 2016. **Completed April 2016 by Sentis Research**
Home Energy Rebate Offer (HERO) - Quality Study of Insulation	Residential	Evaluation Study	2	FortisBC Inc. and BC Hydro	$15	On-site visit of homes with insulation and draft proofing measures **Completed May 2016 by RDH Building Science Inc.**
Home Energy Rebate Offer (HERO) - Quantitative Analysis	Residential	Evaluation Study	2	FortisBC Inc. and BC Hydro	$6	HERO participant analysis to determine inputs for cost effectiveness tests and feedback on 2016 program design.
Home Energy Rebate Offer (HERO) - Insulation Home Visit	Residential	Evaluation Study	2	FortisBC Inc.	$9	On-site visit of homes with insulation and draft proofing measures. **Expected completion by Q2 2017.**
BC Fenestration Market Study	Residential	Market Analysis	2	FortisBC Inc., FortisBC Energy Inc., BC Hydro and MEM	$10	Study to characterize market conditions for fenestration products manufactured, sold, and/or installed in British Columbia . **Completed October 2016 by RDH Building Science Inc.**
Evaluation & Contractor Outreach	Residential	Evaluation Study	ongoing	none	$9	Ongoing studies and workshops to gather contractor feedback and awareness.
Rental Apartment Efficiency Program (RAP)	Residential / Commercial	Evaluation Study	1	none	$3	Ongoing performance testing for RAP participants.
Rental Apartment Efficiency Program (RAP)	Residential / Commercial	Process	1	none	$11	Building owner and Tenant survey for program evaluation. **Completed December 2016 by Cohesium Research**
Energy Conservation Assistance Program (ECAP)	Low Income	Evaluation Study	5	BC Hydro	$82	Ongoing Quality Assurance to ensure all products are installed according to program installation policies and procedures.

[17] Table 12.1 does not include Prefeasibility Studies. Please refer to the Innovative Technologies section (Section 8) for details.

[18] Measurement & Verification studies require time to conduct activities which include, but are not limited to, project commissioning, installing and removal of monitoring equipment, data collection and, data analysis and reporting. The column 'Years the program has been running' will refer to the time required to conduct the M&V activities. M&V activities align with the International Performance Measurement and Verification Protocol (IPMVP). Concepts and Options for Determining Energy and Water Savings. Prepared by the Efficiency Valuation Organization: www.evo-world.org. January 2012.

[19] M&V completion refers to the time period where the actual monitoring and data collection ends. Analysis and reporting will require additional time

Table 12-1: Inventory of DSM Program Evaluation and Evaluation Research Activities Conducted in 2016[17] (continued)

Evaluation Name	Program Area	Type of Evaluation	Years the program has been running [18]	Evaluation Partnership	Actual Evaluation Expenditure (000's)	Evaluation Status [19]
Energy Specialist Program Energy Savings Audit (Update for 2016)	Commercial	Impact	7	none	$25	The study is an update to the Energy Savings Audit to verify energy savings for projects completed in 2015. **Completed May 2016 by Prism Engineering. Preliminary results reported in 2015 Annual Report.**
EnerTracker Pilot Program - Impact Evaluation	Commercial	Impact	4	none	$5	Billing analysis of the program participants' energy usage. **Completed April 2016 by Prism Engineering**
Commercial Water Heating Program	Commercial	Process/Impact	6	none	$52	Customer survey and billing analysis conducted for program evaluation. **Completed October 2016 by Prism Engineering**
Commercial Food Service Incentive Program	Commercial	Process & Impact	5	none	$10	Participant Survey and billing analysis conducted for program evaluation. **Expected completion by Q3 2017**
Apartment Fireplace Efficiency Pilot (AFER)	Innovative Technologies	Measurement & Verification	2	none	$119	High efficiency gas fireplace M&V study. **Completed M&V October 2016 by Building Energy Solutions Ltd**
Combination Space/Water Heating Units Pilot	Innovative Technologies	Process Evaluation	2	none	$11	Results from the completed participant survey will be incorporated in the 2017 billing analysis summary report. **Expected completion by Q3 2017**
Combination Space/Water Heating Units Pilot	Innovative Technologies	Measurement & Verification	2	none	$71	Boiler testing to assess the DHW energy factor. **Completed M&V July 2016 by Natural Gas Technologies Centre (NGTC)**
Heat Reflector Pilot (HRP)	Innovative Technologies	Evaluation Study & Measurement & Verification	1	none	$6	Thermal Imaging completed through RDH in 2016. **Expected completion of Final Report by Q1 2018**
Industrial Optimization Program	Industrial	Measurement & Verification	5	none	$59	M&V was conducted on 15 projects in 2016 of which one completed its M&V requirements. The M&V activities include the completion of an M&V plan, commissioning validation site visits, and M&V reports.

Table 12-2 contains a summary of all program evaluation studies and pilot program reports completed in 2016 and includes a brief description of the methodologies and key findings.

Table 12-2: Summary of Key Findings and Methodology for 2016 Completed DSM Program Evaluation Studies and Pilot Program Reports

	Program Area	Type of Evaluation	Methodology	Outcome from Key Findings
FortisBC Communications Tracking: Energy Efficiency and Conservation	C&EM Portfolio	Communication	Online interviews conducted over three waves with 2,400 (800 per wave) British Columbia adults living within the FortisBC service territory.	**Results**: The percentage of participants had aided awareness of at least one of the three main energy efficiency activities undertaken by FortisBC trended upward from 64% in 2015 to an average over the 3 waves of 66% in 2016. Overall, half of the participants surveyed were classified as being at least somewhat engaged with energy efficiency. **Outcome of Key Findings:** Continue to emphasize the overarching energy efficiency activities rather than individual programs to build awareness.
C&EM Rebates UX Testing - Phase I and II	C&EM Portfolio	Communication	One-on-one user testing sessions	**Results:** Improvements identified in both Phase I and II for the rebates web page. **Outcome of Key Findings:** As a result of the study, improvements were made to the rebates section of corporate website.
Home Energy Rebate Offer (HERO) - Participant Survey	Residential	Process	Online survey completed for 435 program participants between March 3 to March 18, 2016.	**Results:** 87% of participants were satisfied with the overall program and 94% were satisfied with the home upgrades. The factor most likely to have motivated participants to sign up for the program is reduced energy bills, with 78% of participants indicating that 'saving money on energy bills' is their main reason for undertaking the home upgrades. **Outcome of Key Findings:** Feedback from customers was taken into account as new program offer, application form and messaging was introduced September 1.

Table 12-2: Summary of Key Findings and Methodology for 2016 Completed DSM Program Evaluation Studies and Pilot Program Reports (continued)

	Program Area	Type of Evaluation	Methodology	Outcome from Key Findings
Home Energy Rebate Offer (HERO) - Quality Study of Insulation	Residential	Evaluation Study	Site visits for 42 houses with HERO improvements were completed in February and March of 2016 to identify compliant installation practices in the installed upgrades.	**Results:** The results of the site visits revealed good installation practices such as including insulation baffles for soffit vents, insulating and air-sealing attic hatches in many houses, and two-thirds of installs providing sufficient insulation in a uniform and consistent manner, aligned with the rebate applications. **Outcome of Key Findings:** The study suggested that overall insulation and air sealing met minimum standards although variability across contractors suggested that there was need for contractor education about best practices. Also noted some non-compliance that was further addressed through contractor education and face to face meetings.
BC Fenestration Market Study	Residential	Market Analysis	Market surveys (interviews) were conducted with industry entities, including fenestration manufacturers and their suppliers, and builders. Analysis and review of public data sources and literature, and government and utility data from related programs.	**Results:** The report summarizes three key findings pertaining to three research questions. 1) U-value ranges for new and replacement windows. -New construction and replacement (U-values that comply with or exceed the USI-1.80 BCBC. 2) Expected energy savings if U-values are lowered below current regulated levels. - Natural gas heated home in Vancouver can range from 2.0GJ for USI-1.8 windows to 9.8 GJ for USI-1.0 windows 3) Market readiness for manufactures with the introduction of higher-performance, lower U-value products requires a shift away from double-pane windows frames. **Outcome of Key Findings:** Update on current market conditions to inform policy and program development.
Rental Apartment Efficiency Program (RAP)	Residential / Commercial	Process	Two separate surveys were conducted; a building owners survey and tenant survey. A telephone survey was completed for 56 owners/managers and 2 onsite contractors and an online survey was completed for 193 tenants.	**Results**: 91% of the building owners and 71% of the tenants surveyed were "very" or "somewhat satisfied" with the overall program. Assessment of the program communications were positive, with approximately 9 in 10 owners/managers "very" or "somewhat satisfied" with the accessibility of the program information, the ease of understanding the information and knowing how/who to contact regarding the program. **Outcome of Key Findings**: Continue to conduct ongoing tenant and building owner surveys to provide feedback to program design.

Table 12-2: Summary of Key Findings and Methodology for 2016 Completed DSM Program Evaluation Studies and Pilot Program Reports (continued)

	Program Area	Type of Evaluation	Methodology	Outcome from Key Findings
EnerTracker Pilot Program - Impact Evaluation	Commercial	Impact	The evaluation was carried out for 145 sites which had a minimum of 12 months post implementation data available. In addition to analyzing the consumption data, interviews with program participants were conducted to gain a better understanding of site specific behaviors and to determine if gas savings actions were triggered as a result of utilizing the EnerTracker sponsored EMIS software.	**Results:** The evaluation revealed that although some participants utilized the EMIS tool consistently, a significant portion of participants (25%) had not logged into the provided software since starting the program. Moreover, program participants who actively used the provided EMIS tool were found to have reduced natural gas consumption by no more than those participants who did not use the provided EMIS or indeed any energy management software. **Outcome of Key Findings:** Net-to-Gross values were updated for 2016 and the pilot program period ended in 2016.
Commercial Water Heating Program	Commercial	Process/Impact	Online survey for 115 program participants was conducted between May 2 to May 16. 240 participant sites were included in the energy savings analysis which included 12 months post consumption usage.	**Results:** 84% of participants were satisfied with the program and 73% were satisfied with the equipment selection. 23% of participants were not satisfied with the process of completing the application forms or with the program requirements. The overall program average savings is 0.23 GJ/yr/MBH for On-Demand, Boilers and Storage heater types. **Outcome of Key Finding:** Net-to-Gross values updated for 2016 program. Deemed savings for water heaters will be developed in 2018 based in large part on the findings of the Evaluation Study.
Apartment Fireplace Efficiency Pilot (AFER)	Innovative Technologies	Measurement & Verification	**M&V Plan:** Complies with the International Performance Measurement & Verification Protocol. The selected IPMVP option and measurement boundary was Option A[20] **M&V:** M&V was conducted on 4 Multi Unit Residential Buildings in the Lower Mainland area representing 27 participants across the four sites. Baseline data was collected and measured for 3 months (Jan to Mar) and 2 months post retrofit of the direct-vent fireplace.	**Results**: The M&V results indicated an overall change in energy use across all Baseline fireplace types over a normalized Winter Heating Season; average natural gas consumption reduction per hour of runtime of 49 - 52% where high BTU/h units were replaced and a reduction of 25 - 27% where low BTU/h units were replaced. **Outcome of Key Findings**: Results presented to the Residential Program Team. Data to be used to inform program decisions.

[20] IPMVP Option A - Measurement of key parameters governing energy use to assess consumption. www.evo-world.org

Table 12-2: Summary of Key Findings and Methodology for 2016 Completed DSM Program Evaluation Studies and Pilot Program Reports (continued)

	Program Area	Type of Evaluation	Methodology	Outcome from Key Findings
Combination Space/Water Heating Units Pilot	Innovative Technologies	Measurement & Verification	Three models of combi-boilers (CB) and three models of boilers with indirect tanks (IT) were tested to determine the DHW energy factor (EF). The energy factor testing used was the CAN/CSA P.7 testing method which targets residential instantaneous natural gas water heaters .	**Results:** The test results indicated in general, the energy factors for combi-boilers were roughly equal to the recovery efficiency of the corresponding boiler. Average EF varied between 0.80 and 0.84 depending on the model. For the indirect tanks, the energy factors were much lower than the recovery efficiencies. Average EF varied between 0.63 and 0.67. **Outcome of Key Findings:** Continue to gather information from participant survey and energy savings analysis.
Industrial Optimization Program	Industrial	Measurement & Verification	**M&V Plan:** Complies with the International Performance Measurement & Verification Protocol. The selected IPMVP option and measurement boundary was Option B[21] **M&V:** M&V was conducted on (Project reference ITRP003) for a lime kiln upgrade project in a pulp and paper mill.	**Results:** Three year M&V completed with a total verified natural gas savings of 132,000 GJ. The mill reduced their natural gas consumption by 132,000 GJ by upgrading a key mechanical component of their lime kiln. The achieved savings were well above the minimum savings to achieve cost effectiveness of the project and provided the plant valuable feedback on the performance of the energy efficiency upgrade. **Outcome of Key Findings:** M&V project completed with the full incentive payment issued to the participant as the natural gas savings exceeded pre-installation estimates.

12.2 *EVALUATION COLLABORATION*

FEI has continued to seek opportunities to increase collaborative activities with FBC, BC Hydro, and other entities to conduct program evaluation for DSM programs. The number of collaborative activities depends on the timing of the activity, program participants, legal and privacy concerns, and available budget to conduct the study. Tables 12-1 and 12-2 provide information on program evaluation activities conducted in partnership with other organizations. One jointly funded evaluation project was initiated in 2016 as a result of the collaboration efforts between FEI, BC Hydro and the BC Ministry of Energy and Mines; Home Energy Rebate Offer (HERO) – Fenestration Market Study. In addition, BC Hydro and FEI continue to collaborate in the evaluation projects for HERO – Participant Survey, HERO – Quality Study of Insulation, and the Energy Conservation Assistance Program (ECAP).

Collaboration efforts on evaluation have been further enhanced by the MOU on collaboration discussed in Section 2.5. The BC Utilities evaluation staff held update meetings to review the evaluation plans and discuss future evaluation activities. Evaluation staff from the BC Utilities continue to hold update meetings and explore opportunities for future collaboration on program evaluations.

13. DATA GATHERING, REPORTING AND INTERNAL CONTROLS PROCESSES

13.1 *Overview*

The following section demonstrates that FEI has business practices in place to ensure DSM activities and associated spending are in compliance with Commission Orders and the Company's internal control processes. In its 2009 Decision[21], the Commission directed the Company to include a discussion in the DSM Annual Report of the Company's internal data gathering, monitoring and reporting control practices. FEI continues to provide this information.

13.2 *Program Tracking, Evaluation and Reporting Functions*

FEI staff responsible for tracking, evaluation and reporting of DSM activities continue to report to a different director than staff responsible for program development and implementation in order to:

- conduct independent evaluation activities,
- maintain an independent library of inputs into cost effectiveness calculations; and
- centralize reporting processes.

13.3 *Robust Business Case Process Applied to All Programs*

Before a new DSM pilot or program can be implemented, a business case must first be developed. FEI is committed to putting each pilot or program through the appropriate level of internal scrutiny before moving ahead, and believes doing so increases pilot or program effectiveness.

Business cases include information about program rationale and purpose, as well as a description of the target audience, assumptions, cost-benefit tests and proposed evaluation methods. Cost effectiveness analysis is performed using the California Standard Tests (CST) as outlined in the California Standard Practice Manual. FEI uses an in-house cost-benefit modeling tool developed in partnership with expert industry consultants[22] to apply the program costs and benefits in each of the four standard cost effectiveness tests based on the California Standard Practice Manual (Rate Impact Measure [RIM], Utility, Participant, and TRC) and the MTRC in accordance with British Columbia DSM Regulation. The results from this modelling are used as inputs for the business cases, which are approved in accordance with FEI's policy on financial authorization levels.

In addition to the internal business case process, the Commission, in its 2014-2018 PBR Application Decision, directed FEI to submit a written request and business plan for any new

[21] BCUC Order G-36-09 dated April 16, 2009
[22] Willis Energy Services Ltd. and The Cadmus Group Inc. provided input into this in-house cost-benefit modelling.

programs they want to implement that have not previously been identified within the approved DSM Plan. Such requests must demonstrate the new program results in a net improvement to the Portfolio effectiveness or is needed to ensure balanced access to DSM programming among different customer groups. Four such business cases were submitted to, reviewed and accepted by the BCUC in 2016. Three of these were in the Low Income Programs: Space Heat Top up, Water Heating Top Up and the Non-Profit Custom Program. Each of these programs is described in Section 6.2. The fourth business case was for the Specialized Industrial Process Technology Program described in Section 9.2.

13.4 *INCENTIVE APPLICATIONS VETTED FOR COMPLIANCE WITH PROGRAM REQUIREMENTS*

Ensuring that all customer applications are compliant with program eligibility requirements as laid out in program terms and conditions is also part of the internal control process. The Company has a number of mechanisms in place to ensure DSM incentive funding applications are in compliance with program requirements. The verification process is specific to each program and is dependent on the type of program, its complexity, the financial value of the incentive and other parameters. The general principles applied are as follows:

- Each application is reviewed for completeness and accuracy;
- Applications must meet the criteria outlined in the terms and conditions of the program put forward through the approval process;
- Once approved, incentives are distributed to participants; and
- Copies of application and supporting documents are filed and stored for seven years in case of an audit.

13.5 *INTERNAL AUDIT SERVICES*

FEI regularly engages the Company's own Internal Audit Services (IAS) group to review the internal controls associated with DSM activities. The IAS utilizes the most recently completed year of operation on which to conduct their audit (in this case, the 2017 Audit will cover the 2016 DSM operations consistent with past reports). At the time of writing this report, the 2017 Audit of 2016 activity has been initiated but not yet completed. FEI will therefore make the results available in the next annual report or upon request from the Commission, once complete.

13.6 *SUMMARY*

FEI is committed to strong internal controls in all aspects of the DSM programs. As demonstrated in this section, the Company's business practices related to program development, application processing and ongoing monitoring are all sound and subject to continuous improvement.

14. 2016 DSM PROGRAMS ANNUAL REPORT SUMMARY

In 2016, FEI's DSM portfolio expenditures reached 90 percent of Plan with 65 percent of actual DSM program spending going toward customer incentives. With almost 438,000 GJ of annual savings, DSM programming continued to contribute valuable options for customers to reduce their energy use. FEI cost effectively delivered these programs within the spending limits approved by the Commission, and in accordance with the B.C. DSM Regulation. FEI works to ensure DSM programs are operating in compliance with the Company's DSM Guiding Principles and are meeting Provincial requirements for adequacy. FEI also continues to implement good internal data gathering, monitoring and reporting control practices.

Statement of Aboriginal Principles

FortisBC is committed to building effective Aboriginal relationships and to ensure we have the structure, resources and skills necessary to maintain these relationships.

In order to meet this commitment, the actions of the company and its employees will be guided by the following principles:

- FortisBC companies' acknowledge, respect and understand that Aboriginal Peoples have unique histories, cultures, protocols, values, beliefs and governments.
- FortisBC supports fair and equal access to employment and business opportunities within FortisBC companies for Aboriginal Peoples.
- FortisBC will develop fair, accessible employment practices and plans that ensure Aboriginal Peoples are considered fairly for employment opportunities within FortisBC.
- FortisBC will strive to attract Aboriginal employees, consultants and contractors and business partnerships.
- FortisBC is committed to dialogue through clear and open communication with Aboriginal communities on an ongoing and timely basis for the mutual interest and benefit of both parties.
- FortisBC encourages awareness and understanding of Aboriginal issues within its work force, industry and communities where it operates.
- To achieve better understanding and appreciation of Aboriginal culture, values and beliefs, FortisBC is committed to educating its employees regarding Aboriginal issues, interests and goals.
- FortisBC will ensure that when interacting with Aboriginal Peoples, its employees, consultants and contractors demonstrate respect, and understanding of Aboriginal Peoples' culture, values and beliefs.
- To give effect to these principles, each of FortisBC's business units will develop, in dialogue with Aboriginal communities, plans specific to their circumstances.

Energy Market Assessment

Short-term Canadian Natural Gas Deliverability 2016-2018

National Energy Board
Office national de l'énergie

June 2016

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FOREWORD

The National Energy Board (NEB, or the Board) is an independent, federal, quasi-judicial regulator established to promote safety and security, environmental protection and economic efficiency in the Canadian public interest within the mandate set by Parliament for the regulation of pipelines, energy development and trade. The Board's main responsibilities include regulating:

- the construction, operation and abandonment of pipelines that cross international borders or provincial/territorial boundaries, as well as the associated pipeline tolls and tariffs;
- the construction and operation of international power lines, and designated interprovincial power lines; and
- imports of natural gas and exports of crude oil, natural gas liquids (NGLs), natural gas, refined petroleum products and electricity.

For oil and gas exports, the Board's role is to evaluate whether the oil and natural gas proposed to be exported is surplus to reasonably foreseeable Canadian requirements, having regard to the trends in the discovery of oil or gas in Canada.

If a party wishes to rely on material from this report in any regulatory proceeding before the Board, it may submit the material, just as it may submit any public document. Under these circumstances, the submitting party in effect adopts the material and could be required to answer questions pertaining to its content.

While preparing this report, in addition to conducting its own quantitative analysis, the NEB held a series of informal meetings and discussions with various industry and government stakeholders. The NEB appreciates the information and comments provided and would like to thank all participants for their time and expertise.

This report does not provide an indication about whether any application will be approved or not. The Board will decide on specific applications based on the material in evidence before it at that time.

Overview and Summary

This report provides an outlook of Canadian natural gas deliverability[1] from the beginning of 2016 to the end of 2018. The outlook presents three distinct cases, a Higher Price Case, Mid-Range Price Case, and a Lower Price Case, each of which are based on a set of assumptions.

Since mid-2014, lower commodity prices have effected Canadian producers via reduced revenues, constrained cash flows and significantly reduced gas-targeted drilling. Major cuts to capital expenditures were made in 2015. Producers are wrestling with spending within cash flows and having to remain within bank-imposed debt limits, while continuing drilling operations to help minimize declines in reserves and production. Canadian natural gas deliverability is expected to decline in the near-term as reduced drilling activity and continued U.S. competition further challenge Canadian output. The lower Canadian dollar has resulted in additional complications, although providing a modest boost to revenues because exports to U.S. markets are paid in U.S. currency, it also creates challenges because some equipment and required supplies are purchased from the U.S., and paid for in U.S. dollars. Despite this challenging environment North American producers may continue to find deliverability gains on a per-well basis through high-grading[2].

It is expected that gas prices and Canadian drilling activity in 2016 will remain suppressed because the warmer-than-average winter softened demand and left ample storage volumes that require less production to refill. Multiple pipeline projects flowing gas out of the U.S. Appalachian Basin are scheduled to be operational by 2017-2018 and are expected to further challenge western Canadian gas in key markets. The Canadian liquefied natural gas (LNG) picture remains ambiguous. A 2016-2017 final investment decision (FID) for one or more Canadian LNG export projects could accelerate pre-positioning by producers and result in additional Canadian deliverability over the projection period.

In the Mid-Range Price Case, the Henry Hub price of natural gas would initially fall from $2.70/MMBtu[3] in 2015 to $2.50/MMBtu in 2016, climbing thereafter to $3.00/MMBtu by 2018, while Canadian natural gas deliverability declines slightly from 427 $10^6m^3/d$ (15.1 Bcf/d) in 2015 to 412 $10^6m^3/d$ (14.5 Bcf/d) in 2018. The Higher Price Case would see natural gas prices at $4.00/MMBtu by 2018, resulting in more drilling and Canadian deliverability increasing to 434 $10^6m^3/d$ (15.3 Bcf/d) by 2018. In a Lower Price Case, prices would remain at, or below $2.50/MMBtu, and deliverability would decline to 393 $10^6m^3/d$ (13.9 Bcf/d) by 2018. A comparison of the price assumptions for each case can be found in Figure 1.1.

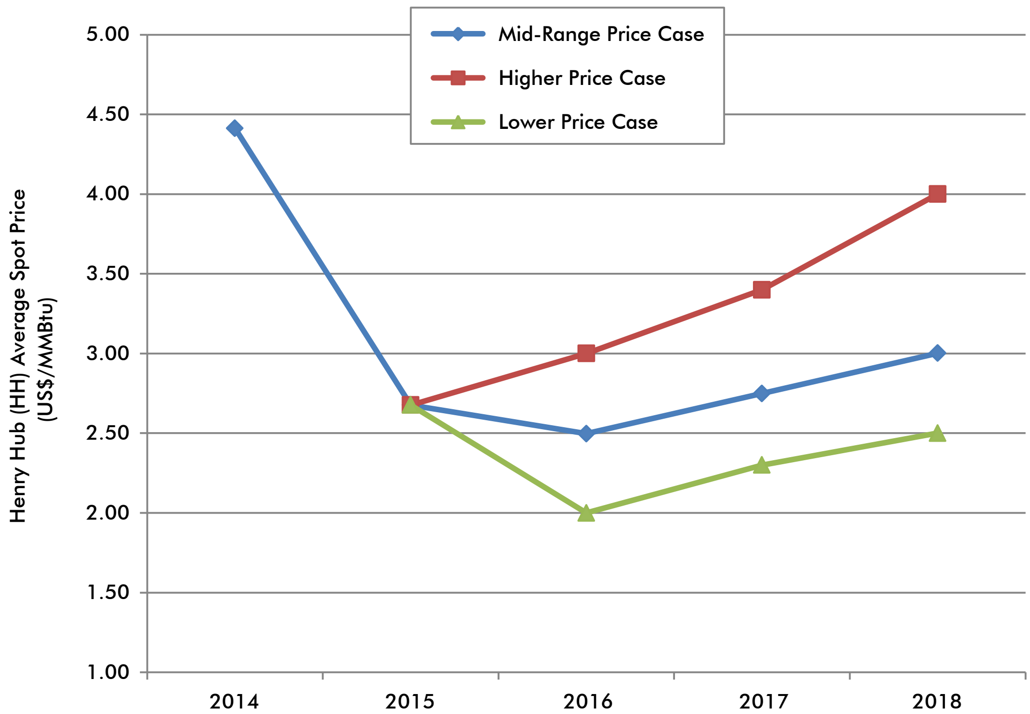
1 Deliverability is the estimated amount of gas supply available from a given area based on historical production and individual well declines, as well as projected activity. Gas production may be less than deliverability due to a number of factors, such as weather-related supply interruptions, and shut-in production due to economic or strategic considerations or insufficient demand.

2 When the amount of investment capital available to industry tightens, producers and service companies attempt to reduce costs while focusing their drilling efforts on the most economic prospects–commonly referred to as 'high-grading'.

3 Unless otherwise specified, North American natural gas prices are quoted at Henry Hub, given in $US/MMBtu and rounded to the nearest $0.05. Canadian natural gas prices are quoted as the Alberta Gas Reference Price and are listed in $C/GJ.

FIGURE 1.1

Historical and Projected Henry Hub Natural Gas Spot Price



The Analysis and Outlook section of this report contain key assumptions for each price case.
The Appendices contain a detailed description of the input assumptions used in projecting deliverability.

Background

The North American Natural Gas Market

North American producers continue to struggle with lower commodity prices. This is resulting in reduced revenues, constrained cash flows, less gas-targeted drilling, and a reduction of oil-derived natural gas production. Reserve write-downs[4] and reduced credit ratings have made it more difficult for some producers to access capital. Consequently, producers are decreasing drilling activity, reducing staff, seeking price concessions from suppliers and pursuing efficiency improvements in order to reduce cost. While the devaluation of the Canadian dollar relative to the U.S. dollar benefits Canadian producers when export sales are paid in U.S. currency, it also disadvantages Canadian producers when purchasing equipment and supplies in U.S. dollars.

Canada

- Canada produced an average of 427 $10^6m^3/d$ (15.1 Bcf/d) of marketable[5] natural gas in 2015, up 2.6 per cent from 2014, remaining well below the 482 $10^6m^3/d$ (17 Bcf/d) peak in 2005.
    - Western Canada is the primary natural gas producing region, contributing 99 per cent of total Canadian natural gas production in 2015. The remainder of Canadian natural gas production is supplied by Nova Scotia, Ontario, and New Brunswick.
- Overall natural gas demand in Canada was up slightly in 2015 at about 269 $10^6m^3/d$ (9.5 Bcf/d) and is expected to see ongoing modest growth as lower gas prices encourage industrial consumption. Rising oil sands production is fueled by natural gas and including gas consumed for cogeneration is now over 88 $10^6m^3/d$ (3.1 Bcf/d). Gradual growth in Canadian electricity demand is being met by a combination of increases in renewable generating capacity (wind, solar and hydro) and from natural gas. Imports of U.S. Marcellus and Utica gas will continue to challenge Canadian gas for markets in central Canada.
- Canada's natural gas exports to the U.S. remained flat in 2015 at about 211 $10^6m^3/d$ (7.4 Bcf/d). Imports of U.S. gas declined moderately in 2015 due to an increase in firm service contracting on Canadian pipelines resulting in Canadian net exports of 158 $10^6m^3/d$ (5.6 Bcf/d) in 2015. This represented about a five percent increase in net exports in 2015, but remained well below the 2007 peak in Canadian exports of 294 $10^6m^3/d$ (10.4 Bcf/d).
- Canadian natural gas exports to the U.S. Midwest continued to decline in 2015 as pipeline reversals and expansions flow more U.S. Marcellus and Utica gas into that market. Part of this decline was made up by increased Canadian gas exports to the western U.S. as higher temperatures increased demand for gas-fired power generation to meet air conditioning demand.

4 A write-down is a reduction in the estimated or nominal value of an asset.

5 Marketable (sales) gas is gas that has been processed to remove impurities and NGLs and meets specifications for use as an industrial, commercial, or domestic fuel.

United States

- U.S. natural gas production has increased steadily since 2005 and averaged 2 103 $10^6m^3/d$ (74.2 Bcf/d)[6] in 2015. This represents an increase of 5.3 per cent year-over-year and a 50 per cent increase over production of 1 401 $10^6m^3/d$ (49.5 Bcf/d) in 2005.
    - Natural gas produced in the U.S. is increasingly derived from tight and shale formations and is serving a growing share of U.S. demand, in turn reducing the need for Canadian natural gas imports.
- The U.S. expects only modest growth in natural gas demand. Only the power generation sector has shown robust demand as lower gas prices have allowed gas-fired power plants to maintain higher utilization rates beyond the typical summer period of air-conditioning loads. In addition, a number of coal plant retirements and increases in requirements for gas-fired generation as a backup for intermittent wind and solar capacity are adding to gas demand. In 2015, U.S. natural gas demand was 2 129 $10^6m^3/d$ (75.2 Bcf/d), an increase of three per cent over the prior year.
- The U.S. shipped its first LNG cargo export in February 2016. By the end of 2018, the U.S. is expected to have operational[7] liquefaction capacity of 241 $10^6m^3/d$ (8.5 Bcf/d) which is equivalent to about 11 per cent of 2015 U.S. natural gas production.
- Mexico is becoming an increasingly important outlet for excess U.S. natural gas supply. The amount of gas moving southward to meet growing Mexican demand represents volumes not available to compete with Canadian gas in other regions of the U.S. and Canadian market.

Mexico

- Mexican natural gas production decreased slightly between 2006 and 2015 to about 114 $10^6m^3/d$ (4 Bcf/d)[8]. Although Mexico may turn out to have sizeable resources of shale gas, its development lags behind the U.S. and Canada. Shale gas production is unlikely to expand rapidly in the short-term.
- Mexican demand for natural gas is expected to increase significantly in the mid to long term due to the planned construction of dozens of natural gas-fired power plants. In 2015 Mexico imported 82 $10^6m^3/d$ (2.9 Bcf/d) of natural gas from the U.S.[9]. It is expected that Mexico will continue to rely on imports to meet incremental demand for natural gas.
- As additional pipeline infrastructure is added, imports from the U.S. are expected to satisfy an increasing portion of Mexican demand and potentially displace some imports of higher cost LNG from other countries. Mexican natural gas imports from the U.S. are expected to increase to 142 $10^6m^3/d$ (5 Bcf/d) by 2020[10].

6 EIA estimate of U.S. Lower 48 dry natural gas production.

7 EIA Natural Gas Weekly Update April 15, 2015.

8 PIRA Energy Group.

9 Energy Information Administration, U.S. Natural Gas Pipeline Exports to Mexico.

10 Energy Information Association: Mexico International Analysis.

Current Trends in Supply and Demand

The North American natural gas market continues to be oversupplied. Storage inventories in the U.S. began 2016 above historical averages due to a warmer than usual winter. Strong U.S. gas production, ample inventories and reduced heating demand are expected to keep the market amply supplied and could keep price soft for most of 2016.

- Cyclical imbalances of supply and demand are typical of the North American natural gas market. Demand often varies because of weather, changes to economic growth, and infrastructure constraints.
    - A typical cycle occurs as follows: during periods of increased demand, prices increase to ration supply and direct it toward the markets that value it most. Higher prices also provide incentives to develop and produce the next most costly natural gas resources which can cause deliverability to exceed demand, subsequently depressing prices. Lower prices discourage production of high cost supply sources but at the same time also foster demand. As demand grows, prices begin to rise again and the cycle repeats itself.
- Natural gas prices have been on a downward trend since early 2014 and oil prices dropped sharply in mid-2014 which subsequently reduced demand for drilling rigs and well-servicing equipment across the oil and gas sector. Producers and service companies have since lowered costs, improved operational efficiencies, and achieved higher levels of production per-well by high-grading.
    - Producers significantly reduced costs in 2015, some reporting cost reductions between 25 and 50 per cent.
    - Although producers will continue to look for further savings in 2016, it is unlikely future cost reductions will be of the same magnitude as those achieved in prior years as the majority of cost savings have likely already been obtained.
- Modern drilling technologies, such as multi-stage hydraulic fracturing and multi-well pads, are now used extensively, improving the size and economics of the Canadian and U.S. natural gas resource base while boosting deliverability.
- It may take years for new major markets to develop for natural gas. Natural gas has largely displaced competing fuels in traditional space-heating markets in Canada and the U.S. already.
    - Proposed LNG export facilities represent a large potential increase in gas demand. Long lead times to obtain approvals, establishing overseas markets, and the construction of facilities are factors that slow down the development of these projects. Currently, none of the proposed Canadian LNG projects with approved export licenses have announced a FID, although one project has issued a conditional FID.
    - Other potential sources of major demand growth could require years or decades to develop to meaningful scale. Examples include growth of the North American petrochemical industry, additional upgrading of bitumen in Alberta, and widespread use of compressed natural gas or LNG for transportation.
- The U.S. has a large inventory of wells that have been drilled but not completed. This allows producers to avoid selling into the market at lower prices, while taking advantage of lower drilling and service costs available because of reduced activity. These wells can be completed later when prices rise, which could rapidly increase supply, stifling large price increases.

Future Uncertainties

Trends in future Canadian and U.S. deliverability will likely follow a pattern similar to previous cycles, but several factors make it difficult to anticipate the duration and extent of the current cycle:

- Many small and mid-sized Canadian oil and gas producers could have difficulty accessing capital, which not only challenges drilling operations, but also increases the chance of bankruptcy or acquisition of smaller producers by larger, more financially stable companies.
    - In lieu of debt financing, producers and service companies in the U.S. and Canada are utilizing private equity[11] investment. This may provide the capital required by smaller and mid-sized producers to continue operations. Currently, there is more private equity investment activity in the U.S. than in Canada.
    - As commodity prices remain depressed, an increase in merger and acquisitions (M&A) is expected. In order to obtain the best deal possible, investors typically wait to see evidence of prices bottoming out before investing. Anticipation of even lower prices partially explains why Canada has yet to see an increase in M&A activity. In 2015, year-over-year M&A activity in the Canadian oil and gas sector fell by almost half, from $41 billion in 2014 to $21 billion[12].
    - The extraction of NGLs[13] (which are priced in relation to crude oil) from natural gas production represents an additional source of producer revenue. As natural gas prices declined after 2008 and crude oil prices continued to rise, the increasing value of the NGLs from some natural gas wells could exceed the value of the natural gas produced. This promoted NGL-targeted drilling and resulted in additional natural gas deliverability based on the value of the NGLs rather than the natural gas. Eventually rising NGL deliverability began creating excess supplies of ethane, propane, and butane in Canada and the U.S. Excess NGL volumes coupled with declining crude oil prices since 2014 have decreased the supplemental revenues generated from NGL-targeted activity and slowed the development of this source of natural gas deliverability.
    - Heavier NGLs such as condensate have higher value in western Canada because they are used to dilute bitumen for pipeline transport. It is possible that condensate-rich gas plays could see sustained drilling activity in western Canada.
- Shale gas resources such as the Marcellus and Utica are close to markets in central Canada, the U.S. northeast, and the U.S. Midwest. Gas from this area has significantly displaced Canadian exports to the North East U.S. market because proximity presents a cost advantage relative to shipping in Western Canada Sedimentary Basin (WCSB) gas.
    - By 2018, newly constructed pipelines in the Marcellus and Utica region could add additional 88 $10^6m^3/d$ (3.1 Bcf/d) import capacity into Canadian markets and 156 $10^6m^3/d$ (5.5 Bcf/d) into the U.S. Midwest. This additional capacity could displace some of the supply provided by the WCSB in these markets.
    - Since July 2015 production from the Marcellus shale has been slowly declining as companies wait for higher prices and new pipeline infrastructure. Production from the Utica however, is increasing and has largely offset Marcellus production declines, continuing to challenge Canadian market share.

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11 Private equity investment generally refers to capital invested by individuals or funds into private (non-publically traded) companies, or into publically traded companies with the intention of taking them private.

12 Evaluate Energy – CanOils M&A database.

13 NGLs are liquid hydrocarbons including ethane, propane, butanes, and pentanes plus. Natural gas containing commercial amounts of NGLs is known as NGL-rich, liquids-rich or wet gas. Dry natural gas contains little or no NGLs.

- Producers are testing gas resources in western Canada that could support proposed LNG exports, potentially increasing drilling in the area. A FID to proceed with a Canadian LNG export project in 2016-2018 could accelerate this activity within the time period assessed in this report.
- The Nova Scotia Deep Panuke project was expected to offset declining output from the Sable Offshore Energy Project. Deep Panuke is now operating seasonally, producing in winter when demand is greater. Increasing amounts of water are being produced with natural gas at Deep Panuke, and this could shorten the project's lifetime.
- The Alberta Government recently reviewed and updated its oil and gas royalties program. The new royalty framework, which comes into effect for wells drilled in 2017, favors efficiency and may create benefits for some producers. The new royalty framework recommends that existing royalties remain in effect for 10 years on investments already made, and royalty changes should only be implemented on new wells[14].
- The lower price of natural gas alongside a change in environmental regulations is encouraging the switch from coal to gas for power generation in the U.S. Coal-to-gas switching for power generation would create additional demand for natural gas. To date, the majority of coal plant retirements have been aging units, not heavily utilized. In the U.S., the extent to which the displacement of modern efficient coal plants equipped with emissions controls by gas plants would depend on the price competitiveness of gas compared to coal. The timing of further displacement in power generation will depend on mandated timelines in government legislation, demand for power generation, and relative prices of gas and coal.

14 Alberta At A Crossroads: Royalty Review Advisory Panel Report – January 2016.

Analysis and Outlook

Canadian natural gas drilling activity decreased significantly in 2015 (Table 3.1) due to lower prices, major slashes to capital expenditures, and a difficult economic environment. Drilling costs are expected to continue declining slightly throughout 2016, as producers find remaining efficiencies. Increased deliverability from the U.S. continues to depress gas prices, rendering some western Canadian natural gas prospects uneconomic to pursue.

Three price cases for Canadian natural gas deliverability are examined in this report. These cases differ primarily in terms of Canadian and U.S. natural gas prices and the rate at which Canadian gas is backed out of key markets by lower cost U.S. supply. The Appendices contain a detailed description of the assumptions used for projecting deliverability.

A summary of the key assumptions used in the cases and their respective deliverability results are shown in Table 3.1.

TABLE 3.1

Pricing Overview and Deliverability Results

		Mid-Range Price Case			Higher Price Case			Lower Price Case		
	2015	**2016**	**2017**	**2018**	**2016**	**2017**	**2018**	**2016**	**2017**	**2018**
Henry Hub (HH) Average Spot Price (US$/MMBtu)	$2.68 [a]	$2.50	$2.75	$3.00	$3.00	$3.40	$4.00	$2.00	$2.30	$2.50
Alberta Gas Reference Price (C$/GJ)	$2.57 [b]	$2.70	$3.00	$3.25	$3.25	$3.70	$4.10	$2.15	$2.40	$2.60
Natural Gas Drilling Expense ($ Millions)	2 052	2 031	2 198	2 441	2 317	2 807	3 323	1 622	1 754	1 854
Natural Gas Intent Drill Days	20 412	21 249	22 965	24 234	23 614	27 875	31 366	17 424	18 817	19 847
Natural Gas Intent Wells	814	848	919	971	943	1 115	1 257	696	753	795
Canadian Deliverability ($10^6 m^3$/d)	427	425	418	412	428	430	434	420	406	393
Canadian Deliverability (Bcf/d)	15.1	15.0	14.8	14.5	15.1	15.2	15.3	14.8	14.3	13.9

[a] GLJ Publications - average of daily market prices.
[b] GLJ Publications.

For this analysis, the Board divides natural gas production in western Canada into conventional, coalbed methane (CBM), and shale gas, with tight gas included as a sub-category of conventional production. Due to large regional differences in geological and production characteristics, the Board further subdivides these categories into smaller geographic areas, or regions, which have similar characteristics for production decline analysis. Within each region, groupings of the producing formations are made on a geological basis. Details on the characterization of the resources are available in Appendix B. Canadian natural gas production outside of western Canada includes:

- Onshore production from New Brunswick and Ontario, which is declining as minimal future drilling activity is expected over the projection period.
- Nova Scotia production from the offshore Sable Island project and Deep Panuke.

Shale gas potential exists in Quebec, New Brunswick, and Nova Scotia, however, provincial policies currently prohibit hydraulic fracturing which is required for shale gas development. It is assumed these policies do not change over the projection period. Natural gas production from the Mackenzie Delta and elsewhere along the Mackenzie Corridor in the Northwest Territories ceased in 2015 on account of lower prices rendering production uneconomic.

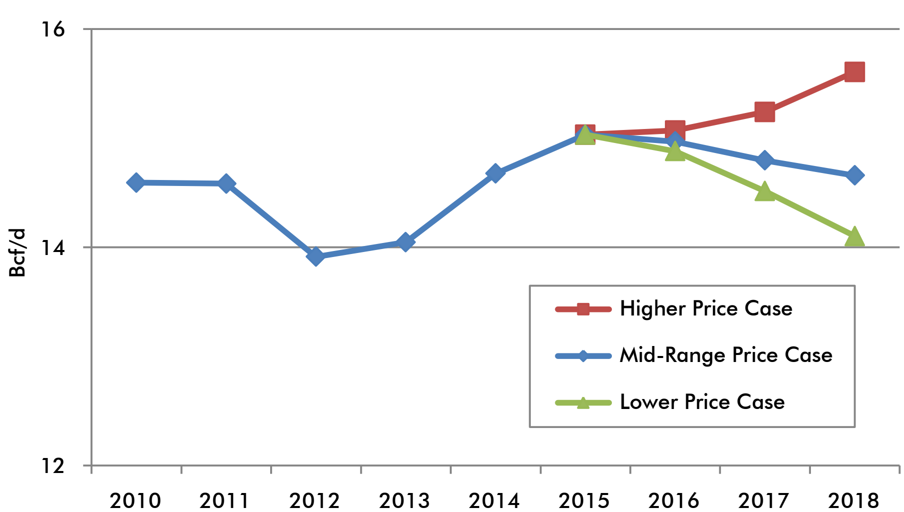
Deliverability Outlooks

- The three price cases cover a range of market conditions: In the Mid-Range Price Case, Canadian gas struggles to maintain market share as low cost U.S. natural gas sources back Canadian supply out of central Canada and the U.S. Midwest market. Deliverability remains relatively flat in 2016 and declines through 2018. By the end of 2018 deliverability declines as newly drilled wells are unable to replace declining production from older wells.
- In the Higher Price Case, U.S. production from the Marcellus and Utica region is needed to support increasing Mexican exports, increasing U.S. LNG exports, additional gas-fired power generation and petrochemical industry requirements, and to offset declines in U.S. natural gas produced from oil wells. These factors increase the opportunity for Canadian gas to flow into key markets. Strong economic growth and U.S. LNG projects finishing ahead of schedule contribute to increased demand over the period. As a result, Canadian deliverability rises throughout the projection period.
- In the Lower Price Case, lower cost Marcellus and Utica shale gas resources further increase their market share in central Canada and the U.S. Midwest, facilitated by new pipeline capacity. Displaced U.S. Rockies supply creates challenges for Canadian gas to access markets on the U.S. West Coast. U.S. LNG exports increase more gradually resulting in increased U.S. gas surplus. Consequently, western Canadian natural gas is further challenged and squeezed out of key markets. Lower prices and reduced market opportunities result in steadily decreasing deliverability over the projection period.

A comparison of the three Canadian natural gas deliverability outlooks to 2018 is shown in Figure 3.1.

FIGURE 3.1

Historical and Projected Natural Gas Deliverability



The levels of drilling activity that support these deliverability estimates are the result of capital investment assumptions and estimated drilling costs. Comparisons of natural gas drilling activity in the three cases in terms of drill days and gas-intent wells drilled are shown in Figure 3.2 and Figure 3.3, respectively.

FIGURE 3.2

Natural Gas-Intent Drilling Days

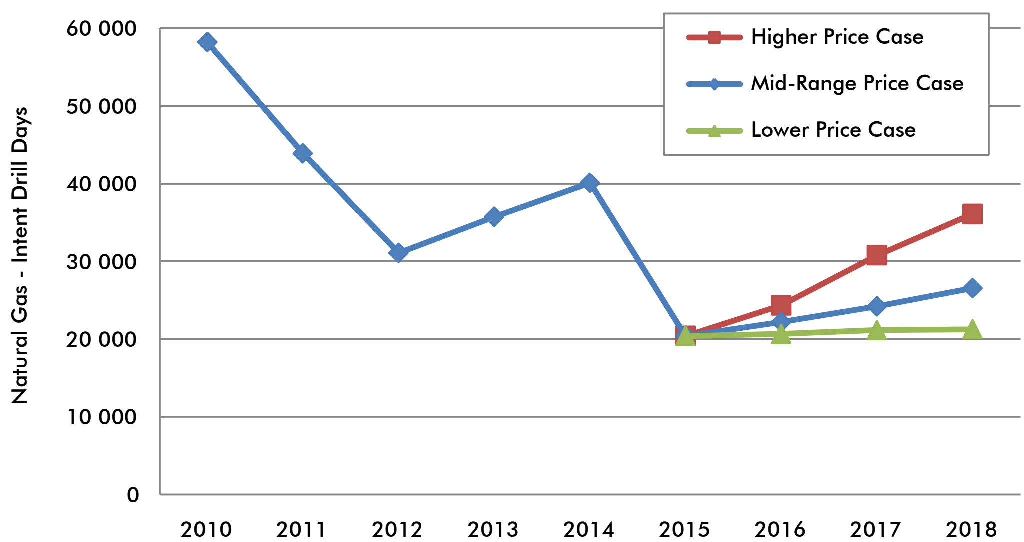
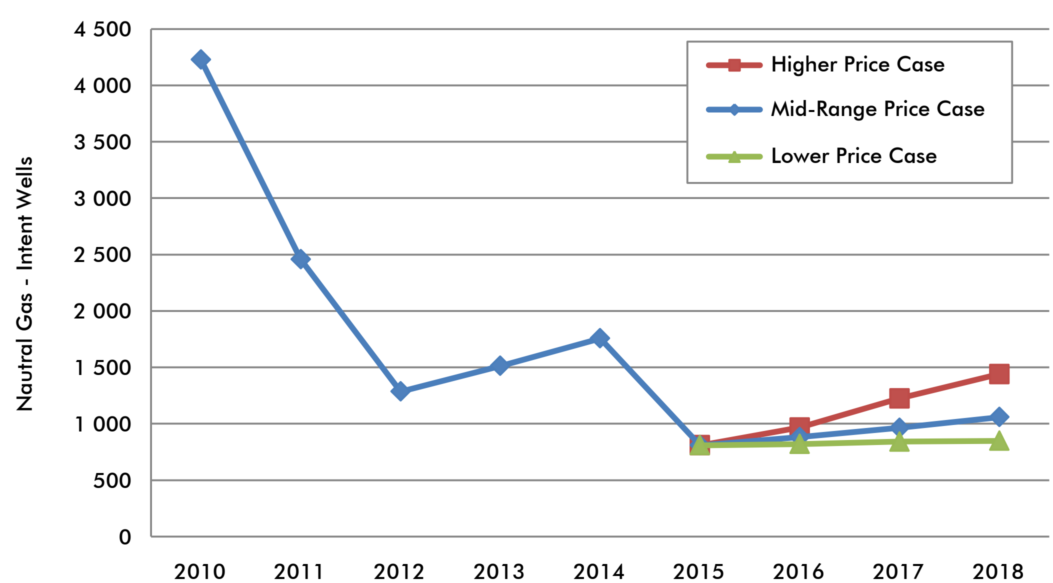


FIGURE 3.3

Natural Gas-Intent Wells



Mid-Range Price Case

Throughout the projection period the Mid-Range Price Case assumes moderate economic growth, weather conditions in line with seasonal averages, continued modest growth in Canadian and U.S. natural gas demand, and on-time completions of U.S. LNG facilities and pipeline infrastructure. Following the warmer-than-average winter of 2015-2016 the North American market remains oversupplied in 2016, both in terms of NGLs and marketable natural gas, resulting in slimmer margins for producers. Following major cuts in 2015, capital expenditures increase slightly over the projection period as pricing conditions improve; however, U.S. natural gas continues to back Canadian supplies out of markets in central Canada and the U.S. Midwest. The outlook for Canadian LNG remains ambiguous with no FID's made before 2017. In spite of additional drilling, Canadian deliverability declines over the projection, as newly drilled wells are unable to fully replace declining production from older wells.

Deliverability Results

In the Mid-Range Price Case, Canadian natural gas deliverability continues to be well above Canadian demand.[15] Canadian deliverability remains relatively flat in 2016 and falls throughout 2017 and 2018 as declines from older wells outpace drilling and production from new wells. Tight gas activity increases over the projection with 700 tight gas wells drilled in western Canada in 2018, including 411 in the Montney tight gas play. The Duvernay Shale play continues to see the most Canadian shale gas activity with 35 wells drilled in 2018. A summary of the Mid-Range Price Case is available in Table 3.2.

TABLE 3.2

Mid-Range Price Case Summary and Results

	Alberta Gas Reference Price	Gas Intent Drill Days	Gas Intent Wells	Average Deliverability	
	C$/GJ			$10^6 m^3/d$	Bcf/d
2015	$2.57[a]	20 412	814	427 [b]	15.1
2016	$2.69	21 249	848	425	15.0
2017	$2.97	22 965	919	418	14.8
2018	$3.25	24 234	971	412	14.5

[a] GLJ Publications.
[b] Annual average of NEB reported provincial production, where available.

Implications

Canadian and U.S. gas markets have been well supplied at historically moderate prices for the past few years. A warmer-than-average winter and elevated storage levels going into 2016 keep prices depressed in the short term. Markets could tighten from reduced capital expenditures, drilling reductions, rising natural gas demand from improved integration of the Mexican market or U.S. LNG projects coming online ahead of schedule.

15 Projections of Canadian demand for natural gas are available in Appendix E.

Higher Price Case

The Higher Price Case assumes a larger recovery for Canadian natural gas deliverability because of higher gas demand from a combination of various factors including: stronger economic growth in the U.S. and Canada, weather that is cooler in the winter and warmer in the summer than average to increase space heating and cooling demand, increased Mexican demand that draws more U.S. gas southward, and U.S. LNG facilities being completed ahead of schedule and heavily utilized. Increased demand boosts prices and results in less displacement of Canadian gas by U.S. supplies. Despite rising natural gas prices, it is assumed that power generators prefer natural gas over coal in specific markets, potentially to meet stricter environmental regulations or to better match variations in the electricity demand profile. It is also assumed that the U.S. petrochemical industry completes a major expansion and increases its use of natural gas and NGLs. Accordingly, Canadian producers are able to obtain capital more easily while continuing to focus drilling efforts on highly productive prospects. A FID in 2016-2017 to proceed with a Canadian LNG export project would accelerate pre-positioning by producers and result in additional Canadian deliverability over the projection period.

Deliverability Results

Canadian natural gas deliverability grows continuously over the projection in the Higher Price Case, increasing from 427 $10^6 m^3$/d (15.1 Bcf/d) in 2015 to 434 $10^6 m^3$/d (15.3 Bcf/d) by 2018. Tight gas production is still the primary source of new production growing from 221 $10^6 m^3$/d (7.8 Bcf/d) in 2015 to 253 $10^6 m^3$/d (8.9 Bcf/d) in 2018. A summary of the Higher Price Case is available in Table 3.3.

TABLE 3.3

Higher Price Case Summary and Results

	Alberta Gas Reference Price	Gas Intent Drill Days	Gas Intent Wells	Average Deliverability	
	C$/GJ			$10^6 m^3$/d	Bcf/d
2015	$2.57 [a]	20,412	814	427 [b]	15.1
2016	$3.24	23,614	943	428	15.1
2017	$3.67	27,875	1,115	430	15.2
2018	$4.13	31,366	1,257	434	15.3

[a] GLJ Publications.

[b] Annual average of NEB reported provincial production, where available.

Implications

Higher prices, increased demand, and improved competitiveness of Canadian gas relative to the U.S. keep deliverability increasing over the projection period. Capital expenditures increase steadily and the supply overhang experienced in the North American market over the past few years diminishes slightly, as harsh weather and U.S. LNG facilities finishing ahead of schedule increase demand and drilling takes place to meet it.

Lower Price Case

In the Lower Price Case, demand for Canadian and U.S. natural gas is assumed to decrease because of warmer winters and cooler summers than average to decrease space heating and cooling demand coupled with more modest economic growth. Other factors include less growth in U.S. exports to Mexico due to slower Mexican demand growth and higher Mexican LNG imports, U.S. LNG facilities not being utilized to maximum capacity, and strong production growth out of the Marcellus and Utica which further displaces Canadian supply. Lower prices reduce revenues, resulting in less capital dedicated to drilling. Canadian producers continue to experience difficulty obtaining debt financing, while private equity investment would occur almost exclusively in the U.S. Canadian natural gas deliverability would remain more than adequate to meet domestic demand. The Lower Price case would also assume no FIDs for Canadian LNG projects are made during the 2016-2018 period.

Deliverability Results

Canadian natural gas deliverability declines in 2016 to 420 $10^6m^3/d$ (14.8 Bcf/d) and falls significantly thereafter reaching 393 $10^6m^3/d$ (13.9 Bcf/d) by 2018. Lower natural gas prices further reduce investment in the sector. A summary of the Lower Price Case is available in Table 3.4.

TABLE 3.4

Lower Price Case Summary and Results

	Alberta Gas Reference Price	Gas Intent Drill Days	Gas Intent Wells	Average Deliverability	
	C$/GJ			$10^6m^3/d$	Bcf/d
2015	$2.57 [a]	20 412	814	427 [b]	15.1
2016	$2.16	17 424	696	420	14.8
2017	$2.42	18 817	753	406	14.3
2018	$2.58	19 847	795	393	13.9

[a] GLJ Publications.
[b] Annual average of NEB reported provincial production, where available.

Implications

Canadian natural gas consumers would benefit from lower natural gas prices in the short term. This case shows the greatest decline in natural gas deliverability which results in intensified competition from U.S. sources of natural gas, as well as a significant reduction in drilling and other gas-related service activities.

Key Differences from Previous Projection

The key difference from the previous deliverability projection, *Short-term Canadian Natural Gas Deliverability Outlook 2015-2017*[16], has been the announcement of major cuts to capital expenditures because of sustained lower commodity prices. Drilling activity in 2015 was significantly lower than the previous year as a result. The warmer-than-average winter of 2015-2016 also reduced natural gas heating demand, keeping storage levels above average going into spring and keeping prices soft.

Commodity prices have been lower for longer than was assumed in the 2015-2017 projection. Producers are adjusting by slashing capital expenditures and operating within available cash flows. In addition to tighter capital constraints, reduced producer creditworthiness has increased the difficulty of obtaining capital. Lower NGL prices due to oversupply are expected to reduce the amount of drilling for liquids-rich natural gas, while low oil prices are expected to reduce oil drilling. Altogether, this has significantly reduced demand in the service sector. Throughout 2015 producers worked with service companies to lower service costs and improve capital efficiency on a per-well basis. Although further improvements are possible, it is unlikely they will be of the same magnitude as in 2014-2015.

The Alberta Reference Price in 2015 was $2.57/GJ, below the $2.85/GJ projected in the 2015-2017 Mid-range Price Case and well below the $3.00/GJ projected in the 2015-2017 Higher Price Case. However, actual production averaged 427 10^6m^3/d (15.1 Bcf/d) in 2015, which was near the Higher Price Case projection of 429 10^6m^3/d (15.1 Bcf/d). Actual production was higher than anticipated in the 2015-17 Mid-range Price Case projection due to improved drilling efficiency and improved initial production from some newly drilled wells.

16 Short-term Canadian Natural Gas Deliverability Outlook 2015-2017.

Recent Issues and Current Trends

Factors that will influence future Canadian natural gas deliverability include:

- The development of a Canadian LNG export market. Canada's LNG future remains uncertain. A FID could increase Canadian natural gas deliverability though the construction of facilities would only occur beyond the projection period. It is likely that a significant portion of natural gas exported as LNG will be produced from corporate reserves devoted to the project. Prior to LNG export project completion, these gas resources will need to be proven by additional drilling and testing, and the resultant production would be sold into the North American market.
- The price spreads between natural gas, oil and NGL. The developing NGL glut and subsequent decrease in NGL prices, along with lower oil prices, may result in reduced NGL and oil-targeted drilling, which produces natural gas as a byproduct. It is possible that reduced gas production from these sources would help to balance markets.
- Coordinated production efforts as a result of acquisitions and the consolidation of smaller North American producers by major companies. Moreover, economies of scale could be achieved by integrating supply chains of major companies, further reducing costs.
- The rate at which Canadian natural gas is displaced from markets in central Canada and the U.S. Additional pipeline capacity from the Marcellus and Utica to the U.S. Midwest will be a key factor affecting markets which have been past supporters of Canadian natural gas.
- The potential for increased future deliverability from the Montney despite lower gas prices. NGL-rich gas from the Montney is some of the lowest cost gas in North America and can be competitive with Marcellus gas in certain markets depending on relative transportation costs and foreign exchange rates.
- Improved economics of North American natural gas production. Technological advancements, efficiency gains, and improved data analytics in drilling and hydraulic fracturing operations have improved production capacity of North American natural gas. Inputs including labour and materials have seen cost rollbacks in response to lower activity levels. Depending on the individual producer, improvements in these economic factors may contribute to increased deliverability.
- The development of oil sands. Natural gas is used as a major fuel source to provide energy for Canadian oil sands projects. Oil sands projects under construction and scheduled to begin production between 2016 and 2018 are generally considered sufficiently advanced to be completed despite lower oil prices. Projects in early stages of planning or development may be postponed until global oil markets become more supportive.
- The pace of coal to gas switching for electricity generation in key markets of Canada and the U.S. This has the potential to increase demand for WCSB natural gas and subsequently increase Canadian deliverability.

LIST OF ACRONYMS

CBM	coalbed methane
EIA	Energy Information Administration
FID	Financial Investment Decision
HH	Henry Hub (U.S. Natural Gas Reference Price)
LNG	liquefied natural gas
NEB	National Energy Board
NGLs	natural gas liquids
USD	United States dollar
WCSB	Western Canada Sedimentary Basin

Units

m^3	= cubic metres
MMcf	= million cubic feet
Bcf	= billion cubic feet
m^3/d	= cubic metres per day
10^6m^3/d	= million cubic metres per day
MMcf/d	= million cubic feet per day
Bcf/d	= billion cubic feet per day
GJ	= gigajoule
MMBtu	= million British Thermal Units

Common Natural Gas Conversion Factors

1 million m^3 (@ 101.325 kPaa and 15° C) = 35.3 MMcf (@ 14.73 psia and 60° F)
1 GJ (Gigajoule) = .95 Mcf (thousand cubic feet) = .95 MMBtu = .95 decatherms

Price Notation

North American natural gas prices are quoted at Henry Hub and given in $US/MMBtu.

Canadian natural gas prices are quoted as the Alberta Gas Reference Price and are listed in $C/GJ.

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Review

Electrical Efficiency of Electrolytic Hydrogen Production

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Common industrial electrolyzers have a nominal hydrogen production efficiency of around 70%. High power dissipation value is the most important drawback of such systems since electric power expense has the largest share in the price of electrolytic hydrogen. The electrical impedance of an electrolysis cell causes a fraction of the applied energy to be wasted as heat while the electric current passes through it. As the prior publications show, many efforts are made to reduce this effect. According to the available literature, several internal and external variables are pointed out to have an influence on the electrical behavior of such cells. This paper provides an insight to these factors in regards to minimize the energy loss of the process of water electrolysis.

Keywords: Water electrolysis, Hydrogen production, Electrical power, Efficiency, power dissipation

1. INTRODUCTION

Electrolytic hydrogen production has been scientifically studied for more than a century [1, 2]. According to the literature, hydrogen has been used by for military, industrial and commercial purposes since late 19th century [3]. Nowadays, electrolytic hydrogen has a share of only 4% [4, 5] in the global production of the most abundant element of the universe [6, 7]. Electricity expense constitutes the largest fraction of hydrogen production costs [9]. High hydrogen production expenses count as the main deficiency of commercial and industrial electrolyzers. Hence electrolytic methods are usually outperformed by other approaches such as steam methane reformation. An electrolyzer is usually subjected to massive current values in order to break the water molecules into oxygen and hydrogen. The reaction equation is noted as below:

$$2H_2O \rightarrow 2H_2 + O_2 \qquad (1)$$

Electrochemical decomposition energy of water is relatively high since water molecules have a stable structure at ambient temperature [8]. Approximately, a minimum voltage of 1.23V is required to be applied to a water molecule at laboratory conditions to break the bonds between hydrogen and oxygen atoms. This voltage is also known as the equilibrium voltage of water. However, much higher voltage levels are used in industrial electrolysis cells. The excess voltage is referred to as the "overpotential" of the process reaction [10]. The overpotential value is affected by different factors, which are going to be discussed in the following sections of this paper.

In addition, by following the Ohm's law (equation 2) the electric power can be calculated as in equation 3.

$$U=RI \qquad (2)$$

$$P=UI \qquad (3)$$

Where U is the electrical potential in volts, I is the electric current in Amperes, R is the electrical resistance in Ohms and P is the electric power in Watts. Obviously, for very large current levels, any slight increase of the cell voltage can cause a drastic raise in the power demand. Moreover, technical data show electrolyzers to usually perform their process under low voltage and high current level conditions.

Massive current densities cause a noticeable value of unwanted ohmic voltage drop between the electrodes. As a result, formation of unwanted electrical power loss and less process efficiency values are inevitable. Many efforts are made in order to force an electrolysis cell to reach a certain current level by applying lower voltage levels to it. Major causes of the overvoltage requirement are introduced and discussed in the following sections of this paper. Moreover, possible modifications are pointed out in order to minimize the unwanted negative effects of each parameter.

2. FACTORS WITH AN INFLUENCE ON ELECTRICAL EFFICIENCY

2.1. Electrolyte quality

Bases and acids are known to change the nonconductive nature of pure water. These compounds have a great reducing effect on the overvoltage value of an electrolyzer [11, 12] due they improve the ionic conductivity aqueous electrolyte compounds. However, the concentration level of acidic and alkali solutions are limited in practice due to the highly corrosive behavior of such materials. A 25% to 30% KOH aqueous solution is reported to have a wide use in electrolyzers [13].

On the other hand, the electrocatalytic performance of water electrolysis cell is known to be limited [14, 15]. This limitation is mainly cause the overall electrical resistance of a cell to rise and will cause the efficiency to fall. Therefore, substitute electrolytes such as ionic liquids have been introduced to improve the conductivity and stability factors of electrolytic baths [16, 17]. de Souza et al. [18] performed a series of experiments on the use of the ionic liquid of 1-butyl-3-methyl–

imidazolium-tetrafluoroborate (BMI.BF4) [19] in water at ambient temperature. The electrode plates of these cases were selected from a number of easily found metals such as carbon steel (CS), Nickel (Ni), Nickel-Molybdenum (Ni-Mo) alloy and Molybdenum (Mo). A maximum efficiency value of 96% was reported for the case of low carbon steel electrodes [20] in 10 vol.% aqueous solution of MBI.MF4. All tests took place at the current density value of 44mA cm^{-2}. The reported efficiency levels of this research are much higher than the average 73% efficiency of common commercial and industrial electrolyzers [21]. However, it should be considered that such electrolyzers usually function at much higher current densities than the mentioned experimental value.

Moreover, any existence of impurities may cause unwanted side reactions in an electrolysis cell [22]. Magnesium, chloride and calcium ions can be named as a few common examples of these impurities. In addition, contaminations can block and passivate the electrode plates and/or separator surfaces [11, 23] and sabotage the inter-electrode mass and electron transfer. The latter-mentioned is another formation cause for the excess ohmic resistance of the electric current path.

2.2. Temperature

Temperature is known to be one of the most effective variables on the electric power demand of an electrolysis cell. Electrolysis process is much more efficient at raised temperatures [20]. The reasons of this behavior can be discussed according to the thermodynamic characteristics of a water molecule, as its splitting reaction potential is known to reduce as the temperature increases. Moreover, ionic conductivity and surface reaction of an electrolyte rise directly with temperature [24]. High temperature water electrolysis requires less energy to reach any given current density in analogy with a low temperature process [25, 26]. As a practical example of the latter, Bailleux [27] tracked the operation of a test hydrogen production plant for two years. Implemented plant technology of this case was much simpler back in early 1980's in contrast with current most recent electrolyzers. The case study plant of this report used a 40%wt potassium hydroxide alkaline solution as an electrolyte to be decomposed under the pressure, current density and temperature range conditions of 20bar, 10kA m^{-2} and 120°C to 160 °C respectively. Data scanners were used to monitor the mentioned parameters as well as the purity of the output gasses in order to determine the unwanted contents of oxygen and hydrogen outlets. The report shows a voltage reduction of 120mV as the temperature was raised from 120°C to 150°C. However, the increased temperature and pressure were mentioned to cause some "stability problems" such as container cracks and gasket leaks.

In more recent experiments, high temperature electrolysis is referred to cases with much higher temperature ranges. As an example of such, we can mention a work of Mingyi et al. [28]. Their tests were conducted for the analysis of the electrochemical behavior and thermodynamic characteristics of a high temperature steam electrolyzer (HTSE). They expressed high temperature water electrolysis to need less energy than conventional low temperature electrolysis processes. More efficient process was observed as a result.

Moreover, they divided the total electrolysis efficiency to three separate and individual factors of: electrical efficiency, electrolysis efficiency and thermal efficiency. They calculated the share of each parameter to be 70%, 22% and 8% respectively from the total efficiency. According to their discussion, increased cell temperature leads to a higher thermal and lower electrical efficiency values where the electrolysis efficiency remains without any significant changes. The authors also reported the possibility of coupling the HTSE device with a high temperature gas cooled reactor (HTGR). When the electrolysis temperature was increased to 1000°C, an overall efficiency of the process of 59% was recorded which was remarkably higher than the 33% initial value. The process efficiency was stated to be more than twice of those of the conventional low temperature electrolyzers of the time.

In addition, Ganley [29] studied the process efficiency of high temperature/ high pressure electrolyte solutions (steam state). The experiments were carried out in a chemical resistant container since the sample electrolyte was a highly concentrated KOH solution heated up to 400 °C. During the studies, the electrolyte was subjected to different values of compression during the experimental work. The electrolyte concentration was set at 19 M at the starting phase of each experiment which is highly corrosive to many metals and alloys. Another varying condition of the experimental work was the electrodes material which is the subject of discussion in following sections. Lower voltage level was required to reach any given current density for temperatures between 200 °C and 400 °C. The results show that a voltage level of 1.8 V was enough to cause a current density of 200 mA cm^{-2} at 200 °C. This value was only 1.5V when the electrolyte was heated up to 400 °C at the same pressure and current density.

As Nagai et al. [30] expressed, heat can reduce the "reversible" potential of water (also known as the equilibrium voltage). This parameter also enlarges the size of the gas bubbles and reduces their rising velocity. The latter-mentioned causes a larger void fraction in the electrolyte and decreases the efficiency as a result. The void fraction is the subject of discussion in section *2.3*.

In another case, Ulleberg [14] developed models for the process. Their thermodynamic and electrochemical models show noticeable cut downs in both over voltage and reversible potential of the heated cells. This expression is also supported by comparing the voltage versus current curves for both cases of low and high temperature electrolysis. They reported remarkably improved efficiency levels to be a resultant of conducting the electrolysis process in high temperatures.

Conducting such processes in drastically high temperature levels on gas state electrolyte is expressed to be more efficient than the low temperature processes although, mechanical, stability and physical properties of such systems are still a concern for manufacturers and designers of industrial and commercial electrolyzers.

2.3. Pressure

Appleby et al. [31] tried to lower the costs of hydrogen production by creating higher current density conditions in conventional electrolyzers According to their research, high pressure electrolytes will consume less power in the process of electrolytic decomposition. The main reason was stated to be the shrinking effect of pressure on the gas bubbles which cause the ohmic voltage drop and power dissipation to reduce. Moreover, high pressure electrolysis has less power demand for the phase of product compression. These experiments were conducted in a typical three compartment electrolyzer with a varying temperature between 25°C and 90°C. Cell current density was kept at 1 mA cm^{-2} with an electrolyte of either a 34%wt or 25%wt KOH solution in distilled water. The electrodes were chosen from pure platinum (99.99%) and smooth nickel (Ni 200) plates with a 1 cm^2 surface area. Authors noted an overall voltage drop of up to 100mV when the conversion process was conducted at a pressure level of under 30 atm. No significant further voltage drop was recorded at higher pressure values (up to 40 atm). The cell voltage vs pressure graph has its highest reduction slope when the pressure was raised from 1atm to 10atm despite of the process temperature.

Referring to a similar work, Onda et al. [32] calculated the energy consumption of compressing a liquid electrolyte to be much less than those of gas state hydrogen compression. These calculations were based on the results of an earlier research of LeRoy et al. [33]. They estimated the ideal temperature and pressure conditions for electrolytic hydrogen production to be around 70 MPa and 250 °C relatively. High temperature and intense pressure will change both Gibbs energy and enthalpy levels of an electrolysis process. Hence, lower voltage level will be required as the temperature rises in high pressures and vice versa. However, in pressure levels higher than 20MPa, they found the voltage rise to be negligible. This behavior became more sensible at lower temperatures. Finally, an electrolysis efficiency enhancement of 5% was observed. Another 50% of energy was saved at the compression phase of high pressure electrolytic hydrogen production.

2.4. Electrical resistance of the electrolyte

Electrical resistance of an object is an evaluation of its opposition to the passage of electric current. The level of this force is proportional to the cross section area and the length of the current path and the material resistivity of the conducting material. The relationship between the mentioned variables is shown in equation 4 as bellow.

$$R = \frac{\rho\, l}{A} \qquad (4)$$

Where A is the cross section area, ρ is the material resistivity, R is the electrical resistance, and l is the length of the current path. Inside and electrolysis cell, electrons start their travel from the surface of an electrode, move through the electrolyte and end their journey at the surface of the other electrode. We can assume the path as an object with the same length as the distance between electrodes, the cross section of the area of electrodes overlap and an equivalent resistivity value. The equivalent resistivity consists of different variables such as the electrodes resistivity, electrical admittance of the electrolyte and the reaction between electrodes surfaces and electrolyte. Hence, the equivalent resistivity is a function of the following variables:

2.4.1. Space between the electrodes

According to equation 4, by reducing the distance between electrodes, lower electrical resistance can be obtained. However, the question may occur that how much proximity of electrode plates is practically possible?

Nagai et al. [30] carried out a series of experiments to find the optimum space between electrodes. They examined the effects of the void fracture between electrodes which is caused by the formation of gas bubbles.

These experiments were conducted at ambient pressure with Ni-Cr-Fe alloy electrodes in a 10%wt potassium hydroxide aqueous solution. They varied the current density, system temperature and the distance between electrodes, their size, wettability and inclination. The results clearly depict that placing the electrodes too close to each other will increase the value of the void fracture and will lead to a less efficient process. This phenomenon became more sensible at high current density levels. By placing the electrodes at different distances and comparing the result values of cell voltage and current, the authors concluded that positioning the electrodes too close to each other will decrease the process efficiency. LeRoy et al. [34] also reported the same effect. They expressed larger electrical resistance of an electrolyte is a result of gas bubbles accumulation in the inter-electrode area. Therefore, this accumulation will cause the process to be less efficient.

2.4.2. Size and alignment of the electrodes

Another variable of equation 4 is the cross section area of an object. Less resistive current path is known to be a result of using electrodes with larger surface areas. Again, in this case, it would be useful to define the term "larger surface area" in more details. This definition will help us to know the practical dimension limits of an electrode plate?

A series of experiments have been conducted in order to test the effects of using electrodes of different sizes on the process efficiency [30]. As the results show, at the same electrode width, larger electrode height will cause additional power dissipation in a cell. The reason was expressed to be the formation of a larger volume of void fraction. The models of gas bubbles movement [35] clearly depict larger amounts of bubble accumulation in higher parts of the electrodes.

These experiments also show that higher efficiency levels can be obtained by placing the electrodes in a vertical position. The latter is caused by reduced ohmic resistance due to the "optimum bubble departure rate".

2.4.3. Forcing the bubbles to leave

Ohmic resistance in an electrolysis bath is related to the bubble coverage of all surfaces since gas bubble accumulation on each surface will reduce its conductivity. Hence, it causes a higher level of ohmic voltage drop [36]. On the other hand, bubbles diameter depends on the current density, temperature and pressure. Pressure value has an inverse correlation with the bubbles size where current density and temperature have an opposite affect it [37]. Moreover, the disengagement rate of gas bubbles from the surfaces and their departure velocity play a significant rule in the value of the electrical resistance of an electrolytic bath. Figure 1 justifies this subject. In this figure, the distance between electrodes *"l"* is broken into *n* smaller segments *"l_i"*. Equation 4 can be used to calculate the resistance for each partial length of l_i. The presence of gas bubbles significantly reduces the efficient cross section area for each l_i. Therefore, it increases the total value of *R*.

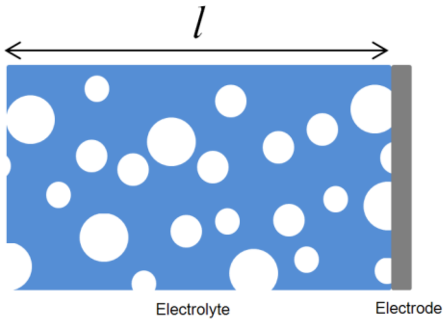

Figure1. The formation of void fraction

Hence, equation 4 could be re-written as bellow:

$$R=\frac{\rho}{A}\left(\sum l_i\right) \qquad (5)$$

Equation 5 and figure 1 depict the effect of void fracture which has been discusses earlier. Many efforts are made to force the bubbles leave the cell environment. As an instance, De Li et al. [38] exposed their experimental electrolysis apparatus to an ultrasonic field in this regard. System efficiency and energy consumption were recorded in both cases of presence and absence of such field. Subjecting the electrolyzer to such fields caused a remarkable cell voltage reduction. The latter was more obvious in the cases of high current density and low electrolyte concentration. An improvement rate of 15% to 18% was observed in high current density experiments. Hence, the authors were able to achieve a maximum energy saving rate of 10% to 25%. Forcing the bubbles to Disengage from electrodes, membrane and electrolyte surface is known to improve the local mass and heat transfer as well as the process efficiency. Power consumption of the ultrasonic generator is expressed to be negligible in contrast with the power demand of the cell itself. A 0.05kW ultrasonic generator provided a field strong enough for a 100kA electrolysis cell. In this case, the field was able to deduct up to 30 kW from the total power demand of the system.

Wang et al. [39] conducted another set of experiments to force the adsorbed gas bubbles on the electrodes and membrane surfaces to detach. They exposed the cell to a super gravity field in this regard. Super gravity condition was simulated by placing the cell in a centrifugal (rotating) installation. In this experiment cell temperature was maintained at 333 °K throughout the process. High gravity acceleration environment is known to increases both velocities of convection flow and inter-phase slip [40]. Therefore, better multiphase separation in gas-liquid and gas-solid phases [41] is a result of subjecting an electrolysis cell to a super-gravity field. Such improved separation leads to easier gas bubble disengagement and faster departure from the electrolyte surface. Lower ohmic loss and over potential are the predicted result of this approach. Wang et al. [39] measured the required level of cell voltage to reach a given current density for different gravity conditions. The results show remarkably lower voltage levels for the cases with higher gravity values. The difference became more significant for increased current densities. Authors reported improved levels of efficiency for the cells which are performing under super gravity conditions. According to this report, a centrifuge installation with a nominal power of 3 kW was able to deduct up to 51 kW from the power demand of a 100 kA industrial electrolyzer.

2.5. Electrode material

A wide range of materials are being used as electrodes. Each metal has a different level of activity, electrical resistance and corrosion resistivity. Platinum and gold are known to be two of the best choices for being used as electrodes. However, high prices limit their usage in industrial and commercial electrolyzers. Aluminum, Nickel, Raney nickel and cobalt are the most common electrode materials for being used in alkaline electrolytic baths. This popularity is the result of their satisfactory price range, corrosion resistance and chemical stability [21].

Appleby et al. [31] conducted a set of experiments by utilizing different electrodes such as 99.99% pure Ni, Pt, Ir and Rh as well as Ni cloth, Ni sinter, Ni-Cd and low impregnation Nickel and cobalt molybdate catalyst on nickel sinter. Each electrode was pre-anodized in order to obtain stable potential characteristics. The results express nickel to show more desirable potential characteristics among the mentioned materials. In addition, authors found woven or porous sintered electrodes to be 30 times more active those with a smooth surface. Larger electrode surface area causes an “Apparent exchange current density”. The latter is known to be the main reason of the excess observed activity.

There is a wide range of variations in the value of electrode-electrolyte activity for different materials. For example, platinum electrodes show higher activity levels in contact with KOH aqueous solutions in comparison with molybdenum plates. Literature show utilization of 1-butyl-3-methylimidazole tetrafluoroborate (BMI.BF4) ionic liquid will lead to exceptional efficiency levels for almost all electrode plates [18].

2.6. Separator material

Placing a separator plate in a cell, blocks the free movement of mass and ions to some extent. Moreover, the presence of such barrier increases the void fracture by further accumulating of gas bubbles in the electrolyte [30]. In addition, the effective electrical resistance of a separator plate is frequently calculated to be as large as three to five times of those of the electrolyte solutions [42].

Electrical resistance of a separator depends on different variables such as corrosion, temperature and pressure [43]. Back in middle 1990’s many scientists named asbestos to be the best choice for being used as a diaphragm due to its highly wettable and porous structure. These features cause a plate to show electrical resistance in practice [44] . However, asbestos is known to be a toxic and hazardous material [44-47]. These characteristics caused the researchers to start looking for substitute materials. Nowadays there are different materials and technologies available to reduce the negative electrical effect of separators [45, 46, 48-50].

2.7. Applied voltage waveform

It is almost common for electrolysis systems to use a steady (Figure 2a) or smooth (Figure 2b) DC voltage to decompose an electrolyte.

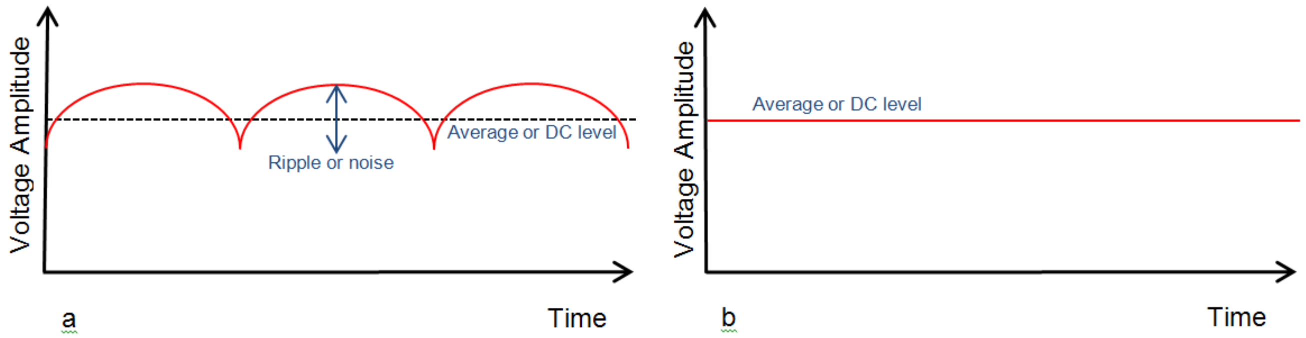

Figure 2. (a) Steady DC voltage waveform. (b) Smooth DC voltage waveforms

Accoring to the Ohm's law, applied DC voltage *U* causes the current *I* to pass through the electrolyte with the resistance of *R* (refer equation 2). Hence, the common method of current or current density regulation is by the application of a certain voltage to a cell. Shimizu et al. [51] conducted their experiment to test the behavior of a cell while the voltage was applied in the form of ultra short pulses. Their goal was to reach higher cell power (increase the gas production rate) without reducing the efficiency. They placed platinum electrode plates 3 cm apart from each other in a 1M KOH aqueous solution. Electrolyte temperature was maintained to 293 ± 2 °K throughout the experiment. The results were compared for the cases of using a conventional DC, and an ultra-short pulse power supply with an output pulse width of about 300 ns. Output frequency and peak voltage of this power supply were adjustable from 2 kHz to 25 kHz and 7.9 V to 140 V respectively.

In the case of applying ultra-short pulses to an electrolysis cell, there will not be enough time for formation of stable double-layers or diffusion-layers. A formation period of 3 µs is known to be required by the authors for diffusion-layers. Moreover, a pulse width of 3 ns is also much less than the time requirement of formation of a stable double-layer which is known to be not larger than several hundred milliseconds. A sample waveform of applied ultra short pulse is illustrated in figure 3.

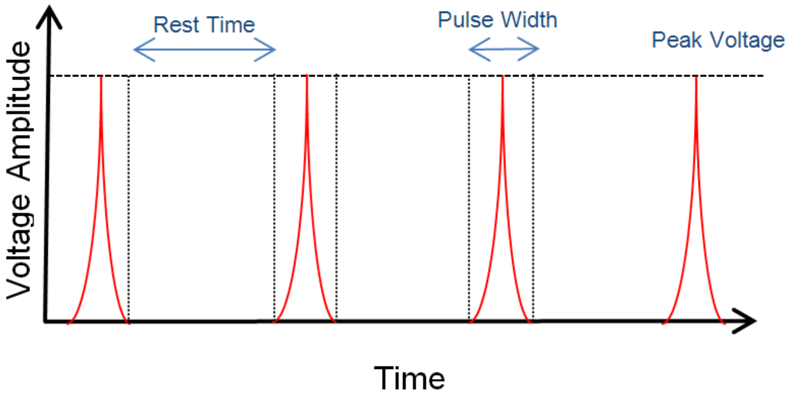

Figure 3. Ultra short pulse waveform

The production rate versus input power graph deviated more from the ideal graph as the input power was increased when the cell was subjected to a pure DC voltage. In addition, the efficiency was reduced significantly. As the authors mentioned, applying 0.25 Watts of power to the cell caused the process to be five times more efficient than the case with a consumption level of 250 Watts.

Regarding to the literature, the utilization of an ultra-short pulse generator provided the possibility of subjecting the cell to higher power levels without causing any further energy loss. The latter is achievable if the power is regulated by adjusting the peak pulse voltage levels. Moreover, raised pulse frequency can deliver extra power to the cell without causing any significant effect on the efficiency. The authors mentioned a lower electron energy level caused by sharper pulse waveforms to be the reason of this behavior.

However, the authors did not provide much information about any possible relation between the peak voltage and frequency regarding the process efficiency. Hence, we believe conducting further researches in this regard might lead to very interesting results.

In another related research, Ursua et al. [52] characterized a commercial electrolyzer unit. The apparatus was able to handle the maximum electrical current and temperature values of up to 120 A and 65 °C respectively. Two different types of voltage regulators were used to deliver the required energy to the system. Their objective was to analyze the behavior, efficiency and power consumption of the system with each power supply.

The first voltage regulator was thyristor based. These regulators adjust their output voltage level by the means of controlling the switching times of a semiconductor device. The semiconductor switch is connected to the AC power line in series. This topology works at the same frequency of the input power line which is either 50Hz or 60Hz (varies by regional standards). Results show the cell to have a non-continues voltage and current waveform. Furthermore, an undesirable distribution of current harmonics was detected in the output waveform. A maximum efficiency of 70.9% could be achieved for this case.

The tests were repeated with a transistor based power supply. This topology works at a much higher frequency (up to 100 kHz). In this case, the time ratio of "conducting" to "cut-off ratio" of a rapidly switching power transistor determines the amount of energy passing through the power supply unit. The load voltage or current is regulated as a result of this action where they usually have an almost pure DC wave form. In addition, the output harmonics of such units are negligible in contrast with those of thyristor based devices. A maximum efficiency rate of 77.6% was observed for the case of using the latter-described power supply. The results of this experimental work show a 10% more efficient conversion process by using a transistor based power regulator.

Unfortunately, experiments on the pure electrical characteristic of electrolysis process are very rare to find. Electrical variables are very common for measuring the electrochemical characteristics of electrolytic baths. However, we believe more study is required to analyze the behavior of such cells as a pure electrical load in order to develop more reliable equivalent circuits.

We should mention that the available equivalent circuits for electrochemical systems usually contain a few non-electrical components such as faradic impedances which are not easily analyzed by electrical approaches. Brad [53], and Armstrong and Henderson [54] Introduced very similar equivalent circuits for an electrolysis cell. These circuits consider the electrical impedance of the electrolysis system to be in a non-linear form. Existence of capacitive and faradic elements is the reason of such consideration. Moreover, it is more common to conduct the electrolysis process by applying a pure DC waveform to the cell which is suitable to test linear impedances and ohmic loads. Therefore, according to the mentioned equivalent circuits, the effect of applying other forms of voltage might lead to interesting and important findings.

3. CONCLUSION

This study provides information about the physical, chemical and electrical propertied of water electrolysis cells with a view on their effects on the efficiency of the process. The possible modifications can be done on a cell in order to minimize its electrical power dissipation.

a. High temperature and pressure processes are more efficient. These parameters can be raised as much as the physical strength of the apparatus allows.

b. Utilization of highly concentrated electrolytes will lead to less impedance values. On the other hand, the use contaminated solutions cause side reactions to take place in the cell and will reduce the lifespan of the apparatus.

c. Placing the electrodes in an absolutely vertical position at a certain distance from each other will reduce the ohmic resistance between them. Moreover, the utilization of metals with high degrees of activity and porous materials will enhance electric and ionic conductivity of the system.

d. Forcing gas bubbles to detach from the electrode and separator surfaces and to leave the system will decrease the void fraction. Lower impedance and higher efficiency levels will be achieved as a result.

e. Selecting the electrodes of larger sizes is an important factor for to enlarge their overlap surface area and therefor the current path. However, since gas bubbles will accumulate in higher altitudes of the cell, certain considerations are recommended to limit the height of the electrode plates.

f. Since the equivalent circuit of a water electrolysis cell contains non-linear elements, more research is required to study the best method of power application to a cell.

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Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues

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Definitions

atm	atmosphere
CCS	carbon capture and storage
DTI	Directed Technologies, Inc.
EHS	electrochemical hydrogen separation
FERC	Federal Energy Regulatory Commission
GTI	Gas Technology Institute
HDS	hydro-desulfurization
IEA	International Energy Agency
IMP	Integrity Management Program
IMT	Integrity Management Tool
in.	inch, inches
ISQ	Instituto de Soldadura e Qualidade
m	meter
NREL	National Renewable Energy Laboratory
PBI	polybenzimidazole
Pd	palladium
PE	polyethylene
PEM	proton exchange membrane
PHMSA	Pipeline and Hazardous Materials Safety Administration
ppb	parts per billion
ppm	parts per million
ppmv	parts per million by volume
PSA	pressure swing absorption
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gauge
PVC	polyvinyl chloride
SMR	steam methane reforming

Executive Summary

Hydrogen is being pursued as a sustainable energy carrier for fuel cell electric vehicles (FCEVs) and as a means of storing renewable energy at utility scale. Hydrogen can also be used as a fuel in stationary fuel cell systems for buildings, backup power, or distributed generation. Blending hydrogen into the existing natural gas pipeline network has been proposed as a means of increasing the output of renewable energy systems such as large wind farms. If implemented with relatively low concentrations, less than 5%–15% hydrogen by volume, this strategy of storing and delivering renewable energy to markets appears to be viable without significantly increasing risks associated with utilization of the gas blend in end-use devices (such as household appliances), overall public safety, or the durability and integrity of the existing natural gas pipeline network. However, the appropriate blend concentration may vary significantly between pipeline network systems and natural gas compositions and must therefore be assessed on a case-by-case basis. Any introduction of a hydrogen blend concentration would require extensive study, testing, and modifications to existing pipeline monitoring and maintenance practices (e.g., integrity management systems). Additional cost would be incurred as a result, and this cost must be weighed against the benefit of providing a more sustainable and low-carbon gas product to consumers.

Blending hydrogen into natural gas pipeline networks has also been proposed as a means of delivering pure hydrogen to markets, using separation and purification technologies downstream to extract hydrogen from the natural gas blend close to the point of end use. As a hydrogen delivery method, blending can defray the cost of building dedicated hydrogen pipelines or other costly delivery infrastructure during the early market development phase. This hydrogen delivery strategy also incurs additional costs, associated with blending and extraction, as well as modifications to existing pipeline integrity management systems, and these must be weighed against alternative means of bringing more sustainable and low-carbon energy to consumers.

Though the concept of blending hydrogen with natural gas is not new (IGT 1972), the rapid growth in installed wind power capacity and interest in the near-term market readiness of FCEVs has made blending a more tangible consideration within several stakeholder activities (Florisson 2012; GM 2010), including recent agreements on “Power-to-Gas” initiatives with Hydrogenics (2012a; 2012b). Delivering blends of hydrogen and methane (the primary component of natural gas) by pipeline also has a long history, dating back to the origins of today’s natural gas system when manufactured gas produced from coal was first piped during the Gaslight era to streetlamps, commercial buildings, and households in the early and mid-1800s. The manufactured gas products of the time, also referred to as town gas or water gas, typically contained 30%–50% hydrogen, and could be produced from pitch, whale oil, coal or petroleum products (Castaneda 1999; Tarr 2004; Melaina 2012). The use of manufactured gas persisted in the United States into the early 1950s, when the last manufactured gas plant in New York was shut down and natural gas had displaced all major U.S. manufactured gas production facilities. In some urban areas, such as Honolulu, Hawaii, manufactured gas continues to be delivered with significant hydrogen blends and is used in heating and lighting applications as an economic alternative to natural gas (TGC 2012; GM 2010).

This report reviews seven key issues related to blending hydrogen into natural gas pipeline networks, which are described briefly in the following sections. Though these issues are interrelated, they are presented separately for the sake of clarifying explanation:

1. Benefits of blending
2. Extent of the U.S. natural gas pipeline network
3. Impact on end-use systems
4. Safety
5. Material durability and integrity management
6. Leakage
7. Downstream extraction

The review material presented in this report relies heavily on a study from the Gas Technology Institute (GTI), which is included as Appendix A. While conventional means of producing and delivering hydrogen are relatively well understood, blending as a means of storing or delivering hydrogen is very dependent on specific characteristics of the natural gas pipeline system. The GTI assessment therefore details the implications of hydrogen blending in relation to the distinct characteristics of the U.S. natural gas pipeline system. This report also relies on the extensive studies conducted within the *NaturalHy* project, associated with the Sixth Framework Programme of the European Commission (Florisson 2012), as well as information from a Greenhouse Gas R&D Programme study sponsored by the International Energy Agency (IEA) (Haines et al. 2003).

Benefits of Blending

Adding hydrogen to natural gas can significantly reduce greenhouse gas emissions if the hydrogen is produced from low-carbon energy sources such as biomass, solar, wind, nuclear, or fossil resources with carbon capture and storage (CCS). Any social or environmental benefits associated with sustainable hydrogen pathways could arguably be attributed to natural gas with a hydrogen blend component in proportion to the hydrogen concentration. In the downstream extraction pathway, use of hydrogen in FCEVs improves air quality by reducing sulfur dioxide, oxides of nitrogen, and particulate emissions and displacing conventional gasoline or diesel fuels. The blending benefit would be similar, in some respects, to the introduction of biogas into the natural gas pipeline as a means of providing a renewable natural gas product to consumers. Conceivably, a credit trading system could apply to natural gas with a specified blend content of renewable hydrogen, paralleling the renewable energy credit system used in the electricity sector. If properly crafted, this credit system could provide an economic incentive for converting otherwise curtailed renewable energy to hydrogen, increasing the energy provided from existing renewable energy production facilities, and enhancing the sustainability of the natural gas supply system. Understanding the techno-economic potential and spatial logistics associated with this type of energy storage and hydrogen delivery system would require additional analysis. Recent efforts to develop such a system in Germany will provide useful empirical data to understand better the potential to apply renewable credits to hydrogen and natural gas blends (Wilson 2012; E.ON 2011).

Extent of the U.S. Natural Gas Pipeline Network

The U.S. natural gas pipeline system has evolved from local manufactured gas networks serving municipalities in the mid-1800s to a vast network of interconnected pipeline systems comprising 2.44 million miles of pipe, 400 underground storage facilities, and 1,400 compressor stations. Natural gas accounted for 24.6 quads of U.S. energy consumption in 2010, roughly 25% of total energy consumed. Moreover, recent increased domestic production rates suggest that the existing natural gas system will continue to provide relatively clean and domestic energy for some time, especially with increased adoption of energy efficiency measures (EIA 2012). Given these characteristics, hydrogen blending could become a widespread, long-term, and integral practice to supplement a critical domestic energy infrastructure.

Impact on End-Use Systems

Several studies have discussed the issue of maximum hydrogen blend levels at which no or minor modifications would be needed for end-use systems, including appliances such as household boilers or stoves and industrial or power generation (Florisson 2010; De Vries 2009; Haeseldonckx 2007; De Vries 2007; Schumra and Klingenberg 2005; Kelly and Hagler 1980). The conditions determining a maximum hydrogen blend level that does not adversely influence appliance operation or safety vary significantly and include the composition of the natural gas, the type of appliance (or engine), and the age of the appliance. The impact of hydrogen blends on industrial facilities must be addressed on a case-by-case basis, and stationary gas engines likely will require changes to control systems (Florisson 2010). Ranges noted as being acceptable generally for end-use systems fall within 5%–20% hydrogen, and most discussions note types of changes, precautions, or costs associated with higher blends. For example, Haines et al. (2003) estimate the cost of upgrades in the United Kingdom, Netherlands, and France with respect to modifications required for 3%, 12%, and 25% hydrogen blends. Given the inertia behind any required changes to end-user appliances or industrial facilities, hydrogen blending likely would begin at very low concentrations and then increase gradually over time (if warranted) as required modifications for higher concentrations are addressed. As noted by Florisson (2009), end-use requirements are generally the most restrictive conditions on increasing hydrogen blend levels in natural gas. The natural gas composition in a given pipeline is an important consideration (Zachariah-Wolff et al. 2007). Meeting these requirements would often preclude risks posed by safety and material integrity concerns.

Safety

Multiple factors must be taken into consideration to assess the safety concerns associated with blending hydrogen into the existing U.S. natural gas pipeline system. It is difficult to make general claims about safety due to the large number of factors involved; detailed risk assessment results likely will vary from location to location. Because hydrogen has a broader range of conditions under which it will ignite, a main concern is the potential for increased probability of ignition and resulting damage compared to the risk posed by natural gas without a hydrogen blend component. The probability of an incident and the consequence of the incident are combined into an overall risk factor. In the literature reviewed, these risk factors have been assessed for hydrogen blends of various concentrations (e.g., 20%, 25%, and 50%), for different sections of the existing natural gas pipeline system (e.g., distribution mains and service lines), and for different conditions (e.g., contained or uncontained releases). The context for describing safety concerns is therefore the degree to which different types of hazards may increase or decrease risks for different hydrogen concentrations, pipeline types, and failure mode conditions. The risk assessment results described here would not apply to new, dedicated hydrogen pipelines carrying pure hydrogen, and blending risks will vary between natural gas pipeline systems of different types, materials, and ages across the United States.

It is important to place energy-related risks into perspective. All large-scale energy systems—including nuclear, fossil fuel and renewable energy systems—present different types of risks to human health and the environment (Schneider 1979; Holdren et al. 1979). The overall risks posed by the existing natural gas pipeline system can be quantified, and these results are used as a baseline for comparing risks associated with hydrogen blends. However, in general, natural gas systems pose a lower risk of severe accidents than do other large-scale energy systems such as coal, petroleum, nuclear, and hydropower (the latter two involving less frequent but higher impact accidents), although they appear to pose greater risk than non-hydro renewables such as wind and solar (Hirschberg et al. 2004; Bergherr and Hirschberg 2008; Bergherr et al. 2012; PSI 2012).

The present study reviews new analysis conducted by GTI of various safety hazards with reference to a numerical risk assessment scale with rankings that range from zero (no significant hazard) to 50 (severe hazard). Within this numerical system, a hazard significance ranking of 10 is described as "minor," 30 is "moderate," and 50 is "severe" (see Appendix A). Though actual rankings may vary based on multiple factors, the general conclusion of the research findings presented here is that adding low concentrations of hydrogen to existing natural gas pipeline systems, at volumes of 20% or less, results in a minor increase in the risk of ignition. Moreover, in instances where natural gas leaks result in explosions, inclusion of 20% or less hydrogen would result in minor increases in the severity of the explosion. Higher concentrations of hydrogen may be acceptable from a safety perspective in transmission lines upstream from distribution lines and city gate metering and pressure regulation stations.

As in any risk assessment, it is important to understand the conditions under which risks are being assessed. The GTI assessment presented here is based upon data specific to the U.S. natural gas supply system. Findings suggest that higher concentrations of hydrogen in distribution mains, up to 50%, present a minor increase in overall risk (including probability and severity). Risks associated with service lines are different because service lines are often found in confined spaces where leaked gas would be more likely to accumulate. If hydrogen concentrations exceed 20% in service lines, the increase in overall risk is more significant than for distribution mains. For both distribution mains and service lines, proper risk management practices, such as the installation of monitoring devices, reduces overall risk. However, adding more than 50% hydrogen to either distribution mains or service lines results in a significant increase in overall risk. Again, these risk results are associated with introducing hydrogen blends into the existing U.S. natural gas pipeline system and do not apply to new, dedicated hydrogen pipelines carrying pure hydrogen, which would be designed and managed differently than the existing natural gas pipeline system.

Material Durability and Integrity Management

The durability of some metal pipes can degrade when they are exposed to hydrogen over long periods, particularly with hydrogen in high concentrations and at high pressures. This effect may be of concern for cases where hydrogen is injected at high concentrations into existing high-pressure natural gas transmission lines. The effect is highly dependent on the type of steel and must be assessed on a case-by-case basis. However, metallic pipes in U.S. distribution systems are primarily made of low-strength steel, typically API 5L A, B, X42, and X46, and these are generally not susceptible to hydrogen-induced embrittlement under normal operating conditions. At the pressures and stress levels occurring in the natural gas distribution system, hydrogen-induced failures are not major integrity concerns for steel pipes. For the other metallic pipes—including ductile iron, cast and wrought iron, and copper pipes—there is no concern of hydrogen damage under general operating conditions in natural gas distribution systems. There is also no major concern about the hydrogen aging effect on polyethylene (PE) or polyvinylchloride (PVC) pipe materials. Most of the elastomeric materials used in distribution systems are also compatible with hydrogen. These topics are reviewed in Appendix A.

Hydrogen blends can influence the accuracy of existing gas meters. The deviation of a gas meter with hydrogen blends varies with the meter design. This deviation was found to be acceptable based on the requirement for recalibration (less than 4%) when a gas mixture containing less than 50% hydrogen is being measured. It is anticipated that meters would not need to be tuned under low hydrogen blend levels (less than 50%) in natural gas (Appendix A). One of the remaining gaps in durability research is the need to study the potential impact of contaminants in hydrogen gas that might be introduced into the network. This would be an issue in cases where the hydrogen production system does not produce pure hydrogen.

In most research programs, the focus of integrity management has been on transmission pipelines because of concerns at high operating pressures, up to 2,000 psi (139 bar), and the pipeline steels that are subject to hydrogen-induced cracking. Hydrogen can be carried by existing natural gas transmission pipelines with only minor adaptations to the current Integrity Management Program (IMP) (Appendix A). The adaptations needed depend on hydrogen concentration and operating conditions of the individual pipelines. These are generally insignificant with concentrations up to 50% hydrogen, but a detailed investigation for every case is mandatory and could result in the upper limitation on hydrogen concentration being reduced (Appendix A).

Natural gas distribution systems are very different from transmission pipelines, and the integrity program for transmission pipelines does not apply to distribution systems. One important difference between distribution systems and transmission pipelines is location with respect to populated areas. The level of hydrogen that is acceptable for transmission pipelines may need to be reassessed for distribution systems in terms of the frequency and severity of fire or explosion in a highly populated area. In addition, the hazards arising from gas leakage in a distribution system may be more severe than in transmission pipelines, especially in a confined service area. The integrity management for distribution systems under hydrogen services may require a leak detector or a monitoring device or sensor. The maintenance costs for distribution systems under hydrogen service likely will increase because these systems will need to be inspected more frequently and likely will require additional leak detection systems. Florisson et al. (2010) outline general conclusions of detailed studies of both durability and integrity issues, and they estimate that modifications to existing integrity management practices may incur an additional 10% cost increase due to hydrogen blends.

Leakage

Hydrogen is more mobile than methane in many polymer materials, including the plastic pipes and elastomeric seals used in natural gas distribution systems. The permeation coefficient of hydrogen is higher through most elastomeric sealing materials than through plastic pipe materials. However, pipes have much larger surface areas than seals, so leaks through plastic pipe walls would account for the majority of gas losses (Appendix A). Permeation rates for hydrogen are about 4 to 5 times faster than for methane in typical polymer pipes used in the U.S. natural gas distribution system. Leakage in steel and ductile iron systems mainly occurs through threads or mechanical joints. Leakage measurements from GTI for steel and ductile iron gas distribution systems (including seals and joints) suggest that the volume leakage rate for hydrogen is about a factor of 3 higher than that for natural gas (Appendix A).

A calculation based on literature data for the permeation coefficient of hydrogen and methane in polyethylene (PE) pipes suggests that most gas loss would occur through the pipe wall, rather than through joints, in distribution mains smaller than 2 in. and operating at 60 psig (5 bar) or higher. Extending this calculation to the larger pipeline network suggests that use of a 20% hydrogen blend within the approximately 415,000 miles of PE pipes in the United States would result in a gas loss of about 43 million ft^3/yr, with about 60% of the losses being hydrogen and 40% being natural gas (Appendix A). Though this estimate of gas loss is almost twice the total gas loss for systems delivering natural gas only, it is still considered economically insignificant. As reference, this theoretical distribution main leakage rate (43 million ft^3/yr) would be 0.0002% of the 24.13 trillion cubic feet of natural gas consumed in 2010 (EIA 2011). Furthermore, this calculation likely overestimates actual gas loss because the permeation coefficient taken from the literature is considered larger than those observed in experiments using pipe under actual operating pressures, especially at lower pressures. In general, hydrogen blends would slightly reduce natural gas leakage due to the higher mobility of hydrogen molecules, resulting in a net reduction in the greenhouse gas impact due to leakage. A calculation for the Dutch pipeline system, based upon experimentally derived permeation coefficients, predicts a gas leakage rate of 0.00005% with a 17% hydrogen blend (Haines at al. 2003). Further investigation and additional empirical data would be necessary to provide more accurate gas loss estimates associated with hydrogen blends.

Though gas loss from service lines is economically negligible, leakage into confined spaces may pose a safety risk. Gas leakage from elastomeric seals at joints in service lines may also increase the risk in confined spaces, and this topic warrants additional risk assessment. Further investigation into specific pipe and seal materials and systems can provide a basis to estimate gas leakage more accurately. This basis can be used to determine whether leakage in confined spaces might present a safety risk over time and the degree to which detection and monitoring devices may be required to manage risks.

Downstream Extraction

Three gas-separation technologies that could be used to extract hydrogen from mixtures in natural gas pipelines have been reviewed: pressure swing adsorption (PSA), membrane separation, and electrochemical hydrogen separation (EHS, or hydrogen pumping). PSA units operating on low hydrogen concentrations, such as 20% mixtures, are feasible. However, these units are sized for the impurities in the gas, so with low hydrogen concentrations, the PSA units become very large. PSA units appear to be economically practical only at pipeline pressure reduction stations (i.e., pressure regulation stations) where the pressure drop is synergistic with hydrogen separation. Without this drop in pressure, uneconomically large amounts of compression energy and compressor capital would be needed to reinject hydrogen-depleted gas back into a pipeline.

Membrane separation technologies work very efficiently with relatively high concentrations of hydrogen, and the purity of the hydrogen product gas can be very high with certain membrane technologies, as they can be designed for high selectivity. Most membrane technology applications recover bulk hydrogen from industrial facilities and do not require high purity levels. Some membrane technologies, however, can realize near 100% pure hydrogen. Dilute hydrogen poses a significant challenge for membrane technology. Recovery of hydrogen with lower concentrations requires a higher pressure differential across the membrane. This means that significant volumes of non-hydrogen gas need to be compressed to high pressures in order for the hydrogen to pass through the membrane. This type of technology may be best suited for high-pressure pipelines (transmission pipelines), where the gas in the pipeline is sufficiently pressurized to allow significant recovery of hydrogen.

Electrochemical separation (also known as hydrogen pumping) is a more elaborate method for bulk hydrogen recovery. Two technologies are currently used: a Nafion-based membrane system and a polybenzimidazole (PBI) system. Nafion-based pumps have been in development longer and are considered more technologically mature, but PBI is more desirable for several reasons. One is the lower compression requirement. For a 1,000-psi pipeline, both the product gas and hydrogen would come out at essentially 1,000 psi (minus specific process pressure drop). However, while pressurization requirements are reduced, system complexity can be higher, and the technology is not as mature as PSA or some membrane technologies. Electrochemical pumping requires water to function, and addition of water involves a humidification system. On the other hand, pipeline gases have to be dry, so a water-removal system is required downstream.

Of the three separation technologies considered, PSA is the most commercially ready. Because PSA is mature and cost information is available, NREL staff estimated the cost of PSA hydrogen extraction assuming conditions for a hydrogen mixture in a distribution natural gas pipeline. Capital cost estimates for the PSA unit are based on quotes and with reference to an N^{th} plant concept, which reflects a mature system that is functionally reliable in the field and has been produced in sufficiently high annual and cumulative quantities to have a capital (and unit) cost approaching the technology's asymptotic lower cost limit. The cost estimate represents a future technology that may be available when hydrogen mixtures can be carried through natural gas pipelines, rather than current PSA technology. This report assesses only the cost of hydrogen extraction. The other costs (injection cost, hydrogen losses along the pipeline, underutilization during lag-in-demand seasons, analytical costs, etc.) are not accounted for here.

For a 10% concentration and 80% recovery factor, the estimated cost of hydrogen extraction by PSA from a 300 psi pipeline is \$3.3–\$8.3/kg hydrogen extracted, for a range of recovery rates of 1,000–100 kg/day. For a 20% concentration and 80% recovery factor, the extraction cost is \$2.0–\$7.4/kg hydrogen extracted, for the same range of recovery rates. These additional supply chain costs are high relative to a competitive hydrogen cost goal of \$2–\$4/kg for FCEV markets (Ruth and Joseck 2011). However, if hydrogen is extracted at a pressure-reduction facility, the high cost of recompressing the natural gas to the original natural gas pipeline pressure can be avoided. The resulting estimated extraction cost for a 10% concentration and 80% recovery factor is \$0.3–\$1.3/kg, with the range resulting from economies of scale for a system size or recovery rate of 1,000–100 kg/day (see Figure 18). These costs per kilogram are reduced by approximately 10% if the hydrogen concentration is increased to 20%. PSA extraction could therefore become a relatively small cost component of the total delivered cost of hydrogen if the extraction is done at a pressure-reduction facility. With major pressure reduction stations often located near large urban areas, downstream extraction could prove to be an economical delivery option. It has been estimated that there are 11,200–14,800 metering and pressure regulating stations with inlet pressures greater than 300 psig in the United States (see section 3.1), and 34,600–56,700 stations with inlet pressures between 100 and 300 psig. Approximately 23%–25% of the stations with inlet pressures greater than 300 psig are contained within vaults, which is typical for stations located near urban or suburban areas. Therefore, it is likely that several thousand high-pressure city gate stations are located in close proximity to large U.S. urban areas where natural gas is transferred from transmission lines to distribution lines, and many of these may be candidates for hydrogen extraction.

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Introduction

Hydrogen can play an important role as an energy carrier in a sustainable, reliable, and cost-effective energy future. This report reviews key issues related to the concept of blending hydrogen into natural gas pipeline networks. Under appropriate conditions and at relatively low hydrogen concentrations, blending may require only minor modifications to the operation and maintenance of the pipeline network. The hydrogen blend component may be carried through to end-user systems, or the hydrogen could be extracted downstream and used in applications such as automotive or stationary fuel cells. In general, based on research to date, only minor issues arise with blends of less than 5%–15% hydrogen (by volume), depending on site-specific conditions and particular natural gas compositions. More significant issues must be addressed for higher blends in the range of 15%–50%, such as conversion of household appliances or an increase in compression capacity along distribution mains serving industrial users. Blends above 50% face more challenging issues across multiple areas, including pipeline materials, safety, and modifications required for end-use appliances or other uses.

Hydrogen blending may prove to be a viable means of increasing the output of renewable energy facilities, such as wind farms, by providing a hydrogen storage and delivery pathway across a broad range of geographic locations. Given the large geographic scope and scale of the existing natural gas infrastructure, even very low blend levels (less than 3%–5%) could absorb very large quantities of otherwise curtailed or uneconomical wind or solar power. Blending renewable hydrogen with natural gas can improve the carbon intensity and sustainability of the final natural gas product delivered to consumers. Though this pathway requires additional analysis and research, and may be limited by site-specific conditions, it appears to be viable in the near term.

Blending may also prove to be a viable means of delivering hydrogen produced in remote locations and extracting the hydrogen downstream near end-use applications, such as FCEVs or stationary fuel cells. Hydrogen pipeline delivery is considered a cost-effective way to move hydrogen from its production location to end users, but only at large volumes and long distances. Moreover, the cost to construct a large-scale, dedicated hydrogen pipeline system is very high, and completion could take decades. Alternative delivery pathways will be employed during the early market growth phase. Some early market pathways, such as tank trucks or onsite production, may endure alongside pipeline delivery in a mature hydrogen infrastructure. If hydrogen blending in natural gas with downstream extraction proves to be economically viable during the early market growth phase, it could prove to be viable in the long term as an additional mode of delivery.

This report reviews seven key and interrelated issues related to hydrogen blending:

1. Benefits of blending
2. Extent of the U.S. natural gas pipeline network
3. Impact on end-use systems
4. Safety
5. Material durability and integrity management
6. Leakage
7. Downstream extraction.

The benefits of hydrogen blending and the extent of the U.S. natural gas pipeline network provide context for the concept of blending and are reviewed in Sections 2 and 3. The next three issues limit the blend fraction that might be found acceptable, in the general order of stringency indicated in Figure 1; actual blend levels that might be found acceptable will be very location and system specific and will depend on a number of factors (Florisson 2009). The impact on existing end-use systems limits the hydrogen blend factor the most and is discussed first (Section 4). Safety is the next most limiting condition (Section 5). Pipeline material durability imposes fewer limitations than end uses or safety but is still an important consideration, especially for high-pressure transmission lines (Section 6). The issue of leakage is addressed in Section 7, and Section 8 discussed methods of extracting hydrogen. A simple cost analysis suggests that extraction at pressure reduction stations is likely to prove more economical than extraction along transmission lines. Though these issues are interrelated, they are presented separately for the sake of clarifying explanation. Section 9 provides a summary and recommendations.

Summary of GTI Subcontract Report to NREL

The Gas Technology Institute (GTI) performed a literature review for NREL and assessed some aspects of blending hydrogen into the existing U.S. natural gas pipeline system. The full GTI report is included here as Appendix A. This review covers the major aspects of blending addressed by the European NaturalHy project (Florisson 2012).[1] GTI also included additional literature sources on material performance in hydrogen environments and provided a scientific basis for assessing the durability and integrity of the existing pipeline infrastructure and potential gas leakage under hydrogen service.

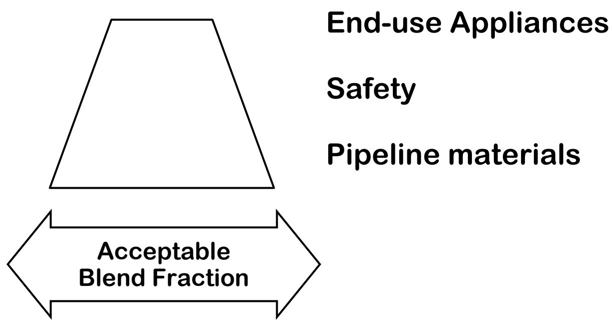


Figure 1. General order of stringency conditions on hydrogen blends for appliances, safety, and material durability (Florisson 2009).

[1] The goal of the NaturalHy Project is to determine the feasible conditions under which hydrogen produced from a centralized production site can be injected into high-pressure transmission pipelines and delivered to end users through distribution networks. The NaturalHy project, which was co-financed by the European Commission through the Sixth Framework Program for research, technology development and demonstration. spanned from 2004 to 2009, (http://www.naturalhy.net/).

Benefits of Blending

Lifecycle Assessment – Literature Review by GTI and NaturalHy

The potential benefits of adding hydrogen to natural gas have been addressed in the "NaturalHy Project-Work Package 1" through life cycle and socio-economic assessment. This study was led by Loughborough University (UK), and participants included COGEN Europe (Belgium)**,** The Energy Research Centre (Netherlands), Instituto de Soldadura e Qualidade (ISQ) (Portugal), Planungsgruppe Energie und Technik GbR (Germany), SAVIKO Consultants Ltd. (Denmark), and Technische Universität Berlin (Germany). The details of this review can be found in Appendix A, Task 4.

In summary, the following are benefits of adding hydrogen to the natural gas network:

- Overall benefits: significant reduction of greenhouse gas emissions if hydrogen is produced from renewable sources.
- Hydrogen in automotive applications: potential benefits from reducing petroleum consumption and improving air quality by reducing sulfur dioxide, oxides of nitrogen, and particulate emissions.
- Greening natural gas: when a hydrogen/natural gas mixture is used in existing appliances for heat and electricity generation. This benefit is similar to increasing the mix of renewable generation on the electricity grid in that it does not require significant changes in end-use equipment.

A better understanding of the cost-benefit tradeoffs for blending in the U.S. natural gas pipeline system, as compared to the European assessment, would require significant additional analysis and investigation.

Renewable Gas Credit Trading Considerations

Renewable natural gas is a very desirable feedstock. In California alone, state incentives for power generation offer $4,500/kW and $2,500/kW for fuel cell systems running on biogas and natural gas, respectively (self-generation incentive program – SGIP). However, California does not require the biogas to be directly used in a fuel cell system, but instead allows credit trading. For example, a water treatment plant that generates methane can choose to clean the methane and inject it in the gas pipeline system, generating certificates for producing renewable natural gas. These certificates can, in turn, be sold to a geographically remote entity that can apply the credits to classifying fossil natural gas as renewable. This entity can then use the gas in a fuel cell and claim credits as if the fuel cell were operating on renewable gas. Renewable methane in such trading is commonly valued at $12–$14/MMBtu (GSE 2011). For example, renewable gas can be purchased by this means from Pacific Gas & Electric. A similar credit trading system is conceivable for renewable hydrogen blended into the natural gas system.

Extent of the U.S. Natural Gas Pipeline Network

This section reviews general characteristics of the U.S. natural gas pipeline network to provide context for the concept of blending hydrogen into natural gas pipelines. Additional analysis would be needed to draw more concrete and detailed conclusions about the technical and economic potential for hydrogen blending with respect to the large amount of information available on pipeline system materials, performance, operation, and regional markets. Advantages of the existing natural gas pipeline network include the following:

- Broad geographic extent
- Interconnectivity
- High capacity
- Well-developed maintenance and control structure
- Well-established safety procedures
- Well-established grid management
- Well-established operational strategies
- Broad public acceptance.

Pipeline Type, Capacity, Miles, Size, and Materials

Four general types of transmission lines are indicated in the supply chain schematic in Figure 2. Gathering lines bring natural gas from various sources to processing plants, typically high-volume and long-distance transmission lines deliver gas to the city gate, and two types of distribution lines—mains and service lines—deliver it to local consumers. Underground storage facilities, typically depleted natural gas caverns or salt domes, and large industrial consumers are connected directly to transmission lines. In terms of supply capacity, the U.S. transmission line system is supplemented by natural gas storage capacity to meet peak demand during the winter heating season, and the distribution pipeline system is sized for this peak demand (EIA 2012).

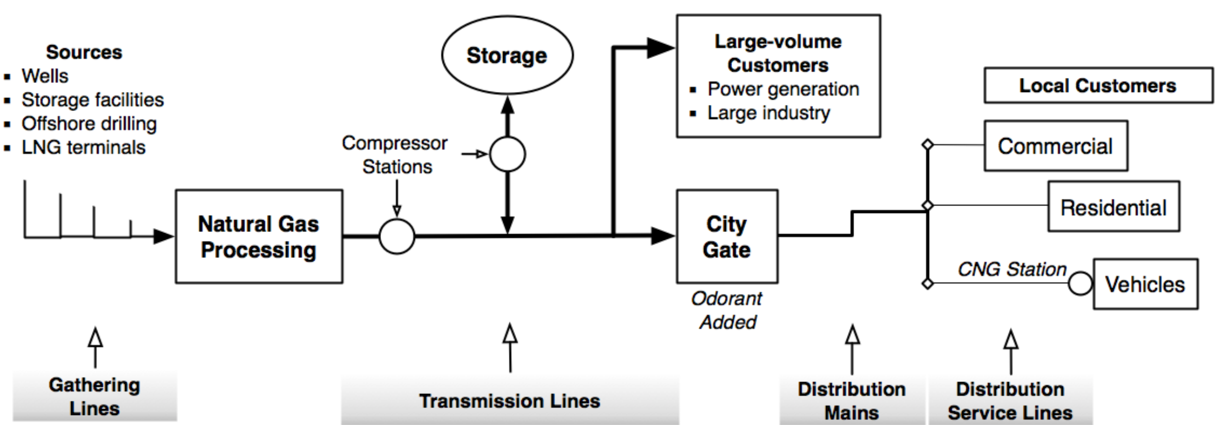


Figure 2. Natural gas supply chain consisting of gathering lines, transmission lines, distribution mains, and distribution service lines.

The annual mileage for each of these pipeline types is shown in Figure 3, with gathering lines and transmission lines changing only slightly and both types of distribution lines experiencing relatively steady growth since 1980. For 2011, the U.S. Department of Transportation reports 1.23 million miles of distribution mains and 0.88 million miles of distribution services lines. In 2011, there were 19,662 and 304,087 miles of gathering and transmission lines, respectively (PHMSA 2012). The network also includes 1,400 compressor stations and 400 underground natural gas storage facilities, most of which are depleted natural gas fields, oil fields, aquifers, and salt caverns (EIA 2012). These elements are indicated in the maps shown in Figures 6, 7, and 8. In 2010, natural gas provided 25% of all energy consumed in the United States (EIA 2011). This extensive infrastructure is a critical component of the U.S. energy system, comparable in scale to electricity and petroleum-based liquid fuels.

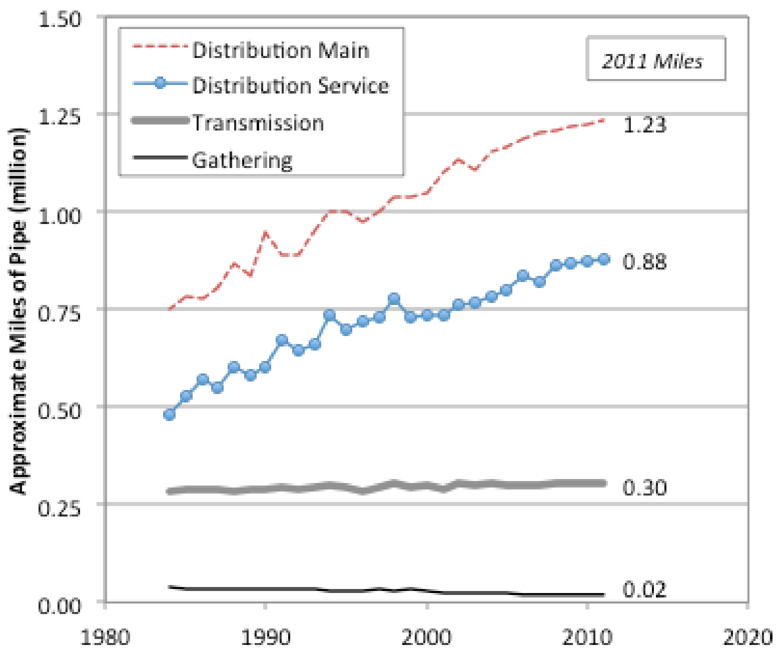


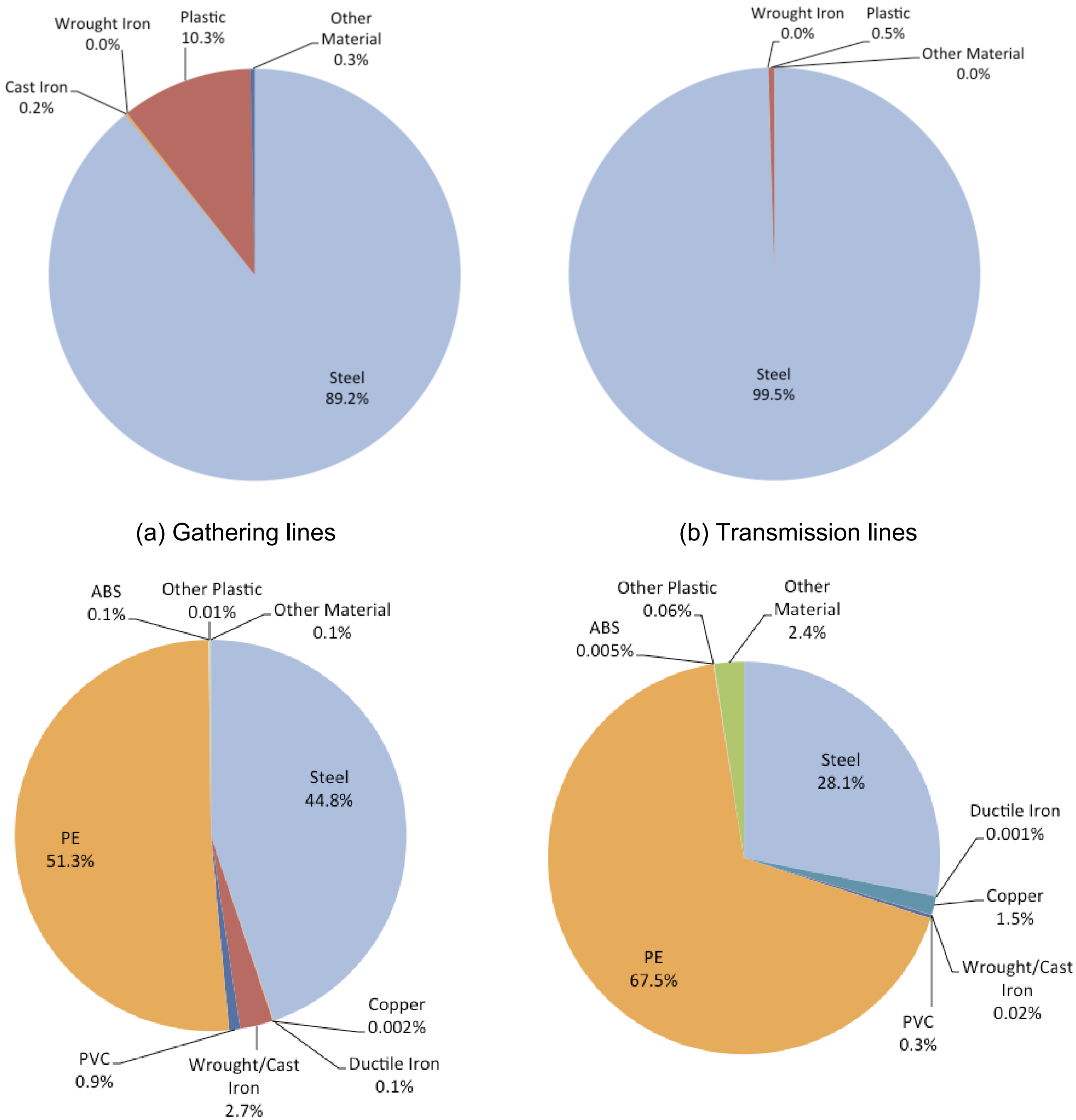
Figure 3. Annual mileage of pipe for four natural gas pipeline types (PHMSA 2012).

City gate stations with metering and pressure regulating equipment are relevant to the concept of blending hydrogen into natural gas pipelines. These stations are located where high-pressure transmission lines transfer gas to distribution systems (also called transmission-to-distribution custody transfer stations) and are therefore candidates for downstream hydrogen extraction. A study conducted by Radian International LLC for the U.S. Environmental Protection Agency and the Gas Research Institute estimated the number of metering and pressure regulating stations, as well as the number of stations with only pressure regulating equipment, in the United States in 1992 based upon data collected from eleven natural gas distribution companies (Campbell and Stapper 1996). The stations were categorized into four types according the inlet pressure (psig): >300, 100–300, 40–100, and <40. Gas pressures in the distribution lines were not specified, but it was noted that stations with inlet pressures less than 300 psig were more typical of stations located downstream from gate stations. This study estimated the total number of U.S. stations using a ratio of the number of stations of each type to the total miles of main distribution lines. Applying these same ratios to the total number of main distribution miles in 2011 results in an estimate of 14,800 stations with inlet pressures greater than 300 psig, and 56,700 stations with inlet pressures between 100 and 300 psig. However, the 2010 Greenhouse Gas Inventory (EPA 2012) estimates the number of stations based upon the ratio of total gas consumption in 2010 and 1992, rather than the station per mile ratios. This approach (Weitz 2012) provides an estimate of 11,200 and 34,600 stations at >300 psig and 100–300 psig, respectively. These estimates may be considered a high and low range on the total number of stations within these pressure inlet categories. Stations with lower inlet pressures, less than 100 psig, are more numerous, ranging from 102,000 to 134,300 stations based upon these two estimation approaches.

Nearly 100% of U.S. transmission pipelines are steel with diameters of 4–48 in. They typically operate at pressures of 600–1,200 psig (42–84 bar) and in some cases up to 2,000 psig (139 bar). Approximately 96% of all onshore and offshore transmission pipelines are steel, wrapped/coated and cathodically protected against corrosion. Details about transmission pipelines can be found in Appendix A. The major U.S. natural gas transportation routes include 11 distinct corridors (Figure 9). The volume of gas delivered is proportional to the width of the routes. Five of them originate in the Southwest (1–5), four deliver natural gas to the United States from Canada (6–9), and the remaining two extend from the Rocky Mountain area (10–11).

Material use in pipelines is indicated by pipeline type in Figure 4. Steel and polyethylene (PE) are the dominant materials (47% and 48%, respectively) in the natural gas distribution system. Main distribution pipes are typically 1.5–8 in. wide and made of either PE (48%) or steel (47%). Distribution service line sizes are typically 0.5–2 in. wide and made of either PE (63%) or steel (33%). Other materials include cast iron and various plastics (see Appendix A). The fraction of miles for all U.S. pipelines (gathering, transmission, and distribution) by material type is indicated in Figure 5. Distribution pipeline pressures are 0.25–60 psig (1.03–5.15 bar) and sometimes up to 100 psig (8 bar). A few distribution pipelines operate at pressures as high as 400 psig (29 bar). Distribution facilities are primarily located in populated areas. Distribution lines do not follow class locations, but most lines fall into Class 3 and Class 4 locations under transmission class location definitions.[2] Distribution piping is frequently located in congested urban areas, typically under paved streets, highways, and other public right-of-ways or utility easements. Additional details about the U.S. natural gas distribution pipelines can be found in Appendix A.

[2] The following are class location definitions from the Code of Federal Regulations (GPO 2011). A "class location unit" is an onshore area that extends 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline. A Class 1 location is: (i) An offshore area; or (ii) Any class location unit that has 10 or fewer buildings intended for human occupancy. A Class 2 location is any class location unit that has more than 10 but fewer than 46 buildings intended for human occupancy. A Class 3 location is: (i) Any class location unit that has 46 or more buildings intended for human occupancy; or (ii) An area where the pipeline lies within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.) A Class 4 location is any class location unit where buildings with four or more stories above ground are prevalent.



(a) Gathering lines

(b) Transmission lines

(c) Distribution mains

(d) Distribution service lines

Figure 4. Pipeline material as a percentage of miles for gathering lines, transmission lines, distribution mains, and distribution service lines (PHMSA 2012).

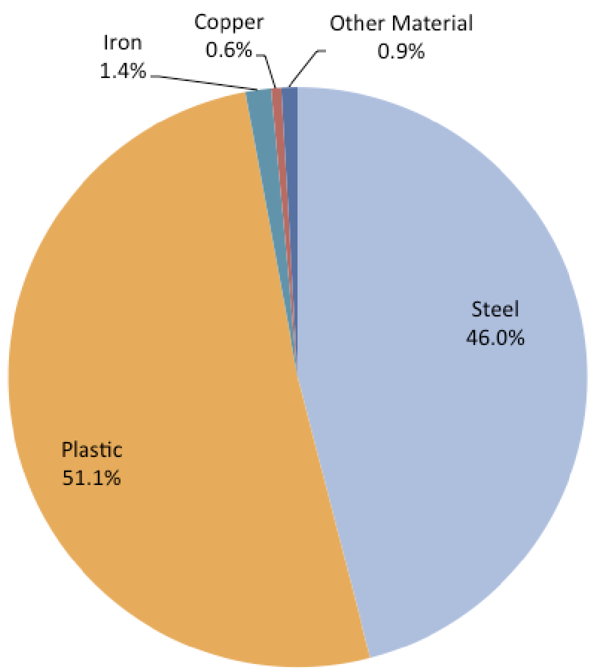


Figure 5. Pipeline material as a percentage of miles of all pipeline types (PHMSA 2012).

Major U.S. Pipeline Corridors

The interstate pipeline grid consists of wide-diameter (20–42 in.), high-capacity pipelines. In 2007, more than 36 trillion ft^3 of natural gas were transported by the interstate pipeline system. Figure 10 shows interstate natural gas supply dependency, particularly designating states that are more than 85% dependent on the interstate pipeline network for their supply. Intrastate natural gas pipelines operate within state borders and link natural gas producers to local markets and to the interstate grid. Intrastate pipelines constitute about 29% of the total miles. Texas and California have the largest intrastate pipeline systems in the nation. Intrastate and interstate pipelines are color coded in Figure 6.

Natural Gas Pipeline Capacity and Utilization

Even though natural gas companies prefer to operate their systems as close to full capacity as possible, the average utilization rate seldom reaches 100% (EIA 2012). Figure 11 shows the interregional natural gas transmission pipeline capacity (2008 data). Utilization rates below 100% do not necessarily entail additional capacity availability, as some companies serve seasonal markets. Exceeding 100% capacity, while remaining within safety limits, is a technique used to temporarily raise pipeline throughput. This is achieved by secondary compression, line packing, or both. Average daily utilization rates also can be increased by integrating storage capacity into natural gas pipeline networks.

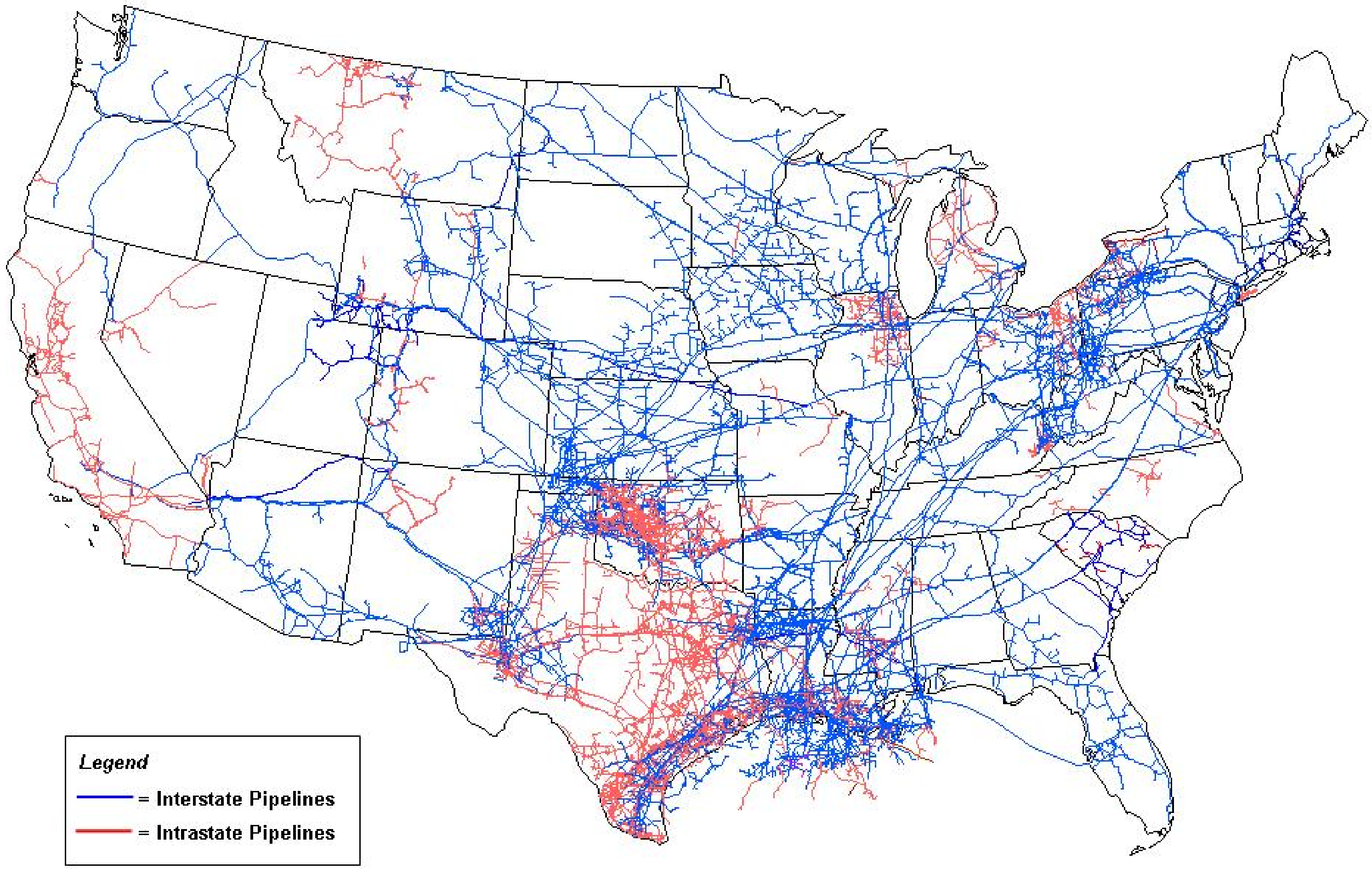


Figure 6. U.S. natural gas pipeline network in 2009 (EIA 2012).
From the U.S. Energy Information Administration (EIA), Office of Oil and Gas Division, Gas Transportation Information System.
The EIA has determined that this informational map does not raise security concerns.

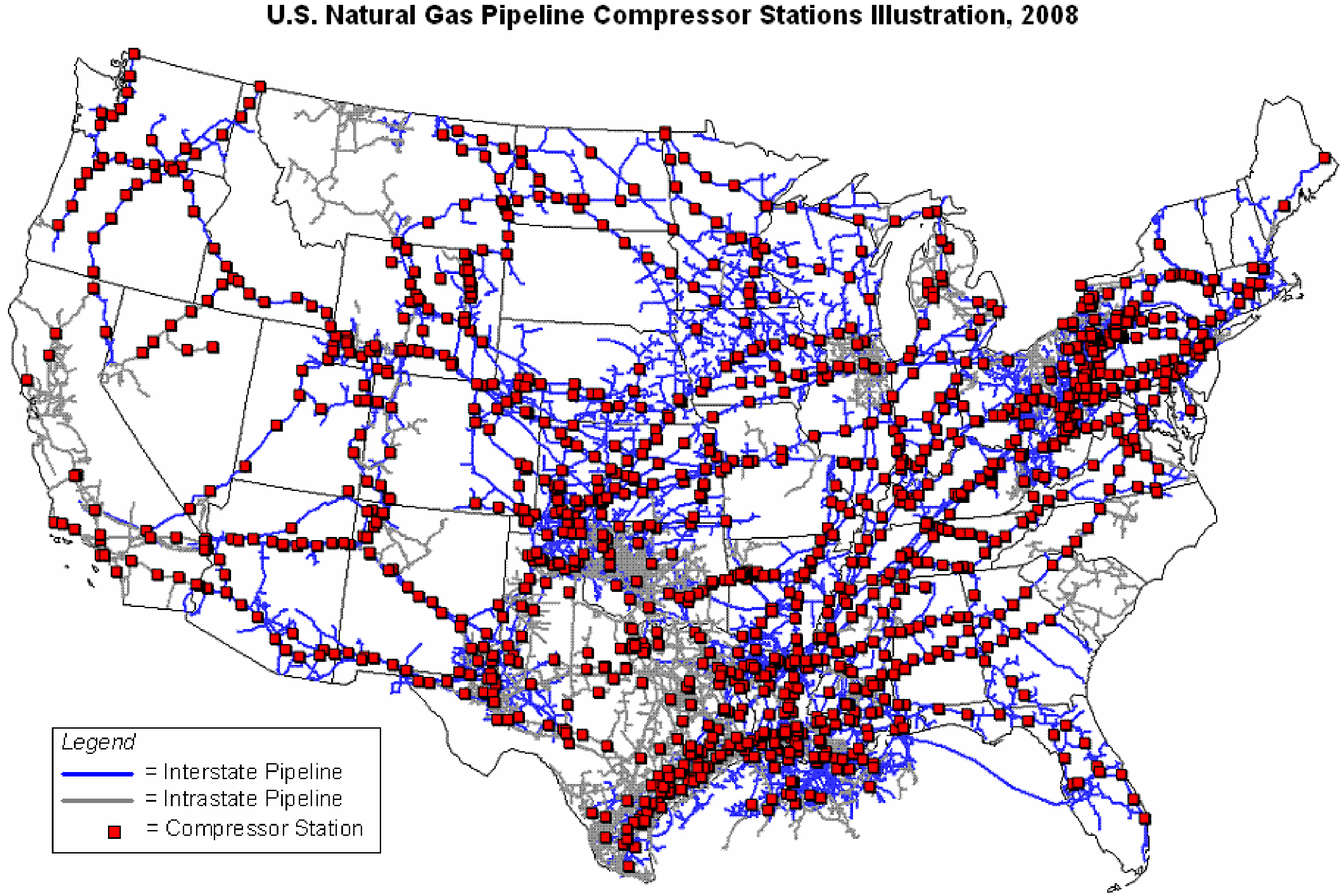


Figure 7. U.S. natural gas pipeline compressor stations illustration (2008) (EIA 2012).

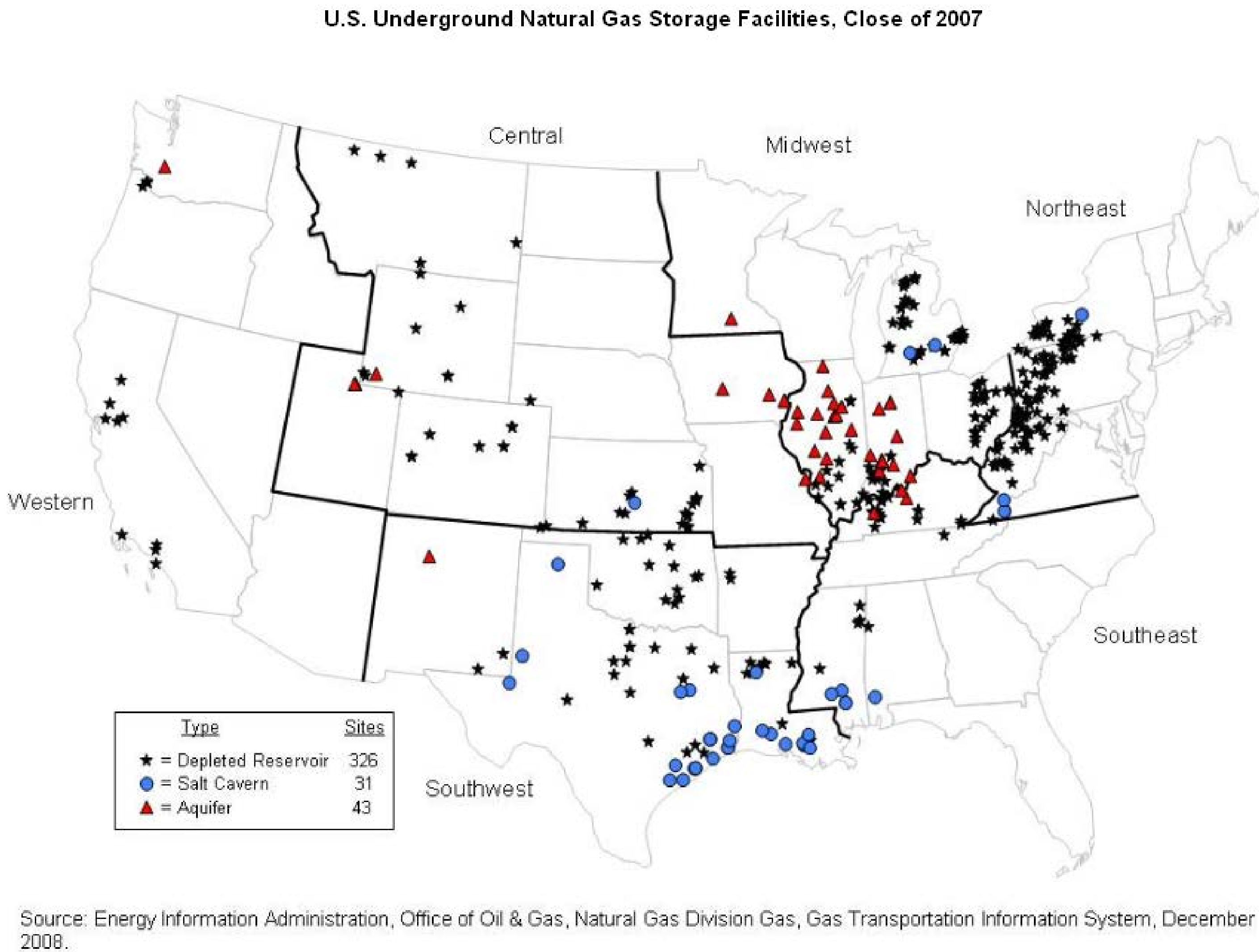


Figure 8. U.S. underground natural gas storage facilities (2007) (EIA 2012).

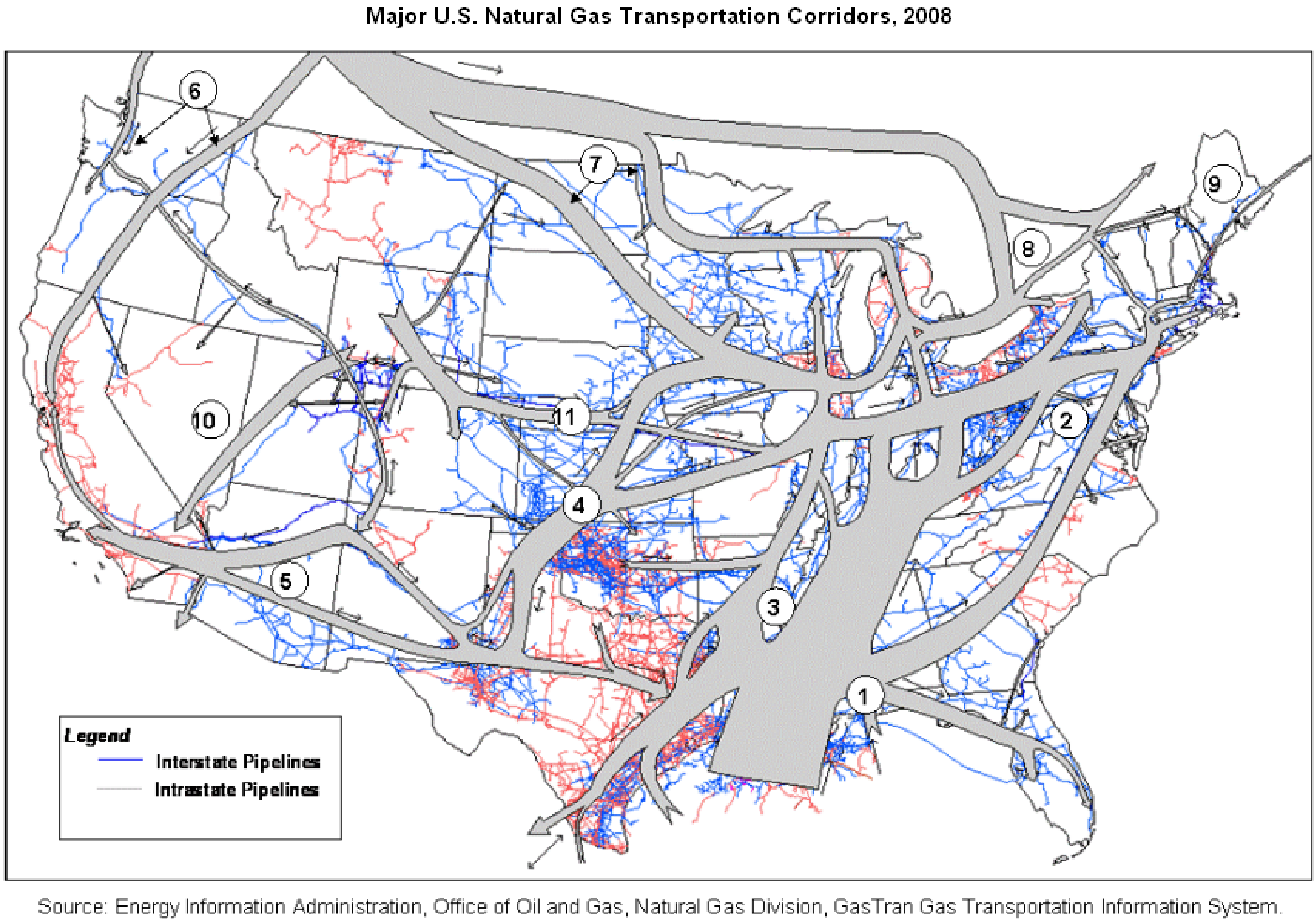


Figure 9. Major U.S. natural gas transportation corridors (2008).
The volume of gas delivered is proportional to the width of the routes. Five routes originate in the Southwest (1–5), four deliver natural gas to the United States from Canada (6–9), and the remaining two extend from the Rocky Mountain area (10–11). Source: EIA 2012.

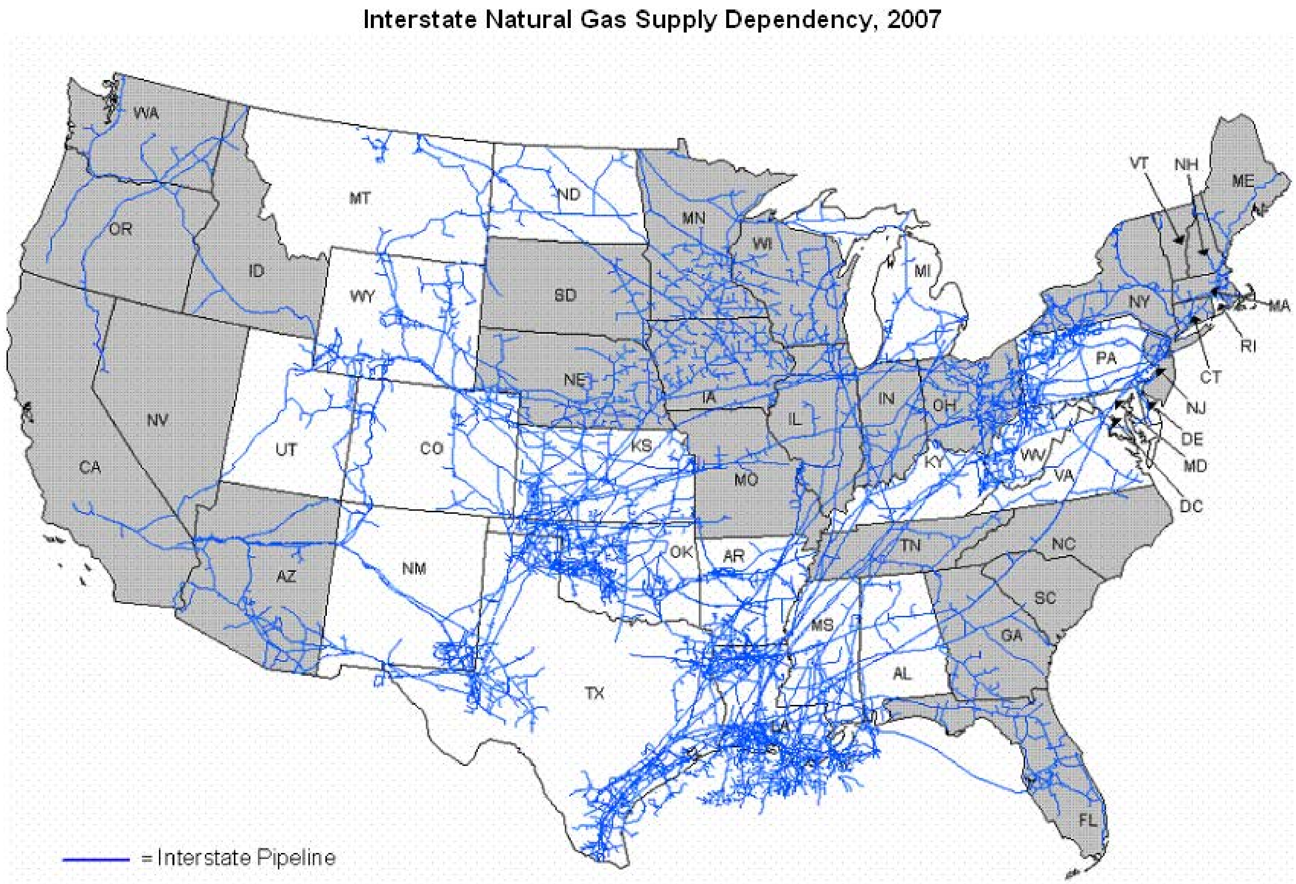


Figure 10. Interstate natural gas supply dependency (2007) (EIA 2012).

States that rely on the interstate delivery system for more than 85% of their natural gas consumption are shown in gray. Note: A state's relative dependence on the interstate natural gas pipeline network for its supplies was determined by the ratio of natural gas consumed within the state in 2007 to the amount of natural gas produced within the state. A state with no natural gas production was 100% dependent on the interstate natural gas pipeline network for its supplies. Source: Energy Information Administration, Form EIA176 "Annual Report of Natural Gas and Supplemental Gas Supply and Disposition" (EIA 2012).

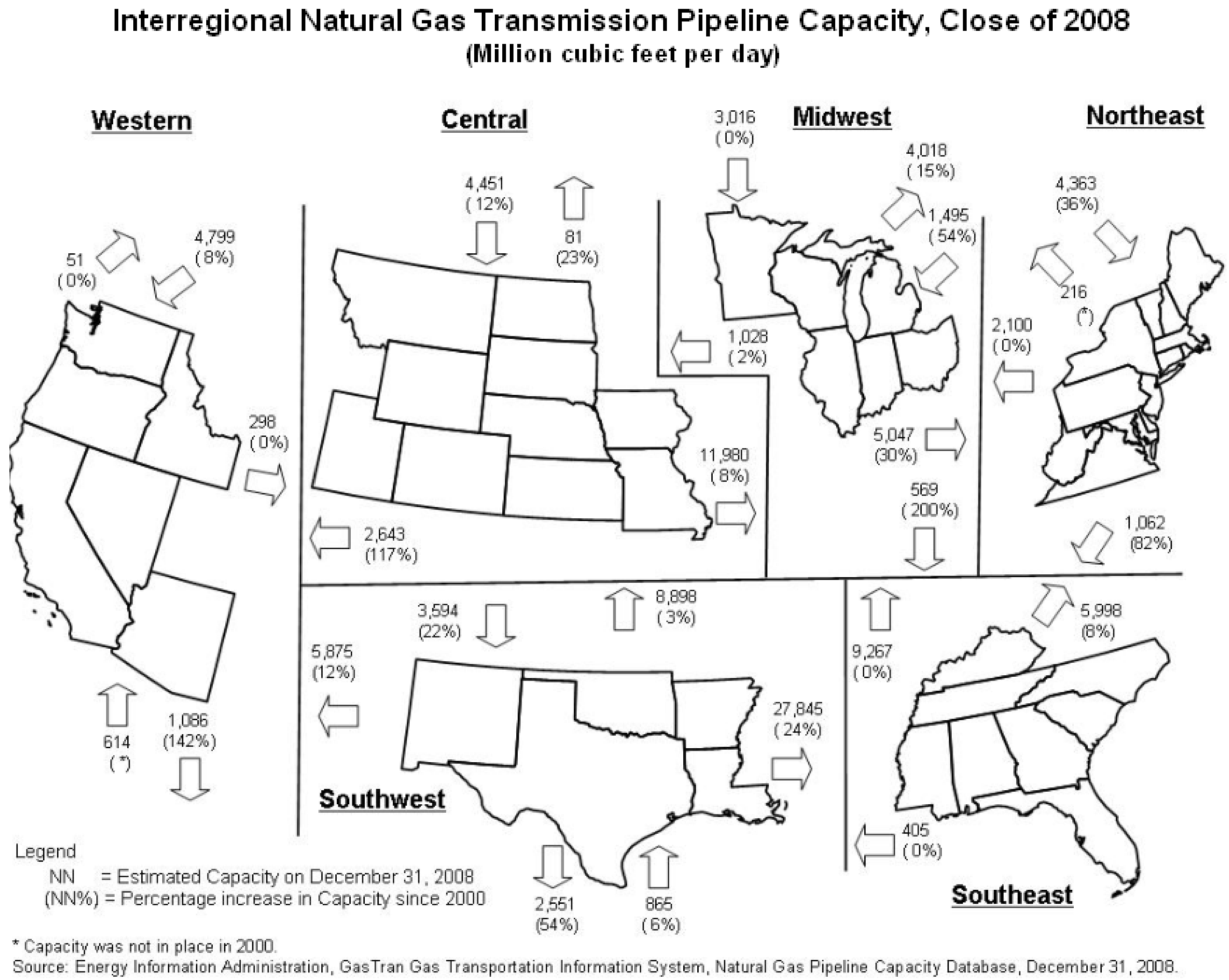


Figure 11. Interregional natural gas transmission pipeline capacity (2008 data) (EIA 2012).

Impact on End-Use Systems

Adaptation of end-use systems is required at higher hydrogen blend levels. NREL reviewed NaturalHy studies on the impacts for the end user that might be caused by adding hydrogen to natural gas pipelines (De Vries 2009). The study included an assessment of maximal hydrogen concentrations that required no or minor appliance adjustments. The study concluded that hydrogen concentrations up to 28% may safely be used with properly serviced existing domestic appliances. Long-term (more than 15 years from now) material compatibility of domestic appliances with hydrogen and natural gas mixtures is uncertain. For poorly adjusted appliances, no hydrogen blends would be acceptable (Florisson 2010). The natural gas composition in a given pipeline is an important consideration (Zachariah-Wolff et al. 2007).

Haines et al. (2003) estimate the cost of upgrades—in the United Kingdom, the Netherlands, and France—with respect to sensor modifications required for a 3% blend ($430,000 to $470,000 for each country) and then the cost of modifying engine controls ($5.6 million in the United Kingdom, $30 million in the Netherlands, and no cost in France), medium-pressure transmission lines ($500–$850 million for each country), and domestic appliances ($170–$470 million for each country) for introduction of a 12% blend.

NaturalHy recommended that the consequences of mixing hydrogen with natural gas for industrial combustion applications be considered case by case. Several restrictions might apply for stationary natural gas engines and modern gas turbines. The preferable operating regime of stationary gas engines does not favor hydrogen concentration variations. These devices will need to be modified or adjusted based on manufacturer specifications. Modern gas turbines have strict fuel specifications. Operation outside of these specifications will require modification or readjustment of control systems with manufacturer permission. Also, unexpected hydrogen concentration variations are unacceptable for gas turbines (Florisson 2010).

Safety

The safety review included publications of the NaturalHy Project (Florisson 2010) and the Greenhouse Gas R&D Programme (Haines at al. 2003) sponsored by the International Energy Agency (IEA). Also, GTI performed a quantitative risk assessment of conveying hydrogen via the current U.S. natural gas distribution system. The details of the review and risk assessment can be found in Appendix A, Task 4.2.

NaturalHy Safety Assessment

The potential risks of transporting hydrogen using the existing natural gas pipeline network have been investigated by "NaturalHy Project in Work Package 2." This work was led by Loughborough University (UK); Leeds University (UK); Commissriat a' l'Energie Atomique (France); Shell Hydrogen; Health and Safety Executive (UK); and National Grid (UK). The NaturalHy Project assessed (through modeling and experimentation) three risks of adding hydrogen to natural gas, which are summarized in the following sections (Lowesmith 2009):

- Gas buildup
- Explosions in enclosures
- Risk from transmission pipelines.

Gas Buildup

The NaturalHy study examined gas buildup behavior in two experimental releases, one in a smaller household room and another in a larger room more typical of a commercial or industrial building. It was found that gas buildup behavior of blends was similar to that of pure natural gas. No separation of hydrogen from the mixture was observed. Increased flow rate resulted in higher gas concentrations, but to a lesser extent than anticipated due to buoyancy-driven ventilation generated by the release. In general, the steady-state concentration following a release is only slightly higher for blends of up to 50% hydrogen, but concentration increases become more significant for hydrogen blends greater than 70% (Florisson 2010; Lowesmith 2009).

Explosions in Enclosures

Compared with explosions of pure natural gas in confined areas, the relative increase in the severity of confined vented explosions was modest for blends with less than 20% hydrogen. A more significant increase in overpressure, and therefore risk or damage, was observed for blends with more than 50% hydrogen. Vapor cloud explosion overpressure can be significantly reduced for higher hydrogen concentrations if ventilation is used or if the structural congestion causing confinement is reduced (Florisson 2010; Lowesmith 2009).

Risk from Transmission Pipelines

Risk here is determined using the following general equation:

> Risk = Frequency of Pipeline Failure × Probability of Ignition × Consequences of the Fire

This risk can be estimated on an individual or societal basis. When defined as an individual risk, the result is the likelihood of a person becoming a fatality in a year. NaturalHy used a risk evaluation model to determine these values. For transmission pipelines, the risk factor was dominated by the rupture of the pipeline (Florisson 2009, p. 24).

Compared to natural gas transmission pipeline explosions, there is a consistent tendency for the severity of the risk with hydrogen mixtures to shift spatially, increasing closer to the point of explosion and decreasing further from the point of explosion. This shift in the spatial extent of risk is increased for higher concentrations of hydrogen, as shown in Figure 12. For the large, high-pressure pipeline represented by results in Figure 12 (914 mm and 70 bar [1,000 psig]), the magnitude of risk to an individual per year declines for hydrogen blends at a distance of 265–400 m and increases closer to the pipeline (0–275 m). The risk associated with explosion of a natural gas pipeline drops to zero at just over 400 m from the pipeline (Figure 12). However, adding 25% hydrogen decreases this distance by about 25 m while slightly increasing risk closer to the pipeline. The important causal factor here is the more rapid dispersion of hydrogen mixtures, which results in lower concentrations at shorter distances and therefore reduced risk at the far edge of the hazard distance. For 50% and 75% mixtures, the hazardous distance is reduced by about 75 m and 100 m, respectively, and the increase in risk closer to the pipeline is more significant. Given this generic risk result for a transmission pipeline, site-specific risks would vary depending on the population density and distribution near the pipeline. As a reference, the area contained within a radius of 280 meters is roughly equal to the area contained between the radii of 280 and 400 meters, which is where the probability of risk is reduced for higher hydrogen blends.

This shift in the spatial extent of risk has been examined for multiple pipeline sizes (Figure 13). The figure compares the risk of explosion for various pipeline diameters with 100% natural gas and a blend of 75% natural gas and 25% hydrogen. The 508-mm pipeline is apparently at a lower pressure than the other pipelines and therefore follows a different trend (Lowesmith 2009). The smaller-diameter pipelines have shorter hazardous distances, and the addition of 25% hydrogen reduces the hazardous distance while slightly increasing risk near the pipeline. This shift is quite small for a 25% blend. As mentioned above, for higher blends and specific pipeline segments, it would become more important to consider population density across the hazard distance to properly interpret the significance of this spatial shift in risk.

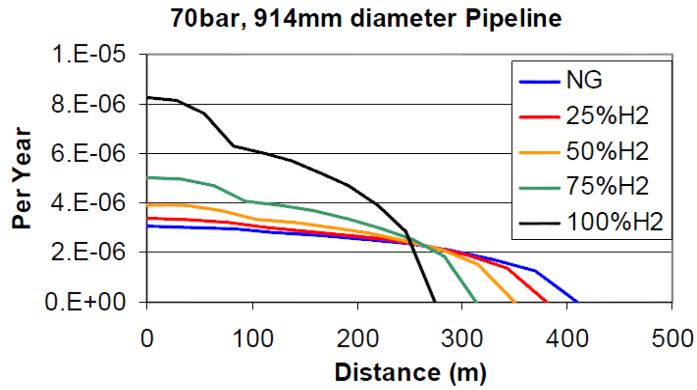


Figure 12. Risk to an individual per year as a function of distance from the pipeline.
Risk shown is individual risk: the likelihood of a person becoming a fatality in a given year. Source: Lowesmith 2009. Displayed with permission.

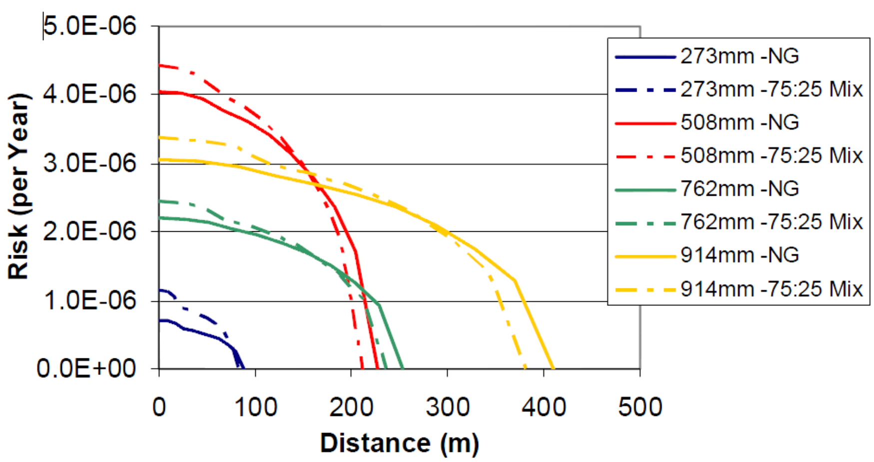


Figure 13. Risk to an individual per year by adding hydrogen to the natural gas pipeline: UK data.
Risk shown is individual risk: the likelihood of a person becoming a fatality in a given year. Source: Lowesmith 2009. Displayed with permission.

Greenhouse Gas Programme Safety Assessment (IEA)

A review of the IEA report on hydrogen blending is provided by Haines et al. (2003). The study focuses on a blend of 25% hydrogen in natural gas and provides a general assessment of hazards associated with a matrix of six causes and six consequences. Notably, compared to the use of natural gas without a hydrogen component, hazards are increased in cases of fire resulting from unburned gas in the air and in the case of burns resulting from the use of gas and open fire in a device or heating appliance. Hazardous phenomena are reduced by blends in four other cases: explosion resulting from unburned gas in air, suffocation due to unburned gas in air, suffocation due to flue gas system (malfunction), and poisoning due to heated media (Haines et al. 2003). Ten other hazards are identified as being unchanged in terms of risk when adding hydrogen to natural gas. Note that the general claim of a reduction in risk posed by explosion due to unburned gas in air is somewhat at odds with the more specific claim of slightly increased overpressure resulting from confined vented explosions with 20% hydrogen blends reported by Lowesmith et al. (2011). This emphasizes the condition-specific nature of risk assessments and the limited degree to which general statements can be used to simplify a complex topic.

Gas Technology Institute Safety Assessment of Distribution Pipelines

Distribution pipeline incidents typically result in a leak instead of a rupture because of their relatively low operating pressures (see Appendix A). According to 2007 data from the U.S. Department of Transportation (PHMSA 13), the following are eight major distribution pipeline failure modes caused by leakage:

- Corrosion
- Material defect
- Natural force
- Excavation damage
- Other outside force
- Equipment malfunction
- Operation
- Other.

GTI assessed the risk aggravation of adding hydrogen at various levels for these failure modes for distribution mains and service pipes. Detailed results are provided in Tables 13 and 14 in Appendix A. In summary, the GTI analysis suggests that adding hydrogen to the natural gas pipeline network increases risk posed by leakage. However, this increase is small for service lines at concentrations of less than 20% hydrogen, and the increase is moderate for distribution mains at less than 50% hydrogen (Appendix A). Again, many different factors influence risk estimates, and actual risks can vary widely from location to location.

Material Durability and Integrity Management

This section briefly notes reviews of pipeline material durability and integrity with the use of hydrogen and natural gas blends. Appendix A provides additional detail. Durability refers to the potential physical and chemical impact of hydrogen on pipeline materials, especially embrittlement of steel, and integrity management refers to the various practices conducted by pipeline operators to inspect, maintain and assess pipeline systems. These topics are discussed in the Executive Summary, and the sections below notes previously conducted reviews.

NaturalHy Studies Review of Durability

Durability was studied in "NaturalHy Project-Work Package 3." This investigation was led by GDF SUEZ (France), with participation by Commissariat à l'Energie Atomique (France), CMI, CSM, DBI Gas (Germany), DEPA, Ecole Nationale des Ingénieurs de Metz (France), Gasunie Technology & Assests (Netherlands), Institut Français du Pétrole, Istanbul Gas Distribution Co. Inc. (Turkey), Instituto de Soldadura e Qualidade (Portugal), StatoilHydro (Norway), TNO Science and Technology (Netherlands), TOTAL (France), and Turkish Scientific and Technical Research Council. The details of this review can be found in Appendix A (Task 4.4).

In addition, the GTI report includes literature sources related to the effect of hydrogen mixtures on pipeline materials and equipment. The details of this review can be found in Appendix A (Task 4.4).

NaturalHy Studies Review of Integrity

The need to upgrade the current IMP for transporting hydrogen and natural gas mixtures was investigated in "NaturalHy Project-Work Package 4." The aim of this project was to provide a specification for an Integrity Management Tool (IMT) that allows the operator to modify the existing IMP for hydrogen service. The cost of the new IMP was also evaluated in this study. This work was led by DBI Gas (Germany), with participation by TNO Science & Industry (Netherlands), Computational Mechanics BEASY (UK), GDF SUEZ (France), PII Ltd. (UK), Istanbul Gas Distribution Co. Inc. (IGDAS), N.V. Nederlandse Gasunie (Netherlands), Instituto de Soldadura e Qualidade (Portugal), Turkish Scientific and Technical Research Council, StatoilHydro (Norway), and TOTAL (France). The details of this review can be found in Appendix A (Task 4.5). Florisson et al. (2010) outline general conclusions of detailed studies of both durability and integrity issues, and they estimate that modifications to existing integrity management practices may incur an additional 10% cost increase due to hydrogen blends.

In the United States, the Pipeline and Hazardous Materials Safety Administration (PHMSA) has implemented integrity management requirements for hazardous liquid and gas transmission pipelines, but no similar requirements currently exist for non-hazardous gas distribution pipelines. In 2009, PHMSA published the final rule effective on February 12, 2010, to establish integrity management requirements for gas distribution pipeline systems. Operators are given until August 2, 2011, to write and implement the integrity program for distribution pipeline systems.

GTI reviewed the natural gas distribution systems and the 14 potential threats to the distribution systems identified by the American Gas Foundation through a survey of utility operators. GTI reevaluated each threat for the conditions under which the systems transport hydrogen and natural gas mixtures. The details of this study can be found in Appendix A (Task 4.5).

Leakage

Hydrogen is a much smaller molecule than methane, so its leakage rate through pipe walls and joints may be greater; it also causes economic and safety concerns because of the total gas loss. Leakage assessments include publications from the NaturalHy Project (Florisson 2012), which focuses on the permeability of plastic pipe materials, including PE and PVC; a report from the IEA Greenhouse Gas R&D Programme (Haines et al. 2003); and other relevant information for gas leakage in the natural gas distribution pipeline under hydrogen services. The details of this review can be found in Appendix A. The following sections summarize the findings.

NaturalHy Pipeline Leakage Assessment

The NaturalHy Project investigated permeation gas loss from plastic pipes in Work Package 3. This work was performed by Gaz de France.

PE80 Pipeline (10% Hydrogen)

The pressures tested were 58, 116, and 174 psig (5, 9, and 13 bar). Table 14 of Appendix A shows the permeation coefficients and gas losses for hydrogen and methane in a mixture of 90% methane and 10% hydrogen. The following are the findings:

- The hydrogen permeation coefficient is four or five times higher than that of methane.
- The permeation rate of methane and hydrogen increases with pressure.
- The aging of pipelines has no apparent significant effect on permeation coefficients.

Polyethylene Disk Samples (20% Hydrogen)

A 20% hydrogen mixture at 58 psig (5 bar) was investigated for leakage (Haines et al. 2003). The leakage rates for methane and hydrogen from this blend under these conditions are 1.1 and 2.3 L/km/day, respectively. For comparison, the permeability of pure methane under similar conditions is 1.4 L/km/day.

Greenhouse Gas Programme Pipeline Leakage Assessment

The IEA Programme performed experimental measurements of the hydrogen permeation coefficient in plastic pipes at 68°F (20°C) (see Table 15 of Appendix A). The hydrogen loss for the Dutch natural gas distribution grid after 17% hydrogen was added is estimated at 0.0005% of the hydrogen transported and therefore was considered insignificant (Haines et al. 2003).

GTI Steel and Ductile Iron Pipe Leakage Assessment

Hydrogen and natural gas leakage in steel or iron pipes primarily occurs through the threads or mechanical joints. The GTI study indicates that the volume leakage rate of hydrogen is three times higher than that of natural gas.

GTI Estimate of Gas Loss in U.S.-Grade Plastic Distribution Pipelines

GTI reviewed U.S. studies on gas loss in plastic distribution pipelines (see Appendix A). The permeation coefficients of hydrogen and methane for the various plastic materials are shown in Table 16 of Appendix A. The hydrogen permeation coefficient in U.S.-grade plastic pipes is five or six times higher than that of methane. GTI performed calculations on gas loss in U.S.-grade plastic pipes for pressures of 60, 3, and 0.25 psig (5.15, 1.22, and 1.03 bar). Results are shown in Table 17 of Appendix A.

Distribution Mains (60 psig [5.15 bar])

Adding 20% hydrogen to natural gas in plastic pipes doubles the total gas loss (77 ft^3/mi/yr). Higher concentrations aggravate this effect.

Service Lines

Service pipelines operate at much lower pressure than distribution mains, so the gas loss is much less significant. For pure natural gas, the gas losses are 2.5 and 0.2 ft^3/mi/yr at 3 and 0.25 psig (1.22 and 1.03 bar), respectively. Even though a 20% hydrogen mixture doubles the gas loss in the service pipeline, it is still economically insignificant.

Downstream Extraction

This section briefly notes the NaturalHy Project's review of using membranes to separate hydrogen from hydrogen and natural gas mixtures. This is followed by a description of technologies used to extract hydrogen from hydrogen and natural gas mixtures and an estimate of the cost of hydrogen extraction.

NaturalHy Membrane Studies Review

The NaturalHy Project focused on developing advanced hydrogen selective membranes for the separation of hydrogen from natural gas/hydrogen mixtures in Work Package 5 (Task 5.3–5.7). This work was led by the University of Oxford, with participation by the Norwegian University of Science and Technology and Compagnie Europeenne des Technologies del'Hydrogene. For details, see the GTI review of the NaturalHy membrane studies in Appendix A (Task 4.6).

Technologies for Extracting Dilute Hydrogen from a Pipeline

The following sections describe hydrogen extraction technologies for hydrogen and natural gas mixtures of 5%–20%. While we are considering the extraction of hydrogen in high purity for transportation, we have to consider that this differs from traditional separations. Most hydrogen today is produced via steam methane reforming (SMR), where natural gas and steam are used to produce a hydrogen-rich stream via the following reaction:

$$\begin{array}{lllllll} CH_4 & + & H_2O & \rightarrow & CO & + & 3H_2 \quad \text{(reforming)} \\ \underline{CO} & \underline{+} & \underline{H_2O} & \underline{\rightarrow} & \underline{CO_2} & \underline{+} & \underline{H_2 \quad \text{(shift)}} \\ CH_4 & + & 2H_2O & \rightarrow & CO_2 & + & 4H_2 \quad \text{(overall)} \end{array} \qquad (1)$$

Pressure Swing Adsorption (PSA)

PSA is a well-established technology. The systems are typically produced in sizes of 50 Nm^3/h–200,000 Nm^3/h. In the above reactions, excess water is used to push the equilibrium to higher hydrogen conversion and discourage side reactions such as coking. The resulting gas mixture is dried by condensing excess steam prior to hydrogen extraction. The dry gas entering the PSA unit has the following approximate composition:

H_2	=	75%
CO_2	=	19%
CO	=	3%
CH_4	=	3%

PSA operates on the adsorption isotherm principle. Every material has a characteristic correlation of surface adsorption of gases versus gas partial pressure. As gas pressure increases, the concentration of adsorbed (immobilized) species on the surface increases. For example, doubling the gas pressure may double the surface concentration of species. In PSA, highly porous packing materials are used. The materials are carefully chosen to adsorb non-hydrogen compounds at elevated pressure (150–300 psig). Multiple materials and layers of packing are typically used, which are tailored to the specific gas composition entering the bed. As reformate gas flows through the packed bed, CO_2, CO, CH_4, and other impurities are retained, while hydrogen passes through the bed. Once the packed bed is saturated, reformate flow is directed to a freshly regenerated bed, and the saturated bed is slated for regeneration. In the regeneration phase, the pressure in the vessel is reduced, thus allowing surface-adsorbed gases to go back in the gas phase. High-purity applications may also utilize hydrogen as a sweep gas to backflow any impurities from the bed. Figure 14 provides a simplified graphical layout of a PSA system.

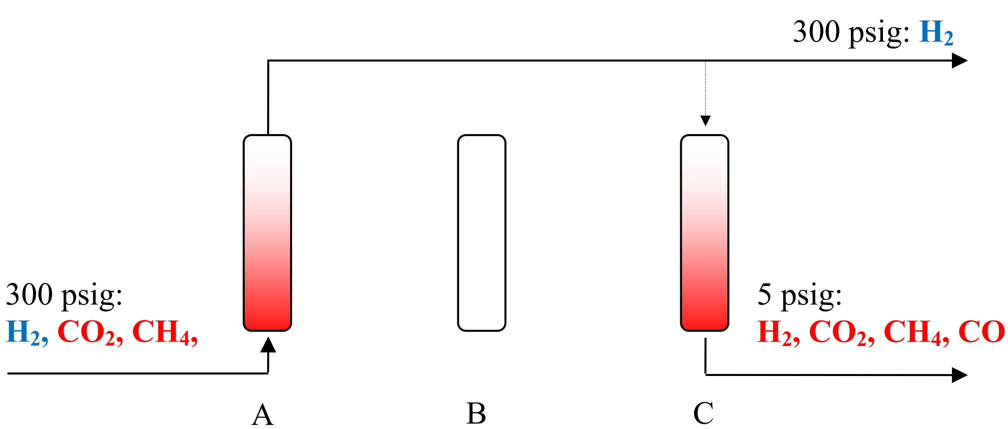


Figure 14. Simplified PSA arrangement.

Notes: Bed A is being actively exposed to reformate. In this bed, all species but H_2 are adsorbed (filtered), and H_2 flows through at high pressure. Once this bed saturates with impurities, flow is directed to a fresh bed (B). Beds are regenerated by reducing the pressure to near-ambient levels and flowing small quantities of product gas to flush impurities.

The cost of PSA units falls into four areas:

- Valving and flow controls
- Vessels
- Packing materials
- Compressors.

PSA technology is the industry standard and works best for high concentrations of hydrogen such as gas streams from conventional SMR production plants, which can be on the order of 75% hydrogen. Many design factors impact a PSA bed embodiment. One important factor to consider is its size vs. level of impurities. The PSA packing layers have two general operating regimes. The upstream portion of the bed is typically saturated with gas during operation and does the bulk of the extraction. The downstream portion of the bed is the fine polishing section of the bed and reduces the concentration of impurities that break through with hydrogen. Thus, the size of the PSA bed is strongly impacted by the concentration of non-hydrogen species entering the bed. For example, if we double the concentration of impurities, a PSA bed would require nearly double the size of the saturation portion of the bed (bulk extraction). The impact is not quite double, as the material saturation point increases for many materials with higher impurity concentration. Additionally, more beds may be required for high concentration impurities. This is due to a higher regeneration period as well as higher temperature swings.

As previously described, PSA units operate by pressure reduction. Gas is provided at high pressure, and impurities are removed at low pressure. In this technology, pressurization of impurities is strictly parasitic as the pressure is not recovered in the regeneration of the bed. As we consider lower concentrations of hydrogen, the concentration of non-hydrogen gas species increases. This means that we would compress larger quantities of gas to recover smaller quantities of hydrogen. For example, in the case of SMR, we would compress approximately 1.3 parts of total gas per 1 part of hydrogen. However, if we consider purification of 10% hydrogen, we would compress 10 parts impurities per 1 part hydrogen. Thus, for equivalent inputs and outputs, our compression work would increase by seven times.

It is notable that typical SMR systems often operate under pressure to avoid bulk gas compression. In such systems, natural gas is taken at pressure from a pipeline, and water is pressurized via liquid pumps (very low auxiliary power). Steam and methane are reacted at pressure to provide high-pressure gas to the PSA units. Hence, the PSA units operate using the pressure of the natural gas pipe and the low pressure of the burner of the SMR unit. This is analogous to conditions found at pressure reduction stations in a natural gas distribution network. In such locations, high pressure gas with potential hydrogen content is present. This gas is taken from transmission pressures as high as 1,000 psig, and pressure is reduced to lower distribution pressures. Gas can be introduced into PSA units at this point for hydrogen extraction, and the beds can be regenerated into the low-pressure distribution lines.

For production of ultra-high-purity hydrogen, the PSA unit can be operated with more frequent cycling of the beds. In such a case, the recovery rate decreases in favor of higher purity product. High-purity hydrogen can also be obtained by a second-stage PSA, which recycles its waste gas to the bulk PSA extraction of via other purification processes such as membrane purification for gas polishing.

Membrane Separation

Membrane technology is another industry-practiced technology for hydrogen extraction and purification. This technology operates on the principle of selective permeation, by which random motion of molecules across a permeable membrane will equilibrate to equivalent partial pressures on each side of the membrane. For example, if one side of a membrane has 50% hydrogen at 1 atm of absolute pressure, and the opposing side has pure hydrogen, the pressure of the opposing side would be 0.5 atm. The equation for this equilibration would thus be:

$$\text{(2)} \quad \begin{array}{c}\text{Side A:}\\ \text{(Total pressure)*(mol fraction)}\end{array} = \begin{array}{c}\text{Side B:}\\ \text{(Total pressure)*(mol fraction)}\end{array}$$

The above equation is for an idealized system, in which the concentrations are equal on both sides. In such a system, the flux is zero, as there is no driving force for gases in either direction across the membrane. To support an appreciable flux, a differential partial pressure of hydrogen would be necessary. For example, the gas pressure of the pure hydrogen side may need to be 0.2 atm, as this would give a driving force of 0.3 atm.

Membrane separation technologies work very efficiently with relatively high hydrogen concentrations. The purity of product gas can be high at very low fractional recovery but monotonically decreases as recovery increases, as the relatively slower co-permeation of impurities proceeds to a greater degree. Most applications using membrane technology industrially recover the bulk hydrogen at 95%–99% purity.

Palladium (Pd) membrane technologies can achieve hydrogen at 99.9999999% purity. At temperatures of approximately 752°F (400°C), Pd efficiently causes hydrogen molecules to dissociate on contact. The resulting protons dissolve into the metal. If the Pd is in the form of a thin membrane and a differential partial pressure is maintained across the membrane, the protons will migrate from the high-pressure side to the low-pressure side, where the protons recombine to form hydrogen atoms. As only hydrogen molecules exhibit this property, extremely pure hydrogen can be obtained from Pd membrane devices.

This technology is employed in the electronics industry to supply hydrogen with a total impurity load in sub-ppb range, and it is being increasingly used in the mobile power market and in renewable fuels research to provide fuel-cell-ready hydrogen from streams of reformate gas.

In practice, the Pd metal is alloyed with another metal to enhance the mechanical strength of the membranes. When copper is included, the resulting membrane can resist degradation by sulfur-bearing compounds at concentrations in the ppm range. Pd micro-channel membrane purifiers would typically be employed in series with a PSA unit and would be used to remove contaminants (for example, CO) that may damage a fuel cell. Pd micro-channel membranes require a hydrogen partial pressure difference to drive the protons through the Pd metal. Typically, a partial pressure of 160–200 psi is optimal (PE 2012).

Dilute hydrogen poses a significant challenge for membrane technology. For example, if 10% hydrogen is fed into a membrane separator, and 70% recovery is being considered, the outlet composition of the gas would be approximately 3%. This means that to support the flux of the outlet elements of the membrane, the pressure ratio would need to be at least 33:1. So, if ambient-pressure hydrogen is recovered, the pressure of the natural gas would need to be at least 33 atm (500 psia). This is, again, an idealized scenario, and a significantly higher ratio than 33:1 would be needed to provide a driving force.

Membrane technology for transmission pipelines may, however, be a good technology fit. Such pipelines often operate at pressures of about 1,000 psig, which provides sufficient driving force for hydrogen extraction. In such systems, the bulk of the process gas retains its pressure, and only a small amount of repressurization would be required to compensate for any device pressure drop.

Electrochemical Hydrogen Separation (Hydrogen Pumping)

Electrochemical Hydrogen Separation (EHS) is a more elaborate method for bulk hydrogen recovery. It operates on principles in common with fuel cell systems, using fuel cell stacks and passing the process gas across one side of the stack. By applying a current across the stack, hydrogen is atomically dissociated from the process gas and is reassociated into hydrogen on the product side. This process operates with very low differential pressure between the process gas and the product gas. Two technologies are used for electrochemical separation: one is based on Nafion and the other on PBI. Nafion is the more mature technology, but PBI is more desirable because the phosphoric acid conditions provide chemical resistance to sulfur contamination and its lower sensitivity to hydration.

PBI membranes require electrical potential to drive substantial current across the stack. As hydrogen concentration differs across the membrane, it needs to be compensated by applying a voltage. Additional voltage is necessary to drive activation, conduction, and diffusion resistances. In the presence of competing adsorption species such as H_2S and CO, the diffusion resistance can increase significantly. This can, however, be balanced with operation at higher temperature (for example, 356°F [180°C]). The power required for EHS is a strong function of the partial pressure of the hydrogen and the total pressure of the product gas. Similar to fuel cell systems, the overpotential required for pumping hydrogen is penalized due to lower hydrogen concentrations. This is exhibited by dilute hydrogen streams requiring higher potentials than concentrated hydrogen streams. Additionally, resistive losses are proportional to the operating current density of the electrochemical separator. At high current density, more resistive losses are experienced. High current density is nevertheless desirable, as the size of the extraction hardware would be smaller and the purity of the resulting gas would be higher. Hydrogen purity is compromised at low current densities due to a constant rate of impurity diffusion across the membrane. At low current density, the diffusion of impurities such as CH_4 would result in a larger fraction in the product. Temperature is another factor of operation. In PBI systems, CO tolerance is accomplished after about 248°F (120°C); beyond that temperature, any CO content of the feed gas degrades performance as a diluent.

EHS systems operating with PBI function with very small differential pressures. High differential pressures are a cause of acid migration in the membrane, which can inactivate the catalytic surfaces of the membrane. However, such a problem is not a major concern when considering high-pressure pipelines such as transmission or distribution pipelines, which are on the order of 500 to 1,000 psig. Hydrogen would be extracted in such systems via EHS to 500 to 1,000 psig. Subsequent gas polishing may be needed, and could be further accomplished with membrane separation as discussed in the previous section. Gas polishing of this type would have a relatively low pressure drop due to the high partial pressure of the feed gas.

Electrochemical processes operating on phosphoric acid or proton exchange membrane (PEM) platforms require water to operate. Phosphoric acid (in PBI) is more tolerant to dry operation, but in the total absence of water it dehydrates to a solid form that is not ionically conductive. PEMs require even more water to operate as the gas needs to be saturated at the operating temperature and pressure. Addition of water involves a humidification system, while pipeline gases have to be dry. Therefore, a water removal system would be necessary. Additionally, the membranes are susceptible to contamination from sulfur and ammonia. Sulfur is always present; ammonia is rarely seen. In cases of natural gas containing ammonia, an upstream gas separator may be required to remove species such as ammonia and sulfur. Of course, sulfur would also be reinjected in the gas downstream to provide odorization. It is also important to consider that PBI will also produce some phosphoric acid vapors (typically in the form of P_2O_5 or P_4O_{10}). These species are highly corrosive and need to be filtered out of the effluent gasses. This species is relatively easily trapped, however, due to its high reactivity.

It is worth noting the additional potential functionality of proton exchange membranes (PEM). While phosphoric acid cannot support more than 2 psi of differential pressure, PEM systems can operate with differential pressure in excess of 1,000 psi. It is well within the state of the art to operate a PEM when pumping hydrogen from about15 psi to 1,000 psi. This can be advantageous with other upstream bulk separations (for example, PBI or a diffusion membrane system). In such a case, a PEM can operate in two functions:

- Electrochemical compressor
- High-purity filter.

Electrochemical compression can be especially valuable at small scales where cost scaling factors for compressors become prohibitive. Unlike compressors, the scaling factor for electrochemical compression is much more linear with size. And because the membrane has few moving parts and avoids fuel cell degradation drivers (catalyst oxidation and contamination), maintenance costs would likely be low.

Sulfur and Constituent Considerations

In all the above technologies, sulfur and odorants would largely need to be removed before the process gas enters the purification equipment, and a scrubbing or hydrodesulfurization (HDS) application would be required. HDS may be the ideal technology, as hydrogen is already present in the feedstock. This technology offers a high density of sulfur capturing and a very low slip rate from the scrubber. Downstream, the gas would need to be reodorized by reinjection of mercaptans. This can be a significant hurdle. Deodorizing gas with 10% hydrogen and 70% recovery would mean that 33 parts of gas would need to be deodorized to recover 1 part of hydrogen gas. It is thus worth investigating in more detail which system type might have higher tolerance for sulfur. For example, the industry-standard HDS process typically operates at 600°F (316°C). This is not practical in a pipeline application. HDS would need a burner, recuperator, and air cooler, with the burner consuming a significant amount of energy. More practical techniques may include metal-doped carbon, damp iron oxide systems, and methyl diethanolamine (MDEA) for large-scale units.

Another major consideration is double-bonded hydrocarbons (ethylene, propylene), which can readily polymerize on many process surfaces and make impermeable coatings. Such components are present in small concentrations in natural gas, and in some pipeline practices (such as propane peak shaving) they can account for more than 1% of the total gas composition. Injection of propane is also likely in case of hydrogen pipelines as heavy hydrocarbons may be used to increase the gas heat content due to it being lowered by hydrogen (Zachariah-Wolff et al. 2007). This is especially challenging for ambient-temperature sulfur-scrubbing technologies, although they are not a significant problem for polymer membranes or PSA.

Oxygen is another constituent sometimes found in pipelines. It is more of an issue downstream from transmission pipelines. For example, gas appliances at high altitudes such as Denver, Colorado, operate more efficiently when premixed with air to compensate for the lower atmospheric oxygen. In this case, air is mixed in at the city gate and would not affect hydrogen transmission along the main line. Oxygen can also be introduced in rare instances such as peak shaving. For example, this is still encountered in areas in the Northeast during peak demands in cold winters. Again, this is typically performed downstream of any transmission line. As both hydrogen and oxygen react instantly on a catalytic surface, EHS would not be able to operate under such conditions. However, oxygen could also be a benefit by reacting with hydrogen to form water on the membrane surface. This water is beneficial as the membrane needs to be hydrated to operate, but is a hazard due to the associated exothermic reaction. As oxygen injection is a rather rare practice, system selection would be a function of local conditions.

Cost Estimate of Hydrogen Extraction from a Distribution Natural Gas Pipeline

NREL performed a cost estimate of hydrogen extraction from a distribution natural gas pipeline employing PSA units. We used Directed Technologies, Inc.'s (DTI) PSA capital cost estimate (DTI 2011) and H2A (DOE 2012) economic assumptions to develop the extraction cost modeling.

DTI's capital cost estimate for PSA units is based on the N^{th} plant concept, which reflects a mature system that is functionally reliable in the field and has been produced in sufficiently high annual and cumulative quantities as to have a capital cost (and unit cost) close to its asymptotic limit. At low manufacturing volumes, capital costs are high due to relatively time-intensive manufacturing and assembly methods. As the manufacturing rate increases, more efficient production methods become economical, capital cost (per unit output) decreases, and unit cost decreases. At extremely high manufacturing rates, all possible cost improvements have been achieved, and production rates are increased only by replicating process machinery. At those levels, capital cost (per unit output) and unit cost flatten in relation to the manufacturing rate.

The N^{th} plant assumption affects the H2A cost computations in two ways. The primary effect is in the estimated value of plant capital cost. The capital cost used in the H2A computation should not pertain to the initial or "one off" cost of a system, but rather to a relatively mature system produced in high volumes. Blended into the capital cost estimate are factors such as bulk discounts on material costs and low-cost manufacturing and assembly methods. These are made possible by serial production of the systems, efficient and streamlined business operations, and a lower profit margin consistent with a mature product that must be priced competitively.

We assess only the cost of hydrogen extraction here. The other costs (injection cost, hydrogen losses along the pipeline, capital cost increase caused by underutilization during lag-in-demand seasons, analytical costs, etc.) are not accounted for here.

The estimated cost of hydrogen extraction by PSA from a 300-psi pipeline is shown in Figure 15. The hydrogen recovery factor from PSA is assumed to be 80%. For a 10% hydrogen concentration, the extraction cost is \$3.3–\$8.3/kg of hydrogen extracted, depending on the scale of extraction or recovery rate in kg/day, as shown in Figure 15. For a 20% hydrogen concentration, the extraction cost across the same scale of extraction drops to \$2.0–\$7.4/kg. The high cost of hydrogen extraction from a natural gas pipeline is largely due to high capital costs. For example, for a 10% hydrogen pipeline, the capital cost contribution to the levelized cost of hydrogen extraction is 61% (Figure 16), 66% of which is the cost of the compressor (Figure 17). Gas pressure at the PSA exit is about 2 atm (30 psi). If hydrogen is extracted from a pipeline at 300 psi, the separated natural gas has to be recompressed back to the pipeline. Due to low concentrations of hydrogen, the amount of natural gas that has to be recompressed is high and requires a large compressor.

High recompression costs can be avoided if hydrogen is extracted at a pressure-reduction facility so natural gas does not need to be recompressed. Pressure differentials can vary between pressure-reduction facilities, but are often significant at the city gate where transmission lines feed into distribution lines. The hydrogen extraction cost for a 10% hydrogen blend under these circumstances is 6 to 11 times lower (\$0.3–\$1.3/kg of hydrogen extracted) depending on the scale of extraction or recovery rate in kg/day, as shown in Figure 18. These extraction costs were modeled for a pressure drop from 300 to 30 psi. Based on this significant cost reduction, it appears that hydrogen extraction from a natural gas distribution pipeline at a pressure-reduction facility will prove to be a lower-cost option, mostly due to the fact that natural gas exiting the PSA unit would require minimal or no recompression.

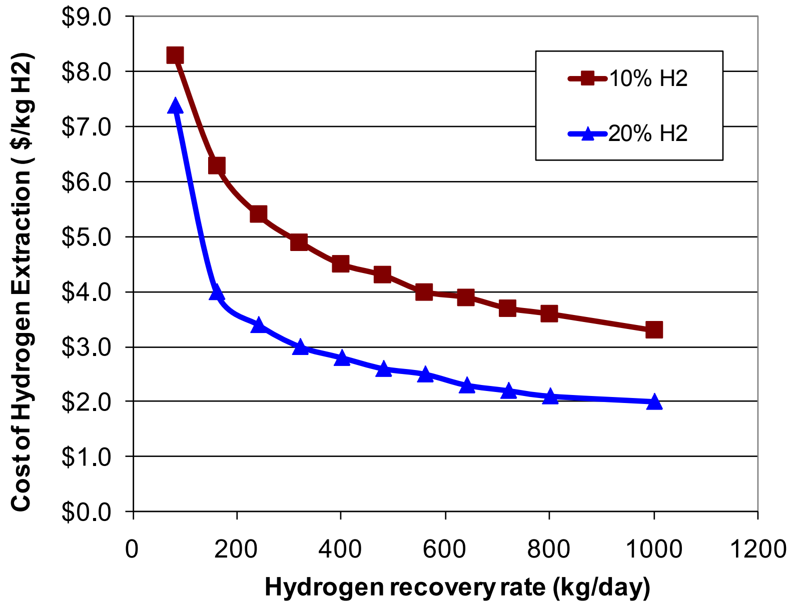


Figure 15. Estimated cost of hydrogen extraction by PSA unit from 300 psi natural gas distribution pipeline (assumed hydrogen recovery factor is 80%).

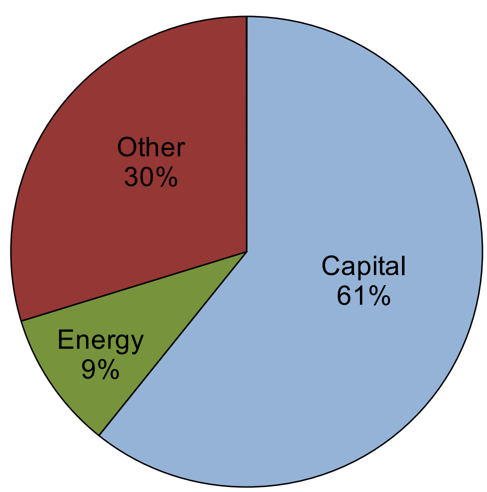


Figure 16. Hydrogen extraction cost breakdown.
Extraction by PSA unit from 300 psi natural gas distribution pipeline with 10% hydrogen added. The hydrogen recovery rate is 100 kg/day and the assumed hydrogen recovery factor is 80%. Cost items in the Other category include labor and O&M.

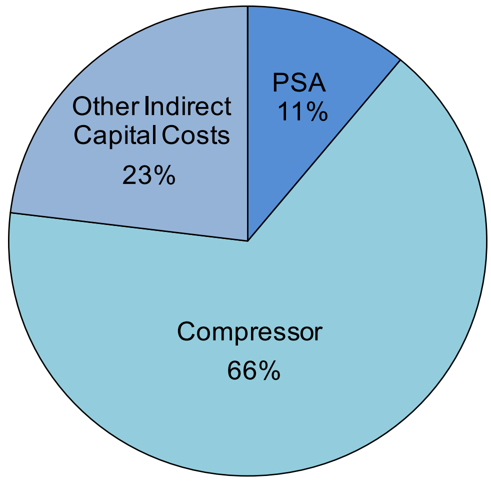


Figure 17. Breakdown of capital cost contribution to the hydrogen extraction cost.
Extraction by PSA unit from 300 psi natural gas distribution pipeline with 10% hydrogen added. The hydrogen recovery rate is 100 kg/day and the assumed hydrogen recovery factor is 80%. Other Indirect Capital Costs include land, engineering and design, and permitting.

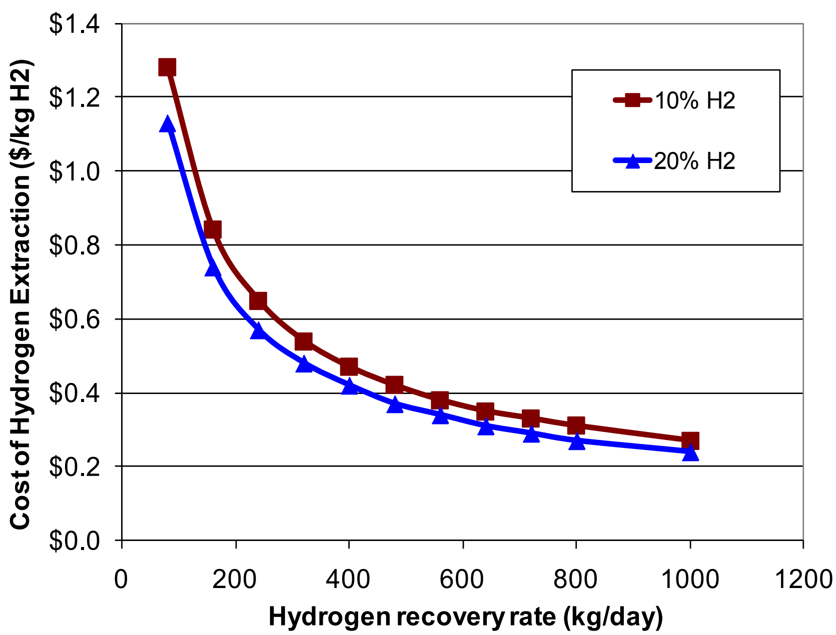


Figure 18. Estimated cost of hydrogen extraction by PSA unit at the pressure-reduction facility (from 300 psi to 30 psi).
Assumed hydrogen recovery factor is 80%.

Summary and Recommendations

Blending hydrogen into natural gas pipeline networks at low concentrations has the potential to increase output from renewable energy production facilities in the near term. In the longer term, blending may provide an economic means of hydrogen delivery when the hydrogen is injected upstream and then extracted downstream for use in fuel cell electric vehicles (FCEVs) or stationary fuel cells. This report reviews several studies of hydrogen blending and provides an assessment specific to the U.S. natural gas pipeline system, included in Appendix A. The implications of hydrogen blending vary with the concentration of hydrogen. Relatively low concentrations of hydrogen, 5%–15% by volume, appear to be feasible with very few modifications to existing pipeline systems or end-use appliances. However, this assessment of feasibility will vary from location to location. Higher concentrations introduce additional challenges and required modifications. Preliminary cost estimates suggest that hydrogen could be extracted economically at pressure regulation stations. For a station with a pressure drop from 300 to 30 psi, we estimate an extraction cost ranging from \$0.3−\$1.3 per kg hydrogen for a 10% hydrogen blend, depending upon the capacity and recovery rate.

This report reviews seven key issues concerning blending hydrogen into natural gas pipeline networks: (1) benefits of blending, (2) extent of the U.S. natural gas pipeline network, (3) impact on end-use systems, (4) safety, (5) material durability and integrity management, (6) leakage, and (7) downstream extraction. These issues are interrelated, but are addressed separately for the sake of clarifying explanation. The first two issues place the concept of blending in context. Issues 3–5 impose restrictions on the acceptable level of hydrogen blending, with requirements for end-use systems imposing the greatest restrictions.

Extensive recommendations for future work to better understand the potential costs and benefits associated with hydrogen blending have been proposed in other studies, particularly in the NaturalHy project funded by the European Commission (Florisson 2012). For additional work on the concept of blending renewable hydrogen into the U.S. natural gas pipeline system, we recommend the following:

1. Research and analysis of the costs associated with modifying U.S. pipeline integrity management systems to accommodate different levels of hydrogen blending.
2. Development of case studies assessing the pipeline system modifications required for specific U.S. regions at multiple hydrogen blend levels.
3. Detailed assessment of the impact of hydrogen blending on U.S. end-use systems, such as household appliances and power production technologies (i.e., engines and turbines).
4. Analysis of hydrogen blending in the near term (e.g., 5−10 years) as a means of economically increasing the output of renewable energy production facilities.
5. Dynamic analysis of the role of natural gas and hydrogen storage in future scenarios where hydrogen blending is prevalent in the U.S. natural gas systems.
6. Analysis of the role of hydrogen blending as a least-cost delivery option in the development of a hydrogen infrastructure for fuel cell electric vehicles.
7. Consideration of hydrogen blending as a strategic option to increase the public benefit derived from the existing U.S. natural gas infrastructure, with a focus on long-term implications for energy supply, energy security, integration of renewable natural gas, and greenhouse gas reductions.

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Appendix A: GTI Subcontract Report to NREL "GTI Review Studies of Hydrogen Use in Natural Gas Distribution Systems"

FINAL REPORT

GTI PROJECT NUMBER 21029

Review Studies of Hydrogen Use in Natural Gas Distribution Systems

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Executive Summary

There is an extensive natural gas pipeline network in the United States. Some studies suggest that it could be a viable solution for the early market to partially use existing natural gas pipelines to deliver hydrogen, mixing it with natural gas in certain proportions, and then separate and purify it for use by an end consumer.

The existing natural gas pipeline networks include the gathering, transmission and distribution pipeline systems. It is considered that hydrogen can be injected into natural gas transmission pipelines and delivered to end users through distribution networks. As hydrogen and natural gas differ significantly in their physical properties, addition of hydrogen to the natural gas pipeline systems must be acceptable in terms of safety and integrity of the network.

In order to assist the development of a delivery go/no-go decision on the use of existing natural gas infrastructure to transport hydrogen from production to end users, GTI performed this literature review for National Renewable Energy Laboratory (NREL) to provide the scientific basis and engineering assessment on some of the aspects related to adding hydrogen in natural gas distribution systems. The scope of this review covers the seven aspects that have been investigated in NaturalHy including "Life Cycle Assessment", "Safety", "Leakage Assessment", "Durability", "Integrity", "End Use" and "Environmental and Macroeconomic Impacts".

In this study, GTI reviewed the available studies related to using the existing natural gas pipeline for hydrogen transportation. The primary focus was on the studies performed by the *NaturalHy Project*. GTI also provided a summary and discussion related to the use of the natural gas network for hydrogen service. This included analysis of the report from the Greenhouse Gas R&D Programme sponsored by the International Energy Agency (IEA) and related results from this study and other publications. The results from this study indicate that adding hydrogen into natural gas has beneficial effects on the environment by reducing greenhouse emissions and air pollutions. But there is not enough information from currently available literature sources to support benefits to the economy and employment.

In addition to the report from the NaturalHy Project, GTI included additional literature sources on material performance in hydrogen environments. GTI provided a scientific basis for assessing the durability and integrity of the existing pipeline infrastructure and potential gas leakage under hydrogen service. The reviewed information finds that there is no major impact from hydrogen on the material integrity under natural gas distribution operating conditions. However, hydrogen leakage through plastic pipe materials and elastomers is much higher than methane, and this may becomes a safety concern in a confined space where accumulation of the gas may increase the likelihood and severity of a fire or explosion.

GTI performed a quantitative risk assessment based on the current natural gas distribution system using the statistical data of US distribution system incidents, together with the survey results on the significant threats in distribution systems provided by utility operators. Using the risk of the system under natural gas service as a baseline, the overall risks at three hydrogen levels (<20%, 20 to 50%, and >50%) were assessed using the results from NaturalHy and other literature sources.

Compared to the current situation with natural gas, the risks present by natural gas distribution systems are increased by adding hydrogen into the system. The impact depends on the hydrogen concentration in the gas mixtures. If less than 20% hydrogen is introduced into the distribution system, the overall risk is not significant, though having hydrogen in natural gas has more impact on the safety in service lines than mains. If the hydrogen level in natural gas increases beyond 20%, the overall risk in service lines can significantly increase and the potential hazards can become severe, while the overall risk in distribution mains still can be moderate up to 50%. For hydrogen level above 50% in natural gas, the risks in both distribution mains and service lines significantly increase, and the overall risk in distribution system becomes unacceptable.

The study of the influence on pipeline integrity by adding hydrogen in the NaturalHy Project focuses on transmission pipelines. It cannot easily be applied to distribution systems because these systems are inherently different from transmission pipelines. The level of hydrogen that is acceptable for transmission pipelines may need to be reassessed for distribution systems in terms of the frequency and severity of fire or explosion in populated areas.

In addition, the hazards arising from gas leakage in a distribution system can be more severe than with transmission pipelines, especially in a confined service area. The integrity management for distribution systems under hydrogen services may require the implementation of a leak detecting or monitoring device or sensor. Currently, there is no available odorant for hydrogen, and this remains a gap to be further investigated.

It is likely that the maintenance costs for distribution systems under hydrogen service will be increased due to the needs for increased inspection frequency and leak detection. Since there is no existing integrity program for distribution system (although a new federal mandate is just being implemented), it is difficult to determine the stepwise maintenance cost of adding hydrogen.

Currently, the membranes used for extracting hydrogen from hydrogen/natural gas mixtures are under development. It is indicated by a recent study that extracting hydrogen from the gas mixture will not adversely affect the downstream gas quality since the Wobbe index and heating value will not be outside statutory requirements.

Electroless plated palladium membranes and carbon molecular sieves (CMS) are two promising technologies that are being considered for further development. Palladium membranes can provide high purity hydrogen, but they are expensive and have to operate at 300ºC. CMS membranes are low cost and can operate at temperatures between 30ºC and 90ºC, but the maximum hydrogen content obtained using CMS membranes is 98%. The most promising future technique would be a hybrid separation system consisting of both palladium and CMS membranes.

Introduction

Hydrogen is considered as an important energy carrier in the future for sustainable, reliable and cost-effective energy. As an energy carrier, hydrogen will provide a secure energy supply by utilizing locally available energy resources such as wind, solar, biogas, nuclear, etc.

One of the main barriers to moving towards a hydrogen economy is developing a reliable and cost-effective hydrogen delivery system. Compared with trucks and trains, pipeline transportation and distribution systems are considered as a safe, environmentally friendly and cost effective way to move hydrogen from its production location to its end users. However, the cost to construct a new widespread pipeline system for hydrogen delivery is huge and it may take decades to complete.

A cost effective transitional hydrogen delivery system would be to use the existing natural gas pipeline network, which offers advantages such as being: (a) widely spread and interconnected, (b) very high capacity, (c) well developed maintenance and control structure, (d) well established safety procedures, (f) well established grid management and operation strategies, and (g) broad acceptance by the public.

Because the physical and chemical properties of hydrogen are quite different from natural gas, the existing natural gas pipeline system is not suitable for delivery of pure hydrogen without significant modifications. However the existing natural gas pipeline system may be able to be used for co-transporting hydrogen with natural gas (i.e., a mixture) with no or minor modifications of the pipeline design, operation, and maintenance. This hydrogen/natural gas mixture could then be used in end user's systems, given appropriate modifications of the appliances, or could be used as pure hydrogen by developing devices to extract hydrogen selectively from the mixture.

Existing natural gas pipeline networks are made up of the gathering, transmission, and distribution pipeline systems. Hydrogen would be injected into natural gas transmission pipelines and delivered to end users through distribution networks.

GTI performed a literature review for the National Renewable Energy Laboratory (NREL) to provide the scientific basis and engineering assessment on the potential for adding hydrogen to natural gas distribution systems. The review is broken down into seven (7) subtasks:

- **Task 4.1: Life Cycle Assessment:**

  The review in this task includes the major natural resource inputs and environmental outputs, socio-economic assessments of employment and economic costs for: (a) current natural gas and related energy systems, (b) transitional natural gas/hydrogen systems, and (c) future complete hydrogen systems.

- **Task 4.2: Safety**

  Review the impact of adding hydrogen on safety and the conditions under which the risk in natural gas pipeline systems is acceptable for transporting hydrogen in natural gas.

- **Task 4.3: Leakage Assessment**

  Review the gas leakage from the pipeline system and the effect that the addition of hydrogen might have on this leakage.

- **Task 4.4: Durability:**

  Review the durability of pipeline materials under hydrogen service at the operating conditions and potential hydrogen levels to be introduced into the system. Indentify potential concerns for pipeline safety and integrity from the impact of hydrogen on material durability.

- **Task 4.5: Integrity:**

Review the potential impact of hydrogen on pipeline integrity. Also review the suitability of current integrity management program (IMP) for hydrogen service and the maintenance cost under hydrogen service. The distribution system is the focus of this task. The current situation of integrity management for distribution pipelines and the issues that may arise with adding hydrogen in natural gas are addressed in the review.

- **Task 4.6: End use:**

Review the development of membranes for the efficient separation of hydrogen from a hydrogen/natural gas stream and the effect on the downstream gas quality after removal of hydrogen.

- **Task 4.7: Impacts:**

Review the environmental and macroeconomic benefits of using the existing natural gas network to transport hydrogen.

Overview – Natural Gas Distribution System in US

US Natural Gas Pipeline Infrastructure

The natural gas delivery pipeline infrastructure is divided into gathering, transmission, and distribution systems, see Figure 1. The distribution system consists of mains, service lines and meter set assemblies which comprise meters, regulators and other installations.

Transmission pipelines are typically linear systems that transport gas over a relatively long distance. These systems have relatively few connections on the main lines.

Distribution pipeline systems are arranged in a network to fit geographical configurations of the service area. There are many connections to the main lines. Networks can be designed in branch or tree configurations, be redundant or supplied by a single feed. Because of the interconnections, each section of pipe could receive its gas flow from more than one direction. A distribution system can be subdivided into pressure districts, where each district is operated at its own pressure level to ensure an adequate and reliable supply of gas to the area's customers.

Comparison of Transmission and Distribution Systems

Transmission pipelines traverse long distances and have few branch connections, predominately located in Class 1 and Class 2 locations as defined in 49 CFR Section 192.5. They are generally large diameter (up to 48″) pipes and nearly 100% of the pipes are steel. Transmission pipelines typically operate at pressure levels between 600 psig (41.4 bar) and 1200 psig (82.7 bar), and in some cases up to 2000 psig (137.9 bar) and the stress levels mostly exceed 20% of the specified minimum yield strength (SMYS) of the steel pipes. Over 96% of the total transmission mileage is wrapped/coated steel pipe that is cathodically protected. Approximately 3% of the total transmission mileage is bare steel with and without cathodic protection. Failure of transmission pipelines usually occur as a catastrophic rupture of the pipeline, caused by the high pressure of the contained gas.

Distribution pipelines are generally small in diameter (as small as 5/8″) and are constructed of several kinds of materials including a significant percentage of plastic pipes. Distribution pipelines also have frequent branch connections for service lines to individual customers. The dominant cause of distribution incidents is excavation damage with third party damage being the major contributor to these incidents. Distribution pipeline failures almost always involve leaks, rather than ruptures because the internal gas pressure is much lower than for transmission pipelines.

Both distribution and transmission facilities are subjected to a variety of periodic inspections mandated by 49 CFR Part 192, see Table 1. The requirements are similar for both transmission and distribution systems with some exceptions. Odorants are required for distribution pipelines and transmission pipelines in populated areas.

Piping Materials of Distribution Network

Department of Transportation (DOT) 2007 Annual Distribution Data shows the piping materials used to construct mains and service lines in distribution networks (Figure 2 and Table 2). The natural gas distribution system in the US includes 1,201,000 miles of distribution mains and 64,804,000 service lines. Steel and polyethylene plastic pipes are the dominant piping materials in distribution systems. The majority of the steel pipes in distribution mains and service lines are coated and cathodically protected.

Historically, distribution mains were primarily made of carbon steel pipe. Since the 1970s, a larger portion of the gas distribution main lines have been made of plastic, mostly polyethylene (PE) and sometimes polyvinyl chloride (PVC). PE pipes are increasingly being used to construct distribution pipelines and replace the aging iron and steel pipes in the low-pressure distribution system because of lower construction and maintenance costs.

As shown in Table 2 and Figure 2, distribution mains are almost evenly divided between steel and polyethylene pipes which account for 47% and 48% respectively. Typical steel grades for the main distribution pipeline include A, B, X42, and X46, see Table 3 for their material properties [10]. Cast iron (CI) and wrought iron (WI) pipes only accounts for 3% of the mains. Many of the cast iron systems were installed over fifty years ago when they were originally used to transport town gas. These lines have been operated for many decades at pressures from 0.25 psig (17.2 mbar) to 60 psig (4.1 bar). There is also a small amount of ductile iron (828 miles) and copper pipes (36.5 miles) used for distribution mains. In addition to polyethylene pipes, PVC and Acrylonitrile Butadiene Styrene (ABS) are the other two plastic pipes used in distribution mains, accounting for 1.8% and 0.2% respectively.

Distribution service lines are primarily made of polyethylene (63%) and steel (33%). The remainder consists of small percentages of copper (1.73%), cast and wrought iron (0.17%), PVC (0.4%), ABS (0.02%) and ductile iron pipes (0.001%). About 1.96% of the total service line pipes are not identified.

The sizes of the typical distribution pipes are between 1.5" and 8" for mains and 0.5" to 2" for service lines. The distribution of the pipe size for steel and PE pipes in distribution mains and service lines is plotted in Figure 3 and Figure 4 respectively. A small percentage of distribution mains and services have a larger diameter pipe, typically for commercial and industrial application.

Elastomeric Sealing Materials in Distribution Network

Elastomers have been used as mechanical coupling seals and gaskets, meter and regulator diaphragms, boots, O-rings, flange seals, valve seats, etc. There are many types of elastomers and the formulation varies with the application. Table 4 lists the type of elastomers that have been used in natural gas distribution systems. Butadiene-Styrene (SBR) and Butadiene-Acrylonitrile (NBR) are the two major elastomers that have been used as gasket, O-ring, diaphragms, flange and quad seals in natural gas industry.

Failure of elastomers could result in leaks. The major failure of elastomers comes from the chemical reaction between the elastomers and chemicals or the adsorption/permeation of the chemicals by the elastomers. This attack results in swelling and softening with a reduction of their tensile strength. The temperature and concentration of the chemical medium determines the degree of deterioration. The absorption and desorption of a gas medium during the change of gas compositions may result in permanent damage of the elastomers.

Some elastomers can be degraded in outdoor conditions when they are exposed to sunlight, ozone, and oxygen. This type of degradation can cause surface cracking, discoloration, significant loss of tensile strength, elongation and other rubbery properties.

Pure mechanical damage is not a frequent failure mode of elastomers. Most mechanical damage occurs as a result of chemical deterioration of the elastomer. When the elastomer is chemically deteriorated, it is more susceptible to mechanical damage. Elastomers become brittle when cooled below their glass transition temperature, and this can lead to brittle fracture of the elastomers.

Operating Pressure of Distribution Network

Distribution pipelines typically operate at pressures ranging from 0.25 psig (17.2 mbar, gas delivered directly to customers without any additional reduction in pressure) to 60 psig (4.1 bar) and sometimes up to 100 psig (6.9 bar). A few distribution pipelines operate at higher pressures of up to 400 psig (27.6 bar high pressure distribution pipelines). The stress levels of the steel pipes in distribution system are normally less than 10% of the ***Specified Minimum Yield Strength*** (SMYS).

Typical Failure Mechanism of Distribution Pipelines

Distribution pipeline incidents typically result in a leak instead of a rupture due to their relatively low operating pressures and the correspondingly lower operating stress. The primary safety concern is that if a leak goes undetected and the gas collects in a confined space, it can eventually ignite and causing an explosion. The total numbers of the leak incidences in distribution systems from the DOT 2007 annual report are summarized in Table 5. The data are plotted as a function of failure mode in Figure 5 .

The exceptional case for distribution systems is "brittle-like cracking" in certain types of plastic pipe, which relates to crack initiation in the pipe wall, followed by stable crack growth, and eventual gas leak. Although significant cracking may occur at points of stress concentration, and near improperly designed or installed fittings, small brittle-like cracks may be difficult to detect until a significant amount of gas leaks out of the pipe and potentially migrates into an enclosed space. Premature brittle-like cracking requires relatively high localized stress intensification that may be the result of geometrical discontinuities, excessive bending, improper fitting assemblies, and/or dents and gouges.

Locations of Distribution Infrastructure Facilities

Distribution facilities are primarily located in populated areas. Distribution lines do not follow class locations, but the majority of the lines would fall into Class 3 and Class 4 locations under transmission class location definitions.

Distribution piping is frequently located in congested urban areas, typically under pavement in streets, highways and other public right-of-ways or utility easements.

Safety Records

The incident data in the Office of Pipeline Safety (OPS) database reported by operators for the period of 1990 through 2002 are summarized in Table 6 showing the causes of transmission and distribution incidents. During the period, there were a total of 957 transmission pipeline incidents and 1579 distribution incidents. The causes of incidents are classified into five major categories:

1. Corrosion
2. Outside Forces
    - First or second party damage;
    - Third party damage;
    - Earth movement (landslide/washout, subsidence, frost heave, earthquake, etc.);
    - Lightning or fire; and
    - Other
3. Construction Operating Error
4. Accidently Caused by Operator
5. Other

Outside force is the predominant cause of incidents for transmission and distribution pipelines, but it is more significant in distribution (60.4% of total incidents and 46.6% of serious incidents) than for transmission (39.8% of total incidents and 36.9% of serious incidents). Corrosion is a much more significant cause in transmission pipelines (23.4%) than in distribution pipelines (3.7%). The other category is a significant cause in both transmission (22.3%) and distribution (23.9%) pipelines. No additional information is available to further determine the cause of these "other" incidents.

Figure 6 shows the serious incidents categorized by system part in the distribution systems reported to OPS from 1990 to 2002. Most of the serious incidents are associated with the mains, followed by services, meter set assemblies and a category termed "Other" and "No Data".

The incident causes also vary with material of construction. Figure 7 shows the serious incidents categorized by construction materials in mains. The serious incidents in mains are primarily from polyethylene plastic pipes, steel, and cast iron pipes. These three materials are the most common pipe materials in distribution systems. Corrosion is an issue with steel systems, less so with cast iron and not at all with polyethylene. Third party damage is the dominant outside force category with all materials, but cast iron is subject to a higher proportion of incidents from earth movement.

The principal materials of construction for service lines are steel and polyethylene plastic. Other materials make up such a small percentage of the piping and are considered negligible. As shown in Figure 8, outside force is the largest cause of serious incidents in service lines, 54% and 76% for steel and polyethylene service lines respectively.

The dominant causes of failure for meter set assemblies are outside forces and “other”, with third party damage comprising most of the outside forces. No corrosion related serious incidents were reported for meter set assemblies during the study period from 1990 to 2002 [27].

Task 4.1 – Life Cycle Assessment

Hydrogen is considered an important energy carrier for a sustainable energy future. Developing a reliable hydrogen delivery system would remove one of the main economic barriers of a hydrogen economy. Pipeline transportation and distribution systems are cost effective ways to move hydrogen from its production location to its end users. There is a potential to transport hydrogen using the existing natural gas pipeline network. The potential benefits of adding hydrogen to natural gas have been addressed in the "NaturalHy Project-Work Package 1" through life cycle and socio-economic assessment.

This study was lead by *University of Loughborough*, and participants included by *COGEN Europe***;** *ECN - the Energy Research Centre; Instituto de Soldadura e Qualidade (ISQ); Planungsgruppe Energie und Technik GbR (PLANET); SAVIKO Consultants ApS;* and *Technische Universität Berlin.*

Life Cycle and Socio-Economic Assessment Literature [1]

The complete life cycle consists of:

- The production of natural gas, related fuels, and hydrogen;
- The construction, operation, maintenance and decommissioning of relevant networks, and
- The utilization of natural gas, related fuels, natural gas/hydrogen mixtures and pure hydrogen.

The life cycle assessment concentrated on primary energy inputs relevant to energy resource depletion, green house gas emissions associated with global climate change, and other gaseous, liquid and solid emissions related to acidification, ozone depletion and eutrophication. Social-economic assessments address direct and indirect job creation, maintenance, and the internal economic costs.

A literature review was performed in this study to examine the existing work on relevant life cycle and socio-economic assessment. In total, 214 references were identified and 172 reviews were conducted. The coverage by technology and type of assessment is extremely diverse. Table 7 lists the technology areas in the literature database.

The references on employment are very limited. Most of the studies were completed during the 1970's and early 1980's and are currently considered outdated.

Standard Procedures for Life Cycle and Socio-Economic Assessment [2]

Standard procedures were established for calculating various environmental impacts, economic costs and employment implications of existing and possible future energy systems. The variables determined in the procedure for calculation include:

- Primary energy inputs as indicator of energy resource depletion;
- Greenhouse gas emissions associated with global climate change (carbon dioxide, methane and nitrous oxide);
- Pollutants affecting urban air quality (sulfur dioxide, oxides of nitrogen, and particulate);
- Internal economic costs; and
- Direct and indirect jobs in the European Union.

The calculations for the existing natural gas network were used as a baseline scenario for comparison against the intermediate scenario with addition of hydrogen:

1) **Baseline Scenario**
    - Natural gas supply

- Natural gas network construction
- Natural gas network operation
- Natural gas network decommissioning

2) Intermediate Scenario

- Adjustment on gas leakage by adding of hydrogen
- Adjustment on Integrity Management Program for transporting hydrogen/natural gas mixture
- Hydrogen separation technologies
- Effect of hydrogen on end-user appliances
- Hydrogen production from different hydrogen generation technologies include:
  - Natural gas reforming without Carbon Capture and Storage (CCS);
  - Natural gas reforming with CCS;
  - Coal gasification with CCS;
  - Nuclear Power electrolysis;
  - Biomass; and
  - Wind power electrolysis.

Overall Benefits of Adding Hydrogen to Natural Gas [2]

The results from the calculation indicate some benefits of adding hydrogen to natural gas:

1) Significant reduction of greenhouse gas emissions if hydrogen is produced from biomass, wind power, and nuclear power
2) Some advantage on greenhouse gas emissions with hydrogen production from fossil fuels with CCS, but no benefits for decreasing primary energy demand or energy resource depletion
3) Potential benefits of selective extraction of hydrogen (this depends on the performance of the separation technology and the subsequent use of the hydrogen and the residual gas)
4) Potential benefits on improving air quality by reducing sulfur dioxide, oxides of nitrogen and particulate emissions if hydrogen is used in transportation and displaces conventional diesel fuel
5) Potential benefit on "greening" natural gas if the hydrogen/natural gas mixture is used directly in existing appliances for heat production and electricity generation

Summary on Life Cycle and Socio-Economic Assessment

The results from this study clearly support the beneficial effects on the environment from adding hydrogen to natural gas including the reduction of greenhouse emission and the improvement of air quality. However, the published work supported by this study addressed to a lesser degree the economic evaluation and employment aspects, and no concluding remarks were made.

Hydrogen has been acknowledged as an alternative energy carrier in US National Energy Policy, and is considered to be a substitute for petroleum-based fuels in light-duty transportation vehicles. A well-developed hydrogen economy will make use of the lowest cost sources of hydrogen, and central station natural gas and coal are the two lowest cost hydrogen sources, followed by various electrolysis-based systems. This could significantly reduce green house gas emissions if carbon capture and storage technologies are used. Large scale hydrogen production plants will likely be built in the future and a national hydrogen transmission and distribution system would be a cost effective way to distribute large volumes of hydrogen over long distances.

Currently, hydrogen is produced in a number of plants and is used primarily in the manufacture of chemicals and petroleum products. There are approximately 700 miles of hydrogen pipelines in US, which lie in the Gulf Coast region where large hydrogen refineries and chemical plants are concentrated. However, there are natural gas networks throughout the US. By utilizing the existing natural gas network for effective delivery of hydrogen in large volumes, there will be beneficial impacts on the society, economy, and environment.

Task 4.2 – Safety

The existing natural gas pipeline networks are designed, constructed and operated for conveying natural gas. The safety of the pipeline system and the risk posed to the public by the supply and use of natural gas are well understood and considered acceptable. Hydrogen has different chemical and physical properties which may adversely affect the risk presented to the public. The major concerns of the impact on safety, by adding hydrogen in the existing natural gas pipeline systems, include the potential rupture of pipeline by hydrogen and the increased probability of gas ignition, and the risk of fire and explosion hazards in an incidental leakage of a hydrogen/natural gas mixture.

GTI has reviewed the publications from NaturalHy Project and the Greenhouse Gas R&D Programme sponsored by International Energy Agency (IEA). The results from the above studies are used as a basis for ranking the severity of fire and explosion hazards in natural gas distribution systems at different hydrogen levels.

In addition, GTI performed a quantitative risk assessment based on the current US natural gas distribution system for conveying hydrogen containing natural gas. The risk factors for the existing distribution systems operated with natural gas was defined with: (a) the statistical data of the fatal incidents occurring in US distribution systems from 1990 to 2002 together with, (b) the survey results on the significant threats in distribution systems provided by utility operators. The overall risks for natural gas service are used as a baseline to compare the risks when hydrogen is added into natural gas distribution systems. The overall risk in distribution systems is assessed at three hydrogen levels that have been investigated in the NaturalHy project and other related research programs.

Risk Assessment by NaturalHy Project (Work Package 2) [3]

The potential risks of transporting hydrogen using the existing natural gas pipeline network have been investigated by "NaturalHy Project in Work Package 2". This work was led by *Loughborough University*, and *Leeds University, CEA, Shell Hydrogen, UK HSE,* and *National Grid participated also.*

The risk is a combination of the likelihood and the consequence (hazard) of an incident. The data and results from NaturalHy Project Work Package 3 and 4 on the durability and integrity of natural gas pipeline for transporting hydrogen/natural blends were used to aid the re-evaluation of the failure frequency of pipelines under hydrogen services. Laboratory scale and large scale experiments were developed to examine the consequence of fire and explosion situations pertinent to hydrogen/natural gas mixtures. Simple and Computational Fluid Dynamic (CFD) models were developed and validated using the experimental data, and the models were used to assess the impact of different level of hydrogen on the severity of the hazards which may arise from a wide range of accident scenarios.

The Impact on the Likelihood of Incident by Adding Hydrogen:

Failure frequency of pipelines is unchanged compared to that of natural gas pipelines with up to 50% hydrogen addition when an appropriate integrity management system is in place. The ignition probability is higher for hydrogen and natural gas mixtures due to the significant reduction in the minimum energy required for ignition and the increase in the upper flammability limit.

The Impact on the Consequence of an Incident by Adding Hydrogen:

The gas buildup behavior is similar in nature to natural gas. The concentration of the gas buildup is slightly higher with hydrogen addition of up to 50% in natural gas, but gas build up concentration significantly increase at hydrogen level above 50%, especially when the hydrogen addition is larger than 70%.

In a vented explosion, 20% hydrogen addition made little difference on the explosion severity, but 50% or higher hydrogen additions will increase the severity.

In an event of gas buildup in a confined space, the explosion severity increases moderately up to 30% hydrogen addition, but it significantly increases for 40% or more hydrogen addition. Fire hazard slightly decreases with hydrogen addition.

Risk Assessment:

A risk assessment tool (LURAP) was produced, based on the analysis of likelihood and consequence, to calculate the risk at different levels of hydrogen in natural gas. It was found that adding hydrogen in the natural gas pipeline increases the risk to an individual at location near the pipeline, but decreases the extent of the hazardous region.

In addition, the risk assessment of the expected background level leakage from the pipeline network indicates that the level of leakage overall is very small and poses no hazard from a safety standpoint.

Overall Safety Effect by Adding Hydrogen to Natural Gas Network (Greenhouse Gas Programme, IEA [11])

The potential change of gas properties by adding hydrogen up to 25% in natural gas and the resulting impact on the hazards have been assessed relative to the use of standard natural gases in this study, and the results are summarized in Table 8. Based on this assessment, adding hydrogen up to 25% increases the explosion risk in a confined room and the probability of a fire. It is concluded in this study that the use of hydrogen blended natural gas under well regulated circumstances should not increase the risk of explosions in comparison to those with unblended natural gas.

Risk Assessment for US Natural Gas Distribution Systems under Hydrogen Service

The potential risks posed to the public by natural gas distribution pipelines are generally assessed by the probability of pipeline failure and the consequence of the failure, i.e.:

$$Risk = Probability * Severity \tag{1}$$

The major failure mode in natural gas distribution pipelines is by leak, and the statistical data published by DOT in the 2007 annual report are categorized into eight failure modes for the leak incidences (see Table 5):

1) Corrosion

Leak resulted from corrosion is one of the failure modes in distribution system. It includes the external corrosion from bare steel pipes, coated/wrapped steel pipes and cast iron pipes, and internal corrosion. The leak from corrosion defects in distribution system can result in the gas buildup in a confined area and create a hazard of fire or explosion.

2) Material Defect

Manufacture related defects are one type of material defects for pipes. These include defective materials, pipe, pipe seam or piping components, etc. The other type of defects are related to construction, such as defective pipe girth welds, defective fabrication welds, stripped threads, broken pipes or couplings for steel pipe, and defective fusion, installation error, and improper back fill for plastic pipes.

This type of failure can result in slow release of gas and will pose fire or explosion hazard if the leak occurs in a confined space.

3) Natural Force

Natural force includes the forces that are applied to the pipeline from earth movement in the event of landslide/washout, subsidence, frost heave, earthquakes, etc. Natural force can result in severe damage of the pipeline and significant release of gas.

4) Excavation Damage

This is the damage of pipes during excavation which normally result in a leak or in rupture of the pipeline.

5) Other Outside Force

This is the damage from the outside force other than natural force or excavation.

6) Equipment Malfunction

This failure results from equipment malfunction, such as gasket or O-ring failure, control/relief equipment malfunction, seal failure, piping component failure, etc.

7) Operation

This is the failure from incorrect operations, e.g., the operator doesn't follow correct operational procedure.

8) Other

This includes the failure modes that don't fall into any of the above categories.

Table 5 and Figure 5 show the percentage of the leak incidents from each failure mode in distribution mains and service lines. Corrosion and excavation are the two frequent leak incidents. In view of adding hydrogen into the distribution system, the likelihood of each failure mode will not be significantly changed. However, the possibility and severity of a fire or explosion can be increased by the presence of hydrogen in natural gas.

The hazards of fire or explosion in natural gas distribution systems are ranked into six levels (no hazard (0), minor (10), minor to moderate (20), moderate (30), moderate to severe (40) and severe (50)) based on the risks posed to the public by pipeline failure, see Table 9. For each category of pipe materials in distribution main and service lines, the hazards are assessed on the eight failure modes based on the incident data from OPS database and the survey results on the significance of the threats in natural gas distribution pipelines provided by utility operators (see Task 4.5) [27].

The risk factors for the five material categories are defined using the ranking in Table 9 for each failure mode and shown in Table 10 and Table 11 for distribution mains and service lines respectively. The last column in Table 10 and Table 11 is the overall risk factors for each failure mode presented by natural gas, and it is calculated by the sum of the risk factor of each type of material times the percentage of this type of material in the system, i.e.:

$$RF_{Overall} = \sum_{(i=1 \text{ to } 5)} [RFi * Pi] \tag{2}$$

$RF_{overall}$: the overall risk factor

RF_i: risk factor for each material category (total of five categories)

P_i: percentage of each type of material in distribution mains or service lines

The overall risks for each failure mode in Table 10 and Table 11 are further assessed for hydrogen/natural gas mixture at three hydrogen levels (< 20%, 20 to 50% and > 50%). These three levels are identified based on the studies in NaturalHy and other literature sources that have investigated the influence of hydrogen concentration on the occurrence of fire or explosion by hydrogen/natural gas mixtures and the severity of the hazards.

In distribution mains, most of the pipelines are considered as in the vented condition. Adding hydrogen in the natural gas will increase the gas buildup near the pipeline, but the change of gas buildup behavior is slight for hydrogen up to 50%. The hazard resulted from slow release of gas, such as the gas leak from corrosion or manufacture defects are not significantly increased by adding up to 20% hydrogen in natural gas, but it will be significantly increased at higher hydrogen level, especially above 50% hydrogen. In the case of pipeline failure by outside forces such as excavation damage or natural force, the explosion hazard is increased with the presence of hydrogen, and the risk factor is significantly increased at hydrogen level above 50%. Table 12 and Table 13 show the influence of hydrogen on the risk factor (for mains and services respectively) of each failure mode and the overall risks at the three levels of hydrogen concentration. The overall risk calculated using Equation (1) indicates that the overall risk in distribution mains is increased by adding hydrogen in natural gas. The increase of the risk is moderate by adding up to 50% hydrogen, but the increase becomes significant when more than 50% hydrogen is added.

On the contrary to distribution mains, many of the pipelines in distribution services are in the confined space, such as within the building area. The leaked gas cannot be vented quickly and the gas buildup in the confined space will increase the possibility of a fire or explosion. Adding hydrogen in natural gas increases the risk factors for all the failure modes in service pipelines. The overall risk is significantly increased at all hydrogen levels, and it becomes severe at hydrogen levels above 20% as shown in Table 13.

Summary and GTI's Concluding Remarks on Safety

GTI performed a quantitative risk assessment on US natural gas distribution systems for carrying hydrogen containing natural gas. The risk analysis is based on the research findings from NaturalHy and other studies related to the influence of hydrogen on the potential risks posed to the public by transporting hydrogen in the existing natural gas network. The statistical data of the fatal incidents occurring in US distribution systems from 1990 to 2002 together with the survey results on the significant threats in distribution systems were used to define the baseline risk factor for each failure mode under natural gas service. The influence of hydrogen were assessed based on the research findings from NaturalHy and other studies, and the risk factors defined for each failure mode at three hydrogen levels that have been investigated in the literature.

Compared to the current situation with natural gas, the risks present in natural gas distribution systems are increased by adding hydrogen into the system. The impact depends on the hydrogen concentration in the gas mixtures. If less than 20% hydrogen is introduced into distribution system, the overall risk is not significant. But the service lines are more critical than distribution mains because they are mostly installed in the confined spaces. In this case, adding hydrogen in the gas increases the explosion risk in the event of a gas leak. If the hydrogen level in natural gas increases beyond 20%, the overall risk in service lines can significantly increase and the potential hazards can become severe, while the overall risk in distribution mains still can be moderate up to 50%. For hydrogen level above 50% in natural gas, the risks in both distribution mains and service lines significantly increase compared to the situation with natural gas, and the overall risk in distribution system becomes unacceptable.

Task 4.3 – Leakage Assessment

Because of the smaller molecular size of hydrogen, the leakage rate of hydrogen though pipe wall and joints may be larger than methane, and result in economic and safety concern of the total loss of gas. GTI has reviewed the publications from NaturalHy Project which mainly focus on the permeability of plastic pipe materials including polyethylene (PE) and polyvinyl chloride (PVC). GTI also reviewed the report from IEA Greenhouse Gas R&D Programme and other relevant information for gas leakage in the natural gas distribution pipeline under hydrogen services.

Assessment of Permeation Loss by NaturalHy Project (Work Package 3) [3, 18]

Permeation loss of gas from plastic pipes has been investigated by "NaturalHy Project in Work Package 3". This work was performed by Gaz de France. In this investigation, real pipes and assemblies were tested at the operating temperatures and pressures with hydrogen/methane mixture in order to more precisely evaluate the permeation of hydrogen through the plastic pipe in the natural gas distribution network.

Three different PE grades (PE 63, PE 80, and PE 100) in the diameter range from 20 mm (0.79") to 200 mm (7.87") with pressure between 14.5 psig (1 bar) and 174 psig (12 bars) or over and temperatures in the range from 5ºC to 25ºC. These represent commonly used polyethylene materials and pipe sizes in the natural gas networks and typical operating conditions. Pure methane and hydrogen/methane mixture containing 10% hydrogen were used in the tests to investigate the permeation behavior of hydrogen/natural gas mixture compared to natural gas. Table 14 shows the permeation coefficient of hydrogen and methane from a test under 58 psig (4 bar), 116 psig (8 bar) and 174 psig (12 bar) with a 32 mm (1.26″) PE 80 pipe. The calculated gas loss based on the experimental data at the test pressures is also included in this table. The results from this study are summarized in the follow [18]:

- There is an incubation time for methane to diffuse through the pipe, while the incubation time for hydrogen is close to zero.
- The permeation rate of methane and hydrogen increases with the increase of the internal pressure.
- The permeation coefficient of hydrogen is 4 to 5 times greater than that of methane in the hydrogen/methane mixture, even if the hydrogen partial pressure is lower by an order of magnitude than that of methane in the mixture.
- The absolute values of methane loss calculated for three type of PE piping materials are far lower than the extrapolated data.
- The aging of the pipes seems to have no significant influence on the permeation coefficients in these experimental conditions.

One type of PVC (PVC-CPE) was also included in this study, and the calculated hydrogen leakage rate from PE and PVC pipes at 2.9 psig (200 mbar) distributing 100% H_2 are [8]:

- PE100: 5.0 liter/km/day, and
- PVC: 13.2 liter/km/day

The leakage rate of methane and hydrogen calculated from PE disc samples under a mixture of 80% natural gas and 20% hydrogen at 58 psig (4 bar) are [8]:

- Methane: 1.1 liter/km/day, and
- Hydrogen: 2.3 liter/km/day

Additional Information on Leakage Assessment

In addition to the gas leakage study in NaturalHy project, GTI also reviewed the report from IEA Greenhouse Gas R&D Programme [11] and other relevant information [13, 18, 19, 29] about hydrogen leakage in natural gas distribution systems.

Gas Leakage from Steel or Ductile Iron Systems [19]:

The leakage in steel and ductile iron systems mainly passes through the threads or the mechanical joints. The leakage measurements carried out by GTI on gas distribution systems indicated that the volume leakage rate for hydrogen is about a factor of three higher than for natural gas.

Gas Leakage from Plastic Pipes and Elastomers [11, 13, AGA handbook]

Leakage Assessment by IEA Greenhouse Gas Programme [11]

The permeation coefficient of hydrogen in several plastic pipes was determined by experimental measurements in this study. The experimental data and the literature data are summarized in Table 15 [11]. A calculation of the total loss of hydrogen was performed in this study based on the experimental data of a representative material from the Dutch grid. The estimated gas loss is 26×10^3 m^3 (918,182 Ft^3) per year when 17% hydrogen is adding into this gas distribution system. This amount of gas loss only represents 0.0005% of the hydrogen transported. Thus the gas loss due to the hydrogen permeation is considered as negligible and will not create a significant problem.

Estimation of Gas Loss for US Distribution Network

The majority of the plastic pipes used in US natural gas distribution systems are polyethylene pipes including medium density polyethylene (MDPE) and high density polyethylene (HDPE). There are also small percentage polyvinylchloride pipes. These materials are similar to those used in European natural gas distribution system, but with different material designation system.

The permeation coefficient of hydrogen and methane in the typical plastic pipe and elastomeric materials that have been used in US distribution systems are summarized in Table 16 [13, 29]. The hydrogen permeation coefficient in the US grade plastic pipe materials are very close to those published by IEA's study [11]. It appears the permeation coefficient of hydrogen is about 5 to 6 times of that of methane in the plastic pipes. The hydrogen permeation coefficient is even higher in elastomers, especially in natural rubber and Buna S, which are 26 and 21 times of that in HDPE.

Because the plastic pipes have much larger surface area than the seals, the gas leakage rate is calculated with plastic pipes to estimate the amount of gas leakage in the entire gas distribution system. The gas leakage rate (V) through plastic pipes can be calculated using the permeation coefficient (P) [30]:

$$V=P*(A/t)*\Delta p \qquad (3)$$

A: the surface area of pipe

t: pipe wall thickness

Δp: the pressure difference between internal and external surface of pipe

High density polyethylene is used as an example for this calculation with a pipe diameter of 1″ and wall thickness of 0.1″ which is a representative pipe dimension in the distribution system. Table 17 shows the calculated hydrogen and methane leakage rate at the typical distribution operating pressures (60 psig (4.1 bar), 3 psig (210 mbar), and 0.25 psig (17.2 mbar)) with various hydrogen concentrations of hydrogen/methane mixtures. The gas leakage data are also plotted vs. the hydrogen content at the operating pressures in Figure 9. The total volume of gas loss of hydrogen and natural gas increases by adding hydrogen due to the higher permeation rate of hydrogen. The total gas loss from a gas mixture containing 20% hydrogen is about double the gas loss from a pure methane, but the amount of gas loss with this hydrogen content from a 1″ HDPE pipe at low pressure (3 psig (210 mbar) and 0.25 psig (17.2 mbar)) is not significant (5.3 ft^3/mile/year and 0.4 ft^3/mile/year at 3 psig and 0.25 psig respectively).

Since the service lines normally operate at 3 psig (210 mbar) or 0.25 psig (17.2 mbar), the total gas loss from service lines is negligible compared to that from distribution mains which operate at 60 psig (4.1 bar) or higher. The estimated total gas loss in the distribution systems at different hydrogen levels in the gas mixture is shown in Figure 10 using 60 psig (4.1 bar) as a representative operating pressure and the mileage for PE pipes with the size less than 2″ diameter which accounts about 69% of the total plastic pipes in distribution system. The gas leakage rates obtained from experimental measurements in NaturalHy are also included in this plot. For pure methane, the gas loss calculated from NaturalHy experimental data is close to the calculation from AGA handbook. However, for the gas mixture containing 10% hydrogen, the gas loss calculated based on NaturalHy experimental data is only half of that based on the permeation coefficient from AGA handbook. The total gas loss for the gas mixture containing 20% hydrogen is about 40 million cubic feet per year, and it is about double the total gas loss from pure methane, but this amount is still not significant from the economy point of view.

Summary and GTI's Concluding Remarks on Gas Leakage

It has been indicated by the research studies and literature data that hydrogen is more mobile than methane in many polymer materials including the plastic pipes and elastomeric seals used in natural gas distribution systems. There is almost zero lag time for hydrogen to penetrate the pipe wall, and the permeation rate of hydrogen is 4 to 5 times faster than methane through the typical pipes used in natural gas distribution.

The permeation coefficient of hydrogen is even higher through most of the elastomeric sealing materials that are used in natural gas distribution systems. Natural rubber and Buna S (SBR) have less sealing ability to hydrogen compared to the other elastomers.

Since plastic pipes have much larger surface area compared to the seals, a typical polyethylene pipe used in natural gas distribution system is used to estimate the gas loss through pipe wall at the general operating pressures. The calculation based on the literature data of the permeation coefficient of hydrogen and methane in the polyethylene pipe (PE 3608 or PE 4710) indicates that the majority of the gas loss is from the pipes in distribution mains which operate at 60 psig (4.1 bar) or higher. The gas loss from the total of 414,830 mile polyethylene pipes with the size less than 2″ in the entire distribution mains is about 40 million cubic feet per year if 20% hydrogen is added into natural gas pipeline system. Though this amount of gas loss is almost double the total gas loss when the systems deliver only natural gas, it is still considered insignificant from the economic point of view. In addition, adding hydrogen in natural gas can slightly reduce the leakage of methane into the environment which is beneficial for greenhouse gas reduction.

The hydrogen permeation coefficient from literature data is higher than that from the experimental measurements in NaturalHy project, especially at lower pressure. This phenomenon is reasonable because the literature data is measured in pure hydrogen and thin polymer films. It is most likely that hydrogen is less mobile in a low concentration hydrogen/methane mixture because the activity of hydrogen is much lower compared to pure hydrogen. Further, the plastic pipe has a much thicker wall and denser structure than the thin film which will increase the resistance for hydrogen to penetrate. Thus, the gas loss based on literature data may over estimate the gas loss from a pipeline system containing low concentration of hydrogen, especially at low operating pressures, e.g. 3 psig (210 mbar) or 0.25 psig (17.2 mbar). In order to obtain a more accurate estimation of the gas loss in the distribution system, it is necessary to perform further investigations testing pipes under general distribution operating pressures and at hydrogen concentrations that are typical of what will be used for blending hydrogen into natural gas pipeline systems.

The amount of gas loss from service lines is negligible from the economic point of view, but gas leaking in a confined space may increase hydrogen concentrations to levels that may become a threat from the safety standpoint. This is the same for elastomeric seals which have higher permeation rates for hydrogen. The accumulation of leaked gas over time may present a safety concern in a confined space where there are many sealed joints. This issue has not been well studied in NaturalHy and the other investigations, and remains a gap for the risk assessment.

It is important to obtain further understanding on hydrogen permeation behavior in plastic pipes and elastomeric materials under the expected operating conditions for hydrogen services. Further investigation should be performed on the existing pipe and seal materials as well as newly developed materials that can be used as a replacement for current materials. This will provide a basis to accurately estimate the gas leakage through pipes and seals, and in particular to determine if the leakage in a confined space over time will present a safety risk and if it is required to implement a leak detection/monitoring device.

Task 4.4 – Durability

It is well known that hydrogen damage is one of the concerns for many metallic piping materials. The occurrence and the severity of hydrogen damage on metallic materials depend on the type of materials, hydrogen concentration and the operating parameters. It is crucial to understand the acceptable hydrogen level that can be blended into natural gas without negatively impacting the lifetime of the infrastructure.

Since hydrogen is the smallest element, it has a greater tendency than natural gas to leak through valves, seals, gaskets and pipes. The accumulation of hydrogen in a confined space may create safety concerns. Gas meters record the volumetric quantities of the gas supplied. Adding hydrogen into natural gas changes the gas properties. Therefore, it is necessary to quantify the deviation of the gas meter when measuring hydrogen/natural gas mixtures at various hydrogen levels.

The above issues relate to material degradation. Leakage and meter accuracy were investigated in the NaturalHy Project-Work Package 3. The aim of this investigation was to develop sufficient knowledge for establishing hydrogen level in the blends, estimating the lifetime for different natural gas networks, identifying and removing bottlenecks for transporting hydrogen in the natural gas network and developing operational guidelines. The goal of the NaturalHy Project is to determine the feasible conditions under which hydrogen produced from a centralized production site can be injected into high pressure transmission pipelines and deliver to end users through distribution networks. Under this scenario, the durability of pipeline materials in distribution network is less of a concern than transmission pipelines because distribution pipelines operate at much lower pressure levels. Thus, hydrogen degradation of metallic components in natural gas distribution systems was not studied in the NaturalHy Project based on the hypothesis that the integrity of metallic components in low pressure distribution systems will not be significantly impacted at the hydrogen levels that are acceptable for high pressure transmission pipe.

In view of the long term goal of the US to use hydrogen as a sustainable energy carrier, hydrogen produced from the satellite, local production sites, will play a role in the hydrogen economy, especially in utilizing renewable energy such as wind and solar. In this scenario, hydrogen is most likely to be blended into natural gas distribution networks directly and the hydrogen level in natural gas determined from the pipeline materials and operating conditions for transmission pipelines could be conservative. A beneficial improvement can be made on the productivity of hydrogen delivery and recovery of hydrogen from gas mixture at end users if higher levels of hydrogen can be injected directly into natural gas distribution systems without adversely impacting pipeline integrity.

In order to provide a comprehensive point of view on the impact from hydrogen on distribution pipeline materials, GTI included other literature sources on materials degradation, hydrogen leakage and gas meter accuracy with hydrogen/natural gas. In addition, GTI performed a thorough review of the pipeline materials using the distribution pipeline data published by DOT and the GTI literature sources. By integrating the literature information with the pipeline materials and operating conditions in the natural gas distribution system, GTI assessed the durability of the US natural gas distribution infrastructure for transporting hydrogen/natural gas mixtures.

Durability (NaturalHy Projects-Work Package 3) [8, 17, 18]

This investigation was led by GDF SUEZ, with participation by Commissariat à l'Energie Atomique, CMI, CSM, DBI-GUT, DEPA, Ecole Nationale des Ingénieurs de Metz, GASUNIE, Institut Français du Pétrole, IGDAS, ISQ, STATOIL, TNO, TOTAL and TUBITAK.

In this project, the effects of hydrogen on the durability of the materials and components used in the natural gas transmission and distribution network, as well as the end user devices were studied.

Hydrogen Affect on the Initiation and Growth of Defects in Transmission Pipelines

This work focused on the hydrogen embrittlement of steel pipes used for high pressure natural gas transmission pipeline, and the crack growth from the existing defects, such as corrosion defects and sharp defects in the welds. It is concluded in this study that adding up to 50% hydrogen into the natural gas transmission pipelines may not cause catastrophic failure. The acceptable hydrogen level depends on the type of steel used for high pressure pipeline.

Because distribution system operate at much lower pressure than transmission pipeline and are built with lower grade steels, no additional studies were performed in NaturalHy to evaluate the risk of hydrogen embrittlement on distribution steel and other metallic pipes. Additional review and evaluation by GTI on the integrity impact from adding hydrogen on distribution pipes are included in the next section.

Hydrogen Permeation in Plastic Pipes in Distribution Network

This work has been reviewed in Task 4.3, and the main conclusion is that permeation of hydrogen through the walls of PE pipes is 4-5 times faster than methane. Nonetheless, the gas permeation loss is still very small and acceptable from a safety, economy and environmental point of view.

Aging of Plastic Pipes in Hydrogen/Natural Gas Blends

Aging of PE pipe materials was tested with laboratory samples and it was concluded that aging effect of hydrogen on PE pipe materials is not significant. But aging of the other polymer materials such as PVC, ABS and the elastomeric sealing materials was not reported in this study.

The Reliability of Gas Meters for Hydrogen Services

Three gas meters with polymer membranes manufactured by Gallus (France), Dresser (Italy) and Elster (Germany) were tested with two gas mixtures (100% methane and 50% hydrogen and 50% methane). The test results on Dresser meter show a positive change, while the test results on Gallus and Elster meters show a negative change in 50% hydrogen/methane mixture compared to 100% methane. But the gaps are less than 2% for all the tested meters and they all decreases at lower flow rate.

Additional Information for the Durability of Pipeline Materials under Hydrogen Services

In addition to the durability studies published by the NaturalHy Project, GTI include additional literature sources related to the effect from hydrogen on pipeline materials and equipments. They are used as supplemental information to provide a comprehensive point of view in terms of the impact from hydrogen on the distribution systems and the basis to assess the potential risks imposed to the system in the presence of different levels of hydrogen in natural gas.

Hydrogen Damage of Metals

Hydrogen damage is a form of environmentally assisted failure that results most often from the combined action of hydrogen and residual or applied tensile stress. The failure includes cracking, blistering, hydride formation and loss in tensile ductility and it has been generally called hydrogen embrittlement (ASM Vol. 13a). In general, the hydrogen damage occurs at a stress level below those typically experienced for a particular metal in an environment without hydrogen. It is affected by hydrogen pressure, purity, temperature, stress level, strain rate, and material microstructure and strength.

The specific types of hydrogen damage have been categorized in ***ASM Handbook Vol. 13A***, see Table 18. This table includes the materials that are susceptible to hydrogen damage, the various types of hydrogen damage, the source of hydrogen and the typical conditions for the occurrence of failure. The first three classes are grouped together and designated hydrogen embrittlement. It appears that the conditions for hydrogen damage on iron or copper do not apply to natural gas distribution system, thus there should be no concern of hydrogen damage on iron and copper pipes in the distribution system. Though hydrogen embrittlement is a potential concern for steel pipe, this effect varies with the steels. In general, high-strength steel (>100 ksi yield strength) are more susceptible to hydrogen induced cracking, while low-strength steel is only subjected to loss in tensile ductility.

Hydrogen Impact on Steel Linepipe

Hydrogen Embrittlement of Steel Pipe [11]

Many steels are prone to hydrogen embrittlement, which is the type of brittle fracture at a sustained load below the yield strength when materials are exposed to hydrogen. High pressure transmission steel pipeline is more of a concern due to the higher stress from the operating pressure and the higher strength of pipeline material, especially the new natural gas pipeline construction. Hydrogen concentration and operating pressure are the most critical factors to cause hydrogen embrittlement.

The steel grades (API 5L A, B, X42 and X46) used in natural gas distribution pipeline are relatively low strength steels. The predominant hydrogen damage for low strength steels is loss of tensile ductility or blistering, but they usually fail in a ductile mode instead of catastrophic brittle fracture in hydrogen environment. The severity of the hydrogen damage depends significantly on the hydrogen concentration and operating pressure.

Hydrogen Assisted Fatigue [13]

Carbon and low alloy steels show accelerated fatigue crack growth and degradation in fatigue endurance limits when expose to hydrogen even at relatively low pressures. The accelerated fatigue crack growth is more pronounced at ambient temperatures and becomes less severe at elevated temperatures. The presence of hydrogen reduces the threshold cyclic stress intensity factor (ΔKth) as well as fatigue life, thus fatigue cracking will be a concern if the pipeline experiences pressure fluctuations.

Enhanced Crack Growth on Existing Defects [11]

Crack growth from existing defects may be enhanced by the addition of hydrogen due to the reduced ductility of steel, and fluctuation of the operating pressure in the pipeline may accelerate this effect.

At low and medium pressures (< 290 psig (20 bar)) in distribution systems, the pipeline will be far less susceptible to hydrogen enhanced crack growth due to the relatively low operating tensile strength compared to the design strength. There is a long history of the successful transportation of “pure” hydrogen at pressures below 290 psig (20 bar) across the world, no operational problems occurring over many decades. Town gas, which contains hydrogen, also has been transported historically in gas distribution pipelines.

Welding Requirements for Hydrogen Services [13]

The welds should be defect free and the weld heat affected zones must match the mechanical and toughness properties of the linepipe. The hardness levels in the weld and weld heat affected zone must be controlled to avoid hard spots to ensure the adequate toughness for hydrogen containing environment.

Hydrogen Impact on Non-Metallic Materials

Compatibility of Polymer Materials with Hydrogen [13]

The degradation of polymer materials in normal environmental conditions includes UV irradiation, chemical attack and thermal breakdown. With respect to the investigation of the polyethylene pipeline for hydrogen service, no degradation by pure hydrogen has been reported. Little or no interaction between hydrogen gas (or any non-polar gas) and polyethylene should be expected [30]. In addition, hydrogen alone does not provide radicals that can cause polymer breakdown. Most of the elastomers are also compatible with hydrogen. Table 19 lists the major plastic and elastomeric materials used in natural gas pipeline and their compatibility to hydrogen.

Though pure hydrogen dose not promote the degradation of polymer materials, some contaminants in hydrogen gas may be harmful to pipeline materials, and the degradation depends on their concentration.

Hydrogen Permeability in Plastics [11]

This has been reviewed in Task 4.3. In plastic pipe systems, hydrogen diffuses faster than methane through the plastic pipe wall, but the total loss of hydrogen is considered insignificant from the economic standpoint.

Impact of Hydrogen on the Durability of Gas Meters [11]

The influence of hydrogen addition was measured for leather and plastic diaphragm gas meters in Polman's study [11]. The deviations in gas metering were determined with natural gas and 17% hydrogen/natural gas mixture at five different flows from 0.013 to 5 m^3/h. For the two types of gas meters, the deviations observed were lower than 0.1%. This deviation can be regarded as negligible considering the calibration standards stating a maximum deviation of 4% for recalibration and repeatability within 0.2%.

This study also examined the required capacity of gas meters for measuring hydrogen/natural gas mixtures. The results indicated that for mixtures up to 17%, the required capacity is not affected by adding hydrogen in natural gas.

It is concluded in this study that the gas meters used in natural gas distribution systems are not expected to be changed.

Summary and GTI's Concluding Remarks on Durability

Impact of Hydrogen on the Durability of Metallic Pipes in Distribution Systems

The metallic pipes in US distribution systems are primarily made of relatively low strength steel, typically API 5L A, B, X42 and X46 in distribution mains. The major hydrogen damage of these steels in a hydrogen containing environment is loss of tensile strength or blistering which strongly depends on the hydrogen content in the environment. They normally fail in ductile mode, and are not the type of steels that are susceptible to hydrogen induced brittle cracking.

In addition, the operating pressure in distribution system is normally less than 250 psig (17.2 bar), and the stress level in most of the steel pipes, generated by operating pressure, is less than 20% SMYS. Under this stress level, the potential risks for the low strength steel pipes in distribution system are low considering the failures by hydrogen (hydrogen induced stress cracking, hydrogen enhanced fatigue cracking or hydrogen enhanced crack growth from the existing defects) which are the major integrity concerns for high pressure transmission pipelines transporting hydrogen.

For the other metallic pipes, including ductile iron, cast and wrought iron, and copper pipes, there is no concern of hydrogen damage under general operating conditions in natural gas distribution systems.

Impact of Hydrogen on the Durability of Plastic Pipes and Elastomers in Distribution Systems

There is no major concern on the hydrogen aging effect on PE or PVC pipe materials. Most of the elastomeric materials used in distribution system are also compatible with hydrogen. There is very small amount of ABS pipes in distribution mains (0.2%) and service lines (0.02%). No investigation on the aging and permeability of this pipe material has been performed. Since this material only takes very small portion in the distribution pipes, and also it is not the pipe material to be used for new construction, the unknown performance from ABS will not significantly affect the overall performance for the plastic pipes in distribution system. If ABS is of direct concern, targeted testing could be conducted. Therefore, it can be concluded that material aging by hydrogen is not a major concern on the durability of the polymer materials in natural gas distribution systems.

One remaining durability gap that needs to be addressed is the potential contaminants in hydrogen gas that may be introduced into the network. The specification for the purity level of the hydrogen gas to be transported by natural gas pipelines has not been determined.

Impact of Hydrogen on the Durability of Gas Meters

The deviation of a gas meter with hydrogen/methane mixtures varies with the manufacture's detail of the meter design, e.g., Dresser meter show a positive change while those from Gallus and Elser show a negative change. Nonetheless, the deviation is acceptable based on the requirement for recalibration (<4%) when they are measuring a gas mixture containing less than 50% hydrogen. The meters may not need to be "tuned" under the potential hydrogen levels (<50%) in natural gas pipeline that are transporting hydrogen/natural gas mixtures.

Task 4.5 - Integrity

There are always existing defects in the pipe materials or welds. The current integrity management for natural gas pipeline systems is based on the operating conditions for transporting natural gas. Adding hydrogen into the pipeline network changes the pipeline operating environment, which may accelerate crack propagation or fatigue failures from the existing defects, and thus adversely impacts pipeline integrity. There may be certain defects which are acceptable under current integrity management criteria which will become critical due to the material property change in hydrogen containing environments.

In the US, the Pipeline and Hazardous Materials Safety Administration (PHMSA) has implemented integrity management requirements for hazardous liquid and gas transmission pipelines, but no similar requirements currently exist for gas distribution pipelines. In 2009, PHMSA published the final rule effective on Feb. 12, 2010 to establish integrity management requirements for gas distribution pipeline systems. The operators are given until August. 2, 2011 to write and implement the integrity program for distribution pipeline systems.

The investigations of the suitability of current integrity programs for hydrogen services have been focused on the natural gas transmission pipelines. The integrity concern in the medium to low pressure distribution system is considered a lower risk compared to high pressure transmission pipeline assuming that the hydrogen level that is acceptable to high pressure transmission pipeline will not create a significant threat to distribution systems which operate at much lower pressures.

Because the natural gas distribution systems are different from transmission pipelines and they are constructed with a large variety of materials and operated with varied pressures and other conditions, it is not appropriate to simply apply the integrity program for transmission pipelines to distribution systems. In order to assess the potential risks of adding hydrogen to the distribution systems, GTI performed a review on the natural gas distribution systems (see the section ***"Overview-Natural Gas Distribution System in US"***) and the potential fourteen threats in the distribution systems which have been identified by the ***American Gas Foundation*** through the survey of a group of utility operators [27]. Each of the threats has been reevaluated by GTI for the conditions under which the systems transport hydrogen/natural gas mixtures. The integrity investigation from the NaturalHy Project is used as a basis to identify the risk to the integrity of distribution systems.

Integrity Management Program for Transporting Hydrogen/Natural Gas Mixtures [4,5,6]

The needs to upgrade current Integrity Management Program (IMP) for transporting hydrogen/natural gas mixtures were investigated in "NaturalHy Project Work Package 4". The aim of this project is to provide a specification for an Integrity Management Tool (IMT) that allows the operator to modify the existing IMP for hydrogen service. The cost of the new IMP was also evaluated in this study.

This work was led by *DBI-GUT*, with participation by *TNO Science & Industry, Computational Mechanics BEASY, GDF SUEZ, PII Ltd., Istanbul Gas Distribution Co. Inc. (IGDAS), N.V. Nederlandse Gasunie, Instituto de Soldadura e Qualidade (ISQ), Turkish Scientific and Technical Research Council (TUBITAK), StatoilHydro and Total.*

Defects in Natural Gas Pipeline Systems and the Potential Impact by Hydrogen

The acceptable defects in the natural gas pipeline systems are defined in the current integrity program by the number, type, distribution and the shape of the defects. The aspects to be concerned with for hydrogen services is the stress generated at a defect and the rate at which the defect can propagate if the stress is over the critical value for crack propagation. Blunt defects, like corrosion, will not generate relatively large stresses. However, sharp defects, like cracks, can cause significant stress and under typical pipeline fatigue loads hydrogen can accelerate crack growth. In general, crack and crack like defects are considered to be more critical than corrosion defects when hydrogen is introduced.

Impact of Hydrogen on the Defect Criticality

A clear impact on the acceptable initial crack size was observed especially for axial defects. The critical size of the defects can be back calculated with an assumed design life based on the knowledge of crack growth rate in a specific environment. The effect of hydrogen on the defect criticality is minor under the selected assumptions in the hydrogen/natural gas mixtures with up to 50% hydrogen. A tool was developed to calculate the probability that a pipeline will fail or a defect will lead to a pipeline failure and the failure rate.

Inspection/Monitoring Tools and Inspection Intervals

The current inspection tools were investigated for their abilities to identify the critical defects under hydrogen services. The modified pipeline inspection tools (MFL, TRIAX, and EMAT) can be applied to find critical defects when transporting hydrogen/natural gas. The inspection interval can be determined for different hydrogen concentrations, loads and geometries of pipeline and defects based on the in-line inspection and probability of failure (POF) calculation results. The expected inspection intervals will be shortened for transporting hydrogen/natural gas mixture, especially for higher hydrogen concentrations. Improvement of the in-line inspection tools of their reliability and sensitivity to identify critical cracks will be beneficial to lowering the probability of failure.

Cathodic Protection (CP) Integrity Management

A prototype of an integrated remote monitoring system has been proven feasible for coated pipelines. This system includes data collection system and a modeling tool to provide a real time display of the CP protection levels along the pipeline. The benefit of using this remote monitoring system is to manage the pipeline integrity in the presence of hydrogen with reduced cost.

Repair Methods

Three currently applied repair procedures have been investigated to determine if they can be used for pipeline repair under hydrogen service. The focus was on the pipeline load and the effect of hydrogen on welding activities. Clock Spring, Metallic Sleeve and Weld Deposit can be used to repair the pipelines that co-transport hydrogen and natural gas, but the performance will be slightly reduced in some cases.

Cost of the Integrity Management for Hydrogen Service

The cost of the integrity management is strongly dependent on the individual circumstances including hydrogen concentration, defect distribution, material properties, loads and integrity targets. The potential increase of the total cost will be less than 10% for the inspection and repair costs on corrosion and cracks if: (a) the hydrogen concentration is less than 50% of the natural gas blend, (b) with the maximum operation pressure of 957 psig (66 bars), and (c) the design life of the system is 50 years or less.

Additional Information for Distribution Pipeline Integrity under Hydrogen Services

Major Threats to Distribution Infrastructure

The threats are classified in ASME Standard B31.8S (Managing System Integrity of Gas Pipelines) as:

1) Time Dependent Threat
    - External corrosion
    - Internal corrosion
    - Stress corrosion cracking (SCC)
2) Stable Threat
    - Manufacturing related (e.g., defective pipe seam or defective pipe)

- Construction related (e.g., defective pipe girth weld, wrinkle bend or buckle, etc.)
- Equipment related (e.g., gasket or O-ring failure, control/relief equipment malfunction, etc.)

3) Time Independent
   - Third party/Mechanical damage
   - Incorrect operations (incorrect operation procedure)
   - Weather related/outside force (cold weather, lightening, heavy rains or floods, earth movements)

The above threats are defined primarily for natural gas transmission system which operate at high pressure and are constructed predominantly with high strength steels which are coated, wrapped or bare. The materials found in distribution pipeline systems are predominantly steel or polyethylene, with some cast iron, wrought iron, other plastics and copper. Some of the threats to transmission pipelines are not applicable to distribution systems. For example, the threat of stress corrosion cracking is not typically a threat to the distribution infrastructure because it is the cracking of a pipeline from the combined influence of tensile stress, a corrosive environment, and a susceptible material. The distribution pipelines do not operate at pressures high enough to produce the stress necessary to create an environment that could include stress corrosion cracking.

With the different materials taken into account, and in view of the incident causes, the nine threats defined for transmission pipelines were expanded to the following fourteen categories of threats for distribution systems which are prioritized in Table 20 [27]. Unlike transmission pipelines, the top two threats to distribution pipelines are the weather-related outside force damage on cast iron and excavation/mechanical damage instead of the time dependent threats from corrosion (external corrosion, internal corrosion or stress corrosion cracking) posed to transmission pipelines. This is because the distribution pipelines are mostly buried in the highly populated area and are frequently subjected to outside force damage.

For the fourteen threats present for natural gas distribution systems, the likelihood of any threat will not be significantly affected by having hydrogen added in the system, but the severity of the hazard may be increased by hydrogen in the case leaking occurs as a result of an incident.

The integrity program may need to be tightened in the future when hydrogen is added to the distribution system. For example, one may need to shorten the inspection intervals to minimize the possibility of pipeline failure, or to implement leak detection or monitoring device for hydrogen. Currently there is no available odorant for hydrogen, and this may require the development of a new odorant. This may lead to a potentially increase of the maintenance cost for the utilities. Since there is no existing integrity program for distribution system (DIMP is just being introduced in the U.S.), the affect on maintenance cost by adding hydrogen cannot be determined.

Summary and GTI's Concluding Remarks on the Integrity under Hydrogen Services

Conclusions in NaturalHy Project on Transmission Pipeline Integrity

The studies on integrity in NaturalHy project is focused on high pressure transportation pipelines. This study concludes that hydrogen can be transported by the existing natural gas pipeline with small adaptations of the current Integrity Management Program. The necessary adaptations depend on the hydrogen concentration and the operating conditions of the individual pipeline. The modifications of current integrity program is considered insignificant if hydrogen in the pipeline is less than 50%, but it requires a detailed investigation for each case and corresponding modification on the upper limitation of hydrogen concentration.

GTI’s Comments on Distribution Integrity

The threat of hydrogen addition on distribution integrity has been considered smaller when compared to transmission pipelines. It should be noted that the natural gas distribution systems are very different from transmission pipelines, and it is not possible to simply apply the integrity program for transmission pipeline to distribution systems. One of the important differences of distribution systems from transmission pipelines is the locations, i.e., the distribution pipelines are in populated areas. The level of hydrogen that is acceptable for transmission pipeline may need to be reassessed for distribution systems in terms of the frequency and severity of fire or explosion in the populated area. In addition, the gas leakage in a distribution system is more severe than transmission pipeline, especially in a confined service area. The integrity management for distribution systems under hydrogen services may require the implementation of leak detecting/monitoring devices or sensors. Currently, there is no available odorant for hydrogen, and this becomes an area for further investigation.

It is likely that the maintenance cost for distribution system under hydrogen service will be increased due to the need for increasing inspection frequency and leak detection.

Task 4.6 - End Use-Hydrogen Separation

One of the challenge for using the existing natural gas network to distribute hydrogen is to separate hydrogen from the mixtures at the end use. Currently, pressure swing adsorption (PSA) is the mature technology used in refineries to produce high purity hydrogen. However, this technology requires large scale units which work best with high levels (normally larger than 50%) hydrogen in the mixtures. A smaller scale separation is desired to extract hydrogen from the hydrogen-natural gas mixtures which contains lower levels of hydrogen (mostly likely below 25%) under typical natural gas pipeline conditions. In addition, the purity of the hydrogen extracted from hydrogen-natural gas mixtures has to match the requirements in the specific application.

Hydrogen-selective membranes are commonly seen as the promising technology for the recovery of hydrogen from the feed stream with a low (<30%) hydrogen concentration. The NaturalHy project has focused on developing advanced hydrogen selective membranes for the separation of hydrogen from natural gas/hydrogen mixtures in "Work Package 5 (Task 5.3-5.7)".

This work was led by *University of Oxford*, and with participation by the *Norwegian University of Science and Technology (NTNU)* and *Compagnie Europeenne des Technologies del'Hydrogene (CETE).* The objects of this work include:

- Developing membranes to recover hydrogen from hydrogen/natural gas mixtures;
- Investigating the physical properties of the remaining stream and methods to re-establish the gas quality; and
- Performing a cost analysis of the membrane system vs. the commercial PSA systems.

In general, membranes are classified into two major types: dense membranes (e.g., metallic membranes) and microporous membranes (e.g., carbon molecular sieves). Both types of membranes have been investigated in NaturalHy project.

Development of High Selectivity Palladium-Based Membranes

Palladium membranes are the most used technology to recover hydrogen from gas streams with a low hydrogen concentration. In order for these membranes to function efficiently, the entire gas feed stream must be heated to temperatures higher than 350ºC. Currently, the commercially available palladium membranes are conventionally "thick" tubular membranes and are very expensive. The object of NaturalHy project is to develop ultra-thin palladium-alloy membranes supported on porous ceramic substrates to achieve coherent, defect-free membranes. One of the processes that can produce a three micrometer thick membrane is electroless plating of palladium onto a porous alumina substrate. The other technology is to deposit thin palladium/silver alloy membranes onto smooth uniform substrates. These membranes operate at 300ºC with good hydrogen flux, high recovery and 100% selectivity for hydrogen. The results from this investigation indicate:

- Electroless plating of palladium onto a porous alumina substrate can produce the membranes that meet or exceed 2010 US DOE targets for membrane hydrogen flux at 400ºC.
- Depositing thin palladium alloyed with silver and copper is not successful because the manufacturing defects in the ceramic support give rise to pin-hole leaks and mechanical problems.
- Magnetron vacuum sputtering is a potential alternative technique, but the challenge is to use perfectly smooth surfaces such as silicon wafers and polymers as the forming surface and then remove of the deposited membrane.

Development of Carbon-Based Membranes

Though palladium membranes are promising for recovery of hydrogen from feed streams with a low (<30%) hydrogen, these membranes have to be heated to temperatures higher than 350ºC in order to function efficiently. This temperature requirement increases the cost and energy input. Carbon-based membranes are able to separate hydrogen at lower or ambient temperature, however the efficiency with respect to flux and selectivity vary depending on temperature and pressure.

Two types of new carbon-based membrane materials suitable for the recovery of hydrogen from hydrogen/natural gas mixtures have been investigated in this project.

Carbon Molecular Sieves (CMS)

Carbon molecular sieves are formed by carbonization (pyrolysis) of a polymeric precursor at temperatures between 400 and 800ºC. This is usually preformed under vacuum or an inert gas such as nitrogen using cellulose derived from plentiful wood pulp which is cheap and abundant.

Periodical regeneration of carbon membranes can recover hydrogen permeation properties and is beneficial to improve long-term performance of the membranes. A regeneration technique that can be applied on-stream while the membrane is in operation has been developed.

The results from this investigation indicate that the CMS sieves can effectively recover hydrogen from the pipeline networks that transport hydrogen/natural gas blends. It provides a greater permeability and better selectivity (up to 98%) than conventional polymer membranes and operates at temperatures between 30ºC and 90ºC. Further development is ongoing to develop larger scale membrane modules and perform lifetime testing.

A Mixed Matrix (MM) Material

The development of the MM-membrane did not provide successful results and the development of this membrane was terminated in this project.

Development of Hybrid Membrane Separation System

It is most likely that the beneficial characteristics from metallic and carbon based membranes can be combined by producing a hybrid membranes to provide an increase in efficiency and flexibility together with lower cost. A carbon based membrane can be used as at the first stage to achieve higher hydrogen content (up to 98%) at almost room temperature and then followed by a palladium membrane for final purification of hydrogen. A hybrid separation system is proposed for further development, see Figure 11.

Summary on Hydrogen Separation Technologies

Electroless plating of palladium and carbon molecular sieves are the two technologies that can be further developed for hydrogen separation from hydrogen/natural gas blends transported by a natural gas pipeline network. A Palladium membrane can provide high purity hydrogen, but is expensive and has to operate at 300ºC. A CMS membrane is low cost and can operate at temperature between 30ºC and 90ºC, but the maximum hydrogen content obtained using a CMS membrane is 98%.

The most promising technique in the future would be a hybrid separation system. This could be constructed by combining palladium and CMS membrane technology. The cost analysis performed in this study indicates that the hybrid system including ancillaries is potentially cheaper than separation by PSA. Small scale PSA systems are under development, but it is problematic for PSA to separate hydrogen from streams with hydrogen content less than 40%, an additional PSA or a CMS membrane can be used in the first stage to concentrate the hydrogen level in the feed.

The analysis performed in this study also shows that the downstream gas quality will not be adversely affected since the Wobbe index and heating value will not be outside the statutory requirements.

Task 4.7 – Impacts (Environmental and Macroeconomic Benefits)

The impact from adding hydrogen into natural gas systems was assessed in "NaturalHy Project Work Package 1". The review of this study by GTI is included in Task 4.1, and below is a summary of the major impacts on environmental and macroeconomic benefits from adding hydrogen in natural gas:

1) Significant reduction of greenhouse gas emissions if hydrogen is produced from biomass, wind power, and nuclear power.
2) Some advantage on greenhouse gas emissions with hydrogen production from fossil fuels with CCS, but no benefits for decreasing primary energy demand or energy resource depletion.
3) Potential benefits of selective extraction of hydrogen (this depend on the performance of the separation technology and the subsequent use of the hydrogen and the residual gas).
4) Potential benefits on improving air quality by reducing sulfur dioxide, oxides of nitrogen and particulate emissions if hydrogen is used in transportation and displaces conventional diesel fuel.
5) Potential benefit on "greening" natural gas if the hydrogen/natural gas mixture is used directly in existing appliances for heat production and electricity generation.

Conclusions

GTI reviewed the studies performed by the *NaturalHy* Project on using natural gas network for hydrogen services. The scope of this review covers the seven aspects that have been investigated in NaturalHy including “Life Cycle Assessment”, “Safety”, “Leakage Assessment”, “Durability”, “Integrity”, “End Use” and “Environmental and Macroeconomic Impacts”. In addition to the reports and publications from the NaturalHy Project, GTI included the report published by the Greenhouse Gas R&D Programme sponsored by International Energy Agency (IEA) and other related publications in this review to develop a comprehensive understanding of the major benefits and limitation of using the existing natural gas network for transporting hydrogen.

The aim of this review was to provide a scientific basis and engineering assessment of the potential impact from hydrogen on the US natural gas distribution infrastructure when hydrogen is blended into the natural gas network. The conclusions of this review not only include the summary of the findings and conclusions from the research investigations, but also include GTI’s comments made for US distribution system by integrating the research findings with the particular conditions for the distribution infrastructure. The main conclusions of the seven tasks are summarized below:

1) Task 4.1 Life Cycle Assessment

The life cycle assessment in the NaturalHy project supports the beneficial effects on the environment by adding hydrogen to natural gas, which include the reduction of greenhouse emission and improving the air quality. However, there is not enough information in this study to support that there is a benefit from the standpoint of economy and employment. No concluding remarks were made in this aspect.

2) Task 4.2 Safety

The research findings indicate that the probability of ignition and the severity of explosion of pipeline systems are increased by adding hydrogen. The risk increased by blending hydrogen into natural gas pipeline systems is related to the hydrogen levels in the gas mixtures, and the increase is slight for hydrogen addition up to 20%.

GTI performed a quantitative risk assessment on US natural gas distribution systems for carrying hydrogen containing natural gas. Compared to the current situation with natural gas, the risks in natural gas distribution systems are increased by adding hydrogen into the system. The assessment results indicate that the risks in distribution mains and service lines are different, especially at higher levels of hydrogen in the system.

If less than 20% hydrogen is introduced into distribution system, the overall risk is not significant for both distribution mains and service lines, but the service lines are more impacted than mains because they are mostly in confined spaces.

If the hydrogen level in natural gas increases beyond 20%, the overall risk in service lines can significantly increase and the potential hazards can become severe, while the overall risk in distribution mains still can be moderate at up to 50% hydrogen.

For hydrogen level above 50% in natural gas, the risks in both distribution mains and service lines significantly increase compared to the situation with natural gas, and the overall risk in distribution system becomes severe.

3) Task 4.3 Leakage

Hydrogen is more mobile than methane in many polymer materials including the plastic pipes and elastomeric seals used in natural gas distribution system. The permeation coefficient of hydrogen is higher through most of the elastomeric sealing materials vs. plastic pipe materials. But the plastic pipes have much larger surface area compared to the seals. Therefore, the leaks through pipe walls accounts for the major gas loss in the systems.

A calculation based on the literature data for the permeation coefficient of hydrogen and methane in the polyethylene indicates that the majority of the gas loss is from the pipes (pipe wall) in distribution mains which operate at 60 psig (4.1 bar) or higher. The gas loss from the total of 414,830 miles of polyethylene pipes with the sizes less than 2″ in the entire distribution mains is about 40 million cubic feet per year if 20% hydrogen is added into natural gas pipeline system. Though this amount of gas loss is almost double the total gas loss when the systems deliver only natural gas, it is still considered insignificant from the economic point of view. Furthermore, this calculation may over estimate the gas loss because the permeation coefficient in the literature is considered larger than the experimental measurements using pipe test under actual operating pressures, especially at lower pressure. Further investigation may be necessary for accurately quantifying the gas loss.

The amount of gas loss from service lines is negligible from the economy point of view, but the gas loss into a confined space may increase hydrogen concentration to levels that may become a threat from the safety standpoint. In addition, the gas leak from the elastomeric seals at the joints in service lines may increase the risk in confined spaces.

Further investigation on the pipe and seal materials can provide a basis to accurately estimate the gas leakage through pipes and seals in order to determine if the leakage in a confined space, over time, will present a safety risk and if it is required to implement a leak detection/monitoring device.

4) Task 4.4 Durability

The metallic pipes in US distribution systems are primarily made of low strength steel, typically API 5L A, B, X42 and X46 in distribution mains. They are not the type of steels that are susceptible to hydrogen induced brittle cracking. In addition, at the stress level generated in natural gas distribution system, hydrogen induced failures are not major integrity concerns for the steel pipes in distribution system.

For the other metallic pipes including ductile iron, cast and wrought iron, and copper pipes, there is no concern of hydrogen damage under general operating conditions in natural gas distribution systems.

There is no major concern on the hydrogen aging effect on PE or PVC pipe materials. Most of the elastomeric materials used in distribution system are also compatible with hydrogen.

The deviation of a gas meter with hydrogen/methane mixtures varies with the manufacture's detail of the meter design. Nonetheless, the deviation is acceptable based on the requirement for recalibration (<4%) when they are measuring a gas mixture containing less than 50% hydrogen. The meters may not need to be tuned under the potential hydrogen levels (<50%) in natural gas pipeline that are transporting hydrogen/natural gas blends.

One of the remaining gaps needs to be addressed for the durability issues is the potential contaminants in hydrogen gas that may be introduced into the network.

5) Task 4.5 Integrity

In the NaturalHy Project and some other research programs, the focus on the integrity issues has been on the transmission pipelines because of the concerns of high operating pressures (up to 2000 psig (138 bar)) and the pipeline steels that are subject to hydrogen induced cracking. It is concluded in the NaturalHy Project that hydrogen can be transported by the existing natural gas pipeline with small adaptations of the current Integrity Management Program. The necessary adaptations depend on the hydrogen concentration and the operating conditions of the individual pipeline. The necessary modifications are not significant with up to 50% hydrogen addition, but a detailed investigation for every case is mandatory and the upper limitation on hydrogen concentration may be reduced.

It should be noted that the natural gas distribution systems are very different from transmission pipelines, and it is not possible to simply apply the integrity program for transmission pipelines to distribution systems. One of the important differences of distribution systems from transmission pipeline is the locations of these systems. The level of hydrogen that is acceptable for transmission pipeline may need to be reassessed for distribution systems in terms of the frequency and severity of fire or explosion in a highly populated area.

In addition, the hazards arising from gas leakage in a distribution system may be more severe than in transmission pipelines, especially in a confined service area. The integrity management for distribution systems under hydrogen services may require the implementation of leak detecting or a monitoring device or sensor. Currently, there is no available odorant for hydrogen, and this becomes an area for further investigation.

It is likely that the maintenance cost for distribution systems under hydrogen service will be increased due to the need for increasing inspection frequency and implementing leak detection.

6) Task 4.6 End Use Hydrogen Separation

Electroless plating of palladium membranes and carbon molecular sieves are the two technologies that can be further developed for hydrogen separation from hydrogen/natural gas blends transported by a natural gas pipeline. Palladium membranes can provide high purity hydrogen, but they are expensive and have to operate at 300ºC. CMS membranes are low cost and can operate at temperature between 30ºC and 90ºC, but the maximum hydrogen concentration obtained using CMS membranes is 98%.

The most promising technique is to making a hybrid separation system by combining palladium and CMS membranes. The cost analysis performed in this study indicates that the hybrid system, including ancillaries, is potentially cheaper than separation by PSA.

Small scale PSA systems are also under developments that include an additional PSA or a CMS membrane in the first stage to concentrate the hydrogen level in the feed.

Downstream gas quality will not be adversely affected since the Wobbe index and heating value will not be outside the statutory requirements.

7) Task 4.7 Environmental Impact

Adding hydrogen in natural gas can significantly reduce greenhouse gas emissions if hydrogen is produced from biomass, wind power and or nuclear power. There are also some advantages related to greenhouse gas emissions with hydrogen production from fossil fuels with CCS, but hydrogen from this source has no benefits for decreasing primary energy demand or energy resource depletion.

Adding hydrogen in natural gas also has the potential benefits of improving air quality by reducing sulfur dioxide, oxides of nitrogen and particulate emissions if hydrogen is used in transportation and displaces conventional diesel fuels. It could also green natural gas if the hydrogen/natural gas mixture is used directly in existing appliances for heat production and electricity generation.

END OF REPORT

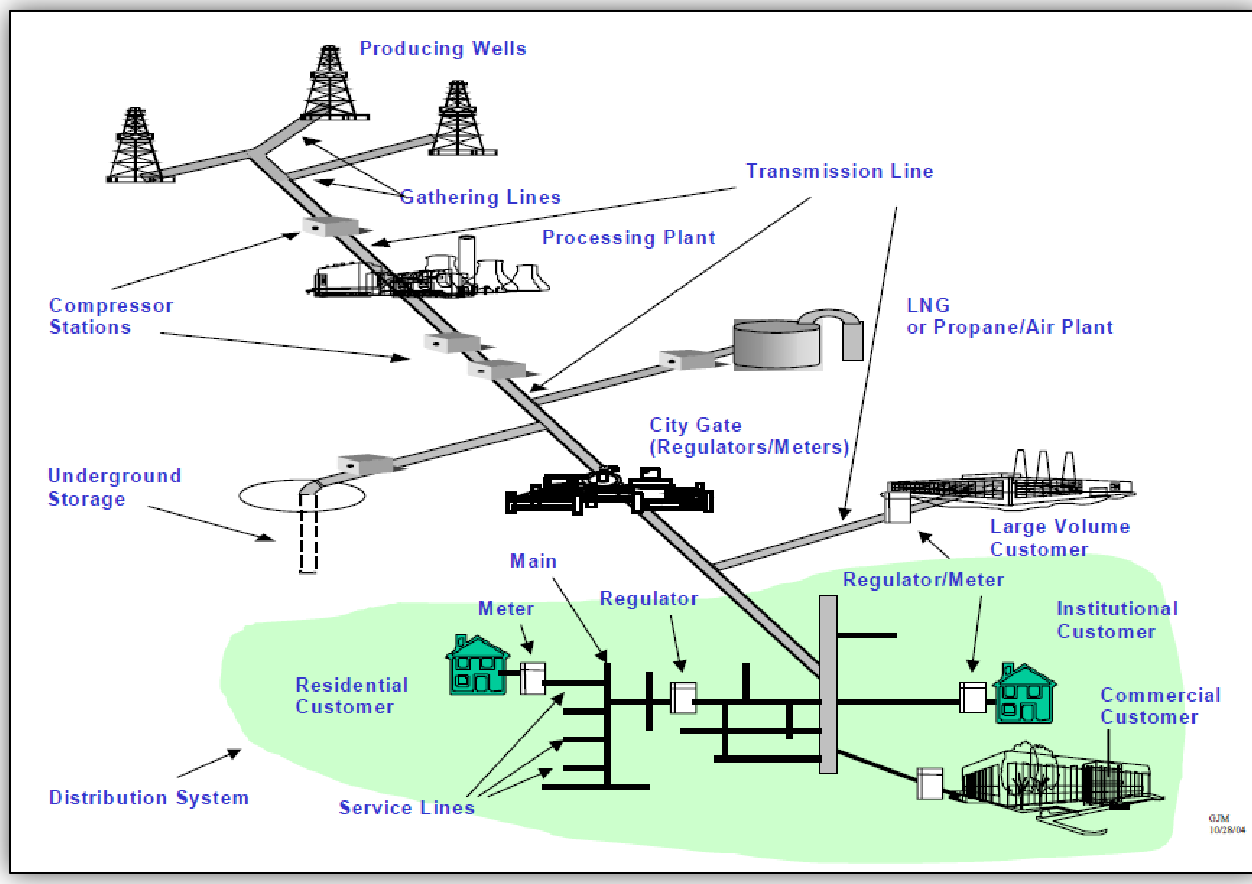
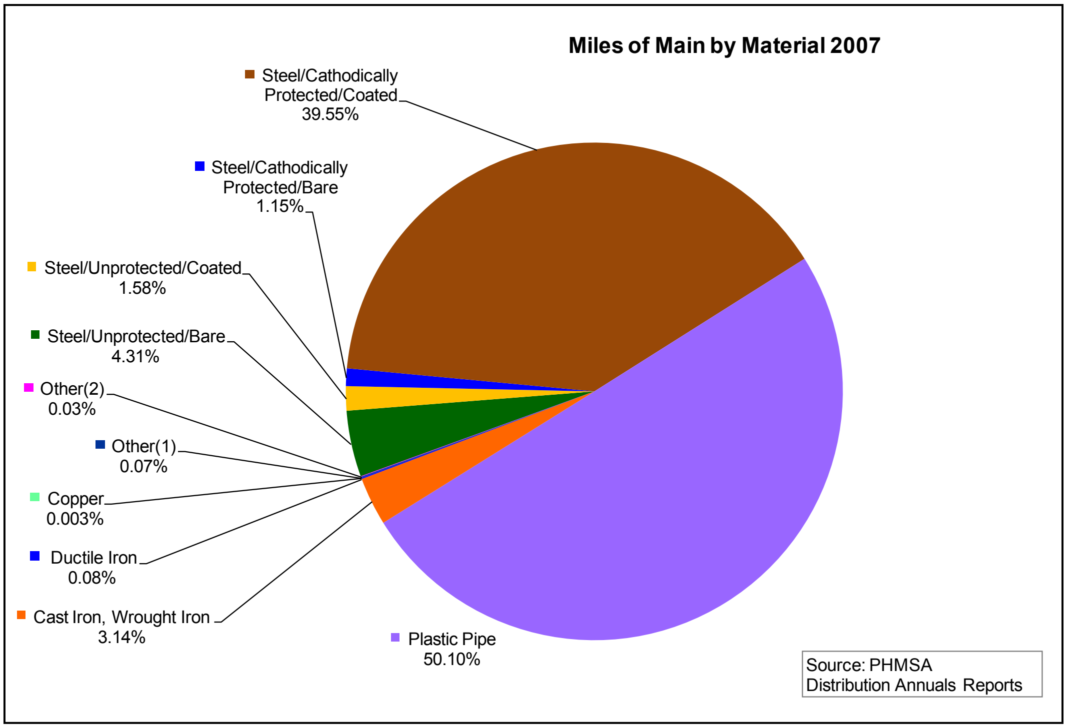


Figure 1. Schematic of the Natural Gas Delivery Pipeline Infrastructure*

Note:

*: Figure from AGF report "Safety Performance and Integrity of the Natural Gas Distribution Infrastructure" [27].



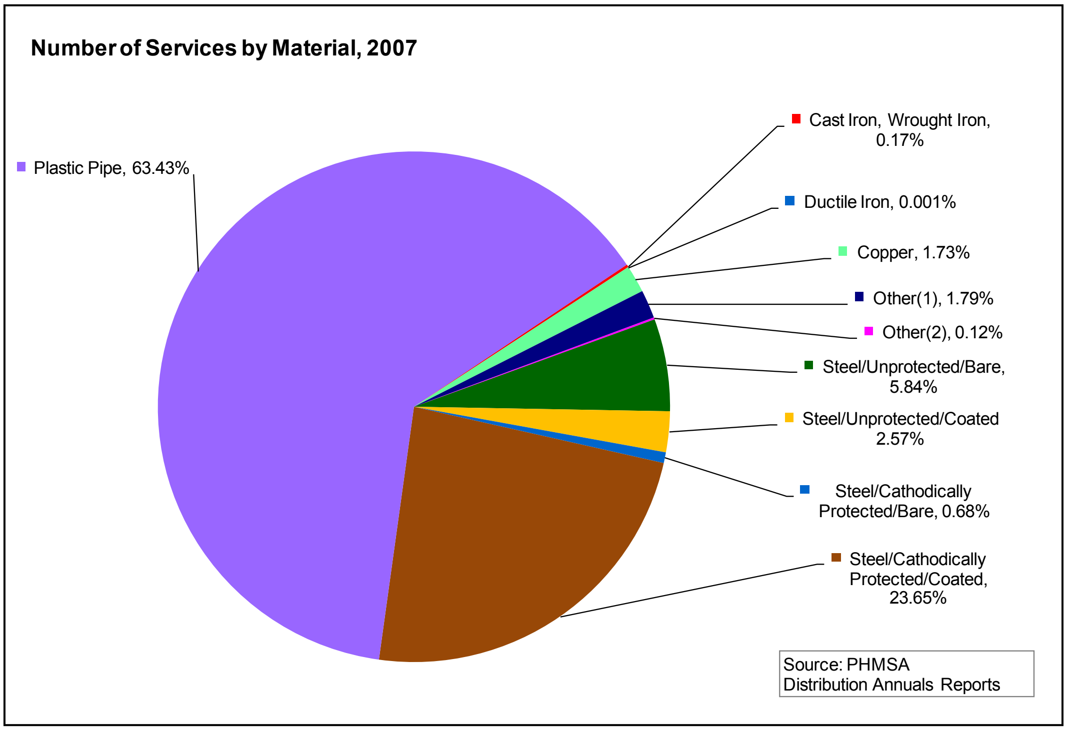
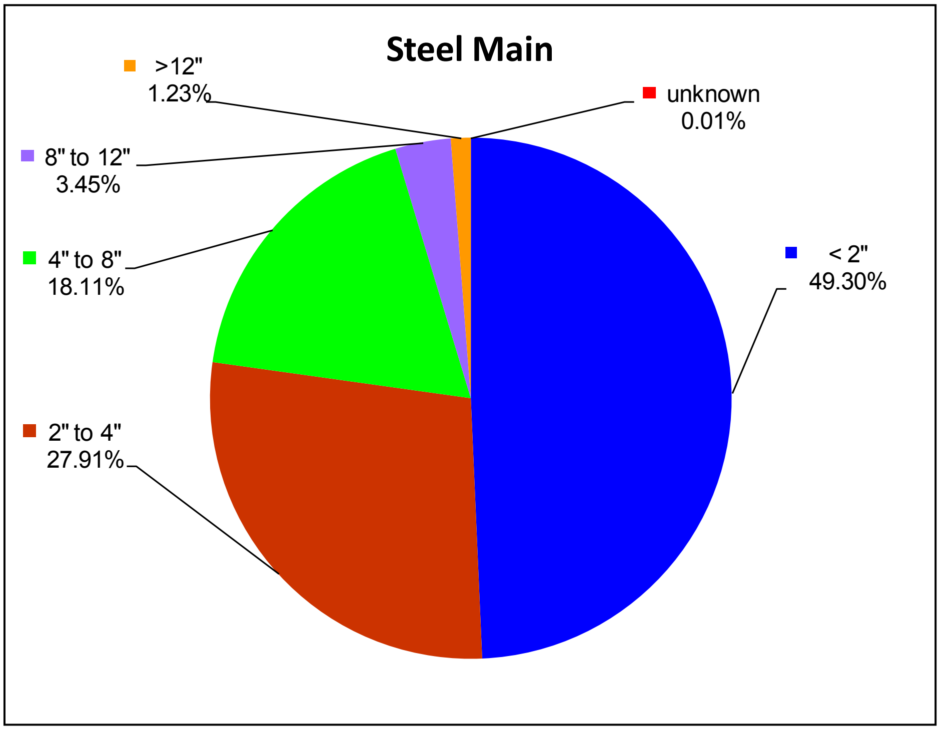


Figure 2. Piping Materials of Mains and Service Lines in Distribution Systems*

Note:

*: Original data from DOT 2007 Annual Report [25]



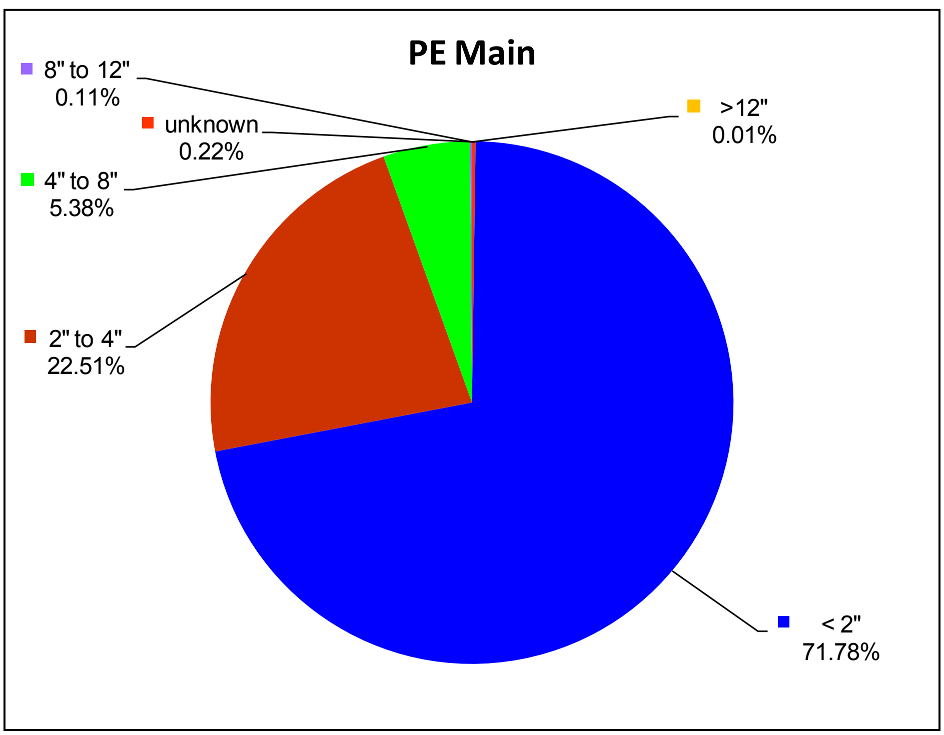
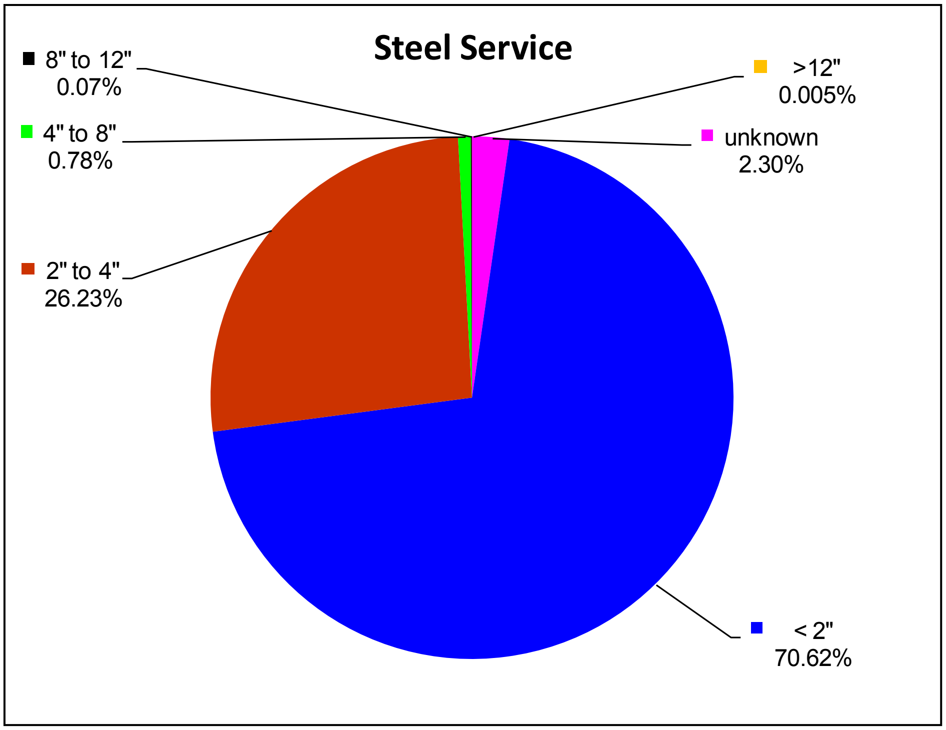


Figure 3. The Distribution of Pipe Size of Steel and PE Pipes in Distribution Mains*

Note:

*: Original data from DOT 2007 Annual Report [25]



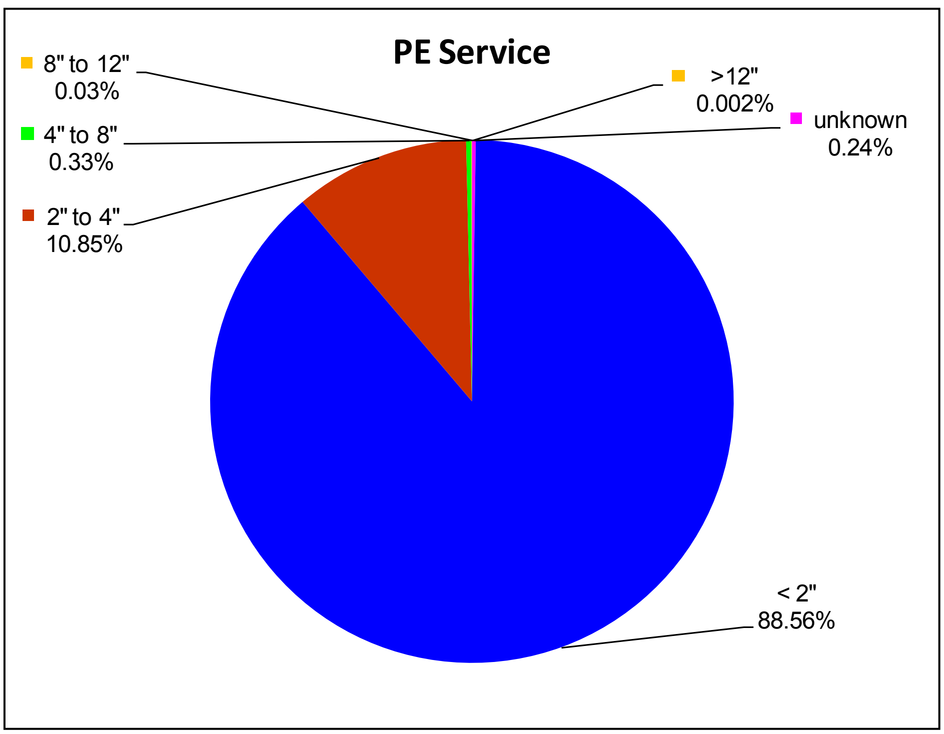


Figure 4. The Distribution of Pipe Size of Steel and PE Pipes in Service Lines*

Note:

*: Original data from DOT 2007 Annual Report [25]

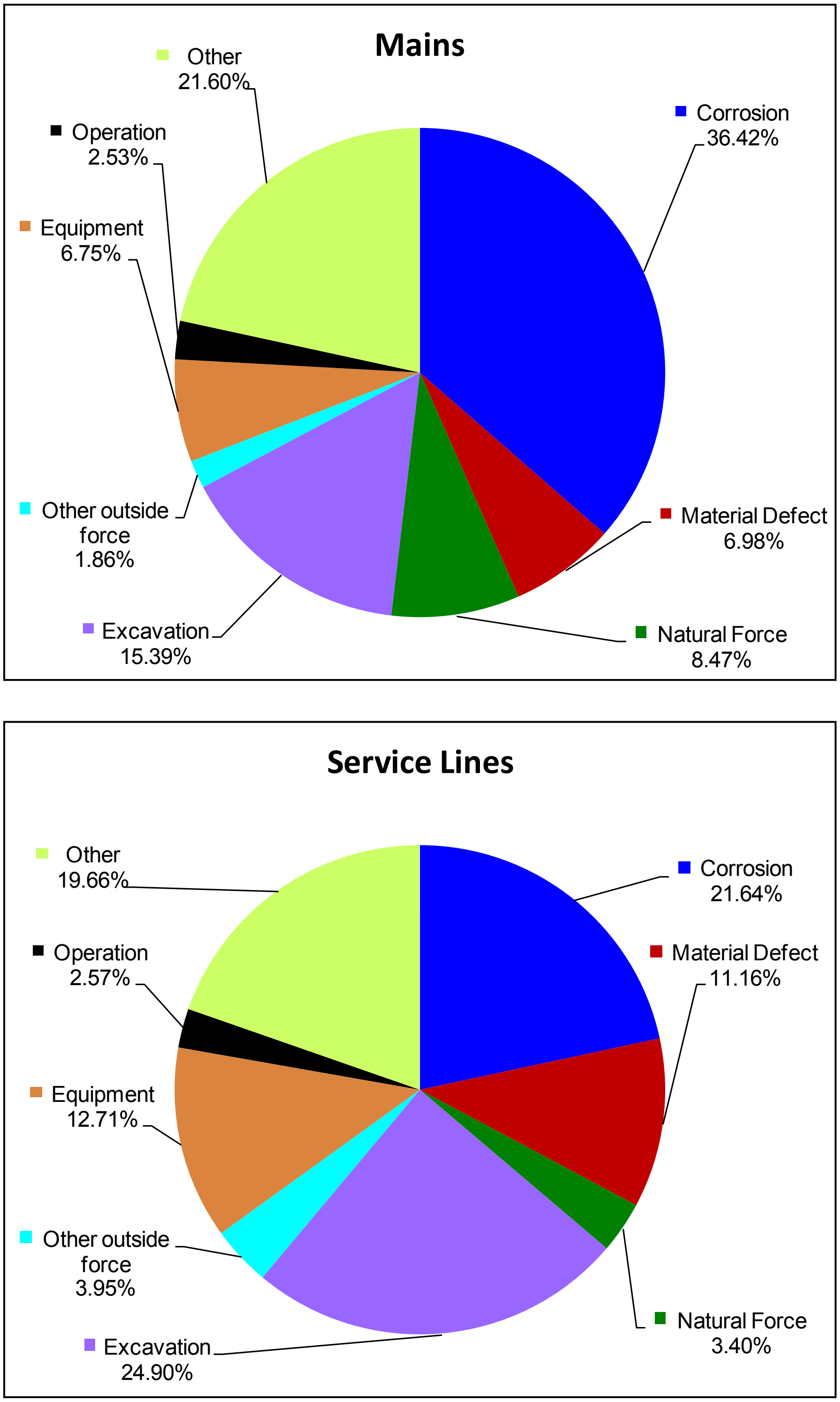


Figure 5. Statistical Data for Leak Incidents in Distribution Mains and Service Lines*

Note:

*: Original data from DOT 2007 Annual Report [25]

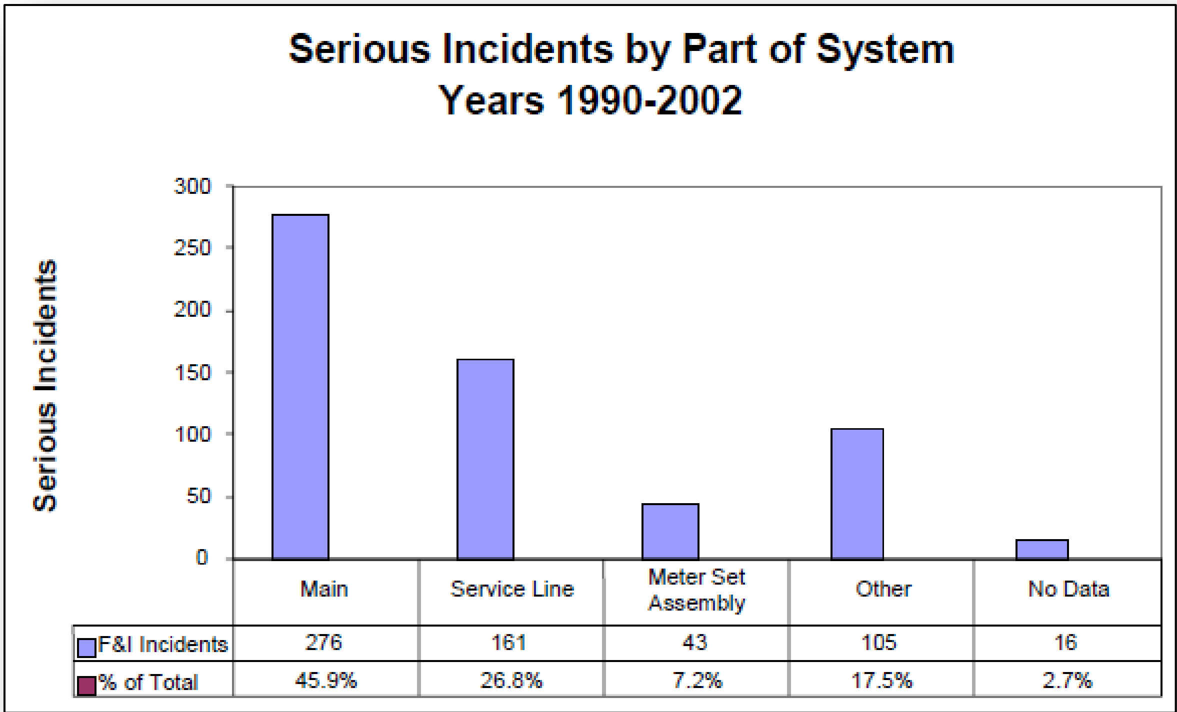


Figure 6. Incidents by Part of the Distribution System*

Note:
*: Plot from AGF report “Safety Performance and Integrity of the Natural Gas Distribution Infrastructure” [27].

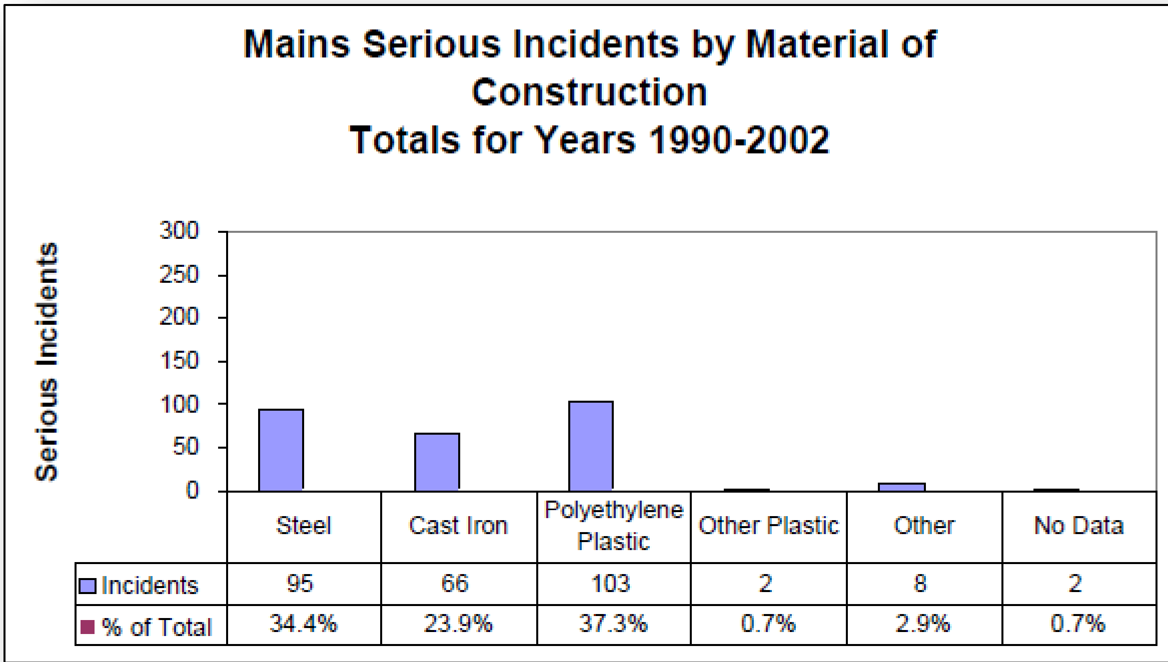
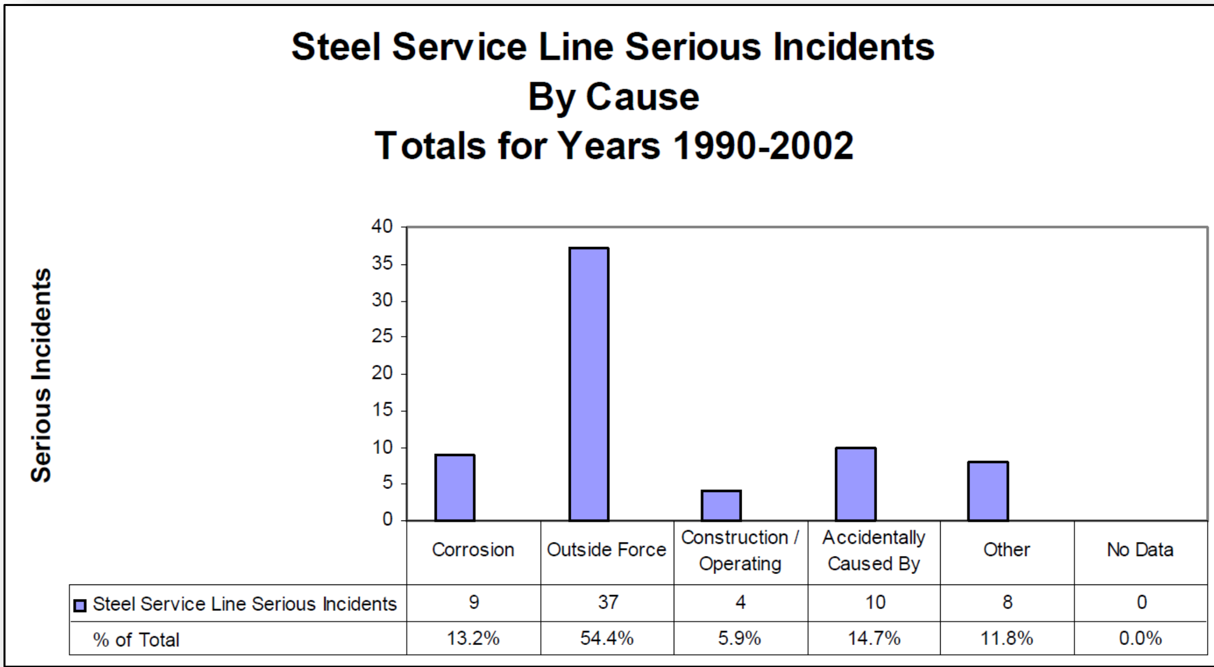


Figure 7. Serious Incidents by Construction Materials of Mains*

Note:

*: Plot from AGF report "Safety Performance and Integrity of the Natural Gas Distribution Infrastructure" [27].



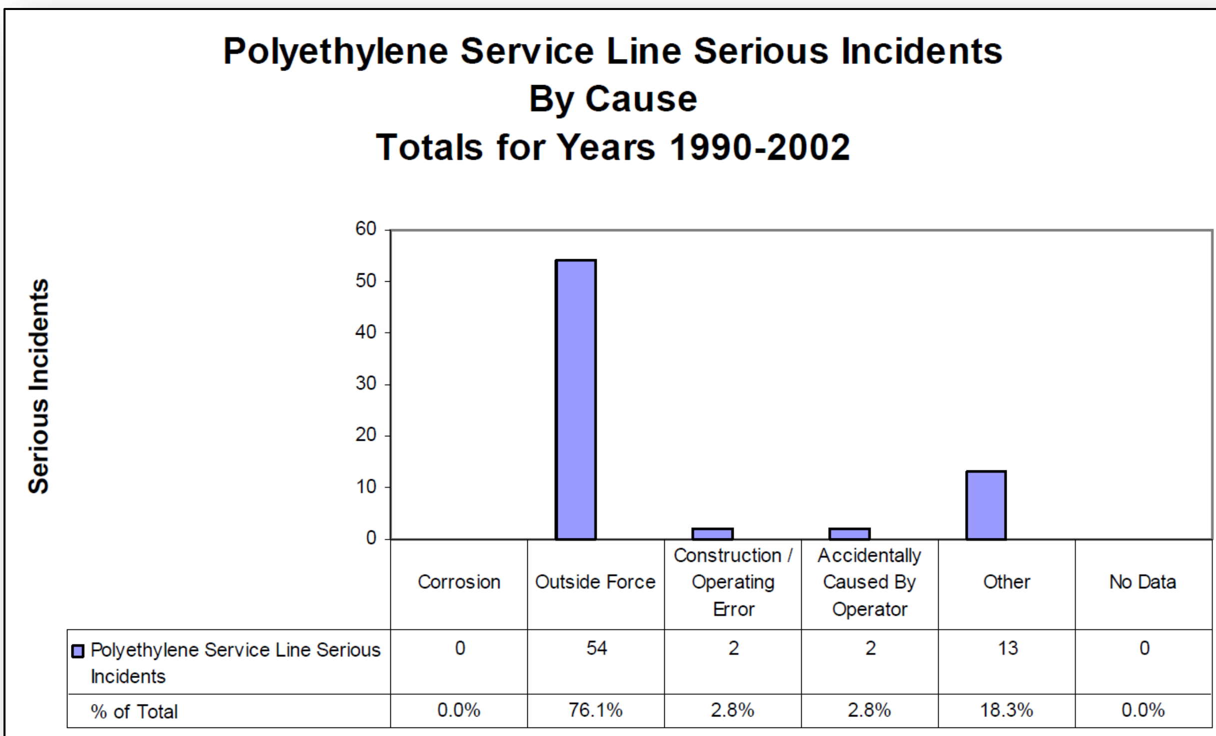


Figure 8. Serious Incidents in Steel and Polyethylene Service Lines by Cause*

Note:

*: Plot from AGF report “Safety Performance and Integrity of the Natural Gas Distribution Infrastructure” [27].

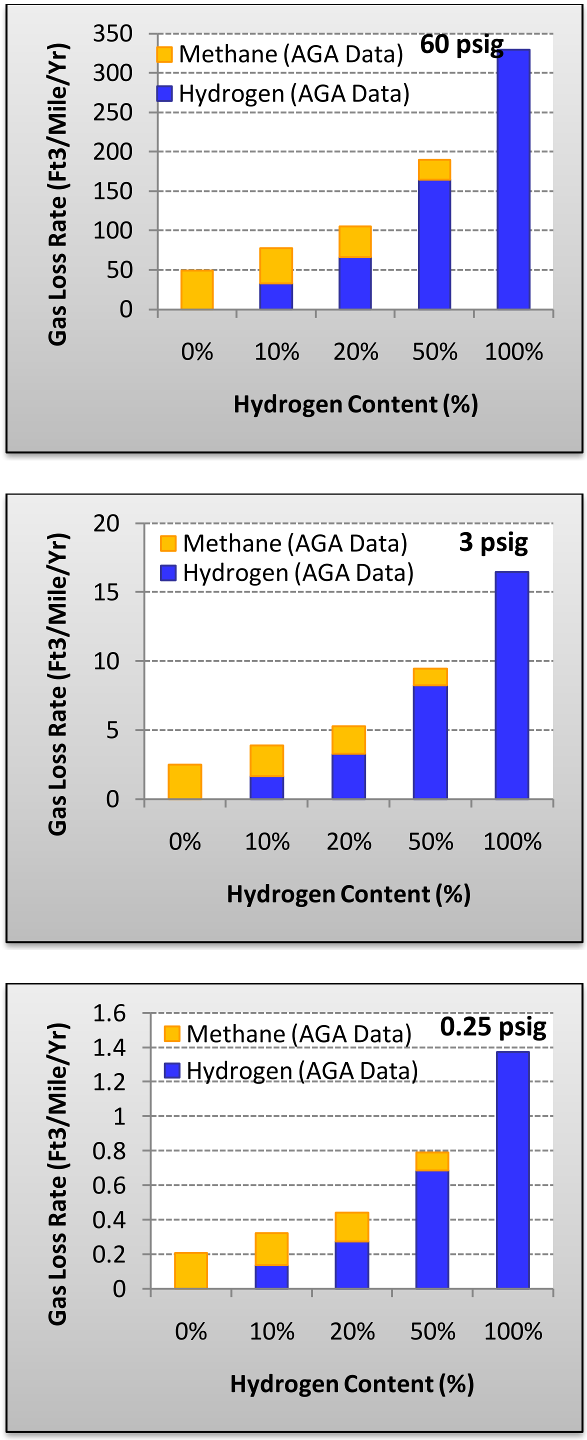


Figure 9. The Calculated Gas Loss Rate vs. Hydrogen Concentration in Hydrogen/Methane Mixtures at the Typical Distribution Operating Pressures (60 psig (4.1 bar), 3 psig (210 mbar) and 0.25 psig (17.2 mbar))*

Note:

*: The data are calculated by Equation (2) using the permeation coefficient data in Table 16 from AGA Handbook "Plastic Pipe Manual for Gas Service" [29].

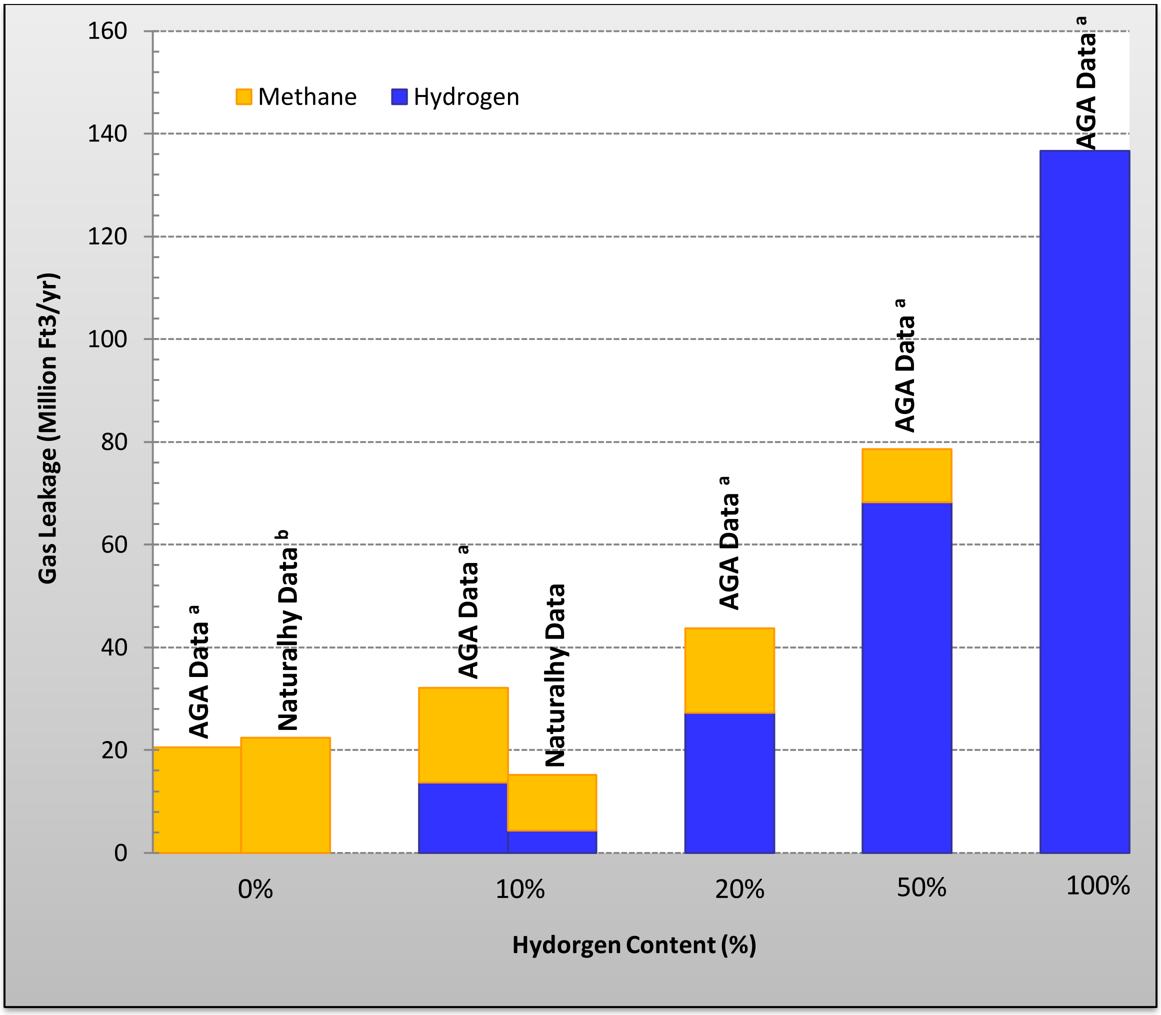


Figure 10. The Calculated Gas Loss from the Gas Mixtures Containing Different Levels of Hydrogen in Distribution System at 60 psig (4.1 bar) Operating Pressure

Note:

a: AGA Data: The data are calculated by Equation (2) using the permeation coefficient data in Table 16 from AGA Handbook "Plastic Pipe Manual for Gas Service" [29].

b: The original data are from the experimental test results in the paper of "Evaluation of the Permeability to CH_4 and H_2 of PE Currently Used in Gas Distribution Networks" [18], and are converted to the English unit.

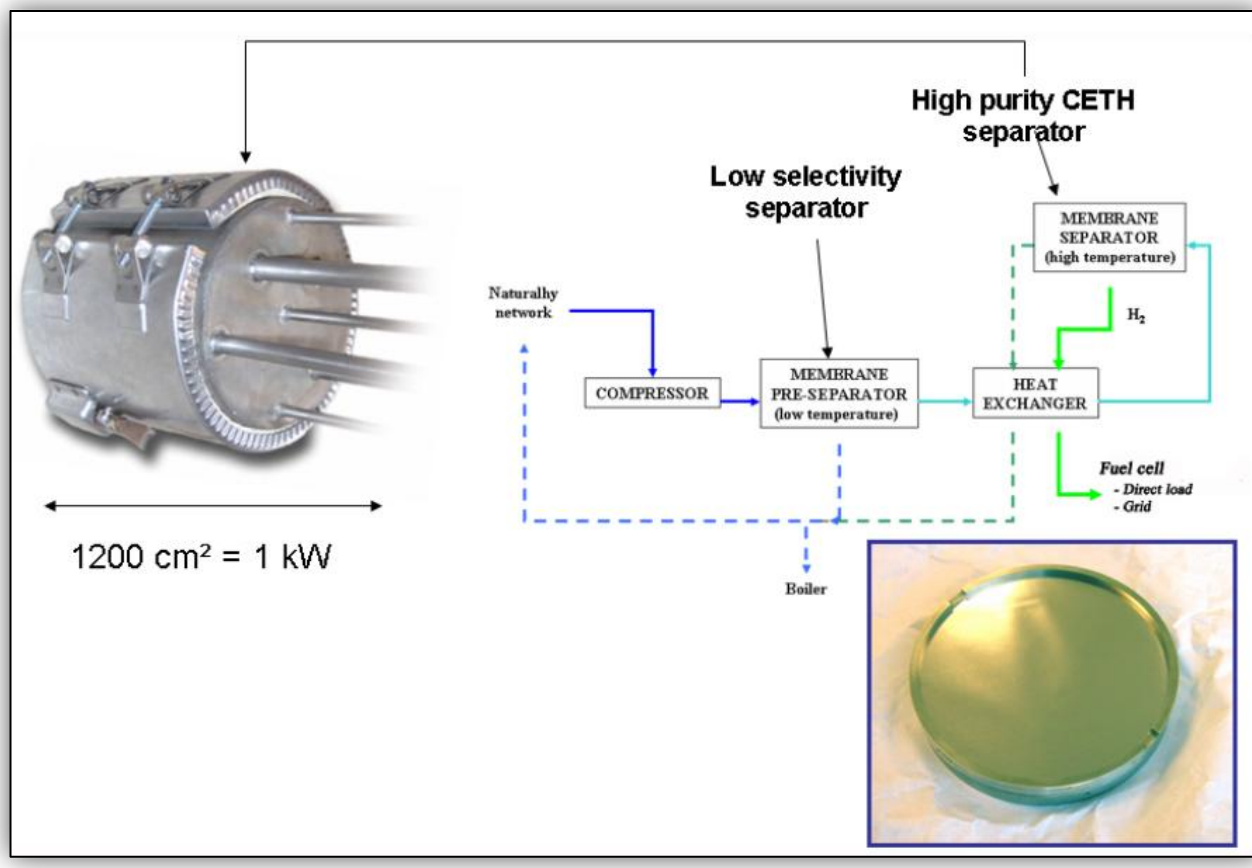


Figure 11. A Hybrid Separation Membrane System for Hydrogen Recovery*

Note:
*: Plot from NaturalHy "Interim Report on Membrane Development for Hydrogen Separation" [7].

Table 1. Regulation Mandated Inspection of Gas Pipeline Facilities*

Distribution	Transmission
Buried pipeline corrosion protection electrical current readings at test stations spaced along the pipeline must be checked at least once a year	Buried pipeline corrosion protection electrical current readings at test stations spaced along the pipeline must be checked at least once a year
Buried pipeline external corrosion control systems must be checked at least 6 times a year	Buried pipeline external corrosion control systems must be checked at least 6 times a year
Equipment monitoring for internal corrosion at points where the risk of such exists must be checked at least once in 6 months	Equipment monitoring for internal corrosion at points where the risk of such exists must be checked at least once in 6 months
Distribution pipelines exposed to the atmosphere must be checked for external corrosion at least once in every 3 years.	Onshore pipelines exposed to the atmosphere must be checked for external corrosion at least once in every 3 years; offshore pipes exposed to the atmosphere must be checked at least once a year.
Whenever the operator has knowledge that any portion of its buried ferrous distribution pipeline is exposed, the exposed portion must be examined for evidence of external corrosion or if the coating is deteriorated.	Whenever the operator has knowledge that any portion of its buried transmission pipeline is exposed, the exposed portion must be examined for evidence of external corrosion or if the coating is deteriorated.
Operator carries out continuing surveillance of its facilities to determine and take appropriate action concerning changes in population density near the pipeline, failures, leakage history, corrosion and other unusual operating and maintenance conditions.	Operator carries out continuing surveillance of its facilities to determine and take appropriate action concerning changes in population density near the pipeline, failures, leakage history, corrosion and other unusual operating and maintenance conditions.
If a segment of pipe is determined to be in unsatisfactory condition, but no immediate hazard exists, the operator must initiate a program to recondition that segment or phase it out. If this is not possible, the operator must reduce the operating pressure of the pipeline, in accordance with prescribed guidelines. If an immediate hazard exists, the operator must take prompt action to repair the segment.	If a segment of pipe is determined to be in unsatisfactory condition, but no immediate hazard exists, the operator must initiate a program to recondition that segment or phase it out. If this is not possible, the operator must reduce the operating pressure of the pipeline, in accordance with prescribed guidelines. If an immediate hazard exists, the operator must take prompt action to repair the segment.
Distribution pipelines in places or structures where anticipate physical movement or external loading could take place must be patrolled at least 4 times a year in business districts and twice a year outside business districts.	Each operator must patrol its transmission pipeline right-of-way at intervals between 4 times and once a year, depending on certain risk factors.

Note:

*: Table from AGF report "Safety Performance and Integrity of the Natural Gas Distribution Infrastructure" [27].

Table 1. Regulation Mandated Inspection of Gas Pipeline Facilities [27] (Continued)

Distribution pipelines in business districts must be checked for leaks at least once a year including tests for gas presence in subterranean facilities and other areas near a leak.	Transmission pipelines carrying odorized gas must be checked for leaks at least once a year.
Distribution pipelines outside business districts must be checked for leaks at least once every 5 years. Where electrical readings for corrosion protection are impractical, the leak checks must be at least once every 3 years.	Emergency shutdown devices at gas compressor stations must be tested at least once a year.
Disconnected gas service lines must be re-tested before being reconnected.	
Each distribution line valve that may be necessary for the safe operation of the system must be inspected at intervals not exceeding one year.	Each transmission line valve must be inspected and partially operated at least once a year.
Each pressure limiting and pressure regulating station must be inspected and tested at least once a year. This includes inspection of the gas pressure history recorded at these stations.	Each pressure limiting and pressure regulating station on the transmission pipeline must be inspected and tested at least once a year. This includes inspecting the gas pressure history recorded at these stations.
Pressure relief devices must be tested at least once a year for the ability to protect the pipeline from over pressure	Pressure relief devices on the pipeline or at compressor stations to must be tested at least once a year for the ability to protect the pipeline from overpressure.
If larger than 200 cubic feet in size, each underground vault housing pressure regulating or pressure limiting equipment must be tested for gas leaks at least once a year.	If larger than 200 cubic feet in size, each underground vault housing pressure regulating or pressure limiting equipment must be tested for gas leaks at least once a year.
(a) A combustible gas in a distribution line must contain a natural odorant or be odorized so that at a concentration in air of one-fifth of the lower explosive limit, the gas is readily detectable by a person with a normal sense of smell.	After December 31, 1976, a combustible gas in a transmission line in a Class 3 or Class 4 location must contain a natural odorant or be odorized so that a concentration in air of one-fifth of the lower explosive limit, the gas is readily detectable by a person with a normal sense of smell unless: (1) At least 50% of the length of the line downstream from that location is in a Class 1 or Class 2 location; (2) The line transports gas to certain facilities; (3) In the case of a lateral line which transports gas to a distribution center, at least 50% of the length of that line is in a Class 1 or Class 2 location; or (4) The combustible gas is hydrogen intended for use as a feedstock in a manufacturing process.
Odorant concentrations must be periodically monitored using test instruments.	Odorant concentrations must be periodically monitored using test instruments.

Note:

*: Table from AGF report "Safety Performance and Integrity of the Natural Gas Distribution Infrastructure" [27].

Table 2. Pipe Sizes and Materials in Distribution Systems*

Type	Size	Quantity	Steel	Ductile Iron	Copper	Wrought/ Cast Iron	PVC	PE	ABS	Other	Total by Size
Mains	Unknown	Miles	44	0	0	3	88	1290	234	9	1667
		%	0.00	0.00	0.00	0.00	0.01	0.11	0.02	0.00	0.14
	< 2"	Miles	275599	0	33	1199	18061	414831	2268	530	712520
		%	22.95	0.00	0.00	0.10	1.50	34.54	0.19	0.04	59.33
	2" to 4"	Miles	156023	214	3	15424	3444	130091	251	157	305609
		%	12.99	0.02	0.00	1.28	0.29	10.83	0.02	0.01	25.45
	4" to 8"	Miles	101239	470	1	15913	366	31077	4	29	149099
		%	8.43	0.04	0.00	1.32	0.03	2.59	0.00	0.00	12.41
	8" to 12"	Miles	19273	70	0	3146	0	625	0	5	23119
		%	1.60	0.01	0.00	0.26	0.00	0.05	0.00	0.00	1.93
	>12"	Miles	6875	73	0	1985	0	37	0	2	8973
		%	0.57	0.01	0.00	0.17	0.00	0.00	0.00	0.00	0.75
	Total by Materials	Miles	559053	828	36	37670	21959	577950	2757	732	1200987
		%	46.55	0.07	0.00	3.14	1.83	48.12	0.23	0.06	100.00
Services	Unknown	Numbers	486667	0	70	52	918	97283	453	487767	1073210
		%	0.75	0.00	0.00	0.00	0.00	0.15	0.00	0.75	1.66
	< 1"	Numbers	14953056	0	703688	96381	224150	36183571	9870	723781	52894497
		%	23.07	0.00	1.09	0.15	0.35	55.84	0.02	1.12	81.62
	1" to 2"	Numbers	5554217	0	416609	10881	32866	4431757	642	60707	10507679
		%	8.57	0.00	0.64	0.02	0.05	6.84	0.00	0.09	16.21
	2" to 4"	Numbers	164653	0	582	621	244	132842	130	525	299597
		%	0.25	0.00	0.00	0.00	0.00	0.20	0.00	0.00	0.46
	4" to 8"	Numbers	15260	332	15	236	7	11066	0	80	26996
		%	0.02	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.04
	>8"	Numbers	1050	46	0	12	0	839	0	1	1948
		%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Total by Materials	Numbers	21174903	378	1120964	108183	258185	40857358	11095	1272861	64803927
		%	32.68	0.00	1.73	0.17	0.40	63.05	0.02	1.96	100.00

Note:

*: Original data from DOT 2007 Annual Report [25]

Table 3. Steel Grades for Distribution Pipelines and Their Material Properties*

API 5L	Min Yield Strength		Min Ultimate Tensile Strength		Min Elongation
Grade	ksi	MPa	ksi	MPa	%
A	30	207	48	331	-
B	35	241	60	413	22.5
X42	42	289	60	413	22.5
X46	46	317	63	434	21.5

Note:

*: Table from CTC report "Existing Natural Gas Pipeline Materials and Associated Operational Characteristics (Hydrogen Regional Infrastructure Program in Pennsylvania)" [10]

Table 4. Elastomers in Natural Gas Distribution System*

	Material Name	Other Names	Type	Acronym
1	Butadiene-Styrene	Buna-S; GR-S	Styrene-butadiene Rubber	SBR
2	Butadiene-Acrylonitrile	Buna-N; Nitrile; Perbunan; Nytek	Acrylonitrile-butadiene Rubber	NBR
3	Natural Rubber	Gum	Natural Rubber	NR
4	Polychloroprene	Neoprene; Bayprene; Chloroprene	Synthetic Rubber	CR
5	Ethylene-Propylene	Nordel; Royalene; Dutral	Synthetic Rubber	EPM & EPDM
6	Polyamide (11 and 12)	Rilsan; Vydyne; Plaskin; Nylon	PA11 & PA12 Elastomer	PA11 & PA12
7	Silicone and Fluorosilicone	Polysiloxanes; Cohrlastic; Green-Sil; Parshiled; Baysilone; Blue-Sil	Silicone Rubber/Polysiloxane	SI &FSI
8	Fluoroelastomer	Viton; Fluorel; Technoflon	High Performance Synthetic Rubber	FKM
9	Perfluoroelastomer	Kalrez; Chemraz; Kel-F	High Performance Synthetic Rubber	FPM
10	Polypropylene	PP	Thermoplastic/Polyolefin	PP
11	Polytetrafluoroethylene	Teflon, Halon	Fully Fluorinated Thermoplastic	PTFE &FTE

Note:

*: GTI internal data source

Table 5. Number of Leak Incidences by Causes for Distribution Mains and Services*

	Mains		Services	
	Number	%	number	%
Corrosion	55553	36.42	71963	21.64
Material Defect	10645	6.98	37124	11.16
Natural Force	12924	8.47	11305	3.40
Excavation	23475	15.39	82814	24.90
Other outside force	2834	1.86	13141	3.95
Equipment	10293	6.75	42279	12.71
Operation	3866	2.53	8557	2.57
Other	32956	21.60	65386	19.66
Total	152546	100.00	332569	100.00

Note:

*: Original data from DOT 2007 Annual Report [25]

Table 6. The cause of Transmission and Distribution Incidents*

Pipeline Safety Record Transmission and Distribution 1990-2002			Incidents by Cause						
			Corrosion	Outside Force	Construction/Operating Error	Accidently Caused by Operator	Other	No Data	Total
Distribution	# of Incidents	Total Incident	59	954	97	84	378	7	1579
		Serious Incident	39	280	59	59	160	4	601
	% of Incidents	Total Incident	3.7	60.4	6.1	5.3	23.9	0.4	100
		Serious Incident	6.5	46.6	9.8	9.8	26.6	0.7	100
Transmission	# of Incidents	Total Incident	224	381	139	0	213	0	957
		Serious Incident	7	38	11	0	47	0	103
	% of Incidents	Total Incident	23.4	39.8	14.5	0.0	22.3	0.0	100
		Serious Incident	6.8	36.9	10.7	0.0	45.6	0.0	100

Note:

*: The data are from AGF report "Safety Performance and Integrity of the Natural Gas Distribution Infrastructure" [27].

Table 7. Coverage of Technology Areas in the Literature Database*

Technology Area	# of References	# of Reviews
Electrical Power-Coal	22	14
Electrical Power-Natural Gas	21	13
Electrical Power-Nuclear Power	10	7
Electrical Power-Oil	14	7
Electrical Power-Renewables	47	35
Electrical Power-Transmission and Distribution	9	9
Hydrogen-Network	13	14
Hydrogen-Production	48	60
Hydrogen-Utilization	11	9
Miscellaneous	6	5
Natural Gas Production, Network and Utilization	46	42
Natural Gas/Hydrogen Network and Utilization	5	3
Oil Production and Processing	13	6
Transport-Using Electricity	10	11
Transport-Using Hydrogen	32	33
Transport-Using Natural Gas	16	16
Transport-Using Oil	17	16
Transport-Using Renewable Energy	12	13

Note:
*: Table from NaturalHy Report "Literature Review Report on Life Cycle and Socio-Economic Assessment Aspects [1].

Table 8. Effect of Hydrogen Addition in Natural Gas on Gas Properties and Hazards*

Properties/Phenomena	Effect of Hydrogen Addition	Main Hazardous Hazards					
		Rupture	Explosion	Fire	Burns	Suffocation	Poisoning
Density	Lower					x	
Viscosity	Lower					x	
Velocity of Dispersion	About the same		x	x		x	
Hydrogen Component	Higher	x					x
Household Gas Pipe Leak Rate	Higher		x	+		x	
Lower flammability limit	About the same level		x	x			
Higher Flammability Limit	Higher		+				
Flammability Range	Wider		x				
Detonability Range	Wider		x				
Explosive Energy/Volume	Lower		x	x			
Explosive Energy/Mass	Higher		x	x			
Minimum Energy for Ignition	Lower		x	x			
Auto Ignition Temperature	Lower		x	+			
Uncontrolled Ignition	Easier		x	x			
Severity of Explosive Damage	Lower		x				
Explosion Risk in Confined Room	Higher		+				
Explosion Risk in unconfined Room	Lower		-				

Note:

*: Table from IEA report "Reduction of CO_2 Emissions by Adding Hydrogen to Natural Gas" [11]

×: hazard exists but unchanged by presence of hydrogen up to 15%

+: hazard increases by presence of hydrogen

-: hazard reduces by presence of hydrogen

Table 9. Ranking of the Hazards in Natural Gas Distribution Systems*

Significance of Hazard	Ranking Assigned
Severe	50
Moderate to Severe	40
Moderate	30
Minor to Moderate	20
Minor	10
None	0

Note:
*: The severity of the hazards is ranked with the numerical system generally used for risk assessment.

Table 10. The Risk Factor [a] for Pipe Material Categories and the Overall Risk Factor [b] at Each Failure Modes in Distribution Mains

Failure Mode	Pipe Material Categories and Their Percentage in Distribution Mains					
	Steel	Cast Iron	PE	Other Plastics	Other	Overall Risk Factor
	46.55%	3.14%	48.12%	2.06%	0.13%	
Corrosion	50	40	0	0	10	**24.54**
Material Defect	30	10	40	30	10	**34.16**
Natural Force	30	50	20	20	10	**25.58**
Excavation	50	50	50	50	50	**50.00**
Other Outside Force	10	10	10	10	10	**10.00**
Equipment	30	30	30	30	30	**30.00**
Operation	30	30	30	30	30	**30.00**
Other	10	10	10	10	10	**10.00**
Total	240	230	190	180	160	**214**

Note:

a: The hazard severity for each pipe material category was assessed at each failure mode by GTI based on the engineering experiences and the reported incident data in natural gas distribution system from 1990 to 2002 in AGF report "Safety Performance and Integrity of the Natural Gas Distribution Infrastructure" [27]. The risk factor for each material category in this table is assigned with the numerical definition of the hazard severity defined in Table 9.

b: The overall risk factor for each failure mode is calculated by the sum of the risk factor of each material category times the percentage of this material in distribution mains, see Equation (2).

Table 11. The Risk Factor [a] for Pipe Material Categories and the Overall Risk Factor [b] at Each Failure Modes in Service Lines

Failure Type	Pipe Material Categories and Their Percentage in Service Lines					
	Steel	Cast Iron	PE	Other Plastics	Other	Overall Risk Factor
	32.68%	0.17%	63.05%	0.42%	3.69%	
Corrosion	50	40	0	0	10	**16.77**
Material Defect	30	10	40	30	10	**35.53**
Natural Force	30	50	20	20	10	**22.95**
Excavation	50	50	50	50	50	**50.00**
Other Outside Force	10	10	10	10	10	**10.00**
Equipment	30	30	30	30	30	**30.00**
Operation	30	30	30	30	30	**30.00**
Other	10	10	10	10	10	**10.00**
Total	240	230	190	180	160	**205**

Note:

a: The hazard severity for each pipe material category was assessed at each failure mode by GTI based on the engineering experiences and the reported incident data in natural gas distribution system from 1990 to 2002 in AGF report "Safety Performance and Integrity of the Natural Gas Distribution Infrastructure" [27]. The risk factor for each material category in this table is assigned with the numerical definition of the hazard severity defined in Table 9.

b: The overall risk factor for each failure mode is calculated by the sum of the risk factor of each material category times the percentage of this material in service lines, see Equation (2).

Table 12. Risk Assessment for Distribution Mains at Three Hydrogen Levels

Failure Mode	Probability [a] (%)	Risk Factor				Overall Risk			
		NG [b]	< 20% H_2 [c]	20 to 50% H_2 [c]	>50% H_2 [c]	NG [b]	<20% H_2 [c]	20 to 50% H_2 [c]	>50% H_2 [c]
Corrosion	36.42	24.54	29.54	29.54	44.54	8.94	10.76	10.76	16.22
Material Defect	6.98	34.16	39.16	39.16	54.16	2.38	2.73	2.73	3.78
Natural Force	8.47	25.58	35.58	35.58	45.58	2.17	3.01	3.01	3.86
Excavation	15.39	50.00	60.00	70.00	70.00	7.69	9.23	10.77	10.77
Other Outside Force	1.86	10.00	15.00	15.00	30.00	0.19	0.28	0.28	0.56
Equipment	6.75	30.00	35.00	35.00	50.00	2.02	2.36	2.36	3.37
Operation	2.53	30.00	35.00	35.00	50.00	0.76	0.89	0.89	1.27
Other	21.60	10.00	15.00	15.00	30.00	2.16	3.24	3.24	6.48
Total	100.00	214	264	274	374	26	33	34	46

Note: The calculation of "Risk Factor" was performed by GTI

a: The probability of each failure mode is the statistical data of the leak incidents in distribution mains from DOT 2007 annual report [25], see Table 5.

b: The baseline risk factor for each failure mode in natural gas distribution mains, see Table 10.

c: The risk was assessed by GTI for each failure mode at different hydrogen levels in natural gas distribution mains compared with the baseline risk with natural gas. The risk factor at each level of hydrogen is calculated by adding the baseline risk factor with the increase of risk factor (ΔRF) at this hydrogen level, which is defined as below:

ΔRF=5: minor increase

ΔRF=10: minor to moderate increase

ΔRF=20: moderate to significant increase

Table 13. Risk Assessment for Distribution Services at Three Hydrogen Levels

Failure Mode	Probability [a] (%)	Risk Factor				Overall Risk			
		NG [b]	< 20% H_2 [c]	20 to 50% H_2 [c]	>50% H_2 [c]	NG [b]	< 20% H_2 [c]	20 to 50% H_2 [c]	>50% H_2 [c]
Corrosion	21.64	16.77	26.77	26.77	36.77	6.11	9.75	9.75	13.39
Material Defect	11.16	35.53	45.53	45.53	55.53	2.48	3.18	3.18	3.88
Natural Force	3.40	22.95	42.95	42.95	42.95	1.94	3.64	3.64	3.64
Excavation	24.90	50.00	70.00	90.00	100.00	7.69	10.77	13.85	15.39
Other Outside Force	3.95	10.00	20.00	20.00	30.00	0.19	0.37	0.37	0.56
Equipment	12.71	30.00	40.00	40.00	50.00	2.02	2.70	2.70	3.37
Operation	2.57	30.00	40.00	40.00	50.00	0.76	1.01	1.01	1.27
Other	19.66	10.00	20.00	20.00	30.00	2.16	4.32	4.32	6.48
Total	100.00	205	305	325	395	23	36	39	48

Note: The calculation of "Risk Factor" was performed by GTI

a: The probability of each failure mode is the statistical data of the leak incidents in service lines from DOT 2007 annual report [25], see Table 5

b: The baseline risk factor for each failure mode in natural gas service lines, see Table 11.

c: the risk was assessed by GTI for each failure mode at different hydrogen levels in natural gas service lines compared with the baseline risk with natural gas. The risk factor at each level of hydrogen is calculated by adding the baseline risk factor with the increase of risk factor (ΔRF) at this hydrogen level, which is defined as below:

ΔRF=5: minor increase

ΔRF=10: minor to moderate increase

ΔRF=20: moderate to significant increase

ΔRF=40: significant increase

ΔRF=50: significant increase at higher degree

Table 14. The Permeation Coefficient and the Calculated Gas Loss from a 32 mm (1.26″) PE80 Pipe Under the Pressures of (58 psig (4 bar), 116 psig (8 bar) and 174 psig (12 bar))*

Gas	Pressure (psig)	Time-Lag (day)		Permeation Coefficient ($\times 10^{-3}$ ft^3-mil/ft^2/day/psig)		Gas Loss (ft^3/mile/year)		
		CH_4	H_2	CH_4	H_2	CH_4	H_2	Total
Pure CH_4	58	6.46	NA	0.18	0	54.07	NA	54.07
90% CH_4 + 10% H_2	58	4.31	0	0.09	0.34	25.90	10.59	36.49
	116	6.39	0	0.12	0.50	67.03	31.04	98.07
	174	5.69	0	0.12	0.52	101.91	48.54	150.45

Note:

*: The original data in this table are from the experimental test results in the paper of "Evaluation of the Permeability to CH_4 and H_2 of PE Currently Used in Gas Distribution Networks" [18], and are converted to the English unit.

Table 15. Permeation Coefficient (10^{-3}×ft^3-mil/ft/day/psig) of Hydrogen Gas for Plastic Pipe Materials at 20°C*

Material	Experiment	Literature
PE80	1.50	1.99
MDPE	1.63	1.10
PE100	1.46	0.00
PEXa	3.37	0.00
PVC	0.91	0.69
Ductile PVC	0.97	0.00

Note:

*: The original data in this table are from IEA report "Reduction of CO_2 Emissions by Adding Hydrogen to Natural Gas" [11], and they are converted to the English unit.

Table 16. Permeation Coefficient ($10^{-3}\times ft^3$-mil/ft/day/psig) of Hydrogen in Plastic Pipe and Elastomeric Materials

Material	Hydrogen	Methane
MDPE (PE2708) [a]	1.43	0.29
HDPE (PE3608) [a]	1.09	0.16
HDPE (PE4710) [a]	1.09	0.16
PVC [a]	0.95	NA
Natural Rubber [b]	28.39	NA
Butyl Rubber [b]	4.27	NA
Buna S (SBR) [b]	23.02	NA
Neoprene (CR) [b]	7.67	NA
Buna N (NBR) [b]	9.12	NA

Note:

a: Data are from "AGA Handbook: Plastic Pipe Manual for Gas Service" [29]

b: Data are from EIA report "Hydrogen Transportation Pipeline" [13]

Table 17. The Calculated Gas Loss Rate (ft^3/mile/year) Based on Literature Data for HDPE Pipes at the Operating Pressures of 60 psig, 3 psig and 0.25 psig*

Hydrogen Content	At 60 psig			At 3 psig			At 0.25 psig		
	H_2	CH_4	Total	H_2	CH_4	Total	H_2	CH_4	Total
0%	0.0	49.4	49.4	0.0	2.5	2.5	0.0	0.2	0.2
10%	32.9	44.5	77.4	1.6	2.2	3.9	0.1	0.2	0.3
20%	65.9	39.5	105.4	3.3	2.0	5.3	0.3	0.2	0.4
50%	164.7	24.7	189.4	8.2	1.2	9.5	0.7	0.1	0.8
100%	329.3	0.0	329.3	16.5	0.0	16.5	1.4	0.0	1.4

Note: The calculation was performed by GTI.

*: The data in this table are calculated by Equation (2) using the permeation coefficient data in Table 16 from "AGA Handbook: Plastic Pipe Manual for Gas Service" [29].

Table 18. Classification of Hydrogen Degradation of Metals*

Type of Damage	Hydrogen Embrittlement			Hydrogen Attack	Blistering
	Environment Embrittlement	Stress Cracking	Loss in Tensile Ductility		
Typical Materials	Steels, nickel-base alloys, metastable stainless steel, titanium alloys	Carbon and low-alloy steels	Steels, nickel-base alloys, Be-Cu bronze, aluminum alloys	Carbon and low-alloy steels	Steels, copper, aluminum
Hydrogen Source	Gaseous H_2	Thermal processing, electrolysis, corrosion	Gaseous H2, internal hydrogen from electrochemical charging	Gaseous	Hydrogen sulfide corrosion, electrolytic charging, gaseous
Typical Conditions	10^{-10} to 10^{4} gas pressure	0.1 to 10 ppm total hydrogen content	0.1 to 10 ppm H_2 of gas pressure exposure	Up to 15 ksi	Hydrogen activity equivalent to 3-15 ksi
	Observed at -150 to 1290°F Most severe at 70°F	Observed at -150 to 210°F Most severe near 70°F	Observed at -150 to 1290°F	400-1100°F	30-300°F
	More severe at low strain rate	More severe at low strain rate	Strain rate important		

Type of Damage	Shatter Cracks, Flakes, Fisheyes	Micro-Perforation	Degradation in Flow Properties	Metal Hydride Formation
Typical Materials	Steels (forgings and castings)	Steels (compressors)	Iron, steels, nickel-base alloys	Vanadium, Niobium, Tantalum, Titanium, Zirconium, Uranium
Hydrogen Source	Water vapor reacting with molten steel	Gaseous hydrogen	Gaseous or internal hydrogen	Internal hydrogen from melt; corrosion, electrolytic charging, welding
Typical Conditions	Precipitation of dissolved ingot	30-125 ksi	1-10 ppm hydrogen content at 70°F for iron or steels	15-15,000 psig gas pressure
	Cooling	70-210°F	Up to 15 ksi gaseous hydrogen at T > 0.5 melting point for various metals	Hydrogen activity must exceed solubility limit near 70°F

Note:

*: Table from ASM Handbook Vol. 13A (Hydrogen Damage) [28]

Table 19. Hydrogen Compatibility of the Plastics and Elastomers Used in Natural Gas Pipeline*

Polymers	Compatibility
Polyethylene	Good
Polyvinyl Chloride	Good
Natural Rubber	Fair
Butyl Rubber	Good
Silicone Rubber	Fair
Neoprene (CR)	Good
Buna S (SBR)	Good
Viton	Good
Buna N (NBR)	Good

Note:

*: Data from EIA report "Hydrogen Transportation Pipelines" [13] and PPI report "Chemical Resistance of Thermoplastics Piping Materials" [31]

Table 20. Operator Perceptions on Threat Significance*

Threat Priority	Threat	% of Respondent
1	Outside Force/Weather Cast Iron Pipe	90
2	Excavation/Mechanical Damage	87
3	External Corrosion Bare Steel Pipe	86
4	External Corrosion (Graphitization) Cast Iron Pipe	71
5	External Corrosion Coated & Wrapped Pipe	69
6	Construction-Related Defects Plastic Pipe	57
7	Outside Force/Weather Steel Pipe	49
8	Construction-Related Defects Steel Pipe	48
9	Incorrect Operations & Operator Error	35
10	Equipment Malfunction	35
11	Manufacture-Related Defects Plastic Pipe	30
12	Outside Force/Weather Plastic Pipe	26
13	Internal Corrosion	22
14	Manufacture-Related Defects Plastic Pipe	22

Note:

*: Table from AGF report "Safety Performance and Integrity of the Natural Gas Distribution Infrastructure" [27]. The identified threats in natural gas distribution systems are prioritized in this table according to the response from the survey performed by AGF with the utility operators. The higher priority is given to the threat accepted by more respondents.

References

	Ref #	Outline	Pub. Yr	Task #	Author and Affiliation
NaturalHy Report	1	**Literature Review Report on Life Cycle and Socio-Economic Assessment Aspects** Compare the current energy system, transition natural gas/hydrogen system, and future complete hydrogen system in terms of: 1. Primary energy inputs vs. energy resource depletion 2. Environmental impact: • Greenhouse gas emissions associated with climate change, • Other gases: NOx, SO_2, PM_{10}, etc., • Liquid and solid emissions associated to acidification, ozone depletion and eutrophication, 3. Direct and indirect job creation and maintenance, and 4. Economic costs.	2004	4.1 4.7	1. N. D. Mortimer and R. E. Horne U. of Warwick, UK 2. K. A. Adamson Technical U., Germany 3. T. Bouquet, S. Minett and S. Craenen, COGEN Europe, Belgium 4. A. de Groot, ISQ, Portugal 5. T. Feck, K. Stolzenburg and R. Steinberger-Wilckens Energy Research Centre of the Netherlands 6. P. Helb, SAVIKO Consultants ApS, Denmark
	2	**What are the Life Cycle Analysis and Socio-Economic Issues (final presentation)** Identify the issues related to using hydrogen as primary energy source: • Emissions, • Employment, and • Cost	2009	4.1 4.7	Nigel Mortimer Loughborough University, UK
	3	**Adding Hydrogen to the Natural Gas Infra-Structure - Assessing the Risk to the Public (final presentation)** 1. Consequences of accidental releases (large scale experiments and mathematical models): • Gas buildup, • Fire, and • Explosion. 2. Failure frequency and ignition probability (engineering judgment and information for durability and integrity work packages). 3. Assess risk to public: • Transmission pipeline failures, and • Explosions in domestic properties.	2009	4.2 4.3	Barbara Lowesmith Loughborough University, UK

	Ref #	Outline	Pub. Yr	Task #	Author and Affiliation
NaturalHy Report	**4**	**Assessment of Repair and Rehabilitation Technologies Relating to the Transport of Hythane:** 1. Assess the suitability of the existing repair and rehabilitation technologies for distribution and transmission pipelines: • Operation pressure within 10 bars • 50% hydrogen in hythane 2. Consequences of repair technologies: • Technological • Economical.	2006	4.5	Jens Huttenrauch and Gert Muller-Syring DBI-GUT
	5	**How Does the Presence of Hydrogen Effect Pipeline Integrity and What Can We Do About It**? **(final presentation)** • When and how to inspect and repair • Specification for an integrity management tool • Software development to calculate probability of failure (POF) • Cost of integrity management by hydrogen addition.	2009	4.5	Gert Müller-Syring, DBI-GUT
	6	**Principles of Resource Allocation Relating to Pipeline Integrity Management (for transmission pipeline).**	2008	4.5	Lise Lanarde GDF SUEZ, France
	7	**Interim Report on Membrane Development for Hydrogen Separation**: • Specifications and target for membrane development • Pd based membrane development (Interim) • Carbon based membrane development (Interim).	2007	4.6	D. F. Uoxf NTUN, CETH
	8	**To What Extend Can Existing Pipelines Accommodate Hydrogen**? **(final presentation)** 1. **Assess the impact of H_2 on transmission pipelines** 2. **Assess the impact of H_2 on distribution network** • Permeability of PE and PVC • Aging of PE • Reliability of domestic gas meters.	2009	4.4	Isabelle Alliat GDF SUEZ
	9	**Decision Support Tool (final presentation)** • Provide the assessment and suitability of adding hydrogen to NG systems in the Netherlands • The results and conclusions of this task are not included in this presentation.	2009	Go/no go decision	Peter Bartlam ISO, Portugal

	Ref #	Outline	Pub. Yr	Task #	Author and Affiliation
CTC Report	**10**	**Existing Natural Gas Pipeline Materials and Associated Operational Characteristics (hydrogen regional infrastructure program in Pennsylvania):** Compare the natural gas pipelines in the U.S. and PA and assess the feasibility of co-transporting hydrogen and natural gas in terms of: • Pipeline materials • Operating conditions • Piping components • Losses and leakage • Pipeline security.	2005	4.2 4.3 4.4 4.6	Concurrent Technologies Corp., PA, US
IEA Green House Gas R&D Program	**11**	**Reduction of CO_2 Emissions by Adding Hydrogen to Natural Gas:** 1. Review the effect of adding hydrogen in natural gas on the safety, economy, environment and the requirement for upgrades to the natural gas network and end user appliances. 2. Review the percentage of hydrogen in NG/H_2 blends and the potential for a three step sequence to phase hydrogen into natural gas pipeline. 3. Review the potential non-technical barriers from the standpoint of economy, psychology or emotion that may hinder the introduction of hydrogen as a substantial energy carrier.	2003	4.1-4.7	E. A. Polman, J.C. de Laat, M. Crowther et al. GASTEC Technology BV, Netherlands
	12	**Present Status of Hydrogen Transport Systems-Using Existing Natural Gas Supply Infrastructures in Europe and the USA** A review on the worldwide hydrogen infrastructure-related projects and the status as related to transporting hydrogen using existing natural gas networks.	2005	4.1-4.7	Takeo Suzuki, Shin-ichiro Kawabata, Tetsuji Tomita, Institute of Energy Economics, Japan (IEEJ)
	13	**Hydrogen Transportation Pipelines** A document on design, construction, and operational requirements for hydrogen transportation pipelines.	2004	4.4	European Industrial Gases Association

	Ref #	Outline	Pub. Yr	Task #	Author and Affiliation
EET Project	14	**Mixing and Transportation of H_2 via the NG Network in Rozenburg** Study of the bottlenecks and advantages/disadvantages of mixing and transporting hydrogen via the existing natural gas infrastructure from technical, institutional, and economical aspects of Rozenburg.	2008	4.3 4.4 4.7	Anish Patil Delft U. of Technology, Netherlands
	15	**The Use of the Natural Gas Pipeline Infrastructure for Hydrogen Transport in a Changing Market Structure** Discusses the energetic and material aspects of hydrogen transport through existing natural gas pipeline.	2006	4.4 4.7	Dries Haeseldoncks, William D'haeselleer, U. of Leuven, Belgium
Naturalhy Project	16	**Assess the Durability and Integrity of Natural Gas Infrastructure for Hydrogen and Natural Gas Blends** 1. Discusses the durability of steel, PE, and gas meters with H_2: • H_2 embrittlement and its effect on toughness and fatigue, • Permeability of H_2 in PE and aging of PE in H_2, and • Accuracy of gas meter (polymer membrane), leakage, and durability. 2. Integrity Management for H_2/natural gas mixture: • Defect criticality may change with H_2 content, • Development of inspection tools, • Development of repair strategies, and • Development of integrity management tool.	2005	4.4 4.5	Isabelle Alliat, J. Heerings, GAZ De France, France
Naturalhy Project	17	**The Value of the Existing Natural Gas System for Hydrogen:** 1. Overview of NaturalHy projects, 2. Durability of steel, PE and gas meters with H_2, 3. Integrity management for H_2/natural gas mixture, and 4. Risks with H_2 in natural gas pipeline.	2006	4.2 4.3 4.4 4.5	1. O Florisson, Gasunie Engineering & Technology, Netherlands 2. Isabelle Alliat, GAZ De France, France
Naturalhy Project	18	**Evaluation of the Permeability to CH_4 and CH_4+H_2 of PE Currently Used in Gas Distribution Networks.** Experimental evaluation of the permeability of CH_4 and CH_4+10%H_2 in PE 63, PE80, and PE100 under operating temperatures and pressures.	2008	4.3 4.4	1. D. Gueugnaut, and Denise rousselot, GAZ De France, France 2. G. Tari, Degaz, Hungary 3. A. Drdöhelyi, Szeged U., Hungary

	Ref #	Outline	Pub. Yr	Task #	Author and Affiliation
	19	**Study of the Behavior of Gas Distribution Equipment in Hydrogen Service-Phase II** Leakage measurements with hydrogen/natural gas mixtures on natural gas distribution system	1980	4.3	Walter J. Jasionowski, GTI, USA
	20	**Pathways to a Hydrogen Society** The diffusion coefficients of hydrogen in Polyethylene (medium density, high density, PE100, crosslinked polyethylene) and Polyvinyl Chloride from literatures and laboratory measurements	2002	4.3	E.A. Polman, A. van Wingerden, M. Wolters GASTEC Technology BV, Netherlands
	21	**ASME B31.8-2007** **Gas Transmission and Distribution Piping Systems**	2007	4.2 4.5	The American Society of Mechanical Engineers
	22	**API 5L (API Specification for Line Pipe)**	2004	4.4	American Petroleum Institute
	23	**ASME B31.12-2008** **Hydrogen Piping and Pipeline**	2008	4.4	The American Society of Mechanical Engineers
	24	**49 CFR Part 192** **Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines (Final Rule)**	2009	4.2 4.5	Department of Transportation Pipeline and Hazardous Materials Safety Administration
	25	**DOT 2007 Annual Distribution Data**	2007	4.2 4.3 4.5	Department of Transportation Pipeline and Hazardous Materials Safety Administration
	26	**Integrity Management for Gas Distribution** **(Report of Phase 1 Investigation)**	2005	4.2 4.5	Department of Transportation Pipeline and Hazardous Materials Safety Administration
	27	**Safety Performance and Integrity of the Natural Gas Distribution Infrastructure**	2005	4.2 4.5	URS Corporation American Gas Foundation
	28	**ASM Handbook Vol. 13A (Hydrogen Damage)**	2003	4.4	ASM International
	29	**Plastic Pipe Manual for Gas Service (8th edition)**	2006	4.3	American Gas Association
	30	**Permeation, Solubility and Interaction of Hydrogen in Polymers- An Assessment of Materials for Hydrogen Transport**	2008	4.4	Savannah River National Lab
	31	**Chemical Resistance of Thermoplastics Piping Materials**	2007	4.5	Plastic Pipe Institute

List of Acronyms

Acronym	Description
ABS	Acrylonitrile Butadiene Styrene
AGA	American Gas Association
AGF	American Gas Foundation
API	American Petroleum Institute
ASM	American Society for Metals
ASME	American Society of Mechanical Engineers
CCS	Carbon Capture Storage
CETE	Compagnie Europeenne des Technologies del'Hydrogene
CFD	Computational Fluid Dynamic
CFR	Code of Federal Regulations
CI	Cast Iron
CMS	Carbon Molecular Sieves
CP	Cathodic Protection
CTC	Concurrent Technology Corporation
DCC	Dutch Corrosion Center
DDT	Deflagration to Detonation Transition
DIMP	Distribution Integrity Management Program
DIMP	Distribution Integrity Management Program
DOE	Department of Energy
DOT	Department of Transportation
ECN	The Energy Research Center
EET	Dutch Economy, Ecology and Technology
GTI	Gas Technology Institute
HDPE	High Density Polyethylene
IEEJ	Institute of Energy Economics Japan
IMT	Integrity Management Tool
IEA	International Energy Agency

List of Acronyms

Acronym	Description
IMP	Integrity Management Program
ISQ	Instituto de Soldadura e Qualidade
LDCs	Local Distribution Companies
LNG	Liquefied Natural Gas
MDPE	Medium Density Polyethylene
MM	Mixed Matrix
NBR	Butadiene-Acrylonitrile
NREL	National Renewable Energy Laboratory
NTNU	Norwegian University of Science and Technology
OPS	Office of Pipeline Safety
PE	Polyethylene
PHMSA	Pipeline and Hazardous Materials Safety Administration
POF	Probability of Failure
PSA	Pressure Swing Adsorption
PVC	Polyvinyl Chloride
SBR	Butadiene-Styrene
SCC	Stress Corrosion Cracking
SMYS	Specified Minimum Yield Strength
UV	Ultraviolet
VCE	Vapor Cloud Explosion
WI	Wrought Iron

END OF TABLE

Environmental benefits and safety

Cleaner fuel for cleaner air

Converting your fleets and vehicles to natural gas not only helps the province meet its greenhouse gas emissions reduction goals, but also helps improve air quality[1] in the communities you serve.

- Natural gas burns cleaner than gasoline or diesel, which can result in less pollution and greenhouse gases.[2]
- Carbon dioxide (CO2) emissions, the principal greenhouse gas that contributes to global warming, are reduced by 15 to 25 per cent.[2,3]
- Natural gas vehicles emit virtually no particulate matter, the harmful microscopic component of air pollution that penetrates deeply into the lungs.[4]

With renewable natural gas (or biomethane), you can reduce the environmental impact of your operations even further. It costs a little extra, but can help to significantly reduce the greenhouse gas emissions created by your fleet. Learn more about renewable natural gas.

The safe choice[5]

With many built-in safety features, natural gas vehicles have a track record of safe operation.

A sealed system and thorough testing for extreme temperature and stress conditions ensures on-vehicle fuel storage systems do not leak. But in the event of a fuel leak, these systems are designed to automatically shut down. A sealed system is also created between the fuel dispenser and vehicle during refuelling. Fuel will not flow unless the fuel dispenser is properly connected to the vehicle, which helps reduce the risk of fuel leaks.

Other safety features

Fuelling site contamination is virtually eliminated with above ground fuel storage tanks for both compressed natural gas (CNG) and liquefied natural gas (LNG) stations. If there is a leak, the fuel will rise into the atmosphere so there is no risk to soil or groundwater. In the event of an LNG leak, the fuel could pool, so containment structures are used around LNG tanks to contain any leaked fuel. The LNG will then change from a liquid to a gas and vent into the atmosphere. Monitoring systems are also used to monitor fuelling station conditions 24 hours a day.

Have questions?

We're here to help. Contact us today.

[1] http://www.gowithnaturalgas.ca/why-natural-gas/environmental-benefits/few-air-pollutants/.

[2] Calculation based on GHGenius model found at http://www.ghgenius.com/. The GHGenius model is based on Canadian fuel and supply sources.

[3] http://www.gowithnaturalgas.ca/why-natural-gas/environmental-benefits/.

[4] US Department of Energy, http://www.afdc.energy.gov/afdc/vehicles/natural_gas_emissions.html.

[5] http://www.gowithnaturalgas.ca/operating-with-natural-gas/stations/safe-design/.

Local businesses capture emissions and save energy through FortisBC pilot program

November 20, 2017

New carbon capture technology introduced for commercial heating systems

SURREY, BC – As part of FortisBC's commitment to providing innovative energy solutions to its customers, the company today announced a new pilot program for businesses. The program uses first in the world carbon capture technology to decrease greenhouse gas (GHG) emissions and save energy.

The technology, produced by CleanO2 Carbon Capture Technologies (CleanO2), reduces the energy usage of commercial boilers that use natural gas and captures and converts carbon dioxide (CO2) into a usable byproduct. This results in cost savings for the commercial business as well as a reduction in GHG emissions.

"FortisBC embraces progressive and sustainable technologies for the benefit of all of our customers. By developing this pilot program, businesses have access to new technology which aligns with broad policy goals for carbon reduction," said Jason Wolfe, director of energy solutions at FortisBC. "New technologies are becoming increasingly important in the move to be more efficient in our energy usage, reducing emissions, all while ensuring customers have access to affordable energy choices such as natural gas."

The carbon capture unit will have an impact on GHG emissions for commercial customers. Organizations that have signed on to the six-month pilot program include Cadillac Fairview Richmond Centre and Blue Horizon Hotel. Both of these businesses embrace creating a more sustainably conscious future for their customers.

"Technologies like carbon capture are the way of the future in terms of reducing emissions and saving energy," said Jaeson Cardiff, CEO of CleanO2. "Our units decrease energy consumption by up to 10 per cent depending upon the boiler size. In addition, our units remove CO2 from flue gas thereby reducing GHG emissions."

The carbon capture unit captures carbon from flue gas to turn it into sodium carbonate, also known as soda ash, a versatile mineral used to make pharmaceuticals, manufacture glass as well as soap. According to CleanO2, the unit can create up to 6.7 tons of soda ash per year and operate for up to 25 years.

The pilot program was developed to assist in advancing the technologies to commercialization and acceptance in the market.

For more information on the pilot program and carbon capture technology, contact: energysolutions@fortisbc.com.

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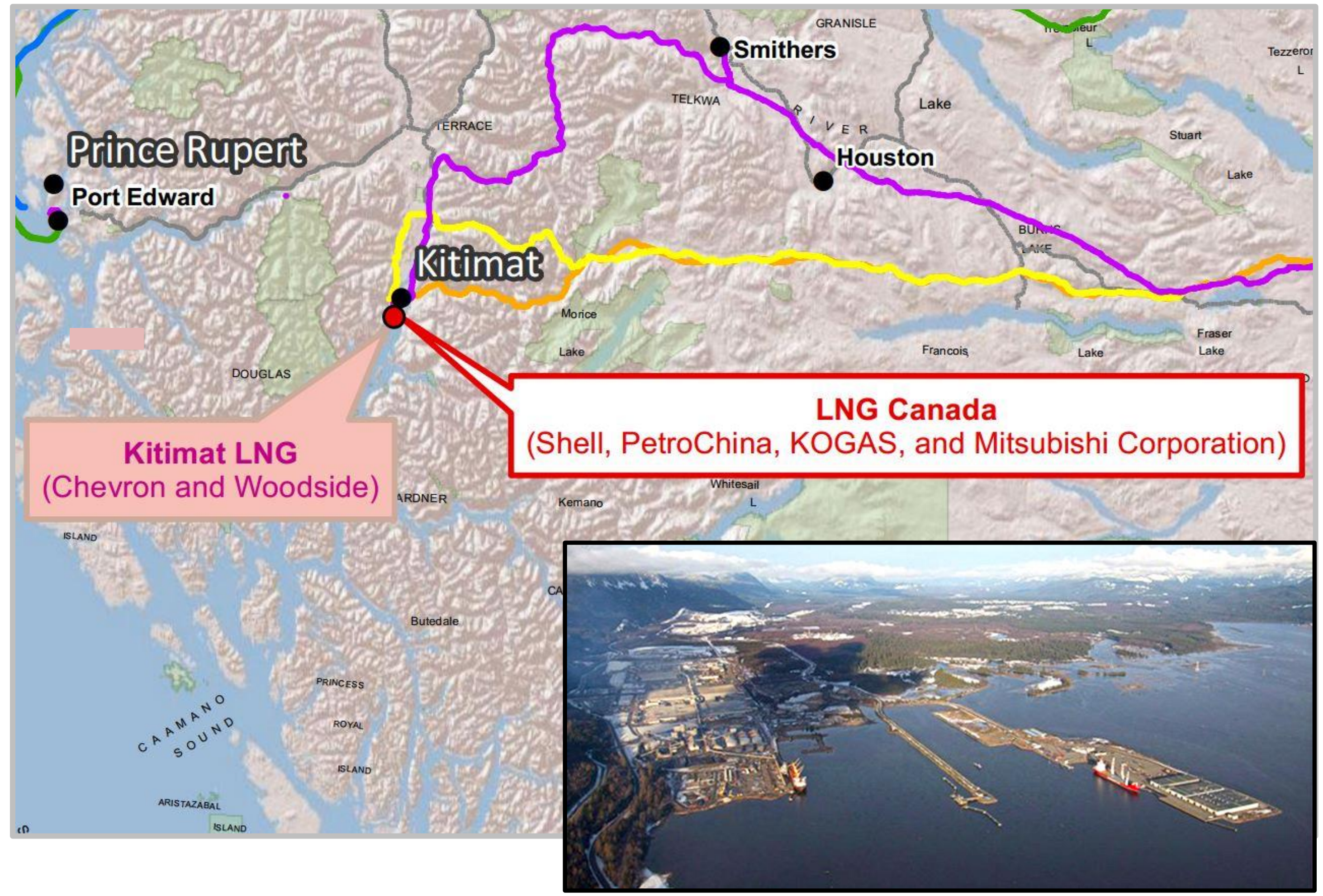
FortisBC Energy Inc. is a regulated utility focused on providing safe and reliable energy, including natural gas, propane and thermal energy solutions. FortisBC Energy Inc. employs almost 1,800 British Columbians and serves approximately 994,000 customers in 125 B.C.

communities. FortisBC Energy Inc. is indirectly, wholly owned by Fortis Inc., the largest investor-owned distribution utility in Canada. FortisBC Energy Inc. owns and operates approximately 48,700 kilometres of natural gas transmission and distribution pipelines. FortisBC is a subsidiary of Fortis Inc., a leader in the North American regulated electric and gas utility industry. For further information visit www.fortisinc.com.

LNG Canada Export Terminal

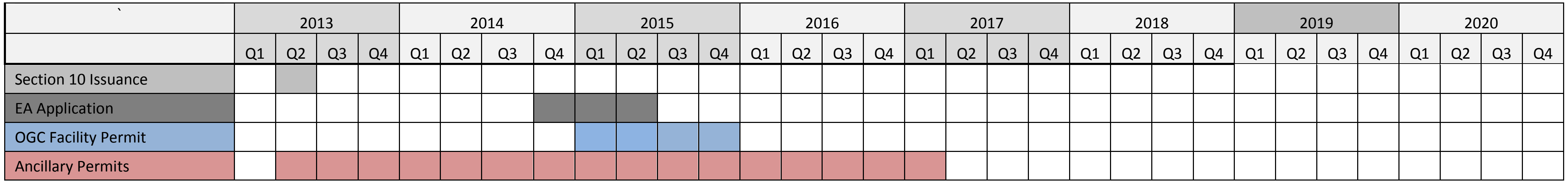
Proponent(s): LNG Canada
Related Infrastructure: Coastal GasLink Pipeline (TransCanada)

LNG Canada, a joint venture company comprised of Shell Canada Energy (an affiliate of Royal Dutch Shell plc – 50%), affiliates of PetroChina Company Ltd. (20%), Korea Gas Corporation (KOGAS) (15%), and Mitsubishi Corporation (15%), is proposing to build an LNG export terminal in Kitimat. The facility will consist of LNG liquefaction and storage facilities, marine terminal facilities, two cryogenic LNG transfer pipelines and supporting facilities and infrastructure. Initially two LNG processing units (called "trains") with capacity to produce 6.5 MTPA each of LNG will be built, with an option to expand the facility to four trains in the future, for a total estimated production capacity of 26 MTPA.



OGC PROJECT OVERVIEW	
Number of authorizations anticipated	15
Number of applications approved to date	14
Number of authorizations in review	1
Number of First Nations involved	1

Gantt Chart



Milestone Dates

NEB	**2016 (Q2)**	Export Licence approved (40 years)
	Current Status Project currently delayed.	
EAO	**2014 (Q4)**	EA Application Start Date
	June 17, 2015	EA Application Completion Date
	LNG Facility Permit issued Dec 22, 2015	
BCOGC	**2015 (Q1)**	BCOGC Application Start Date
	Dec 22, 2015	BCOGC Application Approval Date
	FID decision delayed due to 'global industry challenges'	
Project Start *	**TBD**	Expected Construction Start *(requires FID)*
	TBD	Expected Leave-to-Open Date

Additional notes

- Located on private land, incorporating the former Methanex industrial site.
- On Nov 4, 2014, LNG Canada and BC Hydro signed a power agreement that would see the proponent use electricity for a portion of the power needed to run the facility. The remaining power requirements would be natural –gas generated.
- Proposed LNG infrastructure in vicinity: Kitimat LNG Terminal (Chevron/Woodside)

**Project Start dates are contingent on all necessary approvals being met and are subject to change.*

Appendix E

POTENTIAL GHG EMISSIONS REDUCTION PATHWAYS

APPENDIX E: POTENTIAL GHG EMISSIONS REDUCTION PATHWAYS

1.1 Context

FEI prepared this appendix within the context of a 20-year vision by broadening assumptions beyond the analysis presented in the body of the 2017 LTGRP in order to show the potential contribution that emerging initiatives and technologies could make to long term GHG emissions abatement. Stakeholders have supported including such an appendix in order to better illustrate that pathways to a lower carbon future do exist that include, and may be better enabled by, the use of natural gas and natural gas infrastructure. Aspects of this examination of emerging initiatives and technologies remain speculative at this time. The likelihood of any particular initiative or technology in this appendix developing to the full extent discussed in the appendix remains unknown. FEI recognizes that limited BC-specific data may exist about emerging initiatives and technologies. As a result, this appendix is based on broad and, where applicable, public assumptions. For those initiatives and technologies about which information is available, FEI has utilized such information in its examination. For initiatives and technologies that are less well documented, FEI presents high level discussions only and plans to refine these in future LTGRP submissions when the required input data improves.

1.2 Inputs

1.2.1 ANNUAL DEMAND IMPACT

This appendix uses FEI's annual demand forecast from Section 3 of the 2017 LTGRP. The examination in this appendix uses the 2015 base year as its starting point. In this annual demand forecast, increases in natural gas annual demand result in GHG emissions increases (represented as negative reductions). Decreases in annual demand reduce GHG emissions. FEI's examination in this appendix presents results for the Reference Case and the Global Growth & Carbon Step Change scenario. As outlined in Section 8 of the 2017 LTGRP, the alternate future scenarios of the annual demand forecast include varying levels of natural gas displacement by low carbon thermal energy and electricity. The examination in this appendix does not change these scenario-specific displacement levels.

1.2.2 C&EM IMPACT

This appendix maintains the annual demand energy savings results from Section 4 of the Application. C&EM GHG emissions impacts are calculated via the same method as in Section 8 of the Application.

As informed by the BC CPR, the 2017 LTGRP C&EM analysis method used in Section 4 of the Application already pursues all cost effective demand-side measures. Drawing on the BC CPR analysis, Section 4 of the Application indicates that C&EM energy savings may potentially be increased by increasing C&EM incentive levels from the assumed values. However, estimated total C&EM programming expenditures are more sensitive to such an increase than forecast C&EM energy savings.

1.2.3 RNG IMPACT

This appendix assumes four speculative maximum RNG levels to be achieved by 2036. The first level assumes that FEI will reach its maximum allowance under the GGRR (5 percent of FEI's 2015 non-bypass annual demand, or approximately 8.88 million GJ at up to $30 per GJ energy supply cost) by 2036. The second through fourth levels assume that new technologies, such as cellulosic biogas, will expand the maximum attainable RNG supply up to approximately 94 million GJ by 2036. These levels are based on industry research into potentially available RNG supply and do not account for potential competition for RNG feedstock from non-RNG end uses. The second through fourth levels represent between approximately 25 and 46 percent of FEI's forecast 2036 Reference Case annual demand.

For each maximum level, the examination assumes that RNG annual demand will increase at a constant annual rate from the 2017 LTGRP's forecast 2017 levels to the assumed speculative maximum levels. The examination does not account for potential operational, technical, or safety constraints that may limit FEI's ability to mobilize, inject, or transport RNG in its pipeline system.

This appendix uses the same method for calculating emissions reductions from the RNG initiative as the main body of the Application. As outlined in Section 8 of the Application, this method is conservative because it does not account for avoided landfill methane emissions that are diverted as a result of the RNG initiative. Avoided landfill methane emissions could result in approximately 6 to 12 times additional avoided GHG emissions that FEI currently does not use in its calculated emissions reductions.

1.2.4 POWER-TO-GAS IMPACT

This examination assumes that electrolysers generate hydrogen which is injected into the FEI gas supply. For simplicity, this appendix exclusively applies BC Hydro's average electricity GHG emissions factor for calculating GHG emissions reductions.[1] FEI calculates GHG emissions reductions by comparing the natural gas emissions factor with the emissions factor of BC Hydro electricity, after scaling the electricity emissions factor to account for an assumed 70 percent electrolyser efficiency (based on the nominal hydrogen production efficiency of common

[1] Applying average grid electricity to electrolysis is likely to underestimate potential GHG emissions reductions from power-to-gas. Power-to-gas electrolysers are likely to be driven by marginal electricity and the energy and emissions policy environment encourages marginal electricity generation to be renewable. As such, the marginal electricity emissions factor is likely to be lower than the average grid electricity emissions factor.

industrial electrolysers).[2] This examination does not account for any electric generation, transmission, or distribution losses. Power-to-gas could represent a value-added product for the BC electricity sector. Hydrogen could be produced at times of surplus electricity on the grid, such as during the spring freshet or during periods of high renewable (e.g. wind) generation.

Industry research reflects a broad range of potential maximum power-to-gas levels among the natural gas supply to be viable without significantly increasing risks to end-use appliances, public safety, or the durability and integrity of the existing pipeline networks. These levels approximately extend from 5 percent to 15 percent by volume and depend on the specific infrastructure and end-use characteristics of each jurisdiction which can vary significantly.[3] This appendix assumes two maximum power-to-gas levels: (1) 5 percent of 2036 forecast scenario annual demand by 2036, and (2) 15 percent of 2036 forecast scenario annual demand by 2036. The examination assumes a linear increase from zero percent in 2015 to the assumed maximum levels. This does not account for potential supply limitations of hydrogen or its feedstock materials or for knock-on GHG emissions changes in upstream sectors. This appendix also does not account for any potential BC-specific operational, technical, or safety constraints that may limit the injection, pipeline transport, or end use of power-to-gas supply. The higher of the two power-to-gas levels assumes that technology advances, such as the ability to cost effectively generate synthetic methane from hydrogen, will reduce potential constraints associated with localized concentrations of hydrogen for pipeline injection, pipeline transport, or end-use consumption.

At the assumed electrolyzer efficiency, the two assumed power-to-gas levels would require approximately 4,016 and 12,049 GWh of electric energy, respectively, in the Reference Case in 2036. For comparison, the 2017 LTGRP Lower Bound scenario indicates natural gas load defection and suggests a forecast increase of annual electric load of approximately 17,226 GWh by 2036.

1.2.5 NGT IMPACT

This appendix uses the same NGT GHG emissions reduction analysis method as Section 8 of the Application but splits the NGT impact into a domestic and an international category based on the current boundaries of the BC GHG emissions inventory. For marine bunkering, this means that coastal and trans-Pacific vessels are reported in the international category; only short sea vessels accrue to the domestic category. The international category thus represents GHG emission reductions from converting to LNG coastal and trans-Pacific marine vessels only.

International marine bunkering is a significant source of GHG emissions. However, according to the United Nations Framework Convention on Climate Change, this source of emissions does not fall under any one country's emissions inventory. LNG-bunkered marine vessels can reduce

[2] Appendix D-31: http://www.electrochemsci.org/papers/vol7/7043314.pdf.
[3] Appendix D-32: https://energy.gov/sites/prod/files/2014/03/f11/blending_h2_nat_gas_pipeline.pdf.

their carbon intensity by approximately 20 percent when compared with traditional bunkering fuels.[4] Emissions from shipping activities not included in the provincial GHG inventory amount to about 70 million metric tonnes of CO_2e per year, which is greater than the combined 64 million metric tonnes of CO_2e per year that the entire Province of BC emits per year.

1.2.6 OTHER EMERGING TECHNOLOGIES

Additional emerging technologies do exist which may provide further opportunities for GHG abatement but this examination excludes these technologies as insufficient data is available at this point. The following two examples illustrate this additional GHG abatement potential:

- End-use carbon sequestration, such as the CleanO2 technology for commercial heating systems that FEI supports via a pilot program announced on November 20, 2017, may enable GHG abatement without changing the carbon intensity or annual demand of natural gas;[5] and
- End-use appliance efficiency advancements, such as natural gas-fired heat pumps, may increase the efficiency of natural gas end-use appliances beyond 100 percent.

Together, such additional emerging technologies may enable initiatives which may significantly impact GHG emissions beyond the opportunities quantified in this appendix.

1.2.7 ADDITIONAL CONSIDERATIONS

Some of the emerging initiatives and technologies discussed in this appendix may have non-GHG benefits which are not quantified in this appendix. Some emerging initiatives and technologies may reduce air emissions other than GHG. As outlined in Section 2 of the Application, NGT reduces emissions of Particulate Matter (PM) and Nitrous Oxides (NOx) which have harmful health impacts. Some emerging initiatives and technologies may have wider non-energy benefits. For example, RNG may create an economic use for agricultural waste products.

1.3 Results

Table E-1 below summarizes the speculative pathways resulting from the examination in this appendix. These pathways do not account for all interactive effects. For example, RNG or power-to-gas are not assumed to displace higher carbon emitting transportation fuels even though this would have greater GHG abatement impacts than displacing higher emitting

[4] Appendix D-33: https://www.fortisbc.com/NaturalGas/Business/NaturalGasVehicles/Environmentalbenefitsandsafety/Pages/default.aspx.

[5] Appendix D-34: https://www.fortisbc.com/MediaCentre/NewsReleases/2017/Pages/20171120-Local-businesses-capture-emissions-and-save-energy-through-FortisBC-pilot-program.aspx.

transportation fuels with conventional natural gas (using RNG to displace higher emitting transportation fuels could reduce emissions by approximately 80 percent).

For illustration and as encouraged by stakeholders, FEI assumes hypothetical GHG reduction targets for two summary categories: (1) Stationary Combustion Sources & Industrial Processes and Product Use, and (2) Transport. BC currently does not allocate its legislated GHG emissions reduction targets to specific sectors. FEI also does not create or assign GHG emissions reduction targets but simply conducts activities which realize opportunities for emissions reductions. The 2030 reduction target is based on the Government of Canada's 2017 Nationally Determined Contribution under the Paris Agreement (reducing GHG emissions by 30 percent from 2005 until 2030). When applied to BC's economy-wide GHG emissions, this calculates to a reduction of approximately 26 percent from 2014 until 2030. For the 2036 target year, this appendix uses the target from Section 8 of the Application.

For the first summary category, FEI applies the respective 2030 and 2036 emissions reduction percentage targets to its 2015 base year annual demand. This yields reductions of 26 and 45 percent, respectively, and thus assumes that FEI's annual demand will bear an equal reductions burden as other sectors of the BC economy. For the second summary category, FEI discounts BC's assumed hypothetical economy-wide emissions reduction targets in two successive steps. First to 38.4 percent to account for the ratio of the Transport category to total BC emissions as reported in the 2014 BC GHG emissions inventory, and second, to 45.66 percent to account for the ratio of heavy-duty diesel vehicles, railways, domestic navigation and off-road diesel to total Transport category emissions. This yields the emissions reductions that apply from the assumed hypothetical 2030 and 2036 targets to the total domestic market that is theoretically addressable by FEI's NGT initiative. Nevertheless, emissions in this theoretically addressable market may be reduced by a combination of FEI and non-FEI initiatives.

In the first summary category, combining the annual demand and C&EM impacts with four potential RNG and two potential power-to-gas GHG abatement opportunity levels creates eight different pathways per 2017 LTGRP scenario and target year. To illustrate the range of emissions reduction opportunities across these pathways, each target year in Table E-1 totals the reduction opportunities for the top and the bottom of the pathway opportunity range. The top of the pathway opportunity range overshoots the assumed hypothetical 2030 and 2036 emissions reduction targets, whereas the bottom of the pathway range does not contribute sufficient emissions reductions to equal the assumed hypothetical targets. For each target year in Table E-1, blue field highlighting indicates the minimum RNG opportunity level required for a pathway with the lower power-to-gas opportunity level to meet or overshoot the respective assumed emissions reduction target. Orange field highlighting indicates the minimum RNG opportunity level required for a pathway with the higher power-to-gas opportunity level to meet or overshoot the respective assumed emissions reduction target.

In the second summary category, FEI's domestic emissions reduction pathways alone do not contribute sufficient GHG emissions reductions to equal the assumed hypothetical reductions target. As noted above, the target for this category represents the total addressable market and emissions reductions targets for this market may be met by a combination of FEI and non-FEI initiatives. Additionally, GHG abatement in this category would increase if FEI were to capture a larger proportion of the potential eligible market than assumed in the annual demand forecast from Section 3 of the Application (i.e. 4 and 15 percent of the potential eligible CNG market domestically across the Reference Case and Global Growth & Carbon Step Change scenarios, respectively). This effect would be compounded by fully accounting for interactive effects between categories to enable displacing higher carbon transportation fuels with RNG and power-to-gas. FEI's Global Growth & Carbon Step Change international pathway offers significantly more GHG emissions reductions than indicated by the assumed hypothetical domestic targets. Since climate change represents a global challenge, GHG emissions reductions should be valued as a solution to this challenge no matter which jurisdiction these reductions accrue to for reporting purposes.

Investment in the emerging activities examined in this appendix may cause upward pressure on FEI's rates but such upward pressure may be offset by maintaining or increasing delivered energy amounts via these activities. The impact of NGT on projected delivery rates discussed in Section 8 of the Application illustrates this effect. In contrast, reducing energy amounts delivered by FEI's infrastructure in order to achieve GHG emissions abatement would cause upward pressure on rates without any compensating effect. As outlined in Section 8 of the Application, by continuing to serve BC's thermal energy needs with natural gas, FEI will help to curb increases in electricity demand that would otherwise be caused by gas-to-electric fuel switching in either new or existing buildings. While this electric load avoidance would not eliminate emissions in BC, it would preserve more of BC's clean electricity for potential other end uses, such as power-to-gas or export to other jurisdictions within the electricity trading region. Electricity exports and power-to-gas could economically benefit British Columbians. Electricity exports may also result in greater emissions reductions by displacing coal or natural gas fired electricity generation currently in use in other jurisdictions within the electricity trading region.

Table E-1: Speculative Emissions Reduction Results

	Potential GHG Emissions Reduction Pathways	Forecast Emissions Reductions ($MtCO_2e$, 2015 Base)	
		Reference Case	Global Growth & Carbon Step Change
	1. Stationary Combustion Sources & Industrial Processes and Product Use		
2030	Annual Demand Impact	-0.3	-0.3
	C&EM	0.7	0.6
	RNG at GGRR Cap (2036)	0.3	0.3
	Cellulosic RNG at 51 million GJ (2036)	1.8	1.8
	Cellulosic RNG at 84 million GJ (2036)	2.9	2.9
	Cellulosic RNG at 94 million GJ (2036)	3.3	3.3
	Power-to-Gas at 5% of 2036 Demand by 2036	0.3	0.3
	Power-to-Gas at 15% of 2036 Demand by 2036	1.0	1.0
	Total - Bottom of Range	**1.0**	**0.9**
	Total - Top of Range	**4.6**	**4.6**
	Assumed Domestic Reductions Target	**2.5**	
2036	Annual Demand Impact	-0.5	0.1
	C&EM	0.8	0.7
	RNG at GGRR Cap (2036)	0.5	0.5
	Cellulosic RNG at 51 million GJ (2036)	2.6	2.6
	Cellulosic RNG at 84 million GJ (2036)	4.3	4.3
	Cellulosic RNG at 94 million GJ (2036)	4.8	4.8
	Power-to-Gas at 5% of 2036 Demand by 2036	0.5	0.4
	Power-to-Gas at 15% of 2036 Demand by 2036	1.4	1.3
	Total - Bottom of Range	**1.2**	**1.7**
	Total - Top of Range	**6.5**	**6.9**
	Assumed Domestic Reductions Target	**4.5**	
	2. Transport		
2030	NGT - Domestic	0.2	0.3
	NGT - International	1.4	10.7
	Total - Domestic	**0.2**	**0.3**
	Total - International	**1.4**	**10.7**
	Assumed Domestic Reductions Target	**2.9**	
2036	NGT - Domestic	0.3	0.5
	NGT - International	1.9	14.4
	Total - Domestic	**0.3**	**0.5**
	Total - International	**1.9**	**14.4**
	Assumed Domestic Reductions Target	**5.1**	

1.4 FEI's role in global GHG emissions reductions

Reducing net global GHG emissions is the preeminent objective to mitigate global climate change. FEI is undertaking actions that can achieve net GHG emission reductions outside of

BC. Two important pathways are LNG exports to countries to substitute for more carbon intensive fuels and LNG bunkering for international marine shipping. While these actions will not drive reductions to achieve BC's domestic targets, the scope of BC's emissions reductions activities should be broadened so as to recognize the role FEI can play in helping to reduce global GHG emissions.

1.4.1 LNG EXPORTS

Recent analysis conducted by the International Energy Agency (IEA) in 2017 concludes that LNG exports to China and India from North America are a key component of a global energy transition to limit global warming to two degrees Celsius above pre-industrial levels. According to the IEA's Sustainable Development Scenario (SDS), natural gas becomes the single largest fuel supply at 25 percent of global energy consumption. While absolute gas consumption declines in most of the developed world, it increases over threefold in China and fourfold in India. Natural gas is used to decarbonize power, industry, buildings and transport, substituting for coal and oil consumption. Importantly, gas consumption is 30 percent higher in India and 10 percent higher in China in the SDS compared to the New Policies Scenario reference case. This means that increased gas consumption becomes *more* important as a CO_2 abatement option as each of these countries drives to reduce emissions in line with the goal to limit global warming to two degrees above pre-industrial levels.

In the SDS, LNG exports satisfy most of the new demand for natural gas in these countries. As a result, global LNG trade more than doubles currently traded volumes by 2040. LNG exports from North America to China grow to 150 billion cubic meters by 2040 (approximately double Canada's current gas exports to the US).

LNG exports from BC are well-positioned to reduce GHG emissions. BC's 0.16 tonnes of CO_2 per tonne of LNG intensity target is the lowest in the world. BC's gas reserves in the Montney basin have low formation CO_2. Further, low GHG emissions intensity electricity, cooler climate, and proximity to China all serve to increase the emissions reduction potential of BC natural gas abroad. FEI's Tilbury Phase 1A liquefaction facility is powered by electricity and is anticipated to be one of the cleanest LNG facilities in the world.

Pinpointing the total CO_2 abatement from increased natural gas consumption in export markets requires decomposition analysis with detailed data. A speculative estimate of the total reduction potential can be quantified using high-level IEA data in the World Energy Outlook. Assuming a direct one-to-one substitution of natural gas energy for coal in power generation and other end-use applications, the abatement potential of natural gas substitution is sizeable. Natural gas produces three million tonnes less CO_2 emissions than coal per million tonnes of oil equivalent (Mtoe). In the SDS, natural gas consumption in the non-power end-use sectors increases by 218 Mtoe (259 billion cubic meters) between 2015 and 2040. This means that, assuming direct substitution for coal, natural gas may abate over 600 million tonnes of CO_2 emissions across the non-power end-use sectors. In the power sector, every TWh of natural gas generation that displaces coal reduces emissions by 0.8 million tonnes of CO_2.[6] In the SDS, natural gas power generation increases by 745 TWh from 2015 to 2040. As such, natural gas utilization may abate over 500 million tonnes of CO_2 by 2040.

Taken together, 150 billion cubic meters of exports from North America that substitute for coal consumption could reduce CO_2 emissions by an estimated 400 million tonnes - over 6 times greater than BC's total 2014 emissions.[7] 30 billion cubic meters of natural gas exports would account for approximately 20 percent of forecast total North American exports and would require approximately 23 million tonnes per annum (MTPA) of LNG export capacity. Large LNG export projects proposed in BC, such as LNG Canada, range around 26 MTPA.[8] If BC facilities exported 23 MTPA of LNG to China for coal substitution, associated forecast downstream emissions reductions would be in the order of approximately 80 million tonnes annually (BC's total 2014 GHG emissions are approximately 64 million tonnes).

1.5 Conclusion

The size of the opportunity presented by the potential GHG emissions reduction pathways in this appendix supports investments into further analysis and development of these pathways. FEI will continue monitoring and will, where appropriate, support emerging initiatives and technologies such as the ones discussed in this appendix. FEI emphasizes that, once more specific information becomes available, it will be important to compare on an equal footing the potential pathways discussed in this appendix to alternative GHG emissions abatement pathways, such as domestic electrification.

6 Assuming emissions factors for gas and coal without significant deployment of carbon capture and storage.
7 Assuming natural gas exports are proportionately spread to all major gas consuming sectors in China.
8 Appendix D-35: https://www.bcogc.ca/node/11289/download.

Appendix F

GLOSSARY OF TERMS AND ACRONYMS

APPENDIX F – GLOSSARY OF TERMS AND ACRONYMS

Acronym or Term	Definition
ACP	Annual Contracting Plan
AECO/NIT	Alberta Energy Company/Nova Inventory Transfer - refers to an important storage and exchange point for Canadian natural gas. AECO/NIT is commonly used to refer to the benchmark pricing index for the Alberta natural gas marketplace.
AFUDC	Allowance for funds used during construction - an allowance for the cost of debt and equity funding of capital projects before they are completed and placed into service and included in rate base; the AFUDC recorded for a project is added to the overall project cost.
AIP	Asset Investment Planning
Annual demand	The cumulative daily demand for natural gas over an entire year.
BC	British Columbia
BC CPR	A recent Conservation Potential Review (CPR) conducted jointly by multiple British Columbia utilities.
Bcf	one billion cubic feet
Bcf/d	one billion cubic feet per day
BCH	British Columbia Hydro and Power Authority (BC Hydro)
BCUC	British Columbia Utilities Commission, or Commission - the BCUC is the provincial body regulating utilities in British Columbia.
BP	BP Energy Marketing & Trading – a subsidiary of the BP p.l.c. group of companies.
BTU	British Thermal Units
Burrard Thermal	Burrard Thermal Generating Station (BC Hydro)
CAPP	Central Appalachian
CCE	Cost of Conserved Energy - a standard method for expressing cost-benefit test results for energy efficiency initiatives in dollars per unit of energy savings. Electric utilities use the CCE to express the net cost of saving one unit of utility-supplied energy. In the 2017 LTGRP, FEI uses the CCE to express in dollars per GJ the UCT results; thus the CCE represents annualized and, where applicable, discounted UCT costs divided by annual energy savings.
CEA	*Clean Energy Act*

Acronym or Term	Definition
C&EM	Conservation and Energy Management
CEO	Conservation Education, and Outreach
CGA	Canadian Gas Association
CHBA	Canadian Home Builders' Association
CIAC	Contributions in aid of construction
CLP	Climate Leadership Plan
CLT	Climate Leadership Team
CNG	Compressed natural gas
Commission	*see British Columbia Utilities Commission, BCUC*
CO_2e	Carbon dioxide-equivalent - a unit to express an amount of greenhouse gas emission in terms of carbon dioxide (CO_2) based on the relative global warming potential of each gas. Commonly expressed in million tonnes, i.e. $MtCO_2e$.
CPCN	Certificate of Public Convenience and Necessity - a certificate obtained from the British Columbia Utilities Commission under Section 45 of the *Utilities Commission Act* for the construction and/or operation of a public utility plant or system, or an extension of either, that is required, or will be required, for public convenience and necessity.
Core	A category of FEI customers rely on FEI to both procure their gas supply and also deliver this supply to their meters in a non-interruptible manner. This includes Rate Schedules 1, 2, 3, 4, 5, and 6.
COV	City of Vancouver
CPR	Conservation Potential Review - a comprehensive economic analysis of energy conservation potential that looks at where energy savings opportunities exist (*also see BC CPR*)
CTS	Coastal Transmission System
Daily demand	The amount of natural gas consumed by the Utilities' customers throughout each day of the year.
Demand forecast	A prediction of the demand for natural gas into the future for a given period and under a specified set of expected future conditions.
DES	District Energy System
DHW	Domestic Hot Water

Acronym or Term	Definition
DSM	Demand side management - commonly defined as any utility activity that modifies or influences the way in which customers utilize energy services.
DSM Regulation	Demand-Side Measures Regulation – one of the regulatory instruments that govern utility demand-side measure programs in BC.
Design day, or design hour demand	The maximum expected amount of gas in any one day or hour required by customers on the utility system. Since core customers' demand is primarily weather dependent, design-day or design-hour demand is forecasted based upon a statistical approach called Extreme Value Analysis, which provides an estimate of the coldest day weather event expected with a 1-in-20-year return period. For transportation customers, the design-day is equivalent to the firm contract demand (*also see Peak day*).
DLE	Diesel litre-equivalents
ECA	Emission Control Areas – in marine shipping
EEC	Energy Efficiency and Conservation
EECAG	Energy Efficiency and Conservation Advisory Group
EERS	Energy Efficiency Resource Standards – regulations which require public utilities to demonstrate annual energy savings as a percentage of their total load.
EDI	Electronic data interchange contract – a contract based on a standard protocol for exchanging operational data between natural gas dispatch centers.
EF	Energy Factor or Efficiency Factor
EGH	EnerGuide for Houses
EGP	FEI's Eagle Mountain to Woodfibre Gas Pipeline Project
EIA	Energy Information Administration (U.S.) - a division of the U.S. Department of Energy that provide statistics, data and analysis on resources, supply, production, consumption of energy.
EMAT	Electro-Magnetic Acoustic Transducer – a type of advanced in-line inspection technology for pipelines.
EPA	United States Environment Protection Agency
FBC	FortisBC Inc.
FEED	Front End Engineering Design
FERC	Federal Energy Regulatory Commission

Acronym or Term	Definition
FEI	FortisBC Energy Inc.
FEVI	FortisBC Energy (Vancouver Island) Inc.
FEW	FortisBC Energy (Whistler) Inc.
FID	Final investment decision
Firm Transportation	A category of FEI customers who procure their own gas supply but rely on FEI to deliver this supply to their meters in a non-interruptible manner. This includes Rate Schedules 23, 25, and the contracted firm delivery component of Rate Schedule 22 (including 22A and 22B) and other special Rate Schedules.
GDP	Gross Domestic Product
GGRR	Greenhouse Gas Reduction (Clean Energy) Regulation
GGRA	*Greenhouse Gas Reduction Targets Act*, sometimes also referred to as GGRTA
GHG	Greenhouse gas
GHGI	Greenhouse gas intensity
GJ	Gigajoule - a unit of energy equivalent to one billion joules. One joule of energy is equivalent to the heat needed to raise the temperature of one gram (g) of water by one degree Celsius (ºC) at standard pressure (101.325 kPa) and standard temperature (15ºC).
GLJ	GLJ Petroleum Consultants Ltd. - a private petroleum industry consultancy serving clients who require independent advice relating to the petroleum industry, including the preparation of natural gas and oil price forecasts on a quarterly basis.
GSA	General Electric Company Smallworld GeoSpatial Analysis tool
GTN	Gas Transmission Northwest LLC
GWh	Gigawatt hour - a unit of energy equal to one million kilowatt hours
HDD	Heating degree day - a measure of the coldness of the weather experienced. The number of heating degree days for a given day is calculated based on the extent to which the daily mean temperature falls below a reference temperature, 18 degrees Celsius.
HFO	Heavy fuel oil
HP	Horsepower
HPDI	High pressure direct injection

Acronym or Term	Definition
Huntingdon-Sumas	Gas flow regulating stations on either side of the British Columbia /Washington state (U.S.) border through which much of the regional gas supply is traded.
I-5 Corridor	The natural gas regional market area served by infrastructure located along Interstate-5 in the northwestern U.S. The I–5 corridor includes B.C.'s Lower Mainland and Vancouver Island, Western Washington and Western Oregon.
IEA	International Energy Agency
IFO	Intermediate fuel oil
IG	Island Generation (BC Hydro) - a cogeneration plant located at Elk Falls, Campbell River that supplies electricity and thermal energy on Vancouver Island.
IGC	Island Gas Connector Project - a natural gas pipeline to serve a proposed liquefied natural gas facility on southern Vancouver Island called Malahat LNG.
ILI	In-line inspection
IMO	International Maritime Organization – a specialized agency of the United Nations responsible for regulating shipping.
IP	Intermediate pressure
IRP	Integrated resource plan - a document that details the resource planning process and outcomes that guide a utility in planning to serve its customers over the long term. *(also see LTRP.)*
IRR	Internal rate of return
IT	Information technology
ITS	Interior Transmission System
JPS	Jackson Prairie Storage
km	Kilometer
KORP	Kingsvale Oliver Reinforcement Project
kPa	Kilopascal - a metric measurement unit of pressure. Gauge pressure is often given in units with a 'g' appended, e.g. 'kPag'.
kW	kilowatt (a unit of energy equal to one thousand watts) - the commercial unit of measurement of electric power. A kilowatt is the flow of electricity required to light ten 100-watt light bulbs.

Acronym or Term	Definition
kWh	Kilowatt hour (equal to one thousand watts used for a period of one hour) - the basic unit of measurement of electric energy. On average, residential customers in B.C. use about 10,000 kWh per year.
LMIPSU	Lower Mainland Intermediate Pressure System Upgrade Project
LMSU	Lower Mainland System Upgrade Project
LNG	Liquefied Natural Gas - natural gas stored under low temperature, which turns to liquid form. Approximately 600 times as much natural gas can be stored in its liquid state than in its typical gaseous state; however, specialized storage facilities must be constructed.
Load	The total amount of gas demanded by all customers at a given point in time.
LTERP	Long Term Electric Resource Plan – FortisBC Inc.'s LTERP examines future demand and supply resource conditions over the next 20 years and recommends actions needed to ensure customers' energy needs are met over the long term *(also see IRP)*.
LTRP	Long Term Resource Plan – FEI's LTRP examines future demand and supply resource conditions over the next 20 years and recommends actions needed to ensure customers' energy needs are met over the long term. In 2017, FEI uses LTGRP to distinguish the FEI IRP from the FBC IRP *(also see IRP)*.
LTSP	Long Term Sustainment Plan - an asset management process/planning approach that assists in creating and supporting long term asset replacement plans and capital expenditures.
MDO	Marine diesel oil
MFO	Marine fuel oil
MGO	Marine gas oil
mm	Millimeter
MMBtu	one million British Thermal Units
MMcf/d	one million cubic feet per day
MMscfd	one million standard cubic feet per day, sometimes also mmscfd
MOP	Maximum operating pressure
Mtoe	one million tonnes of oil equivalent
MTPA	one million tonnes per annum
MTRC	Modified Total Resource Cost - a modification to the Total Resource Cost test that is set out in the B.C. Demand-side Measures Regulation to recognize the environmental value of energy conservation.

Acronym or Term	Definition
MW	Megawatt - a unit of power equal to one million watts or one thousand kilowatts, commonly used to measure both the capacity of generating stations and the rate at which electric energy can be delivered.
NEB	National Energy Board
NEBC	Northeast British Columbia
NGT	Natural gas for transportation
NGTL	Nova Gas Transmission Ltd.
NGV	Natural gas vehicles
Normal demand, *also called* **annual demand**	When considering historical normal demand, this is the actual demand experience that has been adjusted to account for weather that has been colder/warmer than normal, i.e. the expected demand during a year of normal weather conditions. When considering forecast normal demand, this is the expected demand under normal weather conditions. Normal weather conditions are based on a rolling 10-year average of heating degree days experienced during each of the 10 years.
NOx	Nitrogen oxides - a form of atmospheric pollutants that are regulated in many jurisdictions.
NPCC	Northwest Power and Conservation Council
NPCC Plan	Northwest Power and Conservation Council Seventh Power Plan
NPS	Nominal Pipe Size – a North American set of standard pipe sizes.
NRCan	Natural Resources Canada
NRES	Neighborhood renewable energy systems – according to the City of Vancouver, a district energy system that runs on renewable energy sources.
NWGA	Northwest Gas Association - a trade organization of the Pacific Northwest natural gas industry. Its members include six natural gas utilities, including FortisBC, serving communities in Idaho, Oregon, Washington and British Columbia, and three interstate pipelines that move natural gas from supply basins into and through the region.
NW Natural	Northwest Natural Gas Company
NWP	Northwest Pipeline
NWIW	Northwest Innovation Works, Inc. – also referred to as NW Innovation
NYMEX	New York Mercantile Exchange
OEM	Original Equipment Manufacturer

Acronym or Term	Definition
PBR	Performance Based Ratemaking or PBR, also frequently called incentive regulation - an approach to determining a utility's rates or revenue requirements that includes incentives for the utility to achieve greater levels of efficiency in managing and operating its utility system, while maintaining (or in some cases improving) its customer service quality. Depending on the desired objectives, PBR can be narrowly focused on a particular aspect of utility service or more broadly based encompassing many aspects of the utility's operations.
PEC	Pacific Energy Corporation
Peak day, peak demand, peak day demand	The maximum expected amount of gas in any one day or hour required by customers on the FEI system. Since Core customers' demand is primarily weather dependent, design-day or design-hour demand is forecasted based upon a statistical approach called Extreme Value Analysis, which provides an estimate of the coldest day weather event expected with a 1 in 20 year return period. For transportation customers, the design-day is equivalent to the firm contract demand (*also see: design day*).
PHF	Peak Hour Factor – the ratio of peak hour consumption to peak day consumption
PI	Prediction Intervals
PJ	Petajoule - a unit of energy equal to 1,000 terajoules or 10^6 gigajoules
PM	Particulate matter – the sum of all solid and liquid particles suspended in the atmosphere; most PM particles form as a result of chemical reactions between pollutants.
PNG	Pacific Northern Gas – a British Columbia natural gas utility with a service territories in Northern British Columbia.
PNW	Pacific Northwest - a region that is commonly referred to as the three northwestern states of Washington, Oregon, Idaho and the Province of B.C.
Posterity	Posterity Group
PRMP	Price Risk Management Plan
PSE	Puget Sound Energy
Psig	Pounds per square inch gauge - a measurement of pressure.
QUEST	Quality Urban Energy Systems of Tomorrow
Rate volatility	The amount to which natural gas rates fluctuate and the frequency of those fluctuations.

Acronym or Term	Definition
Resources	The demand side and supply side means available to meet forecasted energy needs. Examples of supply-side resources within the context of resource planning are pipeline looping, compression and storage.
REUS	Residential End Use Study
RIB	Residential Inclining Block rate (BC Hydro)
RNG	Renewable natural gas
ROW	Right of way
RPAG	Resource Planning Advisory Group
RPS	Renewable Portfolio Standard – a form of regulation requiring a specified percentage of energy/fuel provision to contain renewable energy/fuel.
RRA	Revenue Requirement Application
SCC	Stress Corrosion Cracking
SCP	Southern Crossing Pipeline
SCGT	Simple cycle gas-fired turbine – typically for electricity generation.
SDS	Sustainable Development Scenario – a forecast scenario developed by the International Energy Agency in 2017.
Shut in	A pipeline "shut in" refers to removing a pipeline from service.
SOx	Sulfur oxides – a form of atmospheric pollutants that are regulated in many jurisdictions.
TAC	British Columbia Conservation Potential Review (*see BC CPR*) Technical Advisory Committee – a group of members of the public with significant interest, stake, and experience in determining energy conservation potential in BC; this group provides input and feedback during development of the BC CPR.
Tcf	one trillion cubic feet
TBO	Transportation-by-others – a type of arrangement for pipeline transport whereby one pipeline becomes the shipper on another pipeline system; these arrangements provide additional market access to one pipeline by leasing space on another pipeline.
TD	TD Securities – an affiliate of Toronto-Dominion Bank.
TEDI	Thermal energy demand intensity – an engineering metric for measuring thermal energy transmission through a building envelope.
TJ	Terajoule - a unit of energy equal to 1,000 gigajoules.

Acronym or Term	Definition
TJ/d	Terajoules per day
TP	Transmission pressure
Traditional Annual Method	FEI's traditional time-series based method for forecasting annual energy demand.
Traditional Peak Method	FEI's longstanding and well-established method for forecasting peak energy demand.
TransCanada	TransCanada PipeLines Limited
TRC	Total Resource Cost - a standard cost-benefit test for energy efficiency initiatives that compares the present value of all costs of efficiency for all members of society with the present value of benefits in order to assess the impacts of a portfolio of energy efficiency initiatives on the economy at large.
TSA	Transportation Service Agreement
TWh	Terawatt hour - a unit of energy equal to one billion kilowatt hours
UCA	*Utilities Commission Act*
UBCM	Union of BC Municipalities
UDI	Urban Development Institute
UPC	Use per customer
UPC_{peak}	Peak hour use per customer
UCT	Utility Cost Test - a standard cost-benefit test for energy efficiency initiatives that compares the present value of all costs of efficiency for the utility which offers an energy efficiency program with the present value of benefits in order to assess the impacts of a portfolio of energy efficiency initiatives on the utility specifically.
US	United States
Utilities	*see Fortis Energy Utilities (FEU)*
V2	A specific compressor location on FEI's Vancouver Island Transmission System based on FEI's classification for such compressor locations.
VI	Vancouver Island
VIGJV	Vancouver Island Gas Joint Venture - a joint venture of industrial customers (primarily large mills) on Vancouver Island who contract for transportation services as a single entity.
VITS	Vancouver Island Transmission System, also referred to as VI Transmission System

Acronym or Term	Definition
VPP	Volumetric Production Payment – a tool for managing longer term gas market price risk where the buyer pays an up-front lump sum payment to a gas producer in exchange for specific volumes delivered over the term of the agreement (possibly up to 20 years).
WCSB	Western Canadian Sedimentary Basin
Westcoast	Westcoast Energy Inc.
WLNG	Woodfibre LNG Ltd.
Woodfibre LNG Project	A small scale LNG export and processing facility proposed by WLNG on the site of the formed Woodfibre pulp mill near Squamish.
ZEEA	The avoided cost of gas value stream defined for the MTRC test – the ZEEA is informed by BC Hydro’s long run marginal cost for procuring renewable electricity.

Appendix G

DRAFT ORDERS

Appendix G-1

DRAFT ORDER

bcuc
British Columbia
Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
bcuc.com

P: 604.660.4700
TF: 1.800.663.1385
F: 604.660.1102

ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Energy Inc.
2017 Long Term Gas Resource Plan

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On December 14, 2017, FortisBC Energy Inc. (FEI) filed its 2017 Long Term Gas Resource Plan (Application) pursuant to section 44.1(2) of the *Utilities Commission Act,* for acceptance by the British Columbia Utilities Commission (Commission). FEI is not seeking approval of any particular elements identified within the plan;

B. By Order G-XX-18 dated (Month Day], 2018, the Commission established a written hearing process and a regulatory timetable with two rounds of information requests to review the Application; and

C. The Commission has reviewed the Application.

NOW THEREFORE the Commission orders as follows:

1. The Commission accepts the FortisBC Energy Inc. 2017 Long Term Gas Resource Plan to be in the public interest pursuant to subsection 44.1(6) of the *Utilities Commission Act.*

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

Appendix G-2

DRAFT PROCEDURAL ORDER

bcuc
British Columbia
Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
bcuc.com

P: 604.660.4700
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F: 604.660.1102

ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Energy Inc.
2017 Long Term Gas Resource Plan

BEFORE:
Panel Chair/Commissioner
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On December 14, 2017, FortisBC Energy Inc. (FEI) submitted its 2017 Long Term Gas Resource Plan (2017 LTGRP) to the British Columbia Utilities Commission (Commission) pursuant to section 44.1(2) of the *Utilities Commission Act* (UCA). FEI is not seeking approval of any particular elements identified within the plan;

B. The 2017 LTGRP presents a long term view of how FEI will meet future demand and reliability requirements at the lowest reasonable cost to customers over the next 20 years;

C. The 2017 LTGRP discusses the planning environment; energy demand forecasting; demand side resources; system resource needs and alternatives; gas supply portfolio planning and price risk management and stakeholder engagement. The 2017 LTGRP also includes a 20 year vision for FEI and an action plan;

D. Section 44.1 of the UCA provides that the Commission may establish a process to review a long-term resource plan;

E. The Commission has reviewed FEI's 2017 LTGRP and has determined that a public hearing is appropriate to review the Application and that a written public hearing process should be commenced, a regulatory timetable should be established and a public notice should be issued.

NOW THEREFORE pursuant to section 44.1(6) of the *Utilities Commission Act*, the British Columbia Utilities Commission orders as follows:

1. A written hearing is established for the review of FEI's 2017 LTGRP in accordance with the Regulatory Timetable set out in Appendix A to this order.

2. By no later than January 26, 2018, FEI is to publish the Public Notice, attached as Appendix B to this Order, in the Vancouver Sun newspaper to provide reasonable notice to those parties who may be affected by the plans outlined in FEI's 2017 LTGRP.

3. The Application, together with any supporting materials, will be available for inspection at FEI Office, 16705 Fraser Highway, Surrey, BC, V4N 0E8. The Application and supporting materials also will be available on the FortisBC website at www.fortisbc.com and on the Commission website at www.bcuc.com.

4. Interveners who wish to participate in the regulatory proceeding are to register with the Commission by completing a Request to Intervene Form, available on the Commission's website at http://www.bcuc.com/Registration-Intervener-1.aspx by the date established in the Regulatory Timetable attached as Appendix A to this order and in accordance with the Commission's Rules of Practice and Procedure attached to Order G-1-16.

5. Participants intending to apply for Participant Assistance/Cost Award (PACA) exceeding $10,000 must file a completed PACA Budget Estimate form by [DATE]. PACA applications should be consistent with the Commission's PACA Guidelines and Order G-97-17. Copies of the PACA Guidelines are available upon request or can be downloaded from the Commission's website at http://www.bcuc.com.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of [Month Year].

BY ORDER

Original signed by:

(X. X. last name)
Commissioner

Attachments

FortisBC Energy Inc.
2017 Long Term Gas Resource Plan

REGULATORY TIMETABLE

ACTION	DATE	
	2018	
Commission Issues Procedural Order	Friday, January 5	
FEI Publishes Notice of Filing by	Friday, January 26	
Registration of Interveners and Interested Parties	Thursday, February 1	
Commission Information Request No. 1	Thursday, February 8	
Intervener Information Request No. 1	Thursday, February 15	
FEI Responses to Information Requests No. 1	Thursday, March 22	
Commission and Intervener Information Request No. 2	Thursday, April 5	
Notification by Interveners of Intent to file Evidence	Thursday, April 26	
FEI Responses to Information Requests No. 2	Thursday, May 3	
	No Intervener Evidence	If Intervener Evidence
Intervener Evidence	n/a	Thursday, May 24
Commission and Intervener Information Request No. 1 on Intervener Evidence	n/a	Thursday, June 7
Intervener Responses to Information Requests No. 1	n/a	Thursday, July 5
FEI Final Submission	Thursday, May 17	Thursday, July 19
Intervener Final Submissions	Thursday, May 31	Thursday, August 2
FEI Reply Submission	Thursday, June 14	Thursday, August 16

PUBLIC NOTICE

[Proceeding Name]

On December 14, 2017, FortisBC Energy Inc. filed its 2017 Long Term Gas Resource Plan (2017 LTGRP) for acceptance by the British Columbia Utilities Commission (Commission), pursuant to section 44.1(2) of the *Utilities Commission Act.*

FEI's 2017 LTGRP presents a long term view of how FEI will meet future demand and reliability requirements at the lowest reasonable cost to customers over the next 20 years. The 2017 LTGRP discusses the planning environment; energy demand forecasting; demand-side resources; system resource needs and alternatives; gas supply portfolio planning and price risk management and stakeholder engagement. The 2017 LTGRP also includes a 20 year vision for FEI and an action plan.

HOW TO PARTICIPATE

There are a number of ways to participate in a matter before the Commission:

- **Submit a letter of comment**
- **Register as an interested party**
- **Request intervener status**

For more information, or to find the forms for any of the options above, please visit our website or contact us at the information below.

www.bcuc.com/RegisterIndex.aspx

All submissions received, including letters of comment, are placed on the public record, posted on the Commission's website and provided to the Panel and all participants in the proceeding.

NEXT STEPS

Intervener registration Persons who are directly or sufficiently affected by the Commission's decision or have relevant information or expertise, and that wish to actively participate in the proceeding can request intervener status by submitting a completed Request to Intervene Form by Thursday, February 1, 2018.

GET MORE INFORMATION

All documents filed on the public record are available on the "Current Proceedings" page of the Commission's website at www.bcuc.com.

If you would like to review the material in hard copy, or if you have any other inquiries, please contact Laurel Ross, Acting Commission Secretary, at the following contact information.

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, BC V6Z 2N3

Email: Commission.Secretary@bcuc.com
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Toll Free: 1-800-663-1385