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June 27, 2008

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: 2008 Resource Plan - Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGW") (collectively "Terasen Gas" or the "Companies")

By Letter No. L-70-06, dated November 15, 2006, the British Columbia Utilities Commission (the "Commission") accepted the TGI and TGVI 2006 Resource Plans and directed TGI and TGVI to submit their updated 2008 Resource Plans by the end of the first quarter of 2008. By Order No. G-53-06 dated May 19, 2006, the Commission accepted the 2005 TGW Resource Plan and did not direct a future timeline for a new plan to be filed.

On July 13, 2007, the Commission issued Order No. G-79-07 approving the request by the Companies to file a consolidated 2008 Resource Plan for TGI, TGVI and TGW by the end of the second quarter of 2008.

Pursuant to Letter No. L-70-06, Orders No. G-53-06 and G-79-07, and in accordance with the Commission's Resource Planning Guidelines and Section 44.1 of the *Utilities Commission Amendment Act* (the "Act"), Terasen Gas respectfully submits the attached combined 2008 Resource Plan for the Commission's review.

This Resource Plan submission includes five-year capital plans and statements of facilities expansion, however, the Companies are not requesting approval of those capital plans with this submission. Terasen Gas will file separate CPCN applications, if necessary, for any of those projects, in accordance with the Commission's guidelines.

The Companies are seeking acceptance of this Resource Plan in accordance with Section 44.1 of the Act.

If there are any questions regarding the content of this letter, please contact the undersigned or Ken Ross at (604) 576-7343 or ken.ross@terasengas.com.

Yours very truly,

TERASEN GAS

Original signed by: Shawn Hill

For: Tom A. Loski

Attachments

cc (e-mail only): Resource Plan Stakeholders

2008 Resource Plan

Terasen Gas

www.terasengas.com

EXECUTIVE SUMMARY

Introduction

Terasen Gas Inc. ("TGI") and Terasen Gas (Vancouver Island) Inc. ("TGVI") together provide natural gas service to more than 925,000 residential, commercial, industrial and transportation customers throughout British Columbia. In 2009, the approximately 2,400 Terasen Gas (Whistler) Inc. ("TGW") propane customers will also be converted to natural gas customers, served through the combined transmission systems of TGI and TGVI. Collectively, these three companies are referred to herein as "Terasen Gas" and are the subject of the Terasen Gas 2008 Resource Plan. Table ES-1 summarizes customer and consumption characteristics for each of the Terasen Gas service areas.

Table ES-1 Terasen Gas 2007 Service Area Statistics

	TGI Lower Mainland	TGI Interior	TGVI	TGW
Number of Customers	573,295	249,627	91,242	2,411
Annual Demand (TJ)	86,220	28,310	12,066	742
Peak Day Demand (TJ/d)	931	337	108	6.6
Length of Transmission Pipeline (km)	570	2,290	780	--
Length of Distribution Pipeline (km)	10,960	8,600	3,400	100

The Terasen Gas utilities are subsidiary companies of Terasen Inc. In May 2007, Terasen Inc. and its subsidiaries were acquired by Fortis Inc., the largest investor-owned utility company in Canada. Today almost half of the total gas and electricity customers served by Fortis Inc. are Terasen Gas customers. The B.C. based electric utility FortisBC is also a Fortis Inc. subsidiary and sister company to Terasen Gas.

In its previous Resource Plans, TGI, TGVI and TGW all identified approaching system capacity constraints. For TGW and TGVI these constraints were imminent and the Resource Plans recommended the extension of natural gas service to Whistler and the Mt. Hayes Storage facility on Vancouver Island respectively as preferred solutions. The Mt. Hayes facility would also provide gas supply and system capacity benefits to TGI's Lower Mainland customers. Applications to and subsequent approvals from the British Columbia Utilities Commission ("BCUC") for these projects led to their design and ongoing implementation. With these projects underway, resource planning at Terasen Gas now focuses on other emerging energy policies and trends, and other system and regional gas infrastructure issues.

The resource planning process explores the social, regulatory and market landscapes in which Terasen Gas must continue to operate over the planning horizon. The 2008 Resource Plan examines future demand and supply resource conditions over the next 20 years and recommends actions needed over the next four years. Terasen Gas' Resource Plan is submitted every two years with information and analysis updates and a revised four year action plan. These study timelines ensure that system and regional resources with long lead times are being developed when needed.

Resource Planning Objectives

One of the first steps in this process is establishing an appropriate set of planning objectives against which resource alternatives can be evaluated. Achieving the proper balance between multiple objectives is the key challenge in making resource decisions. Terasen Gas' resource planning objectives apply to all three utilities:

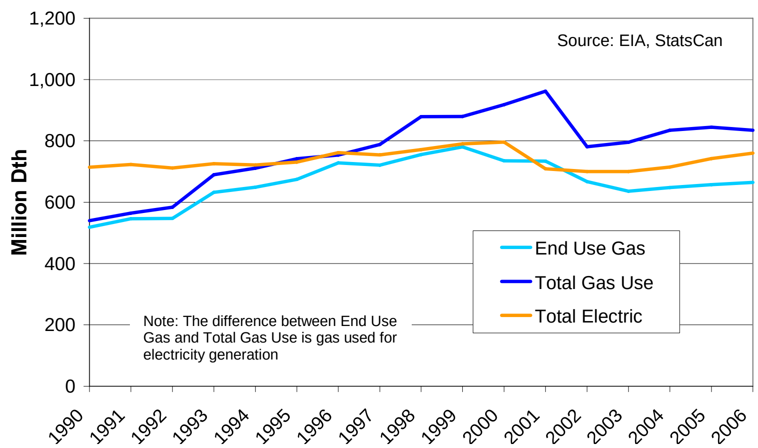
- providing safe, reliable and secure supply;
- delivering cost effective service to customers;
- advancing energy efficiency and conservation; and
- managing social and environmental impacts.

Planning Environment

Social perceptions, government policies and regulations and market trends affecting the energy industry are in a state of flux within both the province and the greater Pacific North West ("PNW") Region, driven by rising energy costs and climate change concerns. The most common forms of energy used within the region - natural gas, electricity and petroleum based fuels for transportation - are traded across jurisdictional boundaries throughout the PNW, while climate change and carbon emissions are global issues. Therefore energy choice and resource decisions need to consider the broader regional implications and not be limited by the boundaries of any one province or state.

Total demand for natural gas in the PNW surpasses that of electricity (see Figure ES-1). Growth in demand from natural gas fired electricity generation in the U.S. PNW is on the rise to meet growing demand for firm electricity.

Figure ES-1 Total Natural Gas and Electricity Consumption in the PNW

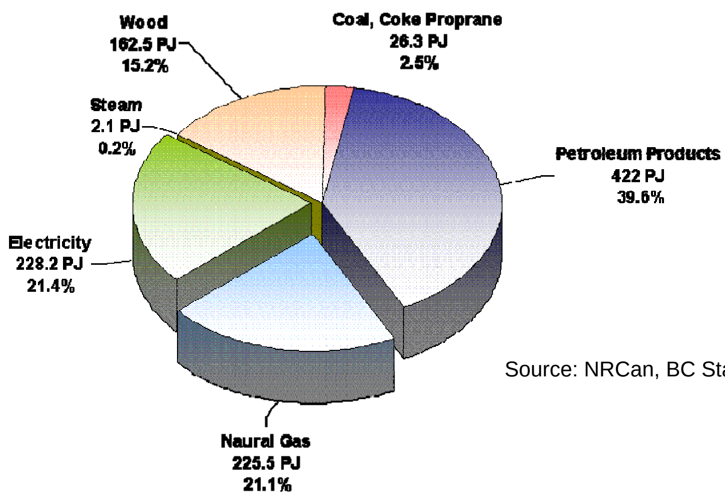


While most states and provinces in the region have implemented some form of mandatory renewable electricity standards, most jurisdictions have limited access to these resources. The economic, environmental and social risks associated with nuclear and coal fuelled generation mean that more natural gas generators are being used to provide base load and peaking electricity as well as firm back up for the intermittent renewable resources being added.

Direct use of natural gas is also viewed in many jurisdictions as the preferred fuel for space and water heating. The main alternative, electric heating, puts additional load pressure onto the electric system which on the margin is being met by natural gas or coal-fired generators. Using natural gas in direct use applications is much more efficient and therefore results in fewer emissions than using gas to generate electricity which is then used to heat homes and businesses.

In B.C., total demand for natural gas equals that of electricity. Natural gas demand is just over half of the energy consumed in petroleum products which are used mostly for the transportation sector (See Figure ES-2). With the province's population expected to grow by about 1 million people over the next 20 years, demand for all types of energy is expected to increase even with more aggressive conservation and efficiency programs. In summary, the size of the pie chart in Figure ES-2 is getting larger and the energy mix that makes up its slices will be determined by a combination of energy costs and government policy and legislation.

Figure ES-2 Annual Energy Consumption in B.C. across Energy Types



Source: NRCan, BC Stats

The B.C. government has legislated that the province become electricity self sufficient by 2016, and that 90% of new generation resources be from clean and renewable resources. In addition, all generation in the province must achieve net zero greenhouse gas ("GHG") emissions by 2016. With high growth in electricity demand expected and a growing deficit of electricity imports and exports for B.C., these goals are challenging and will be costly. Natural gas is an important part of reaching these goals by keeping new and existing heating loads from adding to the amount of electricity required.

Currently, incremental natural gas direct use in B.C. displaces imported electricity that might otherwise be used for space and water heating. This imported electricity is generated using coal or natural gas less efficiently and with higher emissions than direct use of natural gas. In the future, once B.C. becomes electricity self sufficient, greater direct use of natural gas will mean that more excess clean and renewable electricity can be exported to the PNW to replace demand for natural gas and coal fired generation in other jurisdictions. Since both energy trading and the issue of climate change cross jurisdictional boundaries, the best use of energy should be considered from a regional perspective.

The transportation sector offers the largest opportunity in B.C. for carbon emission and other pollutant reductions over the next 20 years. Natural gas can play a much greater role in this sector than it has historically, improving emissions, reducing reliance on oil and supporting technology development in B.C. Natural gas transportation solutions make even more sense given the growing controversy over the impacts of producing increasing amounts of biofuels such as bio-diesel and ethanol on global food markets and economies.

Terasen Gas believes that natural gas has an important role to play in B.C.'s energy future and in helping to reduce carbon and other emissions from the PNW. Planning recommendations contained in the Resource Plan are based on this fundamental understanding.

Trends in Natural Gas Demand

The biggest factor expected to impact demand for natural gas in the province is population growth driving new customer additions. B.C. Stats expects the current 4.4 million people living in B.C. to grow to approximately 5.4 million people by 2028, translating to an expected increase of 250,000 customers over that period. Other demand trends also need to be considered.

Downward pressure on per customer use rates is resulting from a shift to higher efficiency furnace installations as well as a general shift toward developing a higher percentage of smaller, multi-family housing units. These trends are showing up within the TGI customer base, which has a substantial inventory of older furnaces and a higher proportion of high density housing under development. Within TGVI and TGW service areas this trend is overshadowed by other issues affecting gas use and use rates are expected to remain steady.

In addition to the reference case forecast, Terasen Gas developed two other future scenarios that lead to high and low demand forecasts respectively and bound what Terasen Gas believes is the reasonable range of possible outcomes. The **Robust Growth Scenario** includes high economic growth in B.C. and the PNW combined with a general shift toward increasing preference for natural gas as an important energy choice based on cost, energy efficiency and regional emissions. The **Low Growth Scenario** includes lower economic growth combined with a general shift away from preferring natural gas as a fuel choice based on rising costs, changing views about fossil fuel consumption and incentives that drive both the development and demand for alternative energy solutions at a faster than expected pace. Figure ES-3 shows customer additions and annual demand for each forecast. Growth in peak day demand – the amount of daily demand expected on the coldest day planned for – is forecasted to grow under each of the future scenarios (Figure ES-4) since even the most efficient natural gas equipment will be working hardest during extreme cold weather periods.

Figure ES-3 Annual Demand and Customer Additions – All Utilities

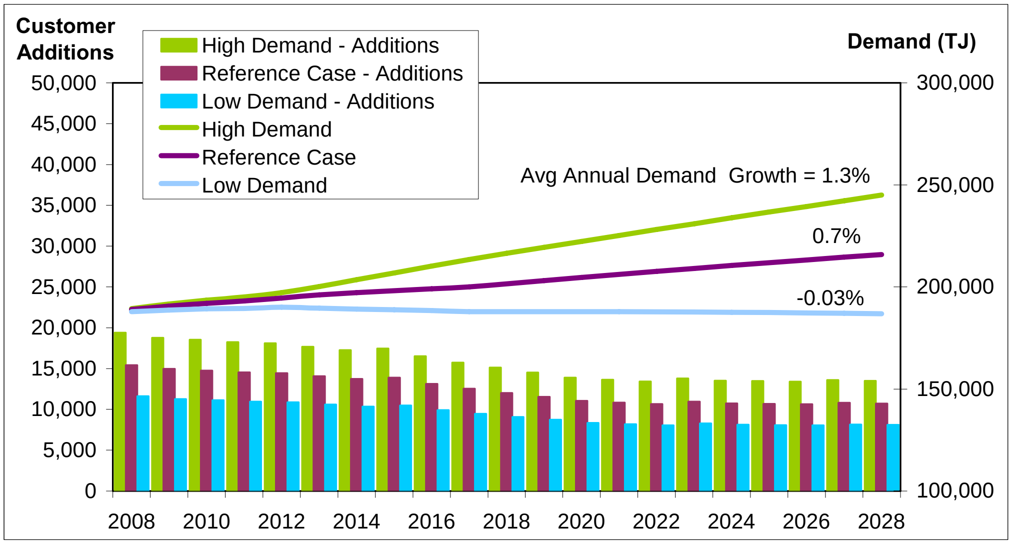
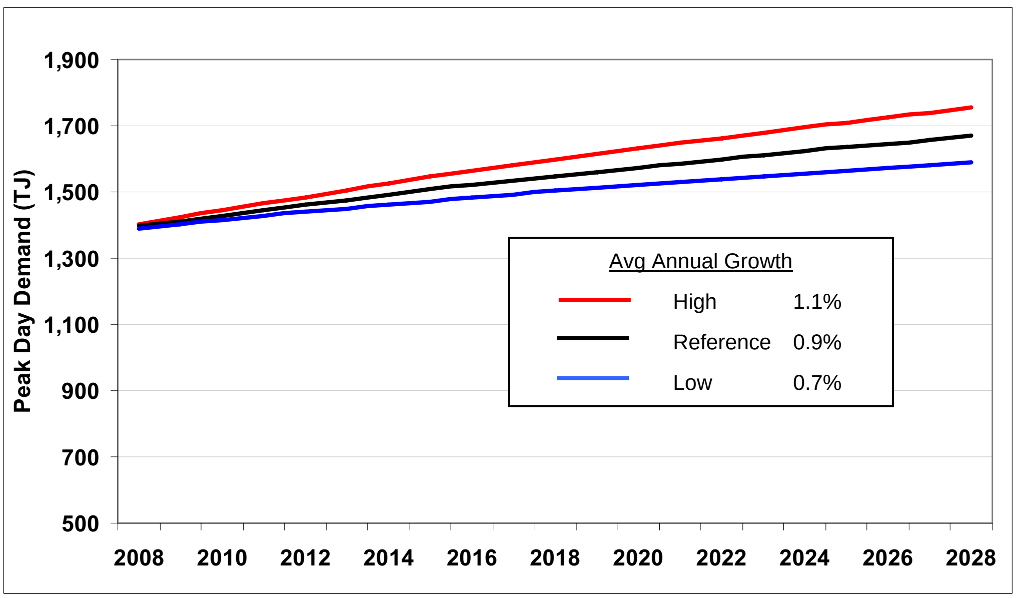


Figure ES-4 Peak Day Demand Growth – All Utilities



Energy Efficiency and Conservation Planning

Terasen Gas has been delivering DSM programs since 1997 in the TGI service regions. Between 2000 and 2007, TGI customers have saved approximately $14 million in annual energy costs and reduced consumption by 1,270 terajoules (“TJ”) annually. As energy prices rise and concerns about climate change grow, so has the focus on energy efficiency and conservation activities.

Terasen Gas has recently made an application to the BCUC for expanded Energy Efficiency and Conservation ("EEC") programming. The new programs include a broader range of both residential and commercial activities than in the past. If approved, the expanded EEC initiative will also harmonize programs being offered to TGI and TGVI customers, provide greater education about energy and conservation issues and equipment, support BC Hydro and FortisBC electricity conservation goals and facilitate access to more EEC incentive funding for customers. Terasen Gas will continue to monitor EEC program trends across B.C. and the PNW to identify further opportunities beyond the current application to intensify EEC activities in accordance with provincial directives.

The new programs include fuel switching measures that will encourage customers to make the most efficient choice of fuels, supporting conservation across energy types, and help to reduce carbon emissions in the PNW region as a whole. In keeping with the 2007 B.C. Energy Plan, the requested increase in spending will encourage development of innovative technologies, natural gas for transportation and energy measurement. Terasen Gas has requested financial treatment of the full expenditure as equivalent to capital, allowing the regulated earned rate of return and amortizing costs over twenty years following the date that the cost was incurred.

The new EEC programs will have a range of impacts on overall annual demand for natural gas. For example, retrofit natural gas efficient equipment programs will tend to shift demand from the reference forecast toward the low forecast. Conversely, fuel switching from other traditional fuels such as electricity or oil to natural gas, will tend to shift demand from the reference forecast toward the high forecast. While these programs will impact annual demand, the ability of these programs to reduce design day demand, however, is minimal, since even high efficiency heating equipment will be working hardest during extreme cold weather.

System Resource Planning

To determine if its pipeline systems and facilities are sufficient to meet demand growth, Terasen Gas examines both supply side resources such as pipeline, compression, and on-system storage to increase the physical capacity of delivery systems, and demand side resources such as energy efficiency programs to reduce demand during peak periods. Extension of natural gas service to Whistler will alleviate capacity constraints for TGW. Construction of the Mt. Hayes natural gas storage facility plus upgrading a compressor station on Texada Island will alleviate the transmission constraints affecting TGVI and TGI's Lower Mainland service regions.

On the TGI Interior Transmission System ("ITS"), however, service through the Okanagan Valley is expected to become constrained by 2016 under reference case demand. Alternative solutions include expanding the pipeline capacity through looping (adding a second, parallel pipeline) north of Penticton, pipeline looping east of Kamloops or adding a storage facility in the north Okanagan area.

New EEC programs could act in a minor way to delay the requirement for new facilities. EEC program implementation is among the factors that could lead to the low demand forecast being realized. A low demand forecast could delay the requirement for new facilities by up to two years.

Alternatively, the strong economic growth being experienced in the central Okanagan may result in additional natural gas demand that could accelerate the need for these system improvements. For example, Terasen Gas is aware that in its own resource planning process, FortisBC has also identified growing capacity constraints in the Okanagan. In its leading Resource Portfolio, FortisBC has included a new natural gas fired peaking generator along with a range of renewable resources in the area. This facility helps to avoid extensive new transmission requirements and provides a firming resource for the renewables. Based on information provided by FortisBC in stakeholder forums, construction of such a facility could accelerate the TGI expansion requirement by up to 5 years. TGI is also investigating the potential for advancing the ITS expansion project based on the benefits that may be realised by increasing the diversity of supply options through improved access to gas sourced from the Alberta market via the Southern Crossing Pipeline.

Responding to Regional Gas Supply Planning Trends

Upstream from the Terasen Gas transmission systems are a network of pipelines and storage facilities that move gas from production and trading areas to distribution utilities, industrial users and electricity generating stations. Heavy reliance on supply from B.C. and lack of storage located close to its service area characterize Terasen Gas' situation relative to other gas utilities in the PNW. The current capability of regional infrastructure to deliver enough gas to meet peak day demands assumes that no service outages or reductions occur anywhere on the system during peak demand. A number of trends in the development and operation of these regional resources may impact Terasen Gas' ability to bring gas to our customers in the most cost effective manner. These trends include:

- approaching regional system constraints;
- increasing diversion of northern B.C. produced gas into the Alberta market and further east;
- converging electricity and natural gas markets as more natural gas fired generation is brought on line in the PNW;
- growing interest in sourcing gas supply from the U.S. Rockies production region for delivery to the PNW; and
- loss of supply 'cushion' from reduced industrial demand that has fuel switching capabilities and can be curtailed during peak demand periods.

Other utilities and owners of infrastructure in the region are also observing these trends and in response, a number of new regional transmission pipelines are being proposed. Some of these pipelines could result in providing greater diversity of supply and more reliability to other portions of the PNW, while leaving Terasen Gas vulnerable to potential rising costs for securing supply and transportation on pipelines from which other regional buyers are reducing commitments. Pursuant to resource planning objectives, Terasen Gas' own best response is to examine alternatives to improve its own supply diversity and reliability.

Two alternatives are available involving Terasen Gas transmission resources. One is the potential extension of transmission service provided by Terasen Gas' Southern Crossing pipeline, which brings gas from Alberta into central B.C. and from there into the Sumas trading hub. Terasen Gas' proposed Inland Pacific Connector ("IPC") pipeline would move gas from Southern Crossing, through the Lower mainland and directly to the trading point at Huntingdon. There may also be an opportunity to connect IPC into the Westcoast Pipeline and optimise service on both systems. The other Terasen Gas system alternative would be to build additional storage resources in the Lower Mainland that could displace more expensive pipeline contracts needed to provide reliable delivery during colder winter periods.

In addition to these on-system alternatives, Terasen Gas could also explore the potential for participating in one of the other regional resource proposals through which it could improve its own regional supply diversity and reliability. Any of these alternatives, if implemented, would become an important part of Terasen Gas' supply portfolio strategy as the competition for limited regional capacity resources increases.

Alternative Energy Opportunities

Terasen Gas is pursuing a number of innovative alternative energy opportunities that can help improve energy efficiency, reduce emissions and optimize energy production and transmission systems within B.C. These opportunities act on Provincial Energy Policy, meet each of Terasen Gas' resource planning objectives and increase the utilization and optimization of existing energy infrastructure.

Transportation is a major contributor to climate change and air quality concerns. The use of conventional transportation fuels, such as gasoline, diesel or propane accounts for about 39% of B.C.'s GHG emissions, making the transportation sector the single largest source. Heavy duty truck fleets, material handling equipment such as forklifts and shipping yard shunt trucks, transit buses and waste management fleets all represent near-term opportunities to convert to natural gas technologies from dirty, petroleum based fuels. Providing natural gas fired shore power for ships docked at B.C.'s ports could help reduce air quality impacts from the largest source of smog forming pollutants in the Fraser Valley.

Terasen Gas is also exploring opportunities in alternative energy supply from waste sources. Waste heat generated by the Coquitlam compressor station that delivers gas into the TGVI transmission system can be captured and used to generate in excess of 15,000 megawatts per hour of clean electricity per year. Also, the adoption of technologies to produce and capture biogas from agricultural waste, wastewater treatment plants and municipal landfills has gained renewed momentum. Terasen Gas is working with other organizations to explore the feasibility of upgrading biogas quality for injection into the natural gas distribution system to serve a range of potential clean end-use initiatives. Access to funding such as the Innovative Clean Energy Fund and other potential sources will help to overcome financial hurdles and develop successful projects that help meet B.C. Energy Policy objectives.

Stakeholder Consultation

Stakeholder needs and concerns are critical to resource planning. More than simply facilitating open communication, effective stakeholder consultation provides the utility with insights that can impact the entire planning process, from trends that influence demand forecasting and DSM analysis to the development of an action plan for implementing preferred planning solutions. Terasen Gas consultation activities included stakeholder workshops, presentations to municipalities throughout the province, distribution of resource planning update newsletters and focussed meetings with select stakeholders seeking input on a range of regional and provincial energy issues and system expansion needs. Additional stakeholder consultation was conducted specific to Terasen Gas' EEC application to the BCUC. Following the filing of this Resource Plan, Terasen Gas will continue discussions with stakeholders regarding its recommendations. This ongoing consultation will also provide insights and feedback for consideration in future resource planning activities.

Action Plan

The actions that Terasen Gas intends to pursue over the next four years based on the information and evaluation provided in this Resource Plan are:

- Implement the new EEC programs once approval from the BCUC has been received and continue research and planning for future EEC programming.
- Continue to monitor demand side programming in B.C. and across North America to identify additional EEC programming that could be implemented over the coming months and years.
- Participate in FortisBC and BC Hydro resource planning to understand the interrelated resource needs of each utility, provide input on their planning processes, and monitor energy issues in the province.
- Influence provincial and regional energy and climate related policy development and liaise with policy makers to ensure the benefits and importance of natural gas in the provincial and regional energy mix are a high priority.
- Plan for and prepare CPCN applications for near-term distribution resource requirements identified in the Terasen Gas 5-year Capital Plans.
- Continue monitoring and evaluating system expansion needs in the Okanagan area, including working with FortisBC to determine potential requirements and timing for providing natural gas service for a new gas fired peaking facility.
- Monitor and investigate the development of regional pipeline and storage infrastructure alternatives, including liaising with those parties proposing new regional resources in order to more fully establish and evaluate Terasen Gas alternatives and opportunities.
- I Identify and pursue innovative clean energy initiatives and funding for made in B.C. solutions in natural gas vehicles, biogas development, advanced metering technologies, waste heat utilization and other alternative energy uses, supplies and systems.

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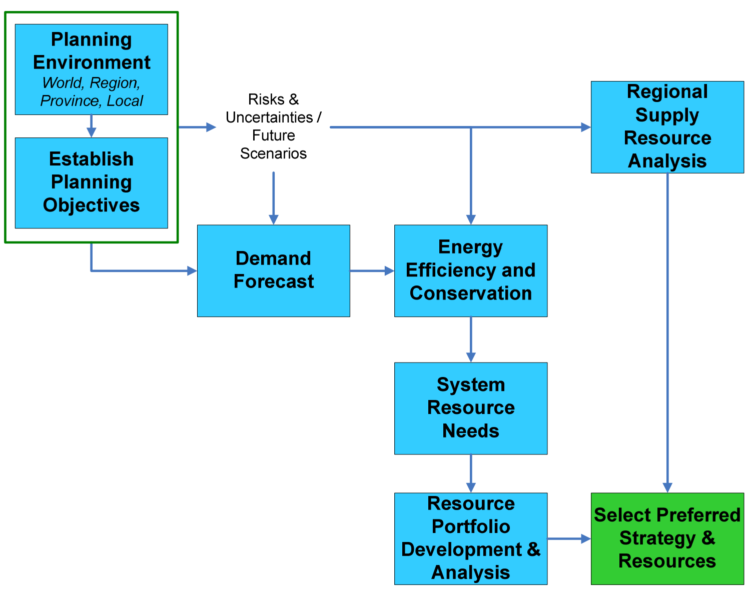
1 INTRODUCTION AND BACKGROUND

British Columbia, as with the rest of the North America, is in a time of rapidly changing energy issues and policies. A growing population is driving the need for more energy of all types within both the province and the Pacific Northwest ("PNW") region, throughout which gas and electric utilities trade energy and energy transportation rights. Many of the regions utilities are facing the need to find new energy supplies and develop new infrastructure to transport that energy from production areas to their customers. At the same time, rising costs, climate change concerns and competition for resources from other regions complicate the decision making process. The search for new energy solutions continues to intensify.

This document presents the 2008 Resource Plan for Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGW"), collectively referred to herein as "Terasen Gas"[1]. The resource planning process begins by closely examining the planning environment the utilities operate in, and identifying expectations for future customer and demand growth. The demand and supply side resource alternatives for meeting that future demand are then assessed, and actions are recommended for ensuring the proper resources are in place to deliver the preferred energy solutions and meet future customer needs. Figure 1-1 outlines the resource planning process for Terasen Gas. The final stage of this process is the development of a four-year action plan that implements the recommendations of the plan and ensures the ongoing assessment of resource requirements and alternatives.

Figure 1-1 Terasen Gas Resource Planning Process Flow Chart

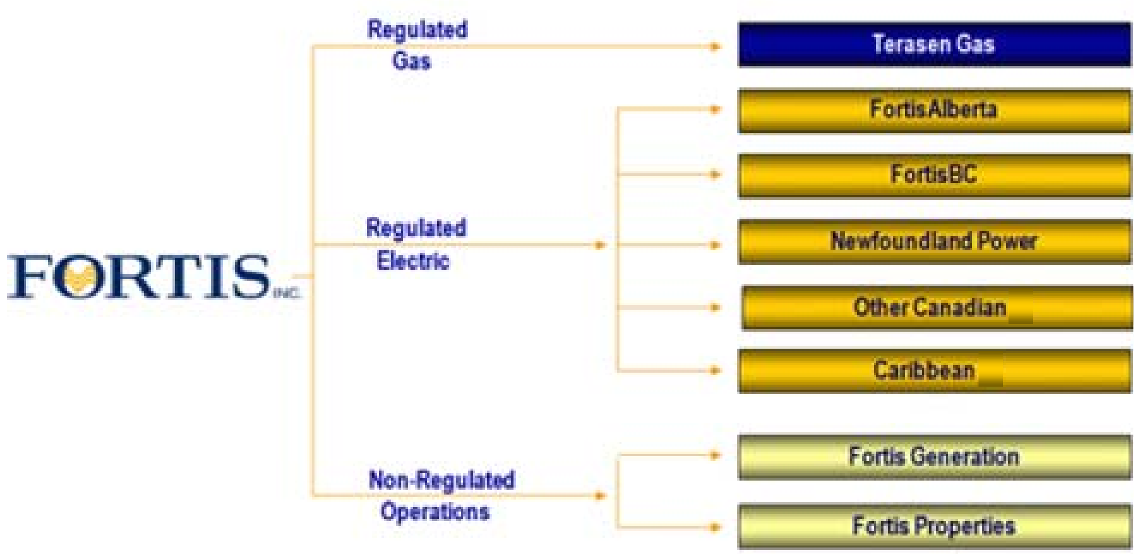


[1] Since many of the staff and administrative resources are shared by the three utilities through approved service sharing agreements, the term "Terasen Gas" in the context of this Resource Plan may also refer broadly to the resources used to undertake activities for one or more of the utilities.

1.1 Introduction to Terasen Gas

The Terasen Gas utilities are subsidiary companies of Terasen Inc. In May 2007, Terasen Inc. and its subsidiaries were acquired by Fortis Inc., the largest investor-owned utility company in Canada. Today almost half of the total gas and electricity customers served by Fortis Inc. are Terasen Gas customers. The B.C. based electric utility FortisBC is also a Fortis Inc. subsidiary and sister company to Terasen Gas. Figure 1-2 shows the relationship of Terasen Gas to other Fortis Inc Companies.

Figure 1-2 Corporate Structure of Fortis Inc. Business Units



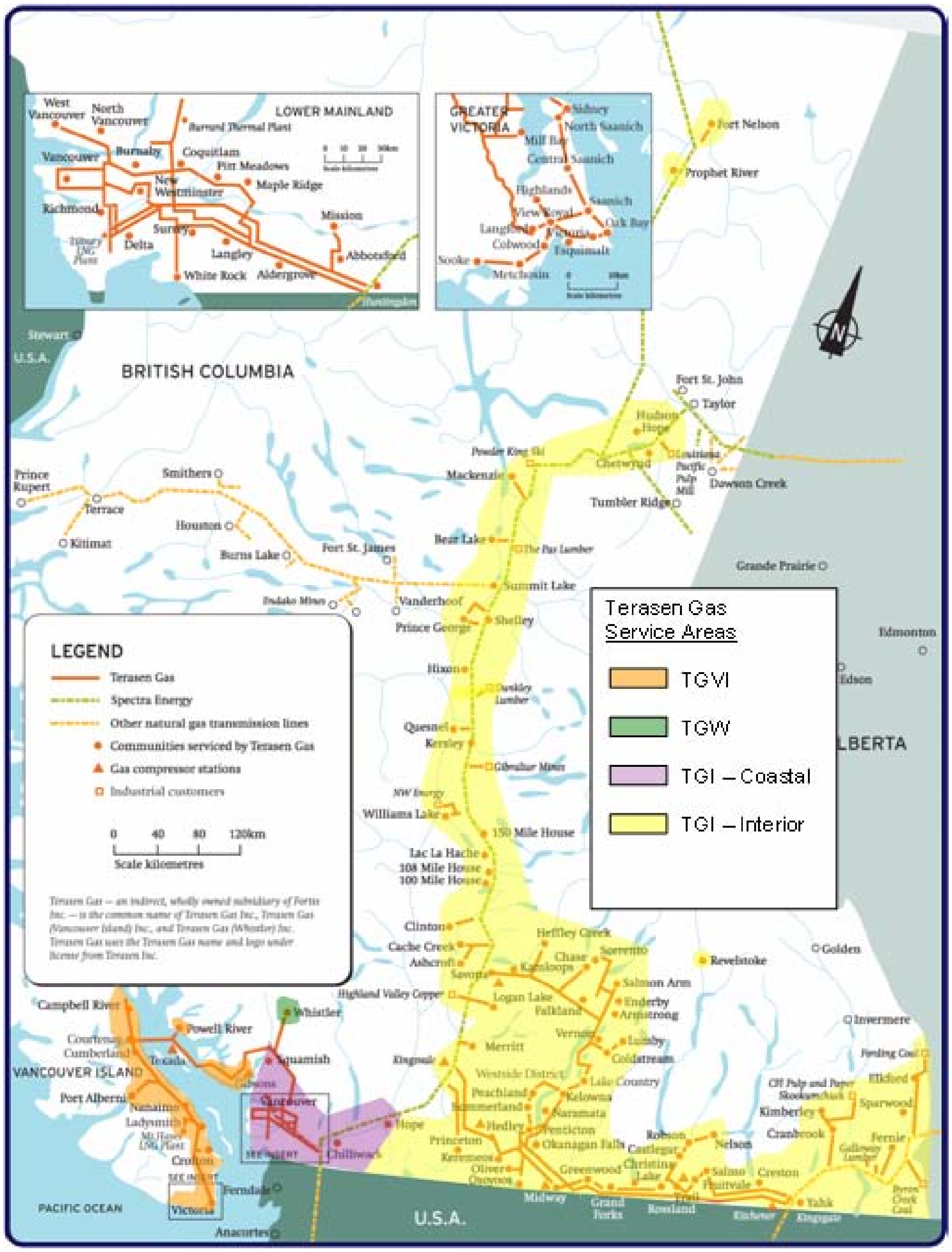
Terasen Gas provides natural gas service to over 925,000 customers in more than 125 communities, or approximately 95% of natural gas users in B.C. These statistics put the combined utilities of Terasen Gas among the largest gas utilities in Canada and make it the largest in the PNW. Table 1-1 provides a summary of customer, demand and pipeline characteristics for each of the Terasen Gas Utilities, with TGI broken out into Interior and Lower Mainland service areas. Figure 1-2 shows the transmission pipelines and service area locations.

Table 1-1 Terasen Gas 2007 Utility Statistic

	TGI Lower Mainland	TGI Interior	TGVI	TGW**
Number of Customers	573,295	249,627	91,242	2,411
Annual Demand (TJ)	86,220	28,310	12,066	742
Peak Day Demand (TJ/d)	931	337	108	6.6
Length of Transmission Pipeline (km)	260	2,090	630	--
Length of Distribution Pipeline (km)*	11,260	8,800	3,550	100

* Includes both low and intermediate pressure pipelines
** Note that currently TGW is a propane distribution system

Figure 1-3 Map of Terasen Gas Transmission Pipelines and Service Areas



1.2 Regulatory Context for Resource Planning

In B.C., like many other regulatory jurisdictions in the region, Integrated Resource Planning is the primary tool for identifying long-range infrastructure requirements and resource acquisition strategies, and for sharing this information with stakeholders. Under the *Utilities Commission Act*, the British Columbia Utilities Commission ("BCUC") has the authority to regulate utilities in the province and to require utilities to, among other things, submit resource plans. In 2003, the

BCUC issued its resource planning guidelines which continue to guide B.C. utilities in the preparation of resource plans. Earlier this year, the BC Provincial Government passed the *Utilities Commission Amendment Act* ("UCA Act"), providing additional direction to the BCUC and utilities for the submission and review of resource plans.

The UCA Act makes changes to the *Utilities Commission Act*, including the addition of Section 44.1, "Long-term Resource and Conservation Planning" and rescinding of Section 45.6 (1) and (2) under which the requirement for resource plans was previously administered. The UCA Act, Sections 44 and 45 of the *Utilities Commission Act* and the BCUC's Resource Planning guidelines are all contained in Appendix A. The recent changes of the UCA Act do not substantially impact Terasen Gas' Resource Plan or planning process since most of the changes simply add clarification for activities, analyses and documentation already being addressed by Terasen Gas.

Resource planning is more than simply a requirement of the BCUC and the *Utilities Commission Act*. It is also a valued strategic planning activity that Terasen Gas has carried out for many years. The key activities which encompass the resource planning process are embedded in the overall planning processes which the Company undertakes in providing service to our customers. In keeping with the Provincial Government's 2007 Energy Policy, effective resource planning requires that consumers have access to the information needed to make the best choices among all available energy sources. The delivery of an effective marketing strategy and programs to assist consumers in making appropriate energy choices is an important component of the resource planning process.

In conducting its own resource planning process, Terasen Gas believes it is also important to understand the planning issues, competitive environment and resource requirements for other utilities in the region because of the common infrastructure and/or the common customer base. As such, Terasen Gas actively participates as a stakeholder in the resource planning efforts of other gas and electric utilities in the region including BC Hydro, Fortis BC and Puget Sound Energy. To facilitate its understanding and response to regional resource issues, Terasen Gas also participates in planning and resource assessment activities and events conducted by regional organizations including the Northwest Gas Association ("NWGA"), the Northwest Power and Conservation Council("NWPCC") and the Pacific Northwest Economic Region ("PNWER"). The regional outlooks provided by these organizations inform the analyses and recommendations in this Resource Plan.

1.3 Resource Planning Objectives

Terasen Gas' resource planning objectives form the basis for evaluating all potential resources in the Plan including major infrastructure projects, gas supply alternatives and demand side programs. The objectives reflect the Company's commitment to providing the highest level of quality energy services to its customers. Terasen Gas' four key resource planning objectives are outlined below.

Safe, reliable and secure supply

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

Cost effective service to customers

Customers and regulators expect the Utility to procure and deliver energy in the most cost-effective and efficient manner possible. The most desirable resource options will provide cost effective service solutions and help to manage rate volatility both in the near term and into the future. Demand Side Management ("DSM") strategies which are cost-effective can add value to customers through more effective use of the gas delivery infrastructure and more efficient use at the burner tip.

Energy efficiency and conservation

Energy efficiency and conservation ("EEC") is one of the key themes in the 2007 B.C. Energy Plan and its policies. In today's world of higher energy prices and need for additional new energy resources, efficiency and conservation remain among the lowest cost alternatives. Substantial potential savings have been identified for natural gas customers. To acquire these savings, Terasen Gas needs to ensure that customers have easy access to information and efficient energy choices and equipment. For this reason, Terasen Gas has made EEC one its key objectives for the 2008 Resource Plan.

Manage social and environmental impacts

It is important to incorporate environmental and socio-economic considerations into the selection process for demand and supply resources by examining the impact of resource selection alternatives on land-use, air emissions, the local economy, and First Nations and B.C. communities served.

1.4 Update on 2005 / 2006 Action Plans

In its previous Resource Plans, Terasen Gas presented a list of actions to implement the recommendations outlined throughout the Plans. Table 1-2 through Table 1-4 provide an update on the 4-year action plan described in the previous Resource Plans for each of the Terasen Gas utilities.

Table 1-2 TGVI 2006 Resource Plan Action Items

	Action Item	Status
1	Continue with existing and implement new DSM initiatives.	Existing DSM programs were completed. A new EEC funding application was submitted to the BCUC in May 2008 for new programming for both TGI and TGVI.
2	Continue to pursue to pursue partnering opportunities regarding energy efficiency measures.	Partnerships with Federal and Provincial agencies, other utilities and appliance manufacturers continue to grow. Approval of the new EEC application will facilitate more partnership opportunities.
3	Extend TGVI's system to serve TGW customers in the Whistler area.	The Squamish to Whistler Pipeline is under construction.
4	Continue to monitor and assess the impact of the BC Hydro 2006 IEP process.	Terasen Gas has been an active participant in BC Hydro's consultation for power generation calls, Power Smart programming, interior to lower mainland transmission and the 2008 LTAP consultations. TGVI has also signed a long-term Transportation Service Agreement with BC Hydro for gas service to the Island Co-generation Project.
5	Obtain approvals to retain and upgrade the Texada Compressor.	Upgrades to the compressor have been completed and ownership of the facility by TGVI became effective on January 1st, 2008.
6	Continue to examine the feasibility of the Mt Hayes LNG facility.	Approval to construct the Mt. Hayes storage facility was received in November 2007, and construction of the facility is under way.
7	Obtain approvals to construct a LNG storage facility on Vancouver Island.	

Table 1-3 TGW 2005 Resource Plan Update Action Items

	Action Item	Status
1	Seek approval to convert the existing propane system to natural gas and enter into an agreement with TGVI for natural gas transportation services.	Approval for the system conversion was received in 2006. Construction of the Pipeline is under way and plans for the conversion of the distribution system and customer connections are being made.
2	Manage the capacity of the existing propane system through bridging facilities or limit customer additions.	An application to initiate bridging facilities was approved and implemented in 2006. TGW continues to monitor the demand-capacity balance of the system and to date; no additional bridging facilities have been required.
3	Continue to examine DSM opportunities in bridging the operating requirements of the existing system until the natural gas pipeline is in place and continue monitoring the implementation of Whistler 2020 and the Sustainable Energy Strategy ("SES") as a DSM resource.	The propane to natural gas conversion and Squamish to Whistler pipeline will allow the Regional Municipality of Whistler ("RMOW") to implement its SES. TGW continues to monitor customer needs in Whistler and opportunities to assist the RMOW with SES initiatives.
4	Continue Support of RMOW's Strategic Vision and Plan, Whistler 2020 and the implementation of the Sustainable Energy Strategy and continue to nurture existing partnerships.	
5	Continue to identify and monitor potential new development along the Sea to Sky corridor that could lead to efficient and cost effective energy load additions.	Terasen Gas continues to monitor new load opportunities along the Sea to Sky corridor. As yet, no firm opportunities have been identified.

Table 1-4 TGI 2006 Resource Plan Action Items

	Action Item	Status
1	Continue to monitor and evaluate customer demand.	Developing customer demand trends and issues are discussed in Chapters 2 and 3 of this Resource Plan.
2	Continue with existing and implement new DSM initiatives.	Existing DSM programs were completed. A new EEC funding application was submitted to the BCUC in May, 2008 for new programming for both TGI and TGVI.
3	Continue to pursue partnering opportunities regarding energy efficiency measures.	Partnerships with Federal and Provincial agencies, other utilities and appliance manufacturers continue to grow. Approval of the new EEC application will facilitate more partnership opportunities.
4	Examine funding opportunities for the preparation and implementation of marketing plans that will help Terasen Gas reach customer targets and build energy efficient gas load for both new and existing customers.	The EEC strategy submitted to the BCUC as part of Terasen Gas' EEC application include funding for marketing programs that educate customers on energy efficiency and help implement new EEC programs, thereby building efficient new gas load for TGI.
5	Monitor customer growth on the Coastal Transmission System ("CTS") system and continue to investigate options to address future capacity shortfalls.	Terasen Gas has identified potential constraints on the CTS; however, utilizing the Mt. Hayes storage facility as a gas supply resource alleviates the need for growth related CTS expansion through the planning period.
6	Work with TGVI to examine the feasibility of the Mt Hayes LNG facility as an on-system storage resource for both utilities.	Approval to construct the Mt. Hayes storage facility was received in November 2007, and construction of the facility is under way. TGI has entered a long-term agreement with TGVI for service from the facility.

2 THE PLANNING ENVIRONMENT

The planning environment sets the context within which energy demand will grow and evolve over the next 20 years. Currently, this environment is undergoing a great deal of change, creating uncertainty in how the energy future in B.C. will unfold over the next several years or even months. Driven by rising energy costs, increasing demand from population growth and social and political reaction to climate change concerns; new policies and legislation have been and continue to be introduced with far reaching implications for energy production, consumption and infrastructure. This chapter provides an overview of the planning environment in which this plan is set. Appendix B examines regional energy planning issues in more detail.

The key messages documented and supported in this Chapter are:

- Since both natural gas and electricity produced and used in B.C. are bought and sold across political boundaries within the region, energy planning and emission issues should be considered within a regional context.
- In political jurisdictions and utility service areas throughout the PNW, natural gas is widely viewed as the environmental choice for fueling a majority of required new electricity generating facilities, since in most jurisdictions new large hydro projects are not permitted due to their impact on the environment. Other renewable resources are limited, leaving natural gas as the best alternative to accompany what renewable resources can be developed.
- Since using natural gas for space heating and other appliances in the home is more efficient than using natural gas to generate electricity (the marginal resource in the PNW) for use in the same applications, direct use of natural gas is the preferred choice for these uses over electricity. Where alternative energy systems such as heat pumps make sense, natural gas remains the preferred back-up fuel.
- Demand for natural gas throughout the region is thus expected to continue growing into the next decade and beyond, led by growth in the residential and electricity generation sectors.
- Utilities and other major buyers of natural gas in the region are seeking cost effective means to increase the diversity of their supply options in order to improve supply reliability and reduce cost exposure from single source supply as demand grows.
- In B.C., where renewable electricity alternatives are more widely available than elsewhere in the region, direct use of natural gas for home heating and appliances is still the right fuel choice over electricity because:
    - B.C. currently imports up to 15% of the electricity needed to meet domestic load requirements[2] and that electricity is primarily generated from lower efficiency coal and natural gas power plants, resulting in higher Greenhouse Gas (“GHG”) and pollution emissions than would result if that self-sufficiency shortfall was met through the direct use of natural gas.

[2] http://www.bchydro.com/policies/index/index3196.html

- Even when B.C. becomes electricity self sufficient sometime in the future, as set out in the 2007 Energy Plan, electricity produced using green and renewable electricity generated in B.C. can/could be exported to displace coal and natural gas fired generation elsewhere in the region, again reducing GHG and pollution emissions.
- With population in B.C. expected to grow by roughly one million people over the next 20 years[3], direct use of natural gas in homes and businesses, along with aggressive energy efficiency, conservation and alternative technology programs, will be an important part of helping to meet the expected tremendous growth in energy demand while reducing GHG emissions throughout the region.
- The biggest opportunity for GHG and pollution emission improvements in B.C. lies within the transportation sector where 39%[4] of B.C.'s GHG emissions are produced. Natural gas can play a significant role in reducing GHG emissions and other pollutants from this sector and help the province reach its GHG reduction targets.
- Even when the cost of carbon emissions has been applied through carbon taxes and other mechanisms, direct use of natural gas is expected to remain an economically competitive energy choice for direct use in homes and businesses.
- All of these natural gas solutions will help B.C. to meet the objectives of the 2007 Energy Plan.

In summary, natural gas in direct use applications is best suited for space and water heating. Electricity, regardless of the fuel used to generate it, should be used for applications where no other fuel substitute is available since these uses alone are creating growth in demand. Further, with B.C. currently being electricity short, natural gas in direct use applications will help to meet growing demand for energy, whereas electricity relied on to meet growing space and water heating loads will make the province's self sufficiency and renewable electricity targets more difficult and expensive to reach.

2.1 Energy Trends and Policies in the Pacific Northwest Region

In this Resource Plan, the term region or regional refers generally to the Pacific Northwest ("PNW"). PNW refers most commonly to the 4 northwestern states (Washington, Oregon, Idaho and Montana) and B.C, also referred to hereafter as the "Region". In some cases, discussion about the Region is expanded to include Alberta and/or Alaska since energy produced in each jurisdiction is traded, transported and consumed throughout the PNW. California is also a Pacific Coast jurisdiction whose actions have many implications for B.C. California has a large population and is a large consumer of energy resources, both from within it borders and elsewhere, including the PNW. It is also a leader in energy efficiency and alternative technologies, and initiatives to address climate change.

[3] http://www.bcstats.gov.bc.ca/DATA/pop/pop/project/bctab1.asp

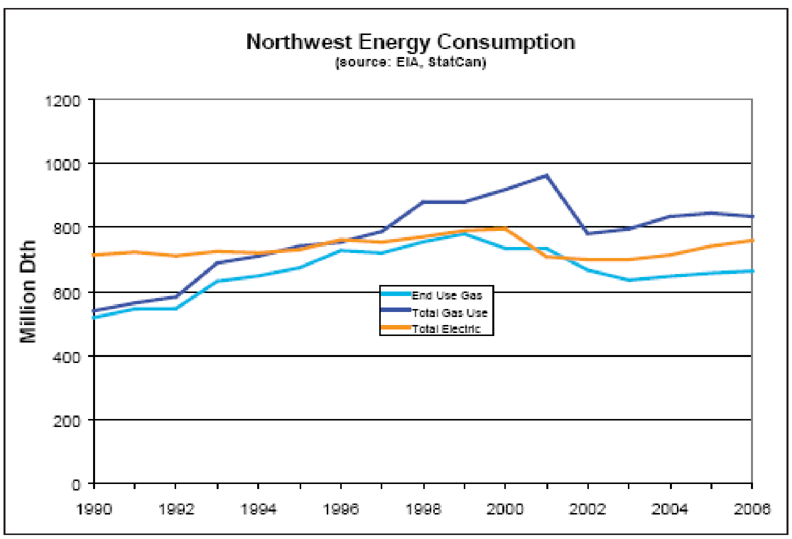
[4] NRCan Comprehensive Energy Use Database for BC

The demands for natural gas and electricity are interlinked through each one being a substitute energy source for the other, and through the use of natural gas as a major source of fuel for existing and planned new generation in the Region. Since both of these energy types are traded across political boundaries and B.C. trades these resources physically within the Region, energy planning in B.C. must consider the regional implications and impacts of the decisions being made. Terasen Gas' participation in the regional energy market means gas procurement activities are conducted in a competitive environment where access to and the cost of resources is affected by regional supply and demand balances.

2.1.1 Demand Trends – Natural Gas and Electricity

In the Pacific Northwest, consumption of natural gas surpasses that of electricity (see Figure 2-1). With continuing population growth expected, demand for both of these energy sources will continue growing. This diagram also indicates that to meet growing electricity demand, use of natural gas as a generation fuel in the region has been increasing since the early 1990s. This trend is evident throughout the period, with the exception being a one-time permanent reduction in industrial demand from the shutting down of the PNW aluminum industry (affecting both electricity and natural gas demand) associated with the Western energy crisis of 2001 – 2002. It is clear that regional demand for both of these energy types is closely linked.

Figure 2-1 Total Gas and Electricity Consumption in the PNW (B.C., Id, OR & WA)

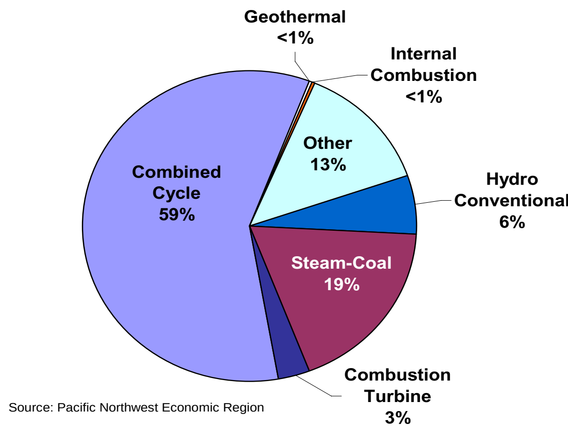


(End use gas is that gas which used for space heating and appliances in homes and businesses.

The difference between total gas use and end use gas is therefore electricity generation fuel.)

Data provided by the Pacific Northwest Economic Region ("PNWER") shows that on a regional basis this trend of increasing gas use for electricity generation is expected to continue. Figure 2-2 indicates that the majority of new generation additions in the region are expected to be fuelled by natural gas. A review of Resource Plans for electric utilities in the region shows that, with the exception of BC Hydro, these utilities plan to rely increasingly on natural gas-fired generation to meet growing electricity demand and future resource requirements. The market is responding by developing new supply alternatives that will service the Region and help to keep natural gas prices competitive. These new supply alternatives are discussed in more detail in Chapter 6.

Figure 2-2 Summary of Electricity Generation Facility Additions 2005 – 2014

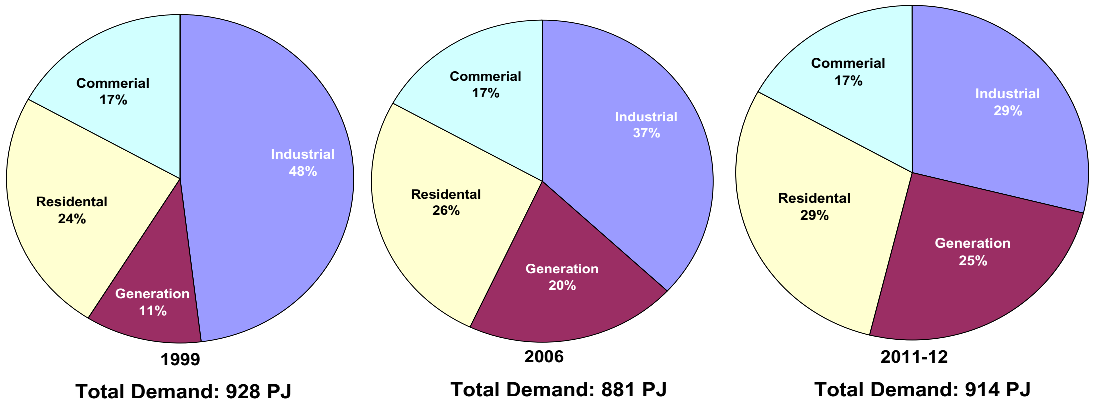


Recent legislation in most jurisdictions in the Region calls for renewable generation resources to make up a greater proportion of utility resource portfolios. In most areas of the Region, however, the renewable resources available are limited to primarily intermittent resources such as wind, small hydro and solar projects that are unable on their own to meet either the expected growth in demand or reliability requirements. For this reason, conventional sources of non-renewable resources[5] are required to both meet the growth in electricity demand and to firm up the intermittent renewable resources that are being added to the electricity grid. Since there are essentially no large hydro projects available except for in B.C., and new coal-fired generation is not permitted or is accompanied by high development risks as a result of expected carbon and pollution emission regulations, most utilities seeking new generation resources are turning to natural gas as a key component of future resource additions.

The NWGA reports the resulting changes in the composition of regional demand shown in Figure 2-3**.** The progression shown in these charts indicates that the proportions of generation fuel and residential demand are growing while industrial gas demand has declined. The right hand chart in Figure 2-3 shows that, with overall demand for natural gas having recovered from the energy crisis of 2001 – 2002 (see also Figure 2-1), growth in these two sectors is expected to continue driving the incremental demand for natural gas into at least the next decade.

[5] Within the Pacific Northwest, only BC considers large Hydro projects as renewable resources.

Figure 2-3 the Changing Make-up of Natural Gas Demand in the Pacific Northwest



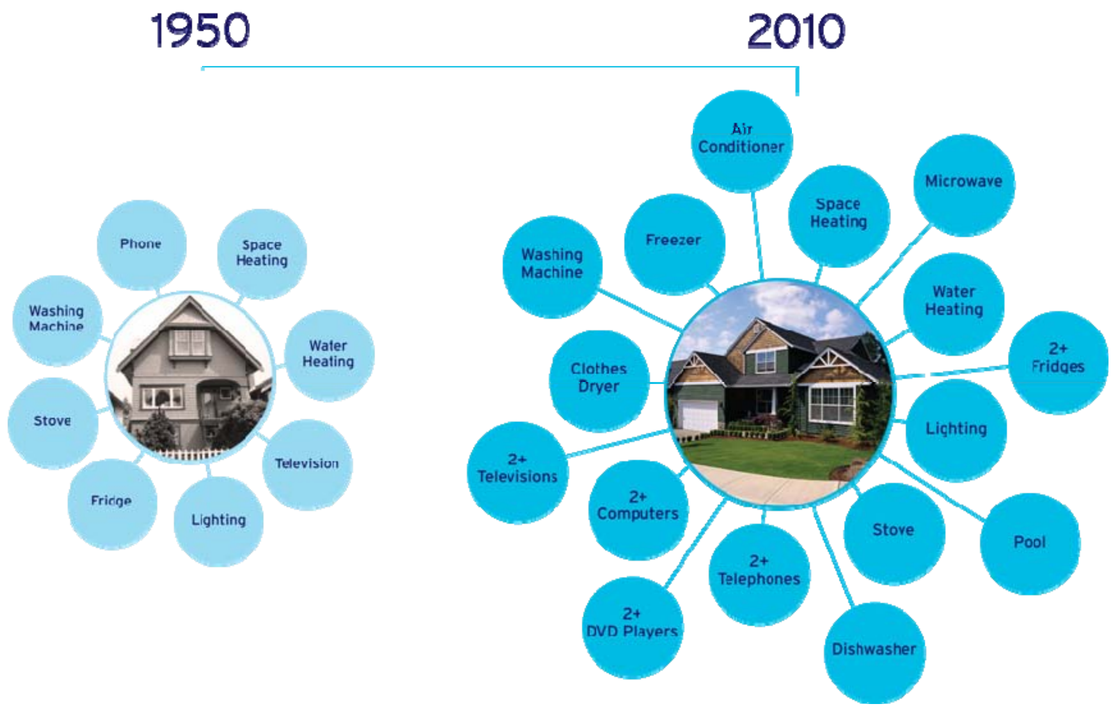
Source: EIA, StatsCan, NWGA

Each year the NWGA prepares a Regional Outlook Study (see Appendix C) which, among other things, reviews these trends. The 2007 Outlook Study noted that the combination of increasing residential and generation demand is causing peak demand to grow more quickly than base load demand, driving the need for new peaking or storage resources. The study also noted, however, that few large base load resources (pipelines) have been added in the Region in recent years and that these resources need to be encouraged in order to access growing production and improve supply diversity. These trends are discussed further in Chapter 6.

2.1.2 Residential Fuel Choice in PNW

Natural gas and electricity are the two most common energy sources for home heating in the PNW. Compared to electricity, natural gas has fewer direct use applications in the home. Where electricity can be used to run lights, electronics and other electric equipment in addition to space and water heating applications, natural gas can only be used for space heating, hot water and appliances. Figure 2-4 shows how, in addition to the growth in population and new homes that require electricity, the number and type of uses for electricity within each home has also grown, making the burden on B.C.'s electricity resources increase much faster. It is important, therefore, that the right fuel be used for its most efficient application wherever practical and cost effective.

Figure 2-4 The Evolution of Residential Demand for Energy



Since natural gas is the marginal source of electricity generation in the PNW, the relative efficiency of these two energy types is an important factor in choosing a home heating fuel, both in terms of energy efficiency and GHG emissions. Since gas fired generating facilities typically operate at between 30 and 55%[6] efficiency, the case is easily made in most areas for direct use of natural gas in the home at 80 to 95% efficiency[7] for new natural gas appliances. In service areas outside of B.C., the choice for direct use of natural gas in homes where available is made easier by the relatively lower cost of natural gas as a heating fuel as shown in Figure 2-5. These principles are being adopted by more and more utilities[8] in the PNW and continue to be studied by regional agencies[9].

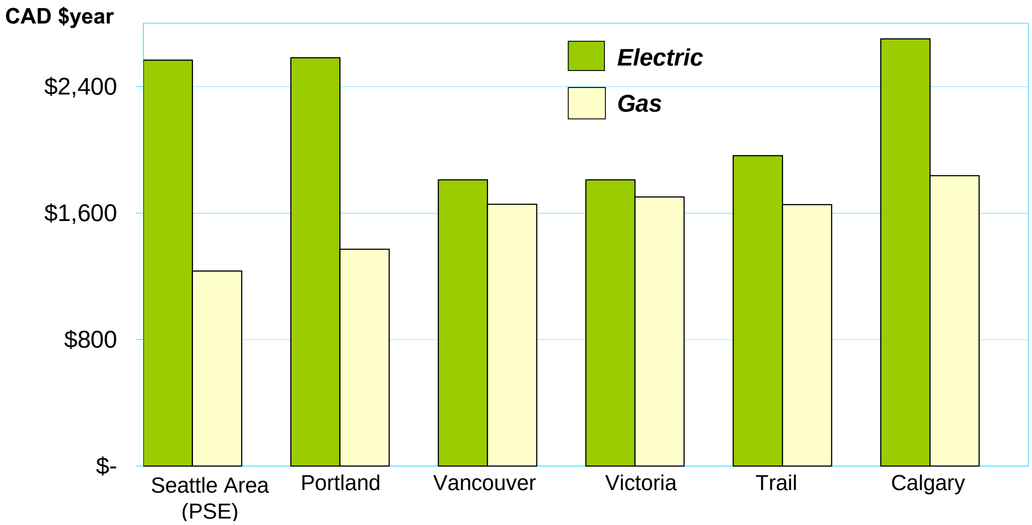
[6] 50-55% is the expected efficiency of a typical new combined cycle, gas fired generating facility. Simple cycle or older combined cycle facilities and coal plants operate at lower efficiencies and have higher GHG emissions – source: Canadian Power Industry Course, 2007. www.powercourses.ca

[7] These are industry standards for mid and high efficiency furnaces respectively.

[8] Avista Energy, a combined electric and gas utility, has been conducting fuel switching to direct use of natural gas since 1991 and Puget Sound Energy is now developing similar programming.

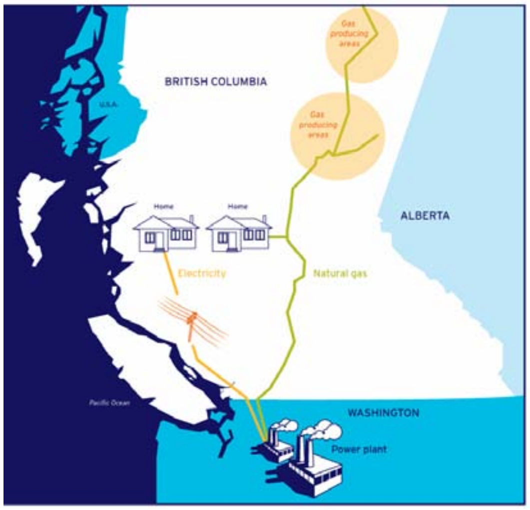
[9] Both the NWGA and NWPCC are undertaking studies related to the potential for direct use to support regional energy objectives.

Figure 2-5 Cost of Natural Gas vs. Electricity for Home Heating in the PNW



ASSUMPTIONS:
Annual Bill - 110 GJ/year
1 USD - 1.03 CAD Bank of Canada USD Conversion Rate
1 GJ = 9.4782 Therms and 277.78 kWh
The electric rates are 90% efficiency adjusted
Rates include all applicable riders
Other utilities' rates are estimates only

Direct Use



Direct use of natural gas for space and water heating in homes and businesses in B.C. will help to meet the electricity self sufficiency targets of the B.C. Energy Plan and will reduce carbon emissions throughout the Region. The growing amount of electricity that B.C. imports is largely generated from natural gas and coal fired generation plants located elsewhere in the PNW. Using natural gas directly at the end use is much more efficient than using it to generate electricity for use in space and water heating.

←

When B.C. reaches its self-sufficiency, surplus and green targets for electricity by 2016 as set out in the Energy Plan, the surplus green electricity will be available for export to neighbouring jurisdictions to replace natural gas and coal fired generation there. Utilities in other parts of the Region are continuing to pursue the potential for programs to replace electric radiant and water heating with natural gas.

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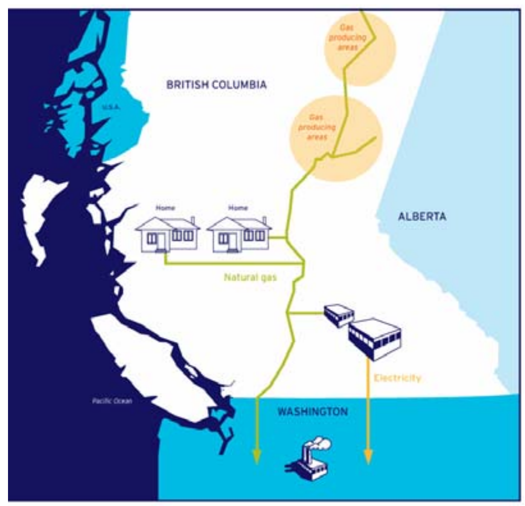


Focus on Issues

2.2 Energy Trends & Policies in British Columbia

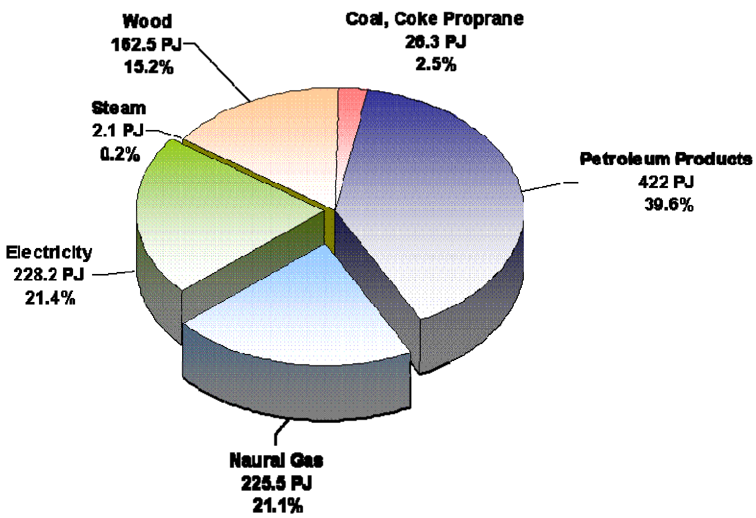
2.2.1 Provincial Demand for Energy

Across all sectors and energy types, 1,066 petajoules ("PJ ")[10] of energy were used in 2004 in B.C. Figure 2-6 shows the distribution of fuel consumption in B.C. across energy types. Petroleum products, consisting largely of transportation fuels, represent the largest slice of this

10 NRCan Comprehensive Energy Use Database

chart. Consumption of natural gas and electricity in the province is approximately equal, each at 21% of annual energy consumed. While B.C. is a net exporter of natural gas (70 - 80% of the natural gas produced here is exported[11]), the province imports approximately up to 15% of BC Hydro's electricity[12] and 70+% of its petroleum[13].

Figure 2-6 Annual Energy Consumption in B.C. across Energy Types



Source: NRCan Comprehensive Energy Use Database, BC Stats

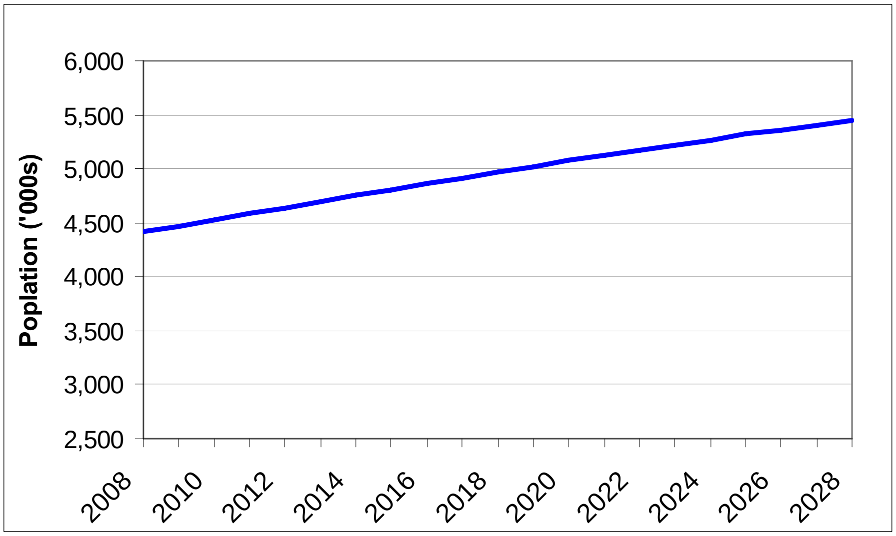
The population in B.C. grows by approximately half a million people every decade (see Figure 2-7). Even with more aggressive conservation and energy efficiency efforts by all utilities and end users, energy consumption will grow to meet the needs of this expected population increase even where use per customer rates are falling. These statistics have important implications for energy costs, carbon emissions and fuel choice in B.C. and the PNW.

11 BC Ministry of Energy, Mines & Petroleum Resources, Oil & Gas Division

12 http://www.bchydro.com/policies/index/index3196.html

13 BC Ministry of Energy, Mines & Petroleum Resources, Oil & Gas Division

Figure 2-7 B.C. Population Growth



Source: B.C. Stats

In summary, the size of overall energy demand depicted by the pie chart in Figure 2-6 will continue to grow. Intensification of EEC programs play an important role in helping to meet incremental demand for energy, but cannot be expected to reverse demand growth. The size and nature of each portion of the pie chart will be determined by a combination of energy costs (capital and operational), government policies and legislation, and education programs that will allow the public to make informed energy use decisions.

2.2.2 Provincial Energy Policy and Regulation

Energy policies and regulation in B.C. have been changing quickly in recent years as a result of both the need to meet increasing energy demand and Provincial climate change response initiatives. A summary review of the various new Provincial legislation and policies below provides regulatory context within which Terasen Gas must set objectives and plan resource development activities.

The 2007 BC Energy Plan – A Vision for Clean Energy Leadership

This Resource Plan has been prepared with consideration for all of the policies in the BC Energy Plan. Key policies in the plan with implications for Terasen Gas Include:

Environmental Leadership -

- Net zero GHG emissions from all new electricity generation and from heritage thermal generation by 2016.
- Clean and renewable generation to account for 90% of B.C.'s total electricity generation resources.
- Promote energy efficiency and alternative energy.
- Bring clean power to communities.
- Address GHG's from transportation.

Energy Conservation and Efficiency -

- Acquire 50% of BC Hydro's incremental electricity needs by 2020 through conservation.
- Implement energy efficient building standards.

Energy Security -

- Maintain B.C.'s competitive electricity rate advantage
- Achieve electricity self sufficiency by 2016.
- Make small power part of the solution.
- A decision on the future of Burrard Thermal.

Innovation -

- Establish the Innovative Clean Energy Fund.
- Implement the B.C. Bioenergy Strategy to take advantage of renewable resources.

Develop B.C.'s Oil and Gas Resources -

- Be among the most competitive oil and gas jurisdictions.
- Be a leader in responsible oil and gas development.

Utilities Commission Amendment Act, 2008 ("UCA Act")

Introduced as Bill No. 15, this legislation received Royal Assent, becoming law, on May 1st, 2008. As described in Section 1, the UCA Act revises a number of sections of the *Utilities Commission Act* with respect to resource planning, including the requirements for utilities to prepare resource and energy efficiency and conservation plans as described in Chapter 1. Conservation planning is discussed in Chapter 4.

The UCA Act puts into law many of the policies of the 2007 B.C. Energy Plan, containing the requirement for BC Hydro to achieve electricity self-sufficiency by 2016, install smart metering and implement the standing offer program. The province wide target for 90% of electricity generation from clean and renewable resources is also formalized in this Act. While these policies may not appear on the surface to impact Terasen Gas, they have implications for the competitive environment in which the utilities operate and provide some direction for Terasen Gas to undertake initiatives that help meet these goals and policies.

The UCA Act also adds a new definition of "government's energy objectives" to section 1 of the *Utilities Commission Act.* These objectives have implications for utility resource planning efforts, encouraging public utilities to:

(a) reduce greenhouse gas emissions;

(b) take demand-side measures;

(c) produce, generate and acquire electricity from clean or renewable sources;

(d) develop adequate energy transmission infrastructure and capacity in the time required to serve persons who receive or may receive service from the public utility;

(e) use innovative energy technologies;

(i) that facilitate electricity self-sufficiency or the fulfillment of their long-term transmission requirements, or

(ii) that support energy conservation or efficiency or the use of clean or renewable sources of energy; and

(f) take prescribed actions in support of any other goals prescribed by regulation.

The Greenhouse Gas Reductions Targets Act ("The Targets Act")

The Targets Act was brought into force January 1, 2008. The Targets Act enshrines in law the provincial government's commitment to becoming carbon neutral, and sets province wide targets for greenhouse gas reductions of 33% from the 2007 level by 2020, and 80% from the 2007 level by 2050. Targets for 2012 and 2016 are to be set by regulation before the end of 2008. While the Targets Act sets targets for making all levels of government and government facilities carbon neutral, it does not specify how the province should achieve these goals.

Bill 37 - Carbon Tax Act

The Carbon Tax Act was introduced as creating a revenue-neutral carbon tax, and requiring the Minister of Finance to return carbon tax revenues to taxpayers through tax cuts. The tax is intended to apply effective July 1, 2008 to the retail purchase or use in BC of the majority of fossil fuels, including gasoline, diesel fuel, natural gas, home heating fuel, propane and coal. The initial tax rate will be based on $10 per tonne of carbon dioxide-equivalent emissions released from burning the fuel, and will increase by $5 per tonne over the following four years reaching $30 per tonne as of July 1, 2012. This Act will add $0.50 per gigajoule ("GJ") to the cost of natural gas in the first year, rising to $1.50 / GJ in the third year of implementation.

Other legislation / regulation that is under development or has recently been passed by the BC Government and which has implications for energy planning are:

- Bill 16 - 2008 Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act
- Bill 18 - Greenhouse Gas Reduction (Cap and Trade) Act
- Bill 27 - Green Communities Act
- Bill 31 - 2008 Greenhouse Gas Reduction (Emissions Standards) Act
- Bill 39 - 2008 Greenhouse Gas Reduction (Vehicle Emissions Standards) Act
- The BC Green Building Code

The initiatives and actions described in this Resource Plan are aimed at addressing either the regulations themselves or the intent of this legislation to reduce carbon emissions and improve energy efficiency.

The Innovative Clean Energy Fund

Although the Innovative Clean Energy Fund itself is not legislation, it has been developed by the B.C. Government as part of its commitment to the 2007 BC Energy Plan. The fund, built up through B.C. utility customer contributions as a nominal tax on their energy bills, is intended for the development and implementation of new, alternative energy solutions in the Province. The Terasen Gas alternative energy initiatives discussed in Chapter 7 of this Resource Plan address the intent of the Province in setting up this plan and through application to the fund can benefit the Provinces utility customers through the development of clean and alternative energy resources.

2.2.3 Competitiveness of Energy Alternatives

2.2.3.1 Natural Gas and Propane Commodity Prices

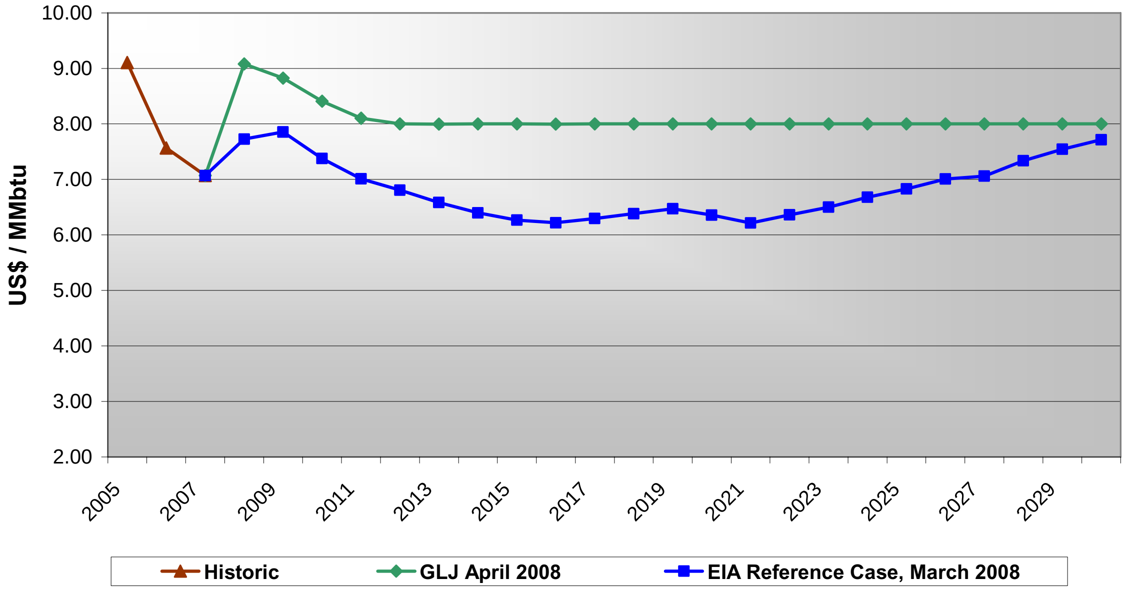
Trends in natural gas and electricity prices send signals to consumers making buying decisions on energy system equipment and fuel choices. Since these are the two primary energy choices for consumers in BC, expectations by consumers of future price increases in the supply of either energy type relative to the other can impact customer additions and load forecasts. This section presents a discussion of natural gas price forecasts prepared by independent sources, as well as a discussion on recent trends and price pressures in electricity and comments on Energy Pricing made by the BC Progress Board in their review of energy opportunities and imperatives in BC. Information reviewed by TGI in preparing this Resource Plan points toward the continued competitiveness of natural gas prices as upward pressures on electric rates continue.

Natural Gas Price Forecasts

Terasen Gas generally utilizes price forecasts generated by other industry experts when analyzing likely future gas consumption for its own customers. GLJ Petroleum Consultants Ltd. ("GLJ") is a private petroleum industry consultancy serving clients who require independent advice relating to the petroleum industry, including the preparation of natural gas and oil price forecasts on a quarterly basis. GLJ prepares commodity price and market forecasts after a comprehensive review of information available to the reported quarter. Information sources include numerous government agencies, industry publications, Canadian oil refiners and natural gas marketers. GLJ's forecasts reflect tracking recent trends in oil and gas supply, demand and transportation issues as well as other trends in the natural gas industry and the cost of competing fuels.

The U.S. Energy Information Service (“EIA”) also prepares a range of gas price forecasts against which the GLJ forecast can be compared for reasonableness. The EIA uses the last 30 years of data, including normal weather and storage inventories to generate the price forecasts. EIA’s 2008 Annual Energy Outlook forecast was released in December 2007, but was subsequently revised to include the impact of the “Energy Independence and Security Act of 2007”. Only the reference case forecast was re-released. The reference case reflects reduced expectations for economic growth and now includes provisions for energy efficiency standards on home heating equipment and other appliances, along with other measures to lower carbon emission intensity. Figure 2-8 presents the GLJ and EIA reference case natural gas demand price forecasts.

Figure 2-8 Third Party Long-range Gas Price Forecasts – Henry Hub



Both forecasts have incorporated the expectation of short-term price increases resulting from current market conditions and production levels. Moving into the mid-term, these forecasts also account for the market expectation of lowering prices as production increases and transmission infrastructure expands to improve access to supplies. Over the longer term, the EIA forecasts a gradual increase in prices, while GLJ keep prices flat in constant dollars.

Short Term Price Considerations

Market prices for natural gas are currently higher than most price forecasters have predicted. The market expectation of short range price increases for natural gas followed by declining, but seasonal pricing is shown in Figure 2-9, which includes forward gas prices against oil based fuel prices. Further discussion on commodity price competitiveness is contained in Appendix D.

Figure 2-9 Historic and Settled Future Commodity Prices – Oil and Natural Gas

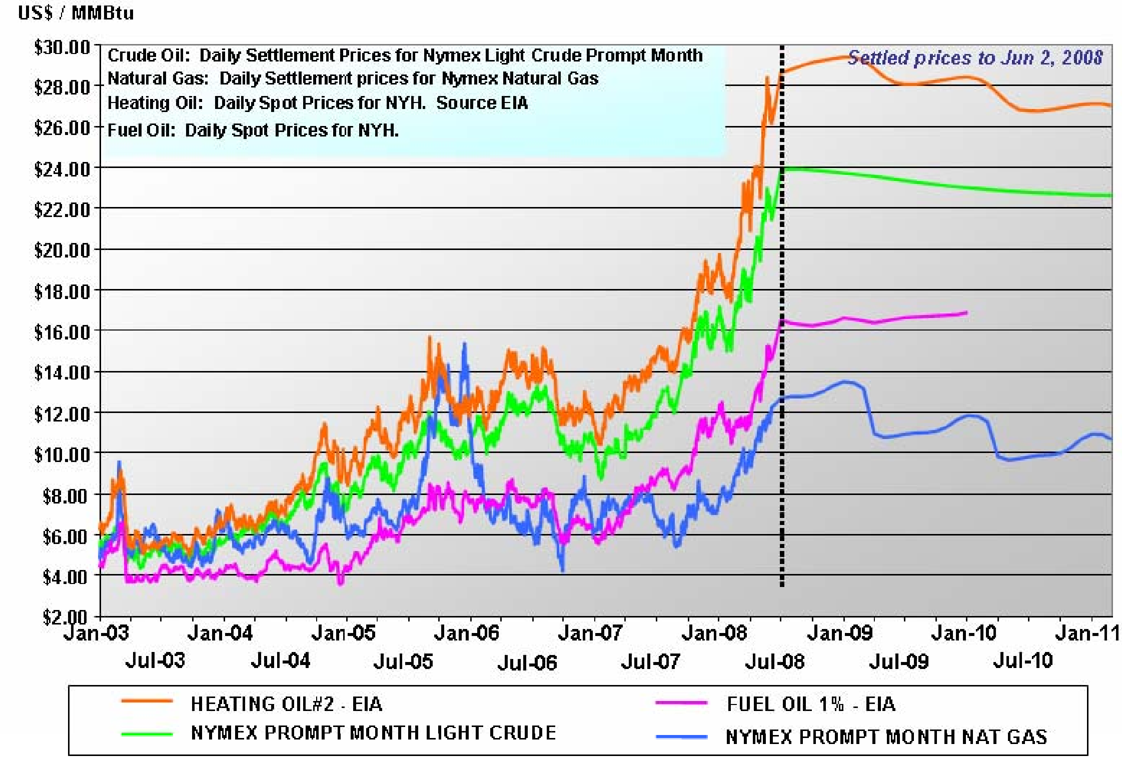


Figure 2-9 also shows that, while oil prices have increased dramatically through 2007 -2008, the separation between oil and gas prices has become larger. This separation may be in part due to the difference in the dynamics of global oil markets versus more regional natural gas markets. The volatility of gas prices is also apparent in this graph along with the trend that spikes in gas prices tend to be short lived.

Propane Prices versus Natural Gas

Some Terasen Gas customers, primarily in Whistler and Revelstoke, are served by Propane Distribution systems. In Whistler, the decision to convert TGW's propane system to natural gas and extend a gas pipeline from Squamish was based in part on the divergence between gas and the more expensive propane commodity prices. Figure 2-10 shows that this divergence has continued. Figure 2-11 shows that TGW's cost for propane has continued to separate from TGI's cost for natural gas. Although this trend will likely be somewhat cyclical, propane prices tend to follow the higher of oil or natural gas prices. Figure 2-10 suggests these trends will continue and oil is currently priced much higher than natural gas. As a result, Whistler customers will benefit from lower commodity rates once the system conversion from propane to natural gas is completed in 2009.

Figure 2-10 Historic Natural Gas Prices versus Propane and Crude Oil

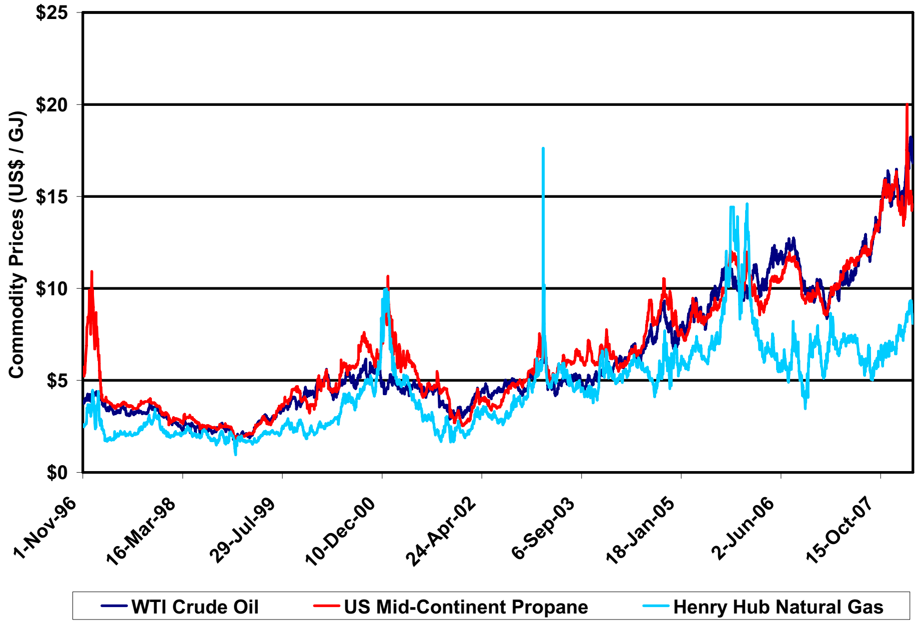
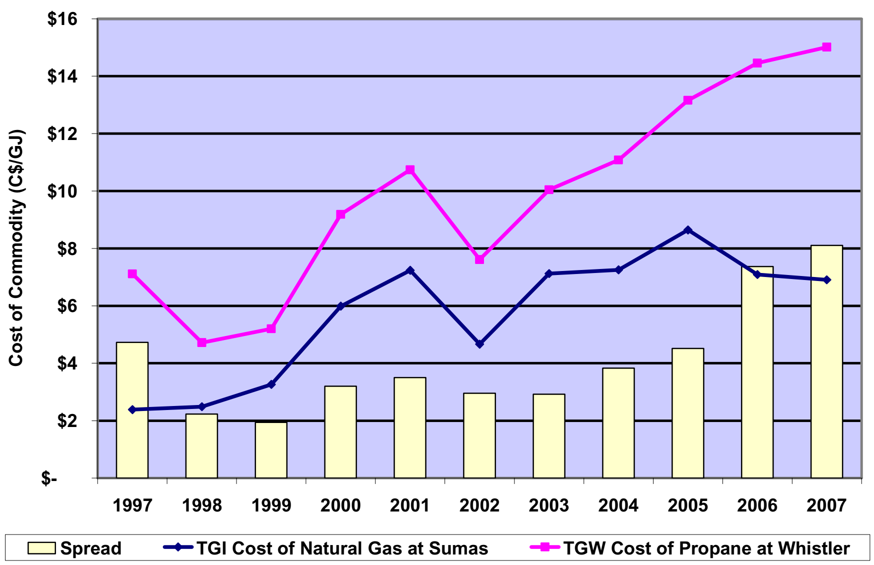


Figure 2-11 Natural Gas versus Propane Commodity Costs for TGW



2.2.3.2 Rate Competitiveness for Heating Energy Choice in BC

Equally important to fuel choice for Terasen Gas customers is the relative annual cost of various heating choice alternatives. While the primary alternatives still remain gas and electricity in B.C., both air and ground source heat pumps are gaining the attention of consumers. A comparison between traditional electric heating systems and natural gas is a relatively straight forward comparison of consumption levels and rates; however, both the physical and economic effectiveness of heat pumps are area and site specific. In addition to comparing traditional fuel choices, Terasen Gas has examined the benefits and risks of installing both ground and air source heat pump technology. A more detailed description of these comparisons can also be found in Appendix D.

Natural Gas and Electric Comparison

Figure 2-12 provides a historical and projected comparison of natural gas bills with the comparable electricity bills. The natural gas bills are based on 110 GJ/year and an assumption of 90% efficiency, while the electricity bills assume 100% efficiency. Going forward the electricity bills include BC Hydro's applied-for F2009 and F2010 revenue requirements increases as well as a proposed inclining block rate being implemented to promote energy conservation in keeping with Provincial energy objectives. Natural gas rates and bills are held constant based on the forward commodity prices discussed above displaying a moderate downwards trend. However, the B.C. carbon tax on natural gas has been added according to the phase-in schedule prescribed by the Province.

Figure 2-12 Residential Natural Gas and Electricity Bill Comparison

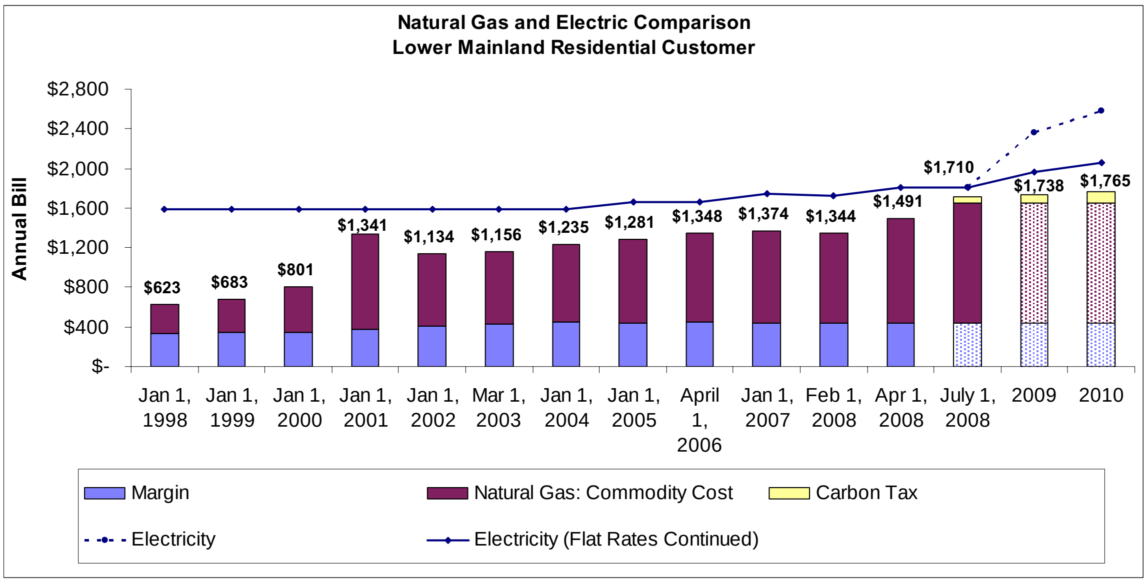


Figure 2-12 demonstrates that while the historical natural gas cost advantage has experienced erosion, natural gas has maintained a favourable competitive position relative to electricity. In the future, the competitive position of natural gas is likely to improve even with the new carbon tax included, particularly if the residential inclining block rate structure is approved and implemented[14].

[14] The residential inclining block rate structure is also referred to as BC Hydro's Residential Inclining Block ("RIB") Rate Application.

Natural Gas Compared to Heat Pumps

In comparing natural gas to air source and ground source heat pumps ("ASHP"s and "GSHP"s, respectively) a few general comments need to be made. Alternative energy systems tend to be characterized by higher upfront capital costs and lower ongoing operating costs (resulting from lower energy consumption) relative to natural gas-based systems. Alternative energy systems also tend to have higher maintenance costs, which erodes some of the benefits of lower operating costs. There are also more unique aspects with these energy systems from one installation to the next than with natural gas-based systems. The cost and configuration of GSHPs, for example, depends on local surface geology and soil conditions. The effectiveness of ASHPs depends on local climate – their efficiency falls off in colder conditions. Further, it is not generally cost effective to size ASHPs and GSHPs to meet the entire peak heating load of a dwelling. A backup system consisting typically of electric baseboard heaters or a natural gas furnace is needed to meet peak heating requirements in the winter, thus increasing the overall capital cost to implement a heat pump system.

Appendix D reviews example comparisons between heat pump technology and high efficiency gas systems from the view point the consumer. The following general observations are made:

- Initial capital cost differences between natural gas systems and ASHPs or GSHPs continue to be significant. Without incentives or other external sources of support, the higher upfront capital costs are likely to continue to be an obstacle to the penetration of ASHPs and GSHPs in the space heating market.
- Annual operating and maintenance ("O&M") costs of ASHPs and GSHPs are currently lower than those for natural gas systems; however, the annual cost advantage is not large enough to provide pay back of the upfront capital cost difference over a reasonable timeframe. With expected trends in electricity rates the annual O&M cost advantage currently enjoyed by ASHPs and GSHPs relative to natural gas installations may be diminished.
- ASHPs and GSHPs operate at higher efficiencies than natural gas systems and on this basis would be expected to provide benefits in achieving the energy efficiency and environmental objectives in the province. However, increased adoption of these technologies may increase the challenge of achieving electricity self-sufficiency in B.C., potentially resulting in increased reliance on imported power until self sufficiency is achieved. This will delay achievement of the desired environmental benefits. Increased adoption of ASHPs and GSHPs will also further impact the cost pressures being faced by electric utilities by increasing annual and peak electricity demand.

2.3 Implications for Planning and Action at Terasen Gas

A growing population is driving a growing demand for all types of fuels. Provincial policies are directing utilities to plan for more intensive energy efficiency and conservation programming, however, these programs will not reverse the need for more supply. Natural gas will continue to play an important role in the energy solutions and economy of the province and the region.

This Resource Plan has been developed with consideration that direct use of natural gas for residential heating is by and large preferred over electrical heating systems both now and once B.C. reaches electricity self sufficiency some time in the future. This assumption is based on the principle that the wisest and most efficient use of energy alternatives must consider the region in which energy resources are traded and carbon emissions are created, rather than be limited to jurisdictional boundaries.

Gas supplies and infrastructure are also needed to meet growing demand for gas fired generation elsewhere in the PNW. Both residential direct use and electricity generation create weather related demand. As these demand sources grow, peak demand will continue to increase relative to base load demand. Since few base load resources have been added in the Region in recent years, however, the number of proposals for base load or pipeline resources are also increasing. Terasen Gas needs to examine alternative regional resource proposals and support those that ensure its own customers continue to have access to reliable and cost effective supply to meet both peak and base load demand.

Terasen Gas has examined the competitive position of natural gas compared to a range of energy system alternatives, particularly for home space and water heating. Upward pressure is expected on costs for all energy types and systems. Generally, natural gas is expected to remain both an economically competitive alternative and a lifestyle choice for residential use. Where alternative energy systems such as heat pumps do appear to make sense for consumers, Terasen Gas expects natural gas continue to play an important role in many of these applications.

It remains possible; however, that natural gas will become a less intensively consumed if alternative energy systems become more available and economical. It is also possible that natural gas will become more intensively used than today if the principle of direct use to help reduce electricity load in BC and elsewhere in the Region becomes more widely adopted by governments, utilities and society as a whole. Terasen Gas needs to examine these alternative futures as well.

In summary, Terasen Gas must continue to develop resources and initiatives that ensure natural gas remains competitive, is used in the wisest and most efficient manner and is part of new clean energy and efficiency initiatives. All of these elements are included in this Resource Plan.

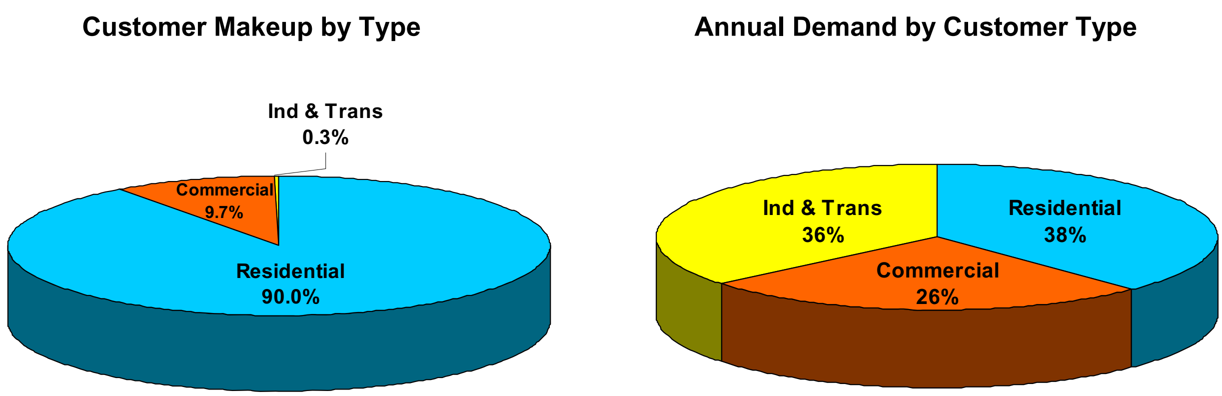
3 TRENDS AND FORECAST FOR NATURAL GAS DEMAND

Two key elements that underpin Terasen Gas' resource planning activities are the forecasts of annual demand and design day demand. The annual demand forecast represents the annual consumption by region and rate class and is used for gas supply planning and rate setting purposes. The design day forecast estimates the maximum daily flow of natural gas that would be expected under extreme weather conditions. The Terasen Gas demand forecasts are used primarily to ensure adequate system capacity and for the determination gas supply resources.

Inputs to the demand forecast include the analysis of data and trends from Terasen Gas' own systems, as well as many of the external factors discussed in the previous chapter. This chapter reviews the interplay of these factors in assessing future demand expectations and presents the demand forecast results. Specific forecast methodology details are provided in Appendix E. Details regarding the demand forecasts for each of the Terasen Gas service areas are provided in Appendices F and G.

On a customer basis, Terasen Gas consists predominantly of residential customers who account for 90% of the customer base. However, on an annual demand basis, there is a relatively even split between residential, commercial and industrial/transportation customers.

Figure 3-1 Terasen Gas Customer and Demand Overview



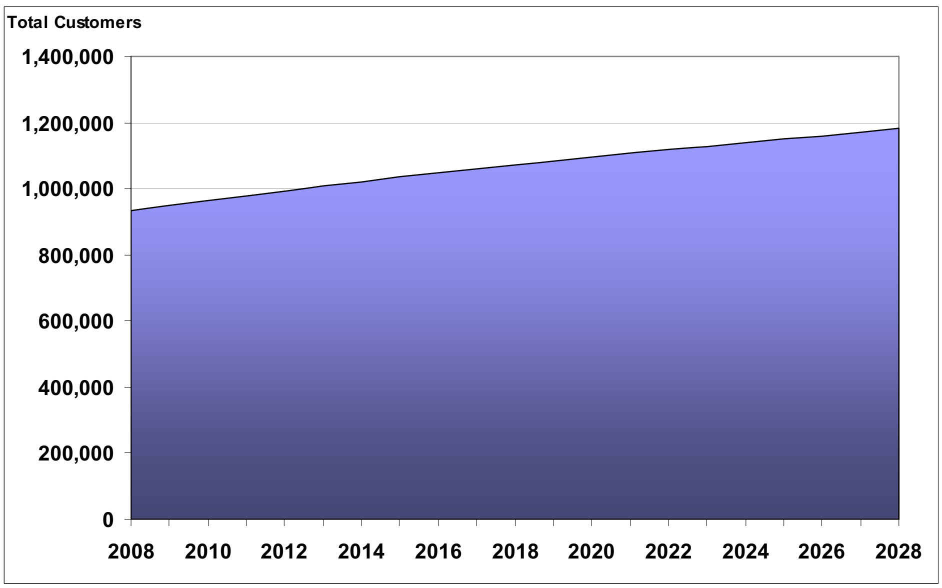
3.1 Market Trends

Though analysis of historical data is an important part of forecasting future demand, an understanding of changes currently occurring in the marketplace and how those changes are expected to manifest themselves in upcoming years is crucial to arriving at an estimation of future consumption by customers. To that end, this section discusses market trends that Terasen Gas has considered in developing its forecasts of customer additions, annual demand and design day demand.

3.2 Population Growth

The most important trend to be considered when preparing the demand forecasts is the anticipated growth in population. Current projections from B.C. Stats, shown in Figure 2-7 estimate that the province will add approximately one million new residents over the course of the next 20 years which will bring the current population of 4.4 million to 5.4 million by 2028. The aggregate effect on Terasen Gas' three utilities is expected to be an increase of approximately 250,000 customers over that same period. This will bring the total number of customers to slightly below 1.2 million by the end of the planning period. Figure 3-2 shows expected customer additions for all three Terasen Gas utilities.

Figure 3-2 Terasen Gas Total Customers



A number of factors must be considered in developing a customer additions forecast from population projections. For example, Terasen Gas' service territory does not extend to all parts of the province. Also, not all new residential housing units within Terasen Gas' service area choose to have natural gas service. Further, typical households in B.C. consist of approximately three people per residence. Analysis of these factors as described in Appendix E, lead to the customer additions forecast presented in Figure 3-2.

3.2.1 Residential Use Trends

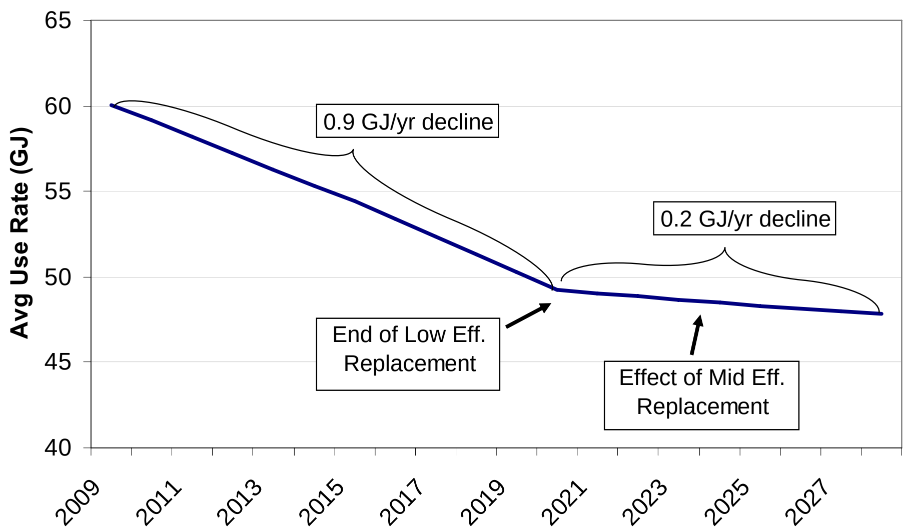
3.2.1.1 Renewal of Existing Furnace Stock

A decrease in residential use per customer rates is a phenomenon affecting mature natural gas utilities across North America. This same trend has been observed in the larger TGI service areas; while for TGVI the same pattern is not observed due to the relatively new and more efficient furnace stock within its service territory. For TGW, no discernable pattern has been identified, most likely due to the resort nature of the community and varying use patterns of land and housing owners and renters.

The main driver in declining use per customer rates in B.C. is the replacement of low-efficiency natural gas furnaces with higher efficiency models. Changes to the building code in 1990 mandated mid-efficiency furnaces as the minimum requirement for homes built since that time. Recent changes to building code legislation now stipulate that high-efficiency furnaces will be required for new construction as of 2008 and place the same requirement on furnace replacements beginning in 2010. Assuming a maximum life of 30 years, it is anticipated that the last of the low-efficiency furnaces will come out of service by 2020. Using the same maximum life expectancy for mid-efficiency units, all of these units will have been replaced by high-efficiency technology by 2040 with the decline of the mid-efficiency furnace stock to begin around 2016.

If all other variables could be held constant, the effect of retrofitting less efficient furnaces with newer high-efficiency units would be estimated to cause a yearly decrease in residential use per customer rates of approximately 0.9 GJ per residential customer. This rate of decline, however, is anticipated to slow to 0.2 GJ/residential customers annually, beginning in 2020 once the low-efficiency units have been phased out. Figure 3-4 depicts the impact of higher efficiency furnace installations through the planning period.

Figure 3-3 NG Furnace - 2005 B.C Stock

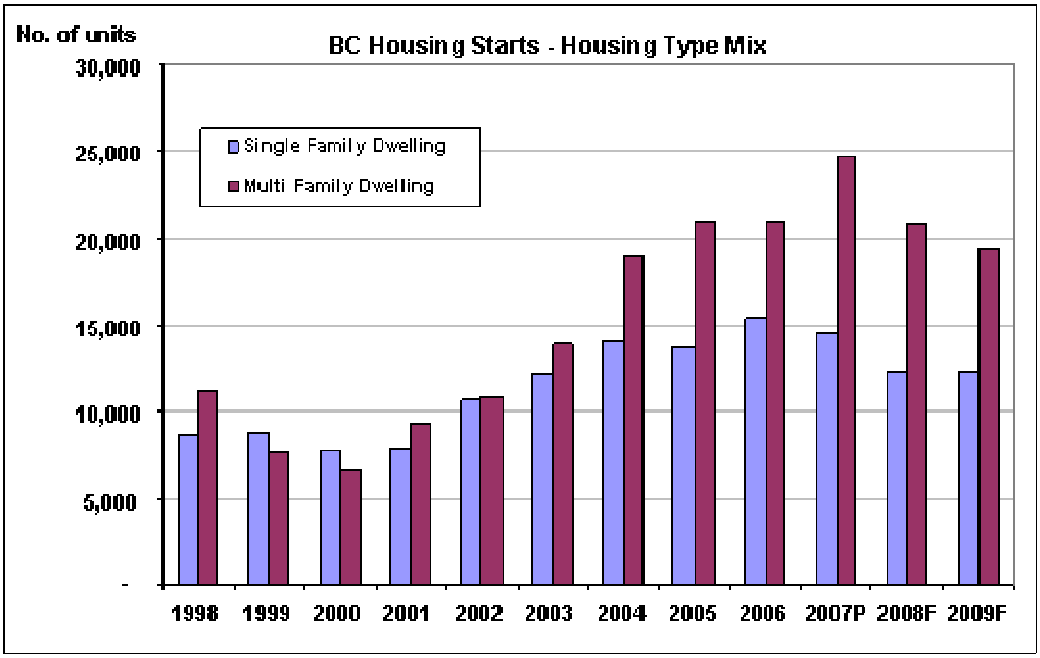


Source: Natural Resources Canada

3.2.1.2 Shift in Housing Type

A dramatic shift in the predominant housing type from single family to multi family has taken place over the past decade as illustrated in Figure 3-4. This shift toward the multi family housing type in B.C. is driven by affordability and limited availability of land for single family home construction. Canadian Mortgage and Housing Corporation ("CMHC") forecasts that the trend is expected to continue for 2008 and 2009. It is not unreasonable to assume that this pattern in housing type will continue for the foreseeable future.

Figure 3-4 B.C. Housing Starts - Housing Type Mix



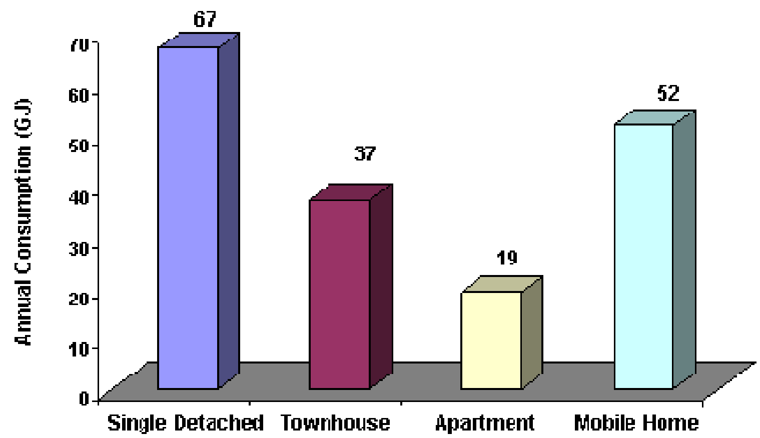
Source: CMHC

An analysis of 2007 customer data estimates that Terasen Gas was successful in bringing natural gas service to approximately 80% of completed residential units (all types) reported by CMHC within Terasen Gas' service territories. Of those new customers, a fairly even distribution of single and multi-family dwellings ("SFD"s and "MFD"s) attachments was achieved.

As a percentage of CMHC completions, Terasen Gas estimates that the vast majority (approx. 95%+) of SFDs installed natural gas service while 60 to 70% of MFD units completed were attached in some form; either with natural gas piped to the unit or serving some common application that benefits all residents of the housing complex. The challenge in assessing the level of penetration into the MFD markets lies in the fact that 80% of the estimated attached MFD units are served by a single common meter. Situations where a common meter provides natural gas to an entire MFD building makes it difficult to determine how much of that consumption is attributable to individual suites as opposed to serving common loads.

This shift in new housing type has important implications for overall residential use rates.
Figure 3-5 shows Natural Resources Canada statistics for space heating only in various housing types in B.C. The data, which includes all energy types, shows that all forms of MFDs use less energy than do SFDs.

Figure 3-5 Space Heating Consumption - All Energy Types

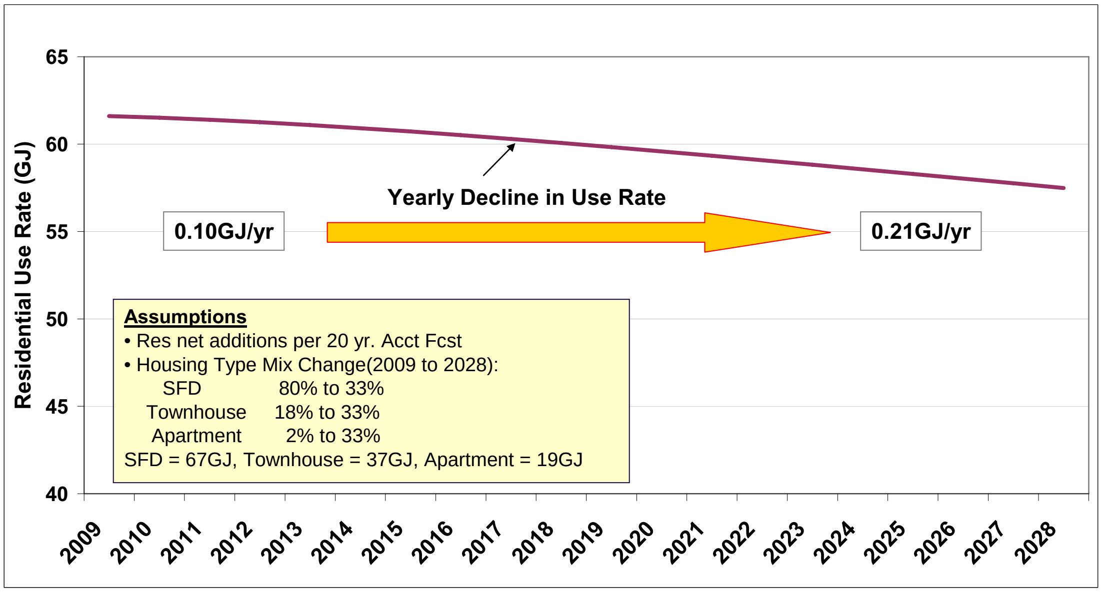


Source: NRCan

The independent effect of these consumption patterns as new customers are added that on average are more heavily weighted towards MFD types, is to decrease residential use per customer rates by 0.1 to 0.2 GJ / year. Figure 3-6 illustrates the effect of holding the typical consumption per housing type and annual customer account additions (15,000 customers/ year) constant while gradually varying the mix of housing types added from 80% SFD, 18% townhouse and 2% apartments in the initial year to approximately 33% for each housing type by the final year (2028). The rate of attachment for MFDs is approximately two thirds of the rate experienced with SFDs. The attachment of MFDs does slightly decrease the overall annual use per customer rate for residential customers.

The values in this analysis are not meant to reflect forecasted values, but are chosen to gauge the impact of shifting housing types on the overall customer base. Though not insignificant, the results suggest that housing type plays a considerably smaller role in residential use rate decline than does the replacement of low-efficiency furnaces.

Figure 3-6 Impact of Shifting Housing Type on Space Heating (Illustration)



3.2.1.3 Natural Gas Competitiveness

Chapter 2 and Appendix D discuss the competitive position of natural gas relative to other fuels and energy systems for home heating. That discussion includes consideration of natural gas rates compared to electricity (the main alternative to natural gas for this purpose in B.C.), furnace oil, propane and alternative systems such as ground and air source heat pumps. Terasen Gas has also examined the impact of the new Provincial carbon tax.

The review of energy alternatives for space heating finds that natural gas is still in a competitive position against other fuels. Although recent increases in natural gas commodity prices and the addition of the carbon tax has narrowed the gap between natural gas and electricity rates, recent and proposed increases to electricity rates by BC Hydro are also occurring and are indicative of rising costs for required new generation and transmission resources. Terasen Gas also expects that electricity imported into B.C. will be taxed[15], due to the marginal resource in neighbouring regions being natural gas fired generation, until such time as the province becomes electricity self sufficient. This last item has not been included in the competitive analysis.

On Vancouver Island, where many homes still use furnace oil, the advantage of natural gas has grown, making the case for conversions to natural gas better. Similarly, the rate advantage for natural gas over propane has also grown which will benefit Whistler customers and may encourage the few remaining propane users in proximity to gas lines in frontier areas of the

[15] This tax could be in the form of a direct B.C. carbon tax or could be implemented as part of a cap and trade or other program developed by the Western Climate Initiative.

Province to also convert. The competitive position of natural gas against these fuel alternatives is expected to keep customer additions and use rates up for each of the service areas.

In areas of the province and in circumstances where alternative fuel systems such as air and ground source heat pumps make sense for customers, natural gas is expected to remain the preferred supplementary fuel to meet peak period demand. Where this occurs, customer additions will not be affected, but the lower gas consumption will tend to lower use rates. The upfront capital costs for these systems, however, are likely to remain prohibitive for many customers and Terasen Gas is not anticipating a significant impact to average use per customer rates. Terasen Gas will, however, continue to monitor developments in alternative energy systems and there impact on demand and service offerings.

3.2.1.4 Reaction to Price Volatility

Short-term reactions to major commodity price increases have been observed as in the case of 2000 / 01, but typically the effect is relatively short-lived. It is suspected, however, that price shocks tend to accelerate the replacement of appliances and the upgrading of buildings. Though likely not having a material impact on long-term use per customer rates, the actions that people take as a result of price shocks can make the decrease in residential use rates steeper in the near-term and likely followed by a slower than average decline for the following years.

3.2.2 Commercial Use

Commercial use per customer rates have been relatively stable across most rate classes since the rise in natural gas commodity costs experienced in 2001. Businesses tend to upgrade more quickly as their consumption rates are higher and there is a financial motivation to keep production and operation costs down. Growth in the economy during this recent period has also likely caused increased business activity and production levels which would offset any reduced consumption due to improved equipment efficiency. In cases where a given commercial rate class has shown relative stability in its use per customer rates, the average growth rate is applied for the first 5 years of the planning period then held constant afterwards.

3.2.3 Industrial Use

For most industrial customers, annual demand is determined based on a yearly survey that gathers customers' input on consumption for the upcoming five years. For those industrial customers who are not surveyed annual demand is projected based on historical data and sector analyses. As described earlier, the forecast for industrial customers assumes no net change in the number of customers over the forecast period, except where written requests for change of service have been received by Terasen Gas.

The discussion of annual and design day demand in this chapter does not include demand for Burrard Thermal Generating Station ("Burrard Thermal"), the Island Co-generation Project ("ICP") and the Vancouver Island Gas Joint Venture mills ("VIGJV"). For capacity planning purposes, future demand expectations for these facilities are discussed in Chapter 5.

3.3 Alternative Future Scenarios

Terasen Gas forecasts future customer additions and demand based on a range of possible future scenarios. While many scenarios are possible, Terasen Gas identifies those combinations of factors which could reasonably be expected to result in high and low demand forecasts. As a result, Terasen examines three future scenarios.

In order to ensure that Terasen Gas is prepared to handle a broad range of potential outcomes, both from a system capacity and commodity supply perspective, two scenarios have been developed that illustrate the maximum and minimum annual demand that would be expected to occur over the planning period with respect to a Reference forecast. In the case of both scenarios, a set of key factors with specific outcomes are identified which would cause a significant deviation, either up or down, from the Reference case.

The Reference Case future scenario is primarily a continuing trends scenario. It assumes the legislation and policies regarding energy and carbon emissions that have been implemented or announced to date are in place for the duration of the planning period. Otherwise, the trends discussed so far in this Chapter are adopted as part of the Reference case future scenario and demand forecast. The high and low demand scenarios are based on future scenarios that deviate from the Reference case in the following ways.

3.3.1 Robust Growth

The Robust Growth scenario is used to illustrate the magnitude of additional consumption that could occur above the level set by the Reference Case and identifies the likely drivers that would cause a high forecast of demand for natural gas. Although there are numerous factors that can affect consumption levels, the following items occurring concurrently are viewed as the main drivers in this scenario:

- The province continues to experience strong economic growth beyond what is currently expected by the provincial Government and economists.
- The natural gas price advantage improves with respect to electricity due to larger than expected increases in electricity rates while natural gas costs remain stable.
- Policies are established that promote the direct use of natural gas for space and water heating in support of achieving electricity self-sustainability in the province and reduced greenhouse gases on a regional basis.

Stronger growth in the provincial economy translates into more people coming to live in the province. This increase in immigration is captured in higher rates of customer additions with respect to the Reference forecast. Terasen Gas also assumes that it makes further inroads into the capture of multi-family dwellings through innovative product offerings such as thermal metering and potential rate designs that encourages the addition of MFD customers in a way that is economical and fair to existing rate payers.

Though the forces affecting residential use per customer rates are not expected to disappear under any scenario, the Robust Growth scenario envisions a situation where use per customer rates stabilize sooner for TGI and actually increase in the long-run in the case of TGVI.

Stronger use per customer rates in all service areas in this scenario would be supported by a higher penetration of natural gas heating appliances in new homes and the conversion to natural gas for space and water heating in existing homes where heating oil or electricity are currently used for that purpose.

For industrial customers a stronger than anticipated economy is reflected by growth in industrial volumes beyond that reflected in the first five years. This additional growth in natural gas demand is expressed as a portion of the long-term GDP growth for the province as forecasted by the Conference Board of Canada.

3.3.2 Low Growth

The Low Growth future scenario is developed to depict the lower bound in consumption with respect to the Reference case that could reasonably occur and identifies the likely drivers that would cause a lower demand for natural gas.

Although there are numerous factors that can affect consumption levels, the following items occurring concurrently are viewed as the main drivers in the Low Growth scenario:

- The province experiences weaker than expected economic growth driven by a U.S. economy that fails to return to its prior strength and in turn causes other economies of the world to slow.
- Technology improvements and increasing efficiencies accelerate conservation efforts. Natural gas heating equipment is replaced at an accelerated pace, and alternative technologies (e.g. solar thermal domestic hot water heating) begin to see broader acceptance in the market.
- The perceived ‘solution’ to climate change causes a shift from natural gas to electricity as people seek to reduce end-use of fossil fuels.

Slower economic growth would slow the pace of immigration to the province and reduce the demand for new housing. This would then manifest itself in terms of a slower rate of customer additions.

Faster conversion of existing heating appliance stock to higher efficiency models and improvements to building envelope technology along with the integration of renewable energy (e.g. solar thermal domestic hot water pre-heating) into existing homes would both accelerate the decline in residential use per customer rates. These conditions would also cause use per customer rates to continue to decline beyond the timeframe applied to the Reference case wherein use per customer rates are expected to stabilize.

Finally, the potential exists that customers may shift some of their heating loads to electricity and that potential new customers forgo natural gas in favour of electricity in the belief that they are helping to minimize carbon emissions. Though not necessarily achieving the desired outcome on a regional or global basis, confusion in the general population on how best to lower carbon emission could lead to both decreased use per customer rates and lower customer additions.

The next sections describe the main components of the Annual Demand forecast common to all three Terasen Gas utilities as well as additional trends that are impacting these forecast components. Details regarding the specific forecasts for each of the individual Terasen gas utilities are included in Appendix F.

3.3.3 Customer Additions

The customer additions forecast is derived from long-term provincial forecasts of household formations at the community level and validated against CMHC's nearer term forecasts in order to reflect the most current market situation. The forecast of customer additions is applied to both residential and commercial rate classes while no growth is assumed for industrial customers. The latest available economic analyses from the B.C. Government, major banks and other organizations are reviewed for consistency with the overall trend in household formations. For the forecast produced in support of the 2008 Resource Plan, the B.C. Statistics 2007 Household Formation Forecast (based on P.E.O.P.L.E. 32) was used to determine customer additions by area over the forecast period.

3.3.4 Use per Customer Rates

The average consumption for a customer in a given region and rate class, or use per customer rate, is determined for all residential and commercial classes based on:

- Historical normalized consumption data
- Any known customer migration between rate classes
- Appliance retrofit activities and other trends

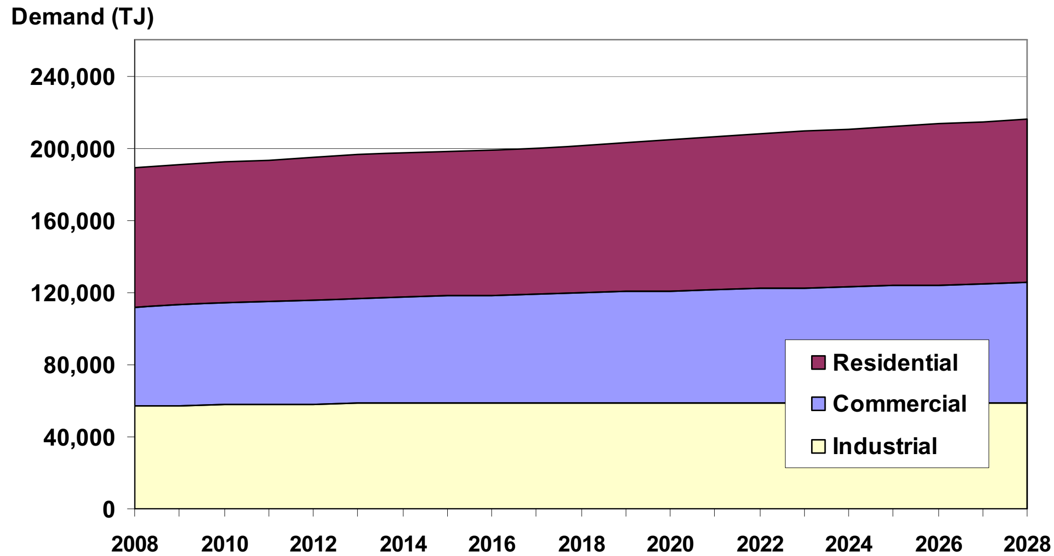
As discussed earlier, residential use per customer rates for mature utilities, such as TGI, have been experiencing declines of approximately 1% per year since the early 1990s. The adoption of mid-efficiency natural gas furnaces beginning in earnest in 1990 and now changes to building codes which will soon make high efficiency for all newly installed furnaces (new construction and retrofit) compulsory, largely explains the decreases in use per customer rates. Other contributing factors include the shift towards multi-family dwellings, better insulated new homes and the upgrading of existing homes.

3.4 Annual Demand Forecast Results – All Companies

3.4.1 Reference Case

On an aggregate basis across all utilities, overall consumption is forecast to rise by 0.7% from 189 PJ to 216 PJ (Figure 3-7) over the planning period under the Reference Case future scenario. Though many factors such as furnace replacement and the shift towards multi-family homes work to drive down consumption on an individual basis, the expected increase in provincial population by 1 million people over the next twenty years more than counteracts these effects to arrive at a net increase in annual demand over time.

Figure 3-7 Reference Case Annual Demand Forecast 2008-2028 – All Companies



3.4.2 *Impact of EEC Programs on the Demand Forecast*

Terasen Gas has recently filed an application with the British Columbia Utilities Commission ("BCUC") for a three year EEC strategy for which a decision is expected in late summer, 2008. For planning purposes, the Resource Plan assumes that the recommended funding request is granted and that the associated changes in consumption materialize as forecasted. The effect of new EEC programs on annual demand is discussed separately from the other Scenarios to avoid confounding the effects of the program with other changes in inputs.

Most of the proposed initiatives will create reductions in annual demand which form a portion of the reductions included in the Low Scenario. It is important to note however that some EEC initiatives are designed to build additional annual demand, rather than reduce it. In the case of load building initiatives, the energy savings will result from transitioning customers who are currently using more carbon intensive fossil fuels (e.g. heating fuel) or imported electricity to high efficiency, clean burning natural gas appliances. This load building portion of the DSM program is captured in TGVI's annual demand forecast as part of the High Scenario.

Table 3-1 EEC Impact on Terasen Gas' Annual Demand Forecast

	Projected Consumption Change by Year (GJ)		
Sector	**2008**	**2009**	**2010**
TGI Residential	-62,680	-136,460	-170,290
TGI Commercial	-161,618	-401,608	-731,880
TGVI Residential	39,759	84,139	133,718
TGVI Commercial	-17,810	-41,944	-80,936
Total over measures	-202,349	-495,872	-849,388

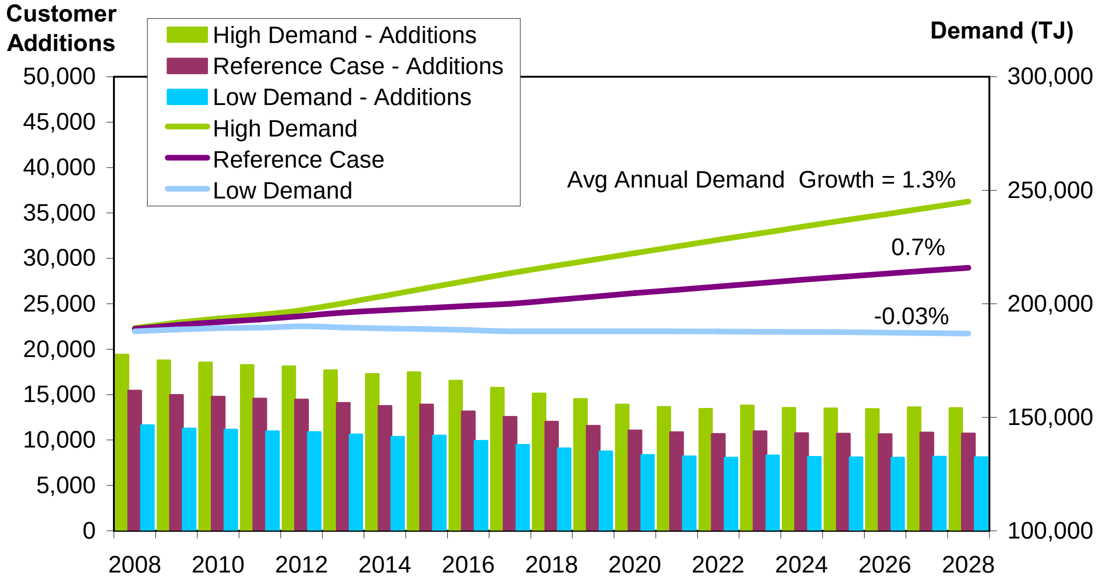
A projection for EEC programs beyond the three year strategy has not been made in the Resource Plan. There is every expectation that there will be ongoing and even expanded DSM activities throughout the course of the planning period, but the specifics of those programs and their impact on demand cannot be determined at this time. Chapter 2 discusses the rapidly changing Provincial and Regional energy related policies. Terasen Gas expects that further policies will be developed and new laws enacted that will impact how natural gas is used throughout the province as the Government works towards its goals for climate change and greenhouse gas emissions. In addition, Terasen Gas is entering a new stage of higher EEC funding with a broader focus than in previous years. Time will be required to gain experience with these new programs before planning can begin for future years.

3.4.3 Annual Demand – Robust Growth and Low Growth Scenarios

Should the province's population grow at a faster than anticipated rate and if people shift their heating loads more towards the direct use of natural gas in an effort to mitigate growth in electrical demand, it is anticipated that natural gas consumption could in fact increase by 1.3% per year, on average, to 245 PJ in the high forecast as illustrated in Figure 3-9. It is important to note that increases in natural gas consumption would likely offset demand for other energy sources such as heating oil and electricity produced from fossil fuels. Also illustrated in Figure 3-9, a small net decrease in annual demand materializes in the Low Growth scenario or low forecast. This decrease is contingent upon a markedly lower growth in population combined with aggressive conservation efforts and a shift towards other energy options for loads that have been traditionally served by natural gas. Under the Low Scenario, annual demand would decrease by 0.3% per year, on average, to 187 PJ by 2028.

Figure 3-8 shows the annual demand forecasts for all three companies combined across all three future scenarios. Appendix G provides the annual demand tables for each company.

Figure 3-8 Annual Demand & Customer Additions – All Companies



3.5 Design Day Demand

Design day demand differs from annual demand in that it estimates the maximum consumption expected to occur during an unusually cold weather event. The forecast of design day demand is a crucial input into Terasen Gas' key activities of securing an adequate supply of natural gas and ensuring that the infrastructure is capable of delivering that natural gas where and when needed. Where demand growth occurs within the Terasen Gas service areas is also a key factor in determining future resource requirements.

The determination of design day demand for the various regions is arrived at through a separate process from the forecast of annual demand. The design day demand forecast establishes the correlation between consumption and weather through regression analysis of measurement and weather data. The other key input is the determination of the temperature that represents the coldest day likely to happen once every twenty years. Applying this temperature to the results of the regression analysis produces design day consumption per customer which is then multiplied by the customer forecast to arrive at the total design day demand. The need to reflect recent data combined with minimizing year-over-year variability is accomplished using a three year moving average.

The forecast of design day demand must be developed to meet expected customer demand during extreme cold weather. The consequences of under-forecasting could result in customers experiencing service interruptions at the most critical time. For this reason, no adjustment is made to the design day use per customer rates to account for changing consumption patterns over time. The use of a three year moving average serves to ensure that actual changes in customer behaviour are reflected on an ongoing basis, but any perceived trends are not projected onto future values. Also, no adjustment is made to design day demand forecasts to incorporate climate change impacts. Though the overall temperature of the planet may be trending upwards over the long-term, there is no certainty to be had regarding the likelihood and severity of extreme weather events specific to the geography covered by Terasen Gas' service territories.

The design day forecasts for each of the Terasen Gas service areas provided in Figure 3-9 to

Figure **3-11**, below illustrate the expected increases in peak day demand over the planning period. As discussed above, growth in customer accounts drives increases in design day demand. With population projections calling for continued increasing growth in provincial population over the planning horizon, it is reasonable to expect an upward trend in peak day demand. The demand forecast tables in Appendix G include the design day demand for each company.

Figure 3-9 TGVI Design Day Demand

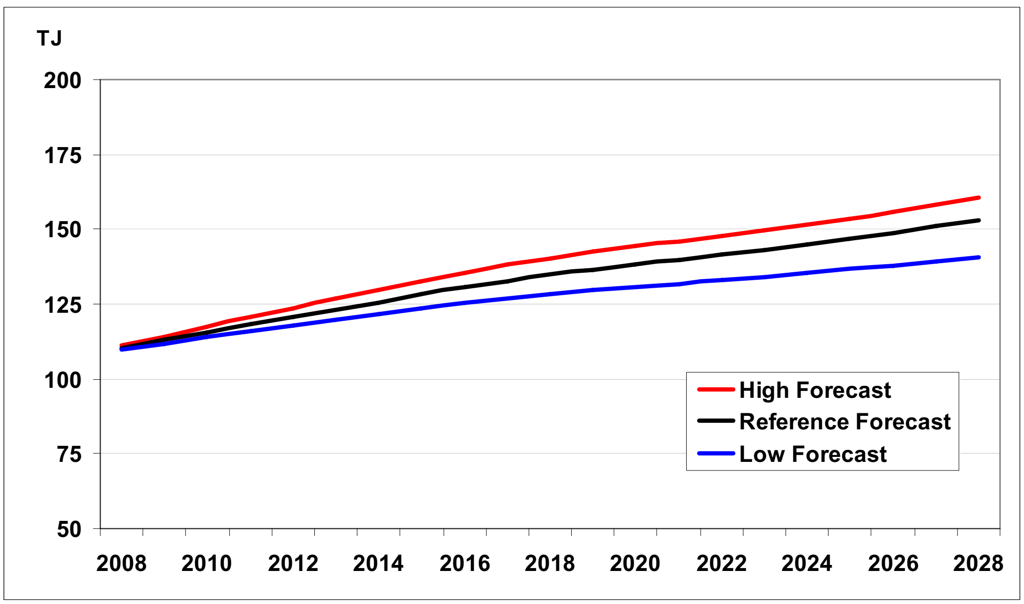


Figure 3-10 TGW Design Day Demand

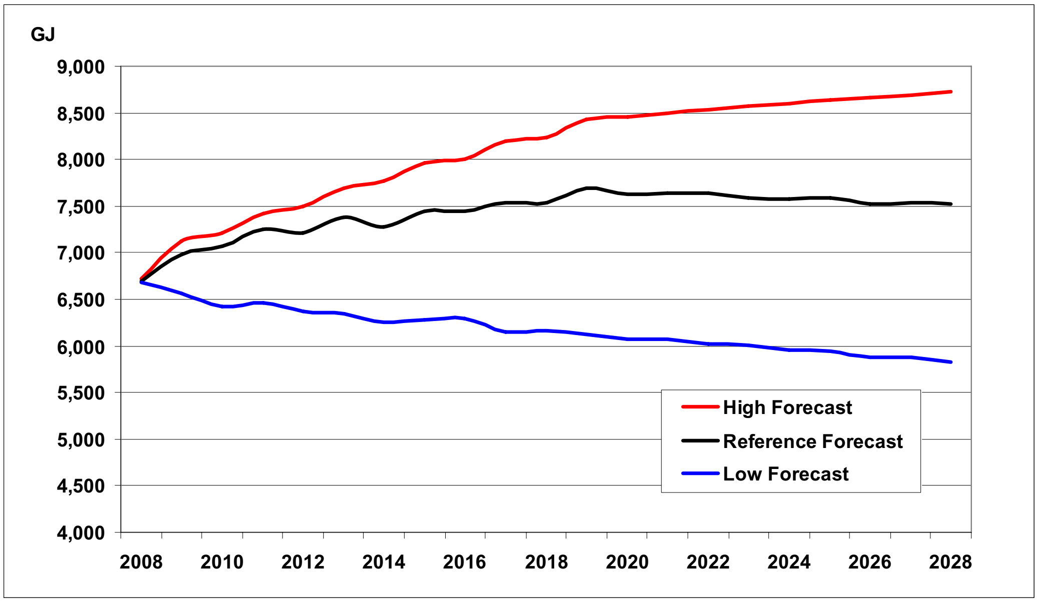
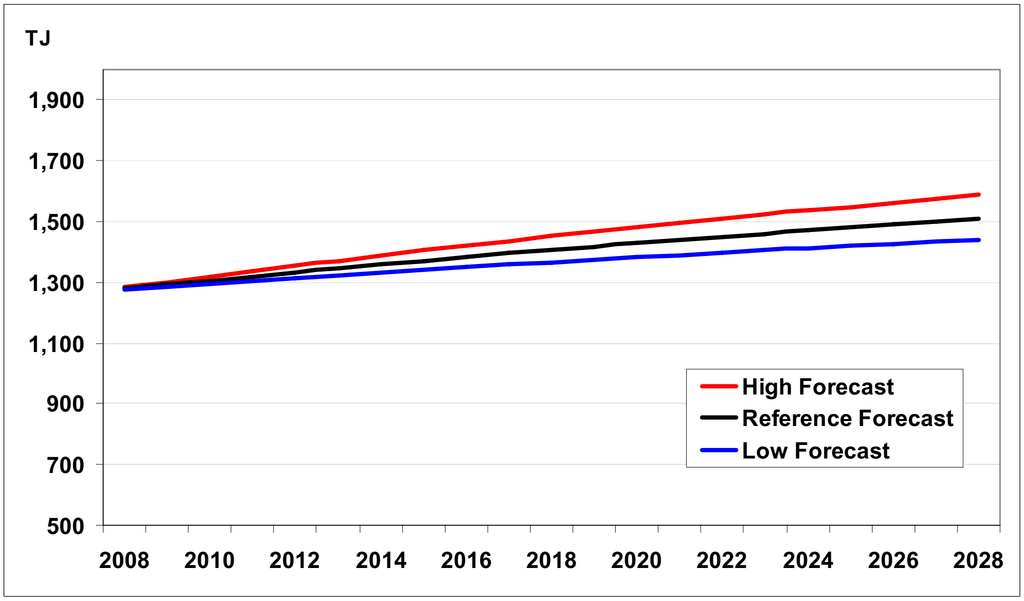


Figure 3-11 TGI Design Day Demand



4 ENERGY EFFICIENCY AND CONSERVATION

EEC programs are the main focus of DSM activities. DSM refers to "utility activity that modifies or influences the way in which customers utilize energy services." TGI has been offering DSM programs since 1997 to its customers, focused on energy efficiency and conservation activity, while TGVI has had a marketing budget allocated for customer additions and efficient load building since the company was acquired from Centra Gas in 2002.

EEC programs have long been important to Terasen Gas in helping to meet customer needs and ensure the wise and efficient use of energy in B.C. A Conservation Potential Review ("CPR") undertaken for Terasen Gas in 2005 and received in 2006 identified substantial additional savings that could be realized beyond the programs existing at that time. The CPR was discussed in some detail in the 2006 Resource Plans. Additionally, climate change concerns, rising energy costs for all types of energy and the scale of expected growth in energy demand has raised the importance of EEC programming for utilities across North America. In B.C., the *UCA Act* became law on May 1st, 2008 and sets out the requirement for utilities to complete DSM plans which are to be included as part of the utility's Resource Plan.

Terasen Gas formally submitted its latest DSM plan to the BCUC on May 28, 2008 in the form of an application to expand EEC programming for residential and commercial rate classes across both TGI and TGVI service territories. This chapter of the Resource Plan provides an overview of past and present EEC programming at Terasen Gas and the background behind the new EEC plan, including a comparative assessment of DSM programming at other gas and electric utilities in the region. The plan submitted to the BCUC is then summarized. The expected impact on the forecast of demand for natural gas is discussed in the final section of this Chapter as well as in Chapter 3.

4.1 Past and Current EEC Programs

Terasen Gas has enjoyed some significant successes within the existing budget and programming. For example, through DSM programming from 2000 to 2007, TGI customers have saved approximately $14 million in cumulative annual energy costs and have reduced consumption by 1,270 TJ. Those cumulative savings will persist, year over year, for as long as the measures that were installed as a result of DSM programming during the 2000 to 2007 time frame remain in place. The current DSM budget is part of the Terasen Gas negotiated settlement and as such, has not changed since 1997. Table 4-1 represents current DSM Investment by Terasen Gas.

Table 4-1 Terasen Gas Funding for DSM Programs

Utility and Service Territory	Program amount	Incentive and rebate amount
Terasen Gas Inc. Lower Mainland and Interior B.C.	$1.624 million	$1.5 million
Terasen Gas Vancouver Island	$500, 000	$650,000
Totals	$2.12 million	$2.15 million

Excellence in Efficiency

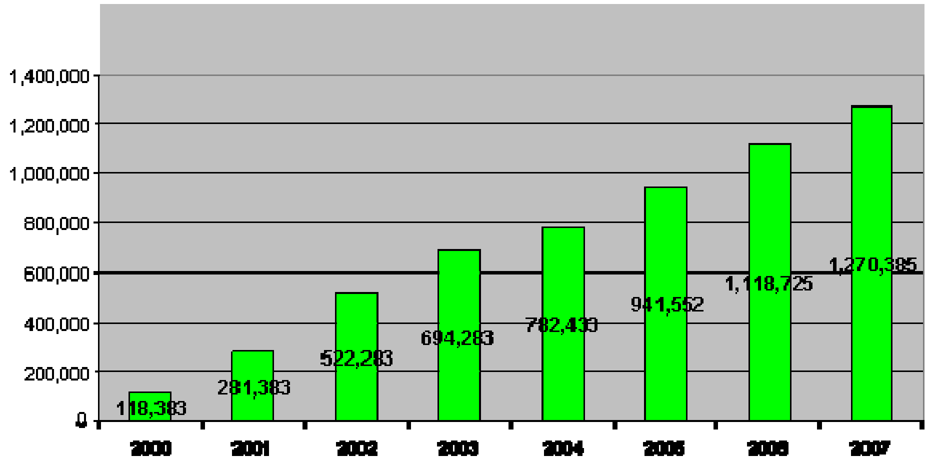
Terasen Gas has been recognized for the success of historical DSM programs. In 2006, the Companies were honoured to receive Natural Resources Canada's Energy Star Award for Campaign of the Year.

And in 2008, Terasen was very proud to be included in the Ministry of Energy, Mines and Petroleum Resources "Energy Efficiency and Community Solutions Team", a finalist for the Premier's Award Promoting Innovation and Excellence.

TGI

Over the past eight years, TGI has helped its customers reduce energy usage by over 1,270 TJ and associated greenhouse gas emissions by approximately 64,000 tonnes through the current DSM budget and programming. These numbers only represent savings from incentive and assessment programs as well as the Destination Conservation Program. Savings that result from education and outreach programs such as Terasen Gas' Hot Tips (for example: weather-stripping, replacing a leaky faucet or installing an aerator on water taps) are in addition to the reported savings. Figure 4-1 shows the TGI energy savings on a cumulative basis since 2000.

Figure 4-1 TGI Cumulative Gas Savings from DSM Expenditure (GJ)



TGVI

The changes in energy usage identified in Figure 4-1 do not include those associated with TGVI. TGVI's DSM approach has historically been focused on marketing and efficient load building since natural gas has only been available on Vancouver Island since 1990. The relative newness of natural gas appliances on TGVI means that opportunities to upgrade existing gas appliances to more efficient versions have been limited. DSM activity for TGVI has historically encouraged conversion of non-gas customers to gas customers, as well as the installation of natural gas equipment in new construction.

A description of all current and past DSM programs implemented by TGI and TGVI along with a summary of the energy savings achieved during the most recent three year period of programming is included in Appendix I. The current level of DSM programming is considered within the reference case of Terasen Gas' demand forecast, since the impact on customer additions and use per customer are recalculated annually as described in Chapter 3.

TGW

TGW has not historically offered defined DSM programs to its customers but has undertaken or participated in a number of initiatives related to energy efficiency. The Whistler Demand Side Management Study commissioned in 2003 led to follow up energy use assessments for select medium and large commercial customers to provide both the Utility and the customer with a better understanding of their energy consumption. Destination Conservation, a school energy efficiency and awareness program delivered to students and administration was offered to the local school board.

TGW also participated in the RMOW's Sustainable Community Plan, helping to develop Whistler's Sustainable Energy Plan. The Sustainable energy Plan views natural gas as an important bridging fuel for the development of new and alternative energy technologies and practices in Whistler that will ultimately reduce the community's carbon footprint. The Sustainable Energy Plan was an important part of the TGVI and TGW application to BCUC to extend natural gas service to the community and convert TGWs customers' fuel from Propane to Natural Gas. With construction of the project underway, the implementation of alternative energy solutions supported by natural gas infrastructure, the immediate carbon intensity reduction that natural gas offers over propane and simply a better general awareness of Whistler specific energy issues that will result, provide the best energy efficiency and conservation effort that TGW could offer at this time. For the future, TGW is collaborating with RMOW on the development of a DSM initiative based on the results the appliance conversion audit.

4.2 Need for Expanded Energy Efficiency and Conservation Programming

A number of factors have led Terasen Gas to apply for expanded EEC programming and provide a context for the types of programs and amount of funding requested. These factors include recent Provincial policy and legislative changes, a comparative analysis of EEC programming in other jurisdictions and the findings of the 2006 Terasen Gas CPR and market changes that impact those findings as well as Terasen Gas' ongoing effort to help customers manage their energy costs. Terasen Gas has also reviewed BC Hydro's most recent CPR and Residential End Use Study ("REUS") to identify and account for differences in the findings or assumptions of these two utilities, which share much of the same service territories.

4.2.1 Provincial Energy Policy and Legislation

Over the last year, rapid changes in public policy initiatives (both provincial and federal) are placing a high level of importance on environmental and energy use issues. The 2002 B.C. Energy Plan was primarily focused on secure, reliable, low cost supply and environmental responsibility as it related to resource development. The 2007 Energy Plan, however, emphasizes the development of B.C.'s natural gas resources, the importance of electricity conservation, electricity self-sufficiency and the need for utilities to pursue all cost effective DSM.

Among the developing legislation or legislative amendments resulting from the Energy Plan are The Greenhouse Gas Reductions Target Act, The UCA Act, Bill 27 (The Green Communities Act), Bill 37 (The Carbon Tax Act) and proposed Building Code amendments that will establish the Province's Green Building Code. Each of these new and proposed legislative changes, as discussed in Chapter 2, are aimed at improving energy efficiency and emissions reductions. Terasen Gas' 2008 EEC application reflects the emphasis government and consumers have put on environmental issues and aims to provide the resources to help consumers reduce energy intensity and support government policy.

Increasing energy prices has also led to increased public awareness and interest in energy saving measures to help reduce residential and commercial energy bills. The Carbon Tax Act is slated to go into effect in July 2008, making all fossil fuel based energy sources subject to a carbon tax that is intended to drive consumers towards more energy efficient and less carbon intensive choices. In the case of natural gas, end users will pay \$0.50 per GJ beginning June 2008, rising in \$0.25 annual increments until reaching \$1.50 per GJ in 2012. Natural gas has the lowest carbon intensity (as described in Chapter 2) and lowest pollution emissions of any fossil fuel and as such, continues to play a major role in helping the province and the Region reach carbon reduction targets.

4.2.2 Review of DSM Programs at Other Utilities

As part of the research for its 2008 EEC Application, and to understand the level of DSM expenditure, types of programs offered and scope of activity at other utilities, Terasen Gas conducted a review of DSM programming in B.C. and other jurisdictions. The study reviewed and evaluated energy efficiency and conservation programs offered by other North American utilities. Background research was collected via the internet from utility, public, government and commission web sites. Initial findings were then followed by personal telephone interviews with key staff responsible for DSM activities at these utilities. Table 4-2 summarizes key findings and clearly shows that the current Terasen Gas EEC expenditure levels are significantly lower than those of other major North American utilities.

Table 4-2 DSM Activity Summary – Other Utilities

Company Name	Utility Type	2007 DSM Annual Budget ($ in millions)	DSM Funding Treatment	Customer Base	2006 Total Revenues ($ in millions)	% Spent on DSM of Revenue	DSM Spend per customer	2006 Annual Sales Volume
Pacific Gas and Electric Company ("PG&E")	Combined	279.0 [1]	Public Purpose Fund	4,200,000 [5]	12,530	2.23%	$66.43	425.9
Manitoba Hydro	Combined	9.0	DSM costs are treated as capital and amortized over a fixed time period.	258,000	517	1.74%	$34.88	147.6 [7]
Southern California Gas Company ("SoCal Gas")	Natural Gas	56.6 [2]	Public Purpose Fund	5,600,000	4,180	1.35%	$10.11	946.0
BC Hydro and Power Authority ("BC Hydro")	Electric	52.3 [3]	DSM costs are treated as capital and amortized over a fixed time period.	1,704,671	4,311	1.21%	$30.68	190.5
FortisBC	Electric	2.5	DSM costs are treated as capital and amortized over a fixed time period.	154,000	208	1.19%	$16.06	11.1
Northwest Natural Gas Company ("NW Natural")	Natural Gas	11.0 [4]	Public Purpose Fund	636,000	1,000	1.10%	$17.30	125.8
Union Gas	Natural Gas	17.0	DSM costs are recovered through rate base	1,300,000	2,100	0.81%	$13.08	1,303.0 [8]
Enbridge Gas Distribution ("Enbridge")	Natural Gas	22.0	DSM costs are recovered through rate base	1,800,000	3,016	0.73%	$12.22	445.0
Gaz Metro Limited Partnership ("Gaz Metro")	Natural Gas	8.8	as O&M	167,000	2,000	0.44%	$52.69	271.8
The Terasen Utilities	Natural Gas	4.3	Program costs as O&M; program incentives are amortized over fixed time period	911,935	1,635 [6]	0.26%	$4.69	208.0 [9]
Puget Sound Energy ("PSE")	Combined	6.1	DSM costs are recovered via a rider on customer bill	718,000	2,905	0.21%	$8.52	205.1
SaskEnergy	Natural Gas	1.6	as O&M	325,000	1,254	0.13%	$4.92	125.0
ACTO Gas	Natural Gas	Part of marketing budget	as O&M	969,200	2,890	n/a	n/a	219.0

Comments:

1 This figure reflects the 2007 DSM budget for electrical and gas initiatives. This covers labor, rebates and advertising. An additional $24 million will be spent on research and evaluation. On average, 86 per cent of funds are related to the electric side

2 This figure is comprised of the following components: $4.9 million (operating costs) and $47.3 million in deferred capital - note that it is an actual figure rather than a budget figure.

3 This figure reflects the 2007 DSM budget which covers labor, rebates and advertising. An additional $4.3 million will be spend on research and evaluation.

4 This figure is the sum of $9 million that is dedicated for DSM and market transformation programs implemented through the Energy Trust of Oregon (ETO) and $2 million for low income weatherization administrated by NW Natural.

5 This figure refers to Natural Gas customers only at PG&E.

6 These are combined revenues for Terasen Gas Inc. and Terasen Gas Vancouver Island

7 Includes sales for residential, commercial and industrial sectors (53PJ) and transportation services (23PJ)

8 This number is comprised of 509 PJ for distribution and 794 PJ for transporation.

9 This includes the total volume numbers for TGVI (including ICLP/Hydro; VIGJV-Inland & Squamish Gas) and TGI.

4.2.3 Terasen Gas Conservation Potential Review

Terasen Gas' current CPR was completed in 2006. The study was designed to analyze the amount of EEC potential in different geographical areas in the TGI and TGVI service territories. The study parameters were based on BC Hydro's 2002 Conservation Potential Review, with one notable exception: the Terasen Gas CPR included an analysis of fuel-switching opportunities. As discussed in Chapter 2, Terasen Gas believes that fuel-switching from electric to natural gas space and water heating in homes and businesses should be an important part of helping B.C. to achieve electricity self sufficiency targets and reducing carbon emissions throughout the PNW.

As discussed in the 2006 TGI Resource Plan, the CPR was commissioned with the intent to file an application for increased EEC activity with the BCUC. The 2006 Resource Plan outlined Terasen Gas' preliminary, high-level understanding of the outcomes of the CPR, as well as recommendations for further EEC planning. Further work on converting the CPR results to EEC program development commenced in the fall of 2006, following the submission of TGI and for TGVI Resource Plans.

Among other things, the CPR and subsequent analysis demonstrated the following key findings:

- Since the last time funding levels were reviewed, there has been a significant change in the market place. Energy prices have increased substantially over the last ten years and there is an increased focus on reducing end user consumption and energy costs. Additionally, there is increased customer and societal desire for finding innovative ways to increase energy efficiency.
- Government policy and direction have responded to public interest concerns and energy utilities are being encouraged and directed to invest more resources into energy efficiency and conservation activities in order to meet public objectives.
- The current levels of funding are inadequate. TGI's current funding levels were established over ten years ago. TGVI funding has also not been altered for many years. Funding for Terasen Gas is substantially lower than that of other utilities.

Terasen Gas believes that the CPR, and subsequent analysis, demonstrates a need to expand cost-effective EEC programs.

4.2.4 BC Hydro CPR Results on Fuel Switching Opportunities

In 2007, BC Hydro contracted Marbek Resource Consultants to undertake a comprehensive technical review, and develop a 2007 CPRfor BC Hydro's service territory. The 2007 BC Hydro CPR built on previous studies to help assess electricity conservation opportunities in B.C. The 2007 CPR identified almost 20,000 GWh/yr of economically feasible energy savings by the year 2020. However, a series of workshops determined that approximately 50% of the economically viable potential is realistically achievable when taking customer behaviour into account. The findings from the 2007 BC Hydro CPR support the 2007 B.C. Energy Plan target of 10,000 GWh/yr savings through conservation by 2020 (50% of BC Hydro's incremental resource needs).

The BC Hydro CPR also included an examination of potential electric savings from electricity to natural gas fuel-switching in certain applications. The total identified electric energy savings from fuel-switching measures that passed the economic screen was between 6,671 GWh/yr and 3,291 GWh/yr in 2026, respectively, under the 2007 CPR current and high natural gas supply cost forecasts.

Although the 2007 CPR found significant Economic Fuel Switching Potential available to BC Hydro, it used current customer rates in its analysis to determine that there is no Achievable Potential for BC Hydro's DSM group, PowerSmart, to actively engage in Fuel Switching programs. This conclusion was based on an assessment that natural gas measures either have excessively long payback periods or cost customers more to install and in some cases marginally more to operate compared to electricity. This contradictory result (Significant Economic Potential vs. Zero Achievable Potential) arises because the retail rates for electricity are lower than BC Hydro's cost of incremental supply.

The Terasen Gas CPR and EEC application disagree with this BC Hydro finding. Electrical rates are on the rise as a result of BC Hydro's need to acquire substantial expensive new generation resources to meet the Provincial electricity self-sufficiency and renewable generation targets. Terasen Gas believes that to reflect the true cost of supplying incremental electricity demand, the analysis of achievable fuel switching potential should include the incremental costs rather than incorporating heritage costs of electricity. This treatment of costs will also perform better in sending consumers the proper price signals, thereby better promoting energy conservation and use of the right fuel for the right application.

Terasen Gas proposes to support fuel switching through its EEC application and believes that electricity customers should be encouraged to participate in helping achieve the economic potential of electricity conservation offered by fuel switching programs. Education and incentives are one mechanism for this encouragement as are the use of connection policies and rates.

4.3 2008 Energy Efficiency and Conservation Application

Through its CPR and subsequent work, Terasen Gas identified numerous areas where our customers could participate in programs designed to lower energy consumption, and therefore their energy bills, if the additional funding for these programs is approved. As such, Terasen Gas has applied to the BCUC for increased EEC funding over a three-year time frame (2008-2010). The overall program expenditures over the three year time frame will equate to $56.6 million. This increased funding will result in a total DSM Investment per customer of $18.45 in the first year, growing to $23.02 in the third year. EEC Investment as a percentage of Gross Revenue will increase to 1.3% by the third year. The Executive Summary to the EEC application is provided in Appendix H.

Terasen Gas filed its Energy Efficiency and Conservation (EEC) application in May 2008. The objectives of the EEC application are to obtain the funding required to provide customers a higher level of efficiency and conservation services and to support government policy while ensuring that shareholders are able to achieve appropriate returns for providing these services.

The EEC application is expected to provide the following:

- Customer access to a wider variety of EEC incentive programs, assisting them to reduce energy consumption, lower their energy bills and reduce the individual and societal impacts associated with energy use.
- Harmonize TGI and TGVI EEC activities.
- Provide education for customers and the public at large about energy and conservation issues, leading to customers making more informed choices about energy equipment and actions and to support the creation of a "culture of conservation" in B.C.
- Maintain a competitive cost for end uses of natural gas, thus maintaining energy diversity in the province.
- Support BC Hydro and FortisBC in achieving their conservation goals, thus helping to minimize the need for all customers of the electric utilities to invest in additional generation and transmission infrastructure.
- Recognize the continued value in adding efficient cost-effective customers to the Terasen Gas distribution systems, keeping the use of natural gas and other energy forms competitive for all customers.
- Encourage the utilization of new and alternative technologies that have not to date enjoyed strong market penetration in British Columbia.
- Support the development and training of skilled trades' people who are fluent in the merits of conservation and efficient technology.
- An increase in allowed spending currently set at $4.274 million annually for TGI and TGVI combined, as shown in Table 4-3.

Table 4-3 TGI & TGVI Proposal for Energy Efficiency and Conservation Activity

Proposed ($million)

Utility	2008	2009	2010	Total by Utility
TGI	$13.996	$15.752	$17.196	$46.944
TGVI	$2.830	$3.043	$3.793	$9.666
Total	$16.826	$18.795	$20.989	$56.610

Incremental to Existing ($million)

Utility	2008	2009	2010	Total by Utility
TGI	$10.872	$12.628	$17.196	$40.696
TGVI	$1.680	$1.893	$3.793	$7.366
Total	$12.552	$14.521	$20.989	$48.062

- A change in financial treatment for Energy Efficiency and Conservation expenditures, treating the full expenditure as equivalent to capital, earning the regulated rate of return, and amortizing costs over twenty years following the year in which the cost was incurred.

This increase in funding supports B.C. Energy Policy Action No. 3, which states that utilities are to pursue all cost-effective DSM opportunities. Terasen Gas believes that the budget amount outlined above reflects all the cost-effective DSM opportunities available to it at this time.
This application is the first major initiative for Terasen Gas in response to the CPR and the 2007 Energy Plan. The evolving energy planning landscape, including the Provincial Government's new energy policies and carbon related legislation, is changing the way B.C. utilities plan demand side programming. Terasen Gas will continue to monitor developments in EEC programming across B.C. and the PNW to identify further opportunities beyond the current application to intensify EEC activities in accordance with Provincial directives.

4.4 Proposed CPR Update

Terasen Gas plans to commission an updated Conservation Potential Review (CPR) Study in 2009, to be received in 2010. The updated CPR will reflect new public policy, the changing energy landscape, and would form the basis of an application to the BCUC for the next stage of EEC funding for the period 2011 to 2014. This study and additional programming will be discussed further in the 2010 Terasen Gas Resource Plan.

4.5 Conclusion – EEC Impact on Demand

The expected impact of the proposed new EEC programs on TGI and TGVI demand has already been captured in the demand discussion in Chapter 3. In particular, Section 3.4.2 explains that EEC programs are expected to have an impact on overall annual demand for natural gas. The effect of those efficiency programs that reduce overall demand is to pull the demand forecast curve down from the reference demand forecast toward the low demand scenario. However, a number of efficiency programs build natural gas load while replacing less efficient or more carbon intensive load served by other fuels. These programs will result in a shift from the reference forecast toward the high demand scenario presented in Chapter 3.

While efficiency improvements that affect annual demand are in the best interest of customers and will help to reduce carbon emissions overall, these programs typically have minimal impact on the amount of gas used during the coldest days expected, since even the most efficient natural gas heating equipment is typically working its hardest during these peak demand events. Terasen Gas has found that these programs typically can delay capacity related infrastructure projects by zero years to up to just a few years. A review of the expected impact of EEC programs on infrastructure requirements for each of the Terasen Gas service areas is presented in Chapter 5.

5 ON-SYSTEM SUPPLY RESOURCES

5.1 Introduction

Once the forecasted growth in natural gas demand in the various service areas has been determined and the expected impact of demand side resources (EEC programming) established, Terasen Gas examines the ability of its own transmission and distribution systems to meet future demand. Chapter 5 focuses on the assessment of the Terasen Gas transmission systems to meet growth related demand, and the system expansion alternatives available to meet any expected constraints. A discussion of distribution system planning is also included. Distribution projects within the 5-year planning horizon of the TGI and TGVI Capital Plans are summarized in Appendix J.

Supply resources must be designed to meet peak demand. Planning for transmission system expansion is based on a peak forecast of demand for core market customers and firm, or non-interruptible, demand from transport customers.

5.2 Transmission System Resource Needs and Alternatives

The capacity of a pipeline system is determined by the diameter and length of the pipeline, the supply and required delivery pressures, and the allowable maximum operating pressure ("MOP"). To overcome friction and allow gas to flow through the pipeline, a pressure differential between the supply and delivery points is required. Compressors are used to increase the pressure differential and move large volumes of natural gas at high pressures through the transmission pipelines to major delivery points. The end pressures, which vary with flow, are controlled by pressure regulating stations before the natural gas enters the intermediate pressure or distribution systems.

Terasen Gas generally has three new resource options to evaluate when planning transmission system expansions:

<u>Pipelines</u>

To increase the effective cross-sectional area of a pipeline section to increase throughput capacity, an existing pipeline can be replaced by a larger diameter pipe, or a parallel pipeline (a loop) can be added to an existing one.

<u>Compression</u>

Compressors are added to increase capacity in two ways. The first is the addition of new units or replacement with larger units to increase the discharge pressure at an existing station. The second is to add new stations along the pipeline to maintain a higher average operating pressure.

On-system Storage

Storage facilities located within a service region are considered 'on-system' supply side resources. While there are two general types of storage alternatives – underground and LNG storage facilities[16] – options available within the Terasen Gas service regions are limited to LNG storage. Natural gas is typically injected into storage during low-demand periods and is withdrawn during high demand periods. During high demand periods, these storage facilities provide direct deliverability into the system to maintain pipeline operating pressure and increase system capacity without the need for additional throughput capacity from pipeline and compression facilities. Since Terasen Gas can call upon its own resources to utilize on-system storage these facilities also increase system security and reliability.

The transmission systems for each Terasen Gas service region are shown in Figure 1-3 of Chapter 1. The TGVI System transports gas to communities and industrial users on the Sunshine Coast and on Vancouver Island, as well as the TGI distribution system in Squamish. TGVI is currently constructing a pipeline extension from Squamish to provide natural gas service to Whistler. TGI operates and maintains two major transmission systems: the Coastal Transmission System (CTS) serving the Lower Mainland, and the Interior Transmission System (ITS) serving the North Thompson, Okanagan and Kootenay regions. In addition, in northern and eastern areas of the province, TGI has transmission laterals that connect to the Westcoast Energy Inc. and TransCanada Inc. BC System pipelines to serve communities and industrial users.

5.2.1 Transmission System Planning Considerations

Supply side resource requirements are identified by system hydraulic analyses. Important considerations in determining the need for transmission system expansion are:

- Optimization of resource capacity addition(s) to meet demand requirements over a 20 year planning period.
- Expected demand under design temperature conditions.
- Firm transportation demand only for capacity planning purposes (capacity additions are not planned to meet interruptible demand).
- Demand variations from core market customers on an hourly basis.

  Core demand typically has a morning peaking period between 6 and 10 am and an evening peaking period between 5 and 9 pm. The peak hour demand for these customers can be as much as 40% above the hourly average of the daily demand. A transmission system must have sufficient capacity to handle these daily fluctuations.
- The amount of line pack available within the transmission system.

  Properties of natural gas allow it to be stored temporarily within the pipeline as the compressors increase pressure to move gas through the system. As demand increases and pressure in the pipeline is drawn down, the amount of gas "packed" in the pipeline ("line pack") is reduced. Pipeline length and operating pressure determine the amount of

[16] LNG facilities cool natural gas into a liquid state and store it in insulated tanks.

line pack available in the system. Longer, higher pressure systems can be designed for peak day conditions, while smaller systems must be designed for the peak hour.

- Long lead times for large infrastructure projects (due to regulatory reviews, public consultation, conceptual design, detailed engineering, and construction schedules).

5.2.2 TGVI System Resource Needs and Alternatives

5.2.2.1 TGVI System Description

Natural gas for TGVI customers is delivered from upstream sources on the Westcoast pipeline system to the Huntingdon-Sumas trading point. At Huntingdon, TGVI contracts for transportation capacity across the TGI CTS to the start of the TGVI System at Eagle Mountain in Coquitlam. From there, gas is transported through 615 km of high pressure pipelines, including three, twinned marine crossings of the Georgia and Malaspina Straits and onto Vancouver Island near Campbell River. Figure 5-1 shows the layout of the transmission system showing the location of the compressor stations and major industrial customers and distribution networks.

TGVI is also currently installing a 50 kilometre steel pipeline extension between Squamish and Whistler to facilitate that community's conversion from propane to natural gas in 2009. The development of the natural gas service in Whistler is further discussed in Section 5.2.3.

Figure 5-1 Layout of TGVI System

5.2.2.2 TGVI Demand and Capacity Balance

The reference forecast for demand on the TGVI system is its core market customers located on Vancouver Island and the Sunshine Coast, the core market customers in Squamish for TGI, and by year 2009 the core market customers in Whistler for TGW. TGVI also transports gas for the pulp and paper mills represented by the Vancouver Island Gas Joint Venture (“VIGJV”), and to BC Hydro’s Island Cogeneration Project (“ICP”) pursuant to a long term Transportation Service Agreement.

Peak demand for TGVI’s core customers is presented in Chapter 3 and Appendix G. Current contract demand requirements for the VIGJV and the ICP are 8 and 45 TJ/d respectively. The TGVI System is currently fully subscribed and relies on a right to call back capacity to ICP from BC Hydro during design weather events in order to serve its core market design day requirements.

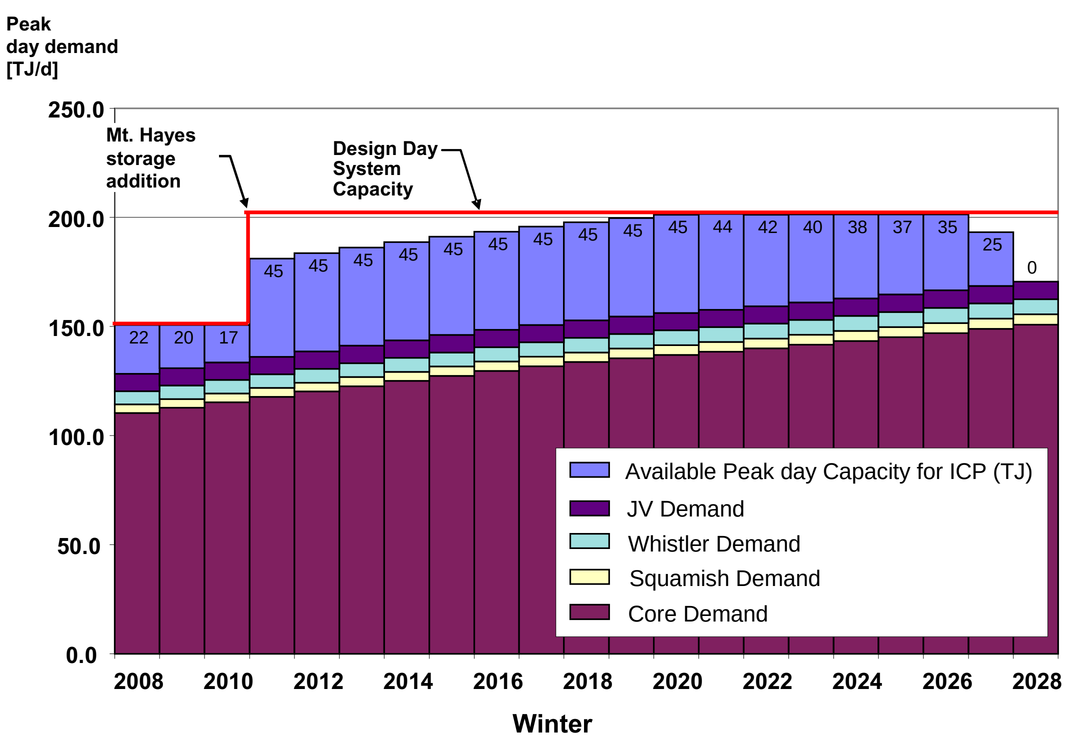
5.2.2.3 TGVI System Resource Needs and Alternatives

In its 2006 Resource Plan, TGVI concluded that a new natural gas storage facility to be constructed near Mt. Hayes on Vancouver Island is the best solution to meet future demand and system requirements. The preferred resource portfolio also includes the retention and upgrading of the V4 Compressor Station on Texada Island and additional compression to be added toward the end of the planning period. Additional benefits of of the preferred portfolio include operational flexibility, regional storage resource benefits for both TGVI and TGI, optimization of the existing system infrastructure and improved system reliability.

Subsequent applications by Terasen Gas to construct and contract for service from the Mt. Hayes facility were approved by the BCUC. Construction of the facility commenced in April 2008 and is will be in service for the 2011/12 winter period. The Texada compressor station upgrade has also been completed.

The Mt. Hayes facility will have a storage capacity of 1.5 billion cubic feet ("Bcf"), a liquefaction capacity of 7.5 million cubic feet per day ("MMcfd"), and a sendout deliverability of 150 MMcfd. TGVI is to retain one third of the Mt. Hayes storage and sendout capabilities while TGI will contract the remaining two thirds. Figure 5-2 shows that further capacity constraints on the TGVI system are not expected until 2021, based on the requirement to meet peak demand for core TGVI customers under the reference case demand forecast, plus transportation requirements for the VIGJV mills (8 TJ/d) and the Island Cogeneration Project (45 TJ/d).

Figure 5-2 TGVI Demand-Capacity Balance with Mt. Hayes Facility



The identified system capacity constraint coincides with the expiry of the TGVI - BC Hydro Transportation Service Agreement (“TSA”) for service to the ICP on Vancouver Island in April 2022. If Terasen Gas and BC Hydro extend the TSA beyond 2021, TGVI would have three resource options to manage the forecast demand for the core market customers, plus the transportation requirements for the VIGJV and the ICP. The first option is to retain more than 1/3 of the storage and sendout capabilities from Mt. Hayes to provide the TGVI System with additional on system supply during peak demand period. The second option is the addition of V2 Squamish Compressor Station with a single compressor unit. Finally, Terasen Gas could seek to renew an existing peaking agreement with BC Hydro allowing curtailment of flows to ICP to meet the core market requirements.

TGVI Demand Forecast Sensitivity

Capacity requirements for TGVI have also been analyzed against the low and high core market demand forecast. Under the low forecast, the next TGVI system constraint would occur in 2027. Under the high forecast, the constraint would occur sooner, in 2014.

With the constraint occurring so far out into the planning period, the planning environment for Terasen Gas and its stakeholders could change significantly. Conducting a detailed evaluation to select the next preferred system expansion solution is premature at this time. Terasen Gas will continue to monitor the demand capacity balance on the TGVI transmission system and work with BC Hydro and other stakeholders to ensure the needs of all TGVI customers can be met, including ICP.

5.2.3 Transmission System Needs for TGW

The existing TGW propane distribution system is at capacity to meet the energy demand at Whistler. TGW’s 2005 Resource Plan Update concluded that construction of a natural gas pipeline from Squamish to Whistler and conversion of the existing propane distribution system to natural gas was the preferred option to meet future demand over expanding the existing propane system. Subsequently, TGVI submitted a CPCN application to construct a pipeline from Squamish to Whistler and TGW submitted a CPCN application to convert the propane distribution system to natural gas. Both projects were approved and are currently under planning and construction to bring natural gas service to Whistler by Year 2009.

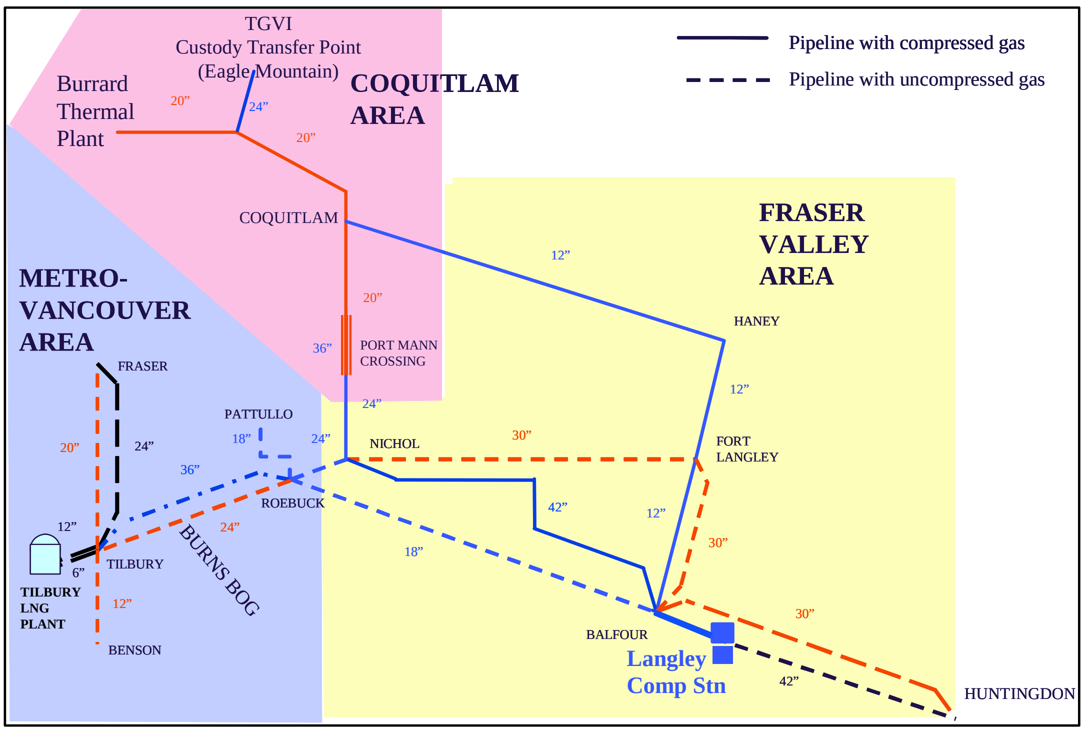
Natural gas demand forecast for TGW customers is expected to be moderate over the long term as an increasing proportion of future demand growth is expected to be met by alternative sources, pursuant to Whistler’s current Sustainable Energy Strategy. This shift in energy choice was planned for within the decisions made by the 2005 TGW Resource Plan. Once gas service to Whistler is complete, Terasen Gas does not expect any additional requirements for supply transmission expansion to serve Whistler over the planning period.

5.2.4 TGI – Coastal Transmission System Needs and Alternatives

5.2.4.1 CTS System Description

The CTS consists of a 265 km network of pipelines providing gas transportation from the Huntingdon-Sumas trading point to various metering and regulating stations in the Fraser Valley, Metro-Vancouver and Coquitlam areas. Other transmission related facilities include the Langley compressor station used to maintain transmission pressures, and the Tilbury LNG storage facility used to provide peaking gas supply to increase system deliverability to the CTS. This system delivers gas to the core market distribution networks in the Lower Mainland, as well as providing transportation service to BC Hydro's Burrard Thermal Generating Station ("Burrard Thermal") and to the TGVI transmission system at Eagle Mountain in Coquitlam. Figure 5-3 is a schematic diagram showing the CTS layout.

Figure 5-3 CTS Schematic



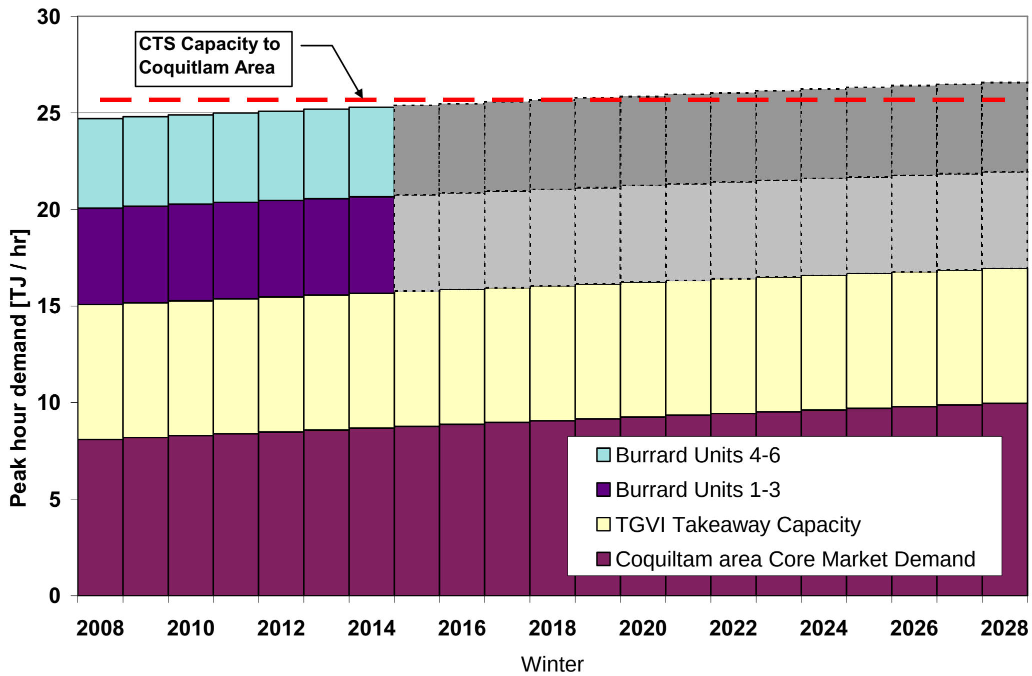
The majority of the CTS in the Fraser Valley and Metro Vancouver areas is already looped and consequently has sufficient capacity to meet long-term demand requirements. The Coquitlam area, however, is primarily fed by a single pipeline from Nichol in Surrey. This single feed carries 15% of the total peak day demand from core market customers in the Lower Mainland, combined with the concentrated demand for Burrard Thermal and TGVI. A secondary line through Fort Langley and Haney serves only approximately 5% of the peak day demand from the Coquitlam area. The Nichol to Coquitlam pipeline could potentially be capacity constrained within the planning period.

5.2.4.2 CTS Demand / Capacity Balance

The peak day core demand for TGI's CTS is discussed in Chapter 3. To assess the resource requirements for the Nichol to Coquitlam pipeline, the peak day demand – capacity balance includes core demand for the Coquitlam area, TGVI take-away requirements including TGVI, TGW and Squamish area core demand as well as VIGJV and ICP demand, and finally the demand required to serve Burrard Thermal.

BC Hydro filed its 2008 Long Term Acquisition Plan ("LTAP") on June 13th, 2008. The LTAP includes reliance on six gas fired generating units at Burrard Thermal. Terasen Gas examined future load alternatives with zero, 3 and 6 units required to be available to meet peak electricity demand. The resulting peak day demand – capacity balance is shown in Figure 5-4.

Figure 5-4 TGI Demand and CTS Capacity to Serve Coquitlam Area



5.2.4.3 CTS System Resource Needs and Analysis

In its 2006 Resource Plan, TGI identified that demand on the Nichol to Coquitlam pipeline would reach capacity within the 20-year planning period. In the absence of the Mt. Hayes storage facility on Vancouver Island, TGI would have four alternative solutions available to solve this capacity constraint:

- Looping the Nichol to Coquitlam Pipeline,
- Adding more compression at the Langley Compressor Station,
- Building a new compressor station closer to the constraint location, and
- Expanding the existing Tilbury storage facility.

Construction of the Mt. Hayes storage facility, however, offers a fifth alternative that alleviates the capacity constraint for the duration of the planning period. The operational flexibility available as a result of the Mt. Hayes facility allows Terasen Gas to manage gas flow to Vancouver Island in two ways:

1. With the Mt. Hayes Facility providing an on-system supply to TGVI during peak demand periods, TGVI's transport requirements across the CTS are reduced.
2. TGI will contract two thirds of Mt. Hayes' storage capacity and deliverability. The delivery of TGI's peaking supplies from the Mt. Hayes facility is largely done through displacement[17], further reducing physical transport requirements to TGVI across the constraint location.

Construction of the Mt. Hayes storage facility commenced in April 2008. Therefore the capacity constraint on the CTS has been deferred beyond the planning period, even with six units operating at Burrard Thermal. TGI may still consider expansion of the Tilbury storage facility, based on the gas supply benefits of additional storage located in the Lower Mainland as described in Chapter 6.

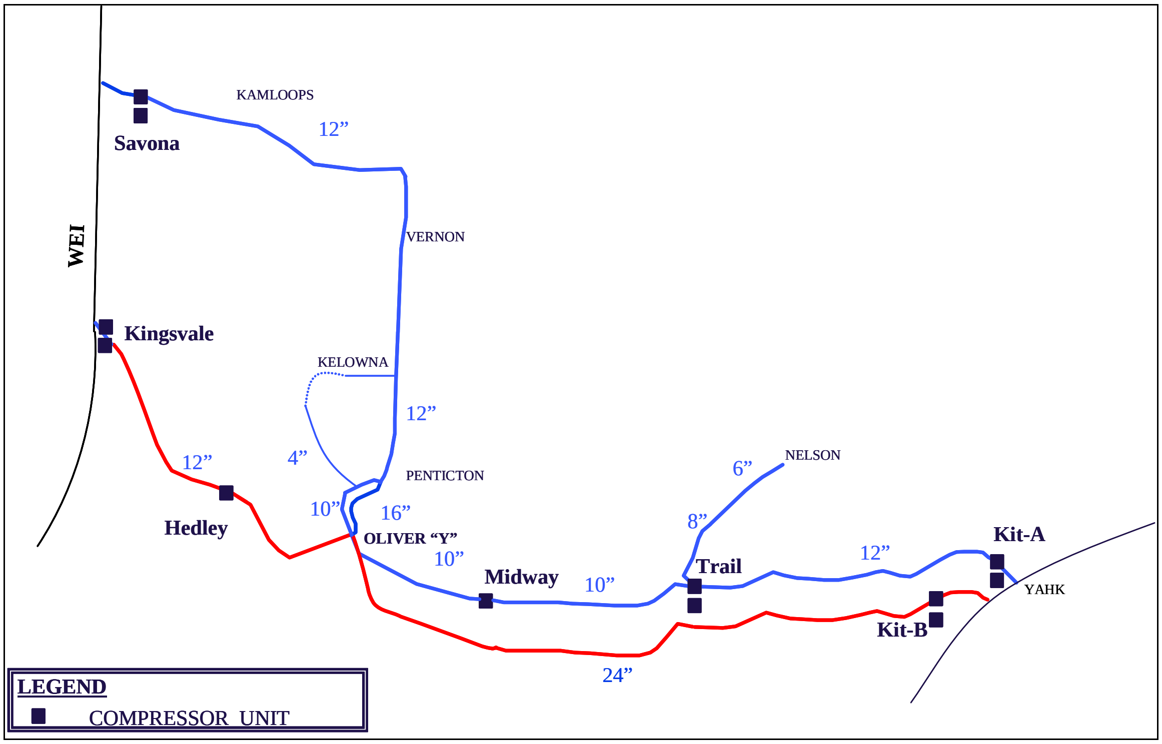
5.2.5 TGI - Interior Transmission System Needs and Alternatives

5.2.5.1 ITS System Description

Figure 5-5 is a simplified schematic of the ITS. The system consists of 1,515 kilometres of transmission pipe operating at MOPs between 700 and 1,440 psig. Gas received from the Westcoast Pipeline at Savona supplies customers in the Thompson and North Okanagan regions. Gas received from the TransCanada Pipeline at Yahk supplies customers in the West Kootenay region via pipelines to Trail and Oliver-Y. The Southern Crossing Pipeline ("SCP") transports gas from Yahk to Oliver-Y. From Oliver-Y, pipelines transport the gas from the SCP to serve customers in South and Central Okanagan. Also, from Oliver-Y, another pipeline transports gas from the SCP to Kingsvale for re-delivery to the Lower Mainland via the Westcoast Pipeline.

[17] TGI would take TGVI's gas at Huntingdon and TGVI would use TGI's gas from the Mt. Hayes Facility to serve Vancouver Island loads.

Figure 5-5 ITS Schematic



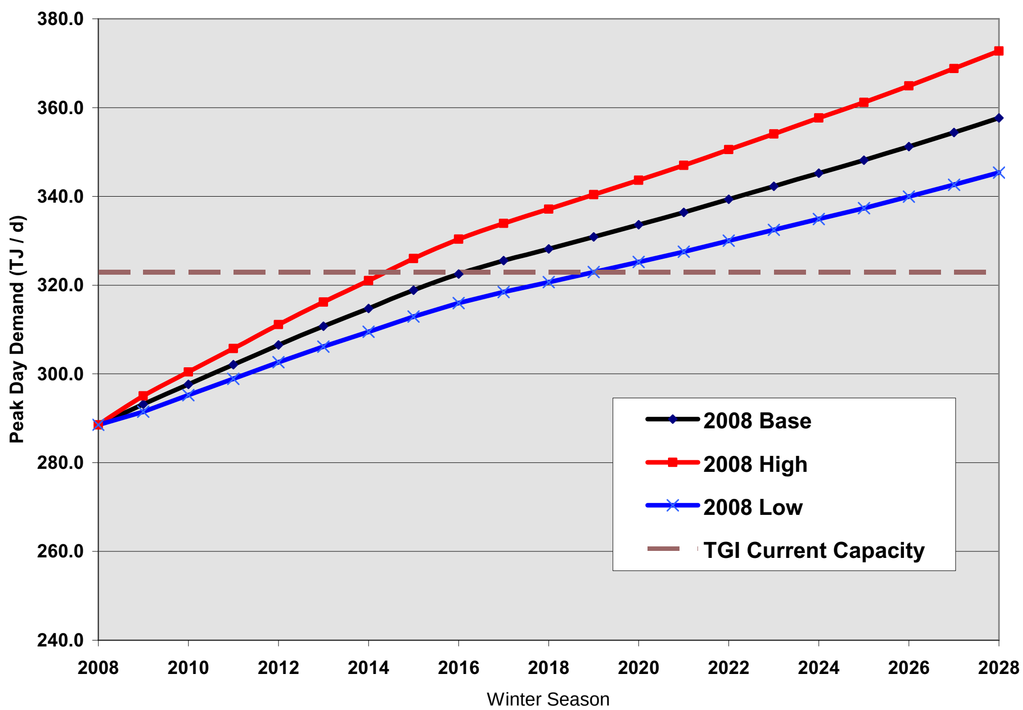
5.2.5.2 ITS Demand / Capacity Balance

Approximately 60% of the current ITS core residential and commercial market demand is concentrated in the South, Central and North Okanagan areas. Approximately 80% of the expected core market growth is also within these areas. This growth is driving the location of future incremental capacity additions on the ITS. Differences in core demand growth between the References, High and Low demand forecasts affect the timing for these facility requirements.

Since gas is delivered to the ITS from two upstream pipelines - the Westcoast Pipeline at Savona and the TransCanada Pipeline at Yahk - the ITS system capacity will be reached when the system capacity from both supply feeds are fully utilized. The current peak day system capacity for the ITS is approximately 320 TJ/d.

Figure 5-6 shows the 2008 Reference, High and Low demand forecasts against existing system capacity for the ITS. Facility additions will be required when the peak day forecast demand reaches the existing system capacity. In the Reference forecast, the peak day demand growth is approximately 3.5 TJ/d each year. With current peak day demand at approximately 290 TJ/d, it will take 8 years for demand growth to reach the current system capacity. A resource addition is therefore required by 2016 under the Reference forecast. For the High and Low forecasts, the first resource addition is required in 2014 and 2019 respectively.

Figure 5-6 ITS Facility Timing



5.2.5.3 ITS Portfolio Development

On the ITS, three resource options have been identified:

- Phased pipeline looping between Penticton and Winfield, north of Kelowna. This pipeline looping would increase gas supply delivered from the TransCanada Pipeline at Yahk via the SCP. The high growth area between Penticton and Kelowna is currently served by a single pipeline. The first two phases of the pipeline looping – Penticton to Naramata (23.7 km) and Naramata to Mission (15.0 km) – would follow the existing pipeline right-of-way. Due to population growth in Kelowna, the final phase if necessary would bypass Kelowna and terminate at Winfield. This phased looping will accompany the addition of a compressor unit at Kitchener-B Compressor Station.
- Phased pipeline looping between Savona and east of Kamloops. This pipeline looping would increase gas supply delivered via the Westcoast Pipeline at Savona. All three phases total almost 58 km of pipeline looping.
- LNG storage facility between Falkland and Vernon. A LNG storage facility allows natural gas to be stored in times of low demands when excess pipeline capacity is available, and provides on-system delivery to the Okanagan regions during high demand periods to augment the delivery capacity of the ITS.

Figure 5-7 indicates the potential geographical locations of the three system resource expansion options on the ITS. Table 5-1 summarizes the required timing for ITS facility additions for the three resource options.

Figure 5-7 ITS System Resource Expansion Options

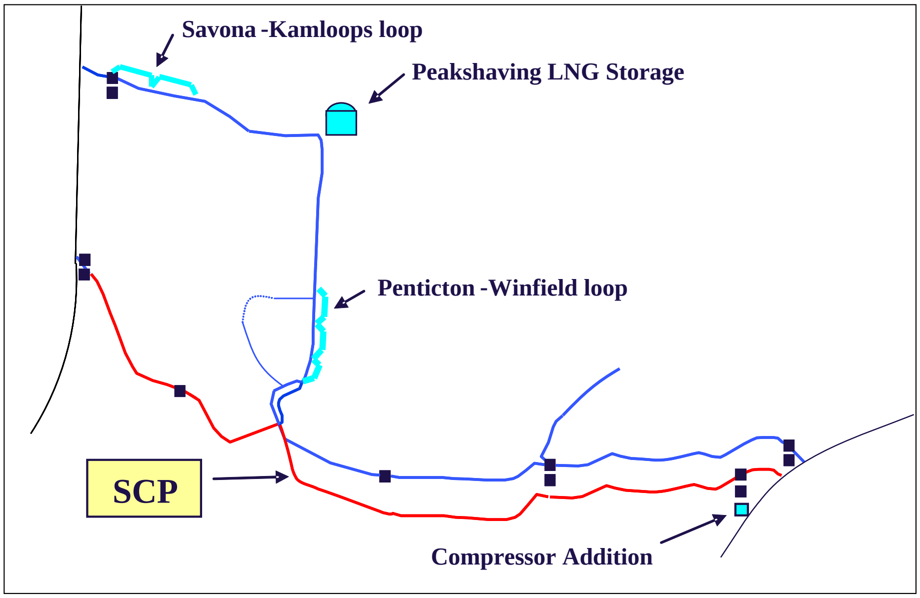


Table 5-1 ITS Resource Requirements

Pipeline Loop from Penticton Option	Penticton to Naramata Loop 23 km NPS 20 3rd compressor unit @ Kitchener-B Station	Naramata to Mission Loop 15 km NPS 20	Mission to Winfield Loop 28 km NPS 20
Low Demand	2019	-	
Reference Demand	2016	-	
High Demand	2014	2025	

Pipeline Loop from Savona Option	Savona to SN-2 Loop, 17 km NPS 16	SN-2 to Kamloops #1 Loop, 15 km NPS 16	Kamloops #1 to Lafarge Loop, 26 km NPS 16 Summerland lateral P-Control Station
Reference Demand	2016	2022	2027

LNG Option	LNG Peakshaving Facility		
Reference Demand	2016		

5.2.5.4 Implications of Potential New Industrial Load on the ITS

FortisBC is an integrated, regulated electric utility that generates, transmits and distributes electricity in the southern interior of British Columbia, serving over 152,000 customers in the Kootenays and Okanagan Regions. In preparing its 2008 Resource Plan, FortisBC has identified a system capacity constraint within its own electrical transmission system in the central/north Okanagan area potentially occurring in the middle of the planning period (2008-2027).

Among the resource options being considered by Fortis BC is a new natural gas fired generating facility located near the system capacity constraint to help meet electrical system stability and reliability requirements. According to information presented by FortisBC at its stakeholder workshops, this facility would also provide system peaking supply and act as a firming resource for a broader portfolio of renewable resources that would help FortisBC to meet Provincial Energy Plan policies and defer the need for future transmission lines through the region.

As of the submission date of this Terasen Gas Resource Plan, FortisBC had not yet completed their integrated resource planning process in which a preferred resource portfolio will be selected. If a natural gas fired peaking facility is included in the FortisBC preferred resource portfolio and proceeds, Terasen Gas expects to supply the facility with fuel via the ITS system. This planning requirement could accelerate the timing for ITS system expansion in the Okanagan. Based on information provided by Fortis BC at its stakeholder consultation sessions, TGI understands that such a facility could be required as early as 2010 - 11. TGI will continue to participate as a stakeholder in the FortisBC planning process and will work with FortisBC to develop and meet the service requirements and timing for such a facility if selected as a preferred resource.

Should another large new industrial load be developed in the Okanagan area before the ITS capacity constrain is reached, it would also have the affect of accelerating the need for a system expansion. At this time no formal inquiries for other new industrial service have been received.

5.2.6 On-system Resource Alternatives to Address Regional Supply Trends

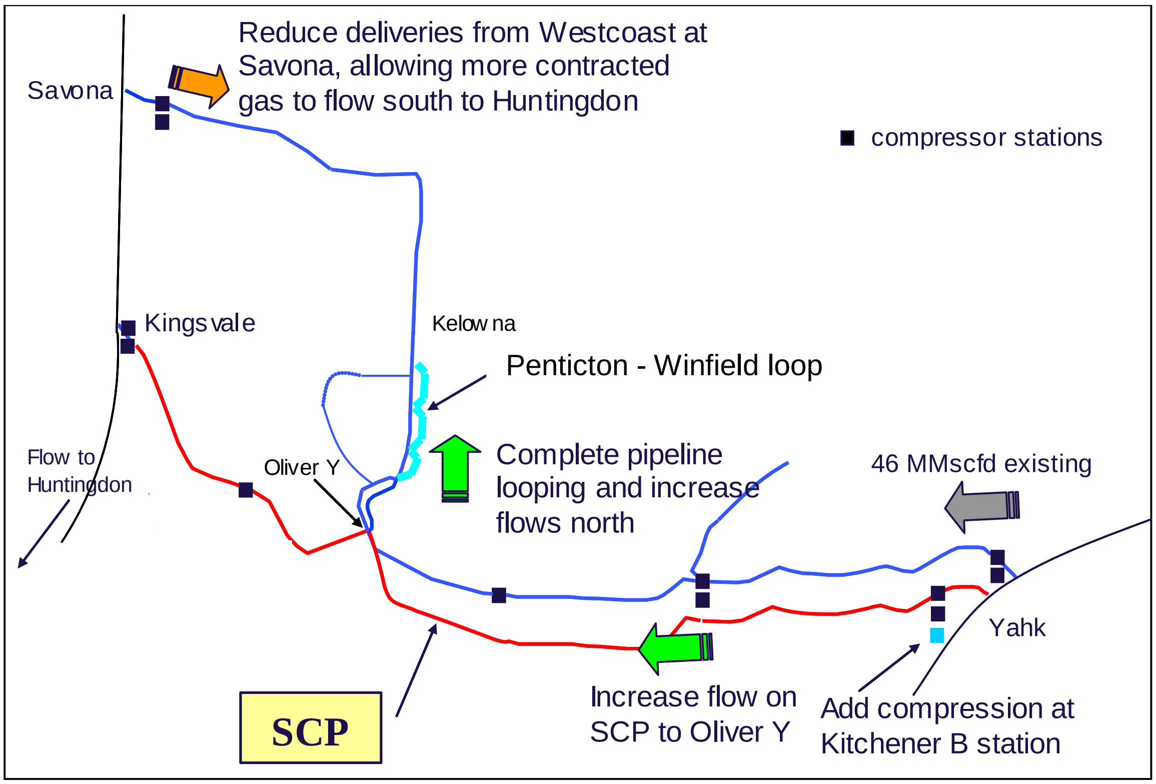
5.2.6.1 CTS - Tilbury LNG Facility Expansion

An expansion of storage and sendout capabilities at TGI's Tilbury storage facility could operate as a regional gas supply resource for Terasen Gas customers. The facilities location upstream from the Huntingdon-Sumas trading point would decrease TGI's reliance on downstream storage and re-delivery requirements. An increase in peaking supply to the PNW region would also reduce gas price volatility at Huntingdon by providing regional capacity to meet peak demand and acting as a backstop against temporary commodity price increases caused by increasing diversion of northern B.C. gas to Alberta. The Tilbury LNG Facility is situated on a 14 acre property in an industrial zone and can potentially accept an LNG storage expansion of up to 4 Bcf, along with the associated liquefaction and vaporization facilities.

5.2.6.2 ITS – Advance the Penticton-Naramata-Kelowna Pipeline Loop

The requirement and timing for this pipeline looping are to resolve system capacity constraints; however, TGI could also optimise the ITS to provide more access from the Alberta market, across southern B.C. to the Huntingdon-Sumas trading point. This alternative includes adding compression at Kitchener B compressor station and advancing the addition of pipeline looping to as early as 2010. Figure 5-8 describes the components of this alternative.

Figure 5-8 ITS System Resource Expansion to optimize supply from Alberta



5.2.7 Impact of New EEC Programs for On-system Resource Needs

Terasen Gas' proposal for new and expanded EEC programming, if approved, will reduce overall annual demand. In terms of deferring capacity constraints; however, only the timing of TGI interior system capacity constraints can benefit from successful implementation of new EEC programming, since constraints on the TGVI and TGI coastal systems are alleviated by constructing the Mt. Hayes storage facility. EEC program implementation is among the factors that could lead to the low demand forecast being realized.

5.2.8 TGI Transmission Laterals

TGI operates transmission laterals that connect to the Westcoast and TransCanada pipelines to serve communities and industrial users in north-central and south-eastern British Columbia. Two transmission laterals have been identified to have insufficient capacity to meet the forecast demand throughout the 20 year planning horizon. The resource needs for these two laterals are discussed below.

5.2.9.1 Fernie Lateral

The Fernie Lateral is a transmission system connected from the TransCanada Pipeline in the East Kootenay region. The lateral consists of a combination of 3 pipelines delivering gas to the town of Fernie and a number of farm taps. Based on the 2008 demand forecast and the actual tap pressure available from TransCanada, the lateral would require a 1.5 km of pipeline looping and an upgrade to the Fernie Gate Station by Year 2021 to meet the forecast capacity requirements. TGI will continue to monitor the actual demand growth and supply pressure from TransCanada to confirm the timing of the resource additions.

5.2.9.2 Cache Creek / Ashcroft Lateral

The Cache Creek/Ashcroft Lateral is served from the Westcoast Pipeline in the Thompson region. The lateral delivers gas to Cache Creek and Ashcroft which are located approximately 70 km west of Kamloops. The lateral consists of a combination of 2 pipelines and is near its capacity to meet demand. Reductions in supply pressure from Westcoast are increasing the frequency of curtailment to an industrial customer on the lateral. Terasen Gas will review the supply pressure data from the current winter of 2007/2008 to confirm this trend is continuing. If the industrial customer served by the lateral will contract for firm transportation service, TGI is considering the addition of a 13 km pipeline loop by the winter of 2009 - 10.

5.3 Terasen Gas Distribution Systems

By convention, Terasen Gas considers infrastructure operating at or below 300 pounds per square inch gauge (“psig”) as distribution assets, which are further divided into:

- Intermediate pressure systems operating from 300 psig to 101 psig.
- Distribution pressure systems operating at or below 100 psig.

For ease of maintenance and operation, safety to the public and reliable service, distribution networks operate at a relatively low pressure. TGI operates its distribution networks at a MOP of 60 psig while TGVI operates its distribution networks at a MOP of 80 psig. Supply resources available for distribution systems include:

- Pressure regulating stations – capacity reinforcement to a distribution network could be obtained by the addition of a new regulating station as an additional supply source; and
- Distribution pipelines - similar to a pipeline except at a lower operating pressure, capacity reinforcement in a distribution network can be increased by increasing the effective cross-sectional area of a distribution pipe section. This can be achieved by replacing an existing pipe with a larger diameter pipe, or adding a parallel pipe (a loop).

Since distribution systems operate at pressure through relatively small diameter pipes, there is essentially no line-pack capability for managing hourly demand fluctuations. Therefore capacity requirements for distribution systems are based on design hourly demand.

Terasen Gas conducts two types of studies on its distribution systems to determine the need for resource additions. An overview study of each distribution network is conducted with a 20-year planning horizon to identify strategies for addressing major distribution requirements resulting from customer growth. A 5-year optimization study is also conducted to identify near-term system reinforcement requirements, generally for arterial feeder lines and intermediate pressure pipelines, which support customer growth.

Additionally, Terasen Gas regularly conducts integrity assessments of its distribution systems. This type of ongoing system evaluation can also result in distribution resource upgrading requirements, but in this case as a result of ongoing system maintenance rather than as a result of customer and load growth. In some cases, the timing for system integrity upgrades can coincide with growth related expansion requirements.

While the 20-year overview studies provide a long-term planning and strategy outlook, Terasen Gas conducts detailed planning for distribution systems through its 5-year Capital Planning processes. The 5-year Capital Plans also include planning for other types of capital expenditures such as IT infrastructure upgrades, service programs such as unbundling of natural gas rates and ongoing system maintenance requirements.

5.3.1 TGI - Metro Vancouver IP System

Beyond the 5-year capital plan view, only the Metro Vancouver IP System is currently identified as requiring major resource additions (greater than $1.0 million) within the 20-year planning period. The Metro Vancouver IP System, fed mainly from Fraser Gate and Coquitlam gate stations, is a ringed network that deliveries gas to the regulator stations throughout Vancouver, Burnaby, New Westminster and Coquitlam. With continuing re-development and densification in Vancouver, the main IP feeder downstream of Fraser Gate Station will require capacity expansion in the long term. The current long range strategy calls for a 2.7 km pipeline loop in 2017, to be followed by a further 2.1 km loop in 2022. Current cost estimates for the Phase 1 and Phase 2 loops are $5.0M and $3.9M in $2007 CDN (excluding AFUDC), respectively. Terasen Gas will continue to monitor the requirements of the Vancouver IP system and assess the resource alternatives available.

5.3.2 5-year Capital Plans / Statement of Facilities Extensions

The remaining infrastructure projects being planned for Terasen Gas' distribution systems are analyzed and presented through the 5-year capital planning process. In addition to distribution infrastructure, the 5-year capital plans for each company include requirements for information technology and other capital expenditures required for ongoing business operations, meeting customer needs and remaining competitive for the health of the business. The projects being planned by Terasen Gas in its capital plans are numerous.

Terasen Gas has segmented its 5-Year Capital Plans as follows:

Regular Capital Plan
- Customer Driven Capital
- Non-Customer Driven Capital

Major Capital Plan
- Capital Projects that do not require a CPCN
- Capital Projects that require a CPCN

Regular Capital expenditures have been categorized into either customer driven capital or non-customer driven capital. This category excludes Capitalized Overheads, Contributions in aid of Construction ("CIAC") and Allowance for funds used during construction ("AFUDC"). Major Capital projects have been categorized into projects which do not require a CPCN and those which do require a CPCN to proceed.

A number of the major capital projects in the Terasen Gas capital plans which require submission of CPCN application have already been approved. Those projects for which Terasen Gas may submit new CPCN applications and will be studying over the coming months are TGVI's replacement of two units at the V1 Coquitlam compressor station and rehabilitation work for TGI's crossing of the South Arm of the Fraser River. A description of each project is provided in Appendix J.

TGI and TGVI 5-Year Capital Plans for the period 2008 to 2012 are presented in Appendix J to provide additional background and context for the Resource Plan. The only large project planned for TGW is the conversion of the Whistler Propane distribution system to natural gas which received CPCN approval in 2006 and is discussed previously in this Chapter. Spending for the conversion will receive deferral accounting treatment. The approved expenditures for the conversion and the anticipated regular capital spending for TGW are also included in Appendix J.

Terasen Gas is not submitting these Capital Plans for the purposes of approval by the BCUC as part of its review of the 2008 Resource Plan. Terasen Gas believes that the regulatory review process for Resource Plans is not the appropriate forum for review of its Capital Plans. Consistent with past practice, Terasen Gas continues to believe that the appropriate forum for review of its Capital Expenditures is its annual review filings.

As the 5-Year Regular Capital and Major Capital Plans include all planned capital expenditures, Terasen Gas believes that this information satisfies the requirements of the statement of facilities extensions as set out in Section 45(6) of the *Utilities Commission Act*. Terasen Gas has endeavoured to provide comprehensive 5-Year Capital Plans for TGI and TGVI as part of its submission. However, the projects and figures contained herein are subject to change and may be revised to reflect additional information as part of the revenue requirement filings, which are anticipated by the early fall of 2008.

5.3.3 System Resource Portfolio Conclusions and Recommendations

System capacity needs for each of the Terasen Gas transmission systems over the next 20 years have been assessed. With construction of the Whistler pipeline extension underway and plans in place for the conversion of the existing propane system to natural gas, the transmission system serving TGW is not expected to need capacity upgrades through the planning period. Similarly, ongoing development of the Mt. Hayes storage facility on Vancouver Island alleviates the need for transmission system expansion for TGVI in all except the high demand forecast scenario, and on the TGI CTS in all of the demand scenarios. On TGI's ITS, however, Terasen Gas has identified an expected capacity constraint in 2016 in the Okanagan area.

Circumstances that could advance the need for ITS system expansion include higher than expected demand from core customers, and the potential for new industrial load in the Okanagan. FortisBC, through its own resource planning process, has identified a potential new natural gas fired electricity generating facility in the Okanagan area as one of the resource options being considered to provide a peaking resource and firm back up for a broader renewable resource portfolio.

With the long lead times required for new infrastructure projects, Terasen Gas needs to examine resource alternatives for the ITS in more detail and more fully assess the potential for additional demand for gas fired generation by FortisBC. Opportunities also exist to expand TGI transmission infrastructure to help provide added regional supply resources. Growing risks to gas supplies at the Huntingdon – Sumas trading point could be reduced by expanding the Tilbury storage facility and by advancing the addition of pipeline looping and compression on the ITS. Terasen Gas should explore these opportunities more closely as part of its action plan.

Two of TGI's transmission laterals are identified as potentially needing expansion within the 20-year planning period. Only the Cache Creek / Ashcroft lateral is approaching constraints in the near-term, depending on industrial load requirements. Terasen Gas will continue to monitor the demand – capacity balance on all of its laterals and assess expansion alternatives if necessary.

Two anticipated distribution projects are currently identified by Terasen Gas as requiring CPCN applications. The replacement of compressor units at TGVI's Coquitlam station and rehabilitation of the TGI's crossing of the South Branch of the Fraser River are included in the Terasen Gas Capital Plans provided in Appendix J.

6 GAS SUPPLY PORTFOLIO AND REGIONAL RESOURCE PLANNING

6.1 Introduction

Upstream from the Terasen Gas transmission systems are networks of larger pipelines, storage facilities and market trading points that move gas from production and trading areas and deliver it to end market users such as utilities, large industries and electricity generating stations. Utilities in the region need to either own or contract for transportation and storage capacity from these regional resources to ensure the gas they need to serve their customers throughout the year can be delivered. Figure 6-1 shows the geographic relationship of the regional resources available to the PNW.

The region's pipeline infrastructure provides access to base load supply from two major production basins; the Western Canadian Sedimentary Basin ("WSCB") and the Rocky Mountain area in the western U.S. ("U.S. Rockies"). The opportunity to shape gas supply to the winter peaking nature of regional demand is provided by underground and Liquefied Natural Gas ("LNG") storage facilities. Underground storage facilities are located both upstream near production areas (Aitken Creek and Carbon), and downstream closer to load centers south of Huntingdon (Mist and Jackson Prairie). LNG storage facilities, such as TGI's existing Tilbury facility, are generally constructed near the end markets they serve. The current capability of regional infrastructure to deliver enough gas to meet peak day demands assumes that no service outages or reductions occur anywhere on the system during peak demand.

Figure 6-1 Production Areas and Existing Regional Infrastructure Serving the PNW

6.2 Terasen Gas Supply Portfolio Planning

6.2.1 Overview

Terasen Gas' gas supply planning process continues to focus on securing cost-effective resources that ensure the safe and reliable delivery of natural gas to meet firm core customer requirements. A supply portfolio refers to the combination of resources that a utility uses to ensure the physical delivery of gas to its distribution systems is sufficient to meet demand throughout each day of the year, including the design day. Consistent with the NWGA strategy to ensure the PNW maintains an adequate mix of natural gas supplies and infrastructure, planning efforts at Terasen Gas aim to develop a supply portfolio which provides access to a variety of resources, and most effectively meets customer demand characteristics.

6.2.2 Current Supply Portfolio

Terasen Gas' responsibility to provide reliable supply refers to having sufficient resources to meet design day demand. The supply obligation also extends to the management of elevated loads over sustained periods of colder weather, and mitigation of any interruptions in delivery capacity related to natural gas transport and storage infrastructure.

Critical to ensuring adequate supply is a portfolio characterized by resource diversity. Maintaining a variety of resources facilitates operational flexibility, more efficient use of resources, and minimizes potential for stranded cost. As such, the choice in incremental resource is based on a combination of the relative cost of various market alternatives and the impact of those alternatives on overall cost, operational constraints and risk over the total supply portfolio.

Appendix K provides the Annual Contracting Plans for both TGI and TGVI, submitted to the BCUC in the second quarter of 2008. Figure 6-2 and Figure 6-3 illustrate the resource mix in the existing gas supply portfolio for TGI and TGVI, highlighting the seasonal nature of demand and showing why winter peaking load is best met with shorter duration resources. Storage resources in the current supply portfolios include a combination of firm upstream seasonal storage at Aitken Creek and Carbon (150 terajoules per day ("TJ/day"), shorter duration market storage at Jackson Prairie and Mist (250TJ/day), and on-system peaking storage at Tilbury LNG (166TJ/day). Once completed, the Mt. Hayes storage facility resource will be included in both of these portfolios, meeting incremental peaking demand and displacing other higher cost seasonal resources. In 2009, following the conversion of the TGW propane system to natural gas, a relatively small amount of incremental base and seasonal load will be added to TGI's portfolio requirements.

Figure 6-2 2008-09 Supply Portfolio for TGI

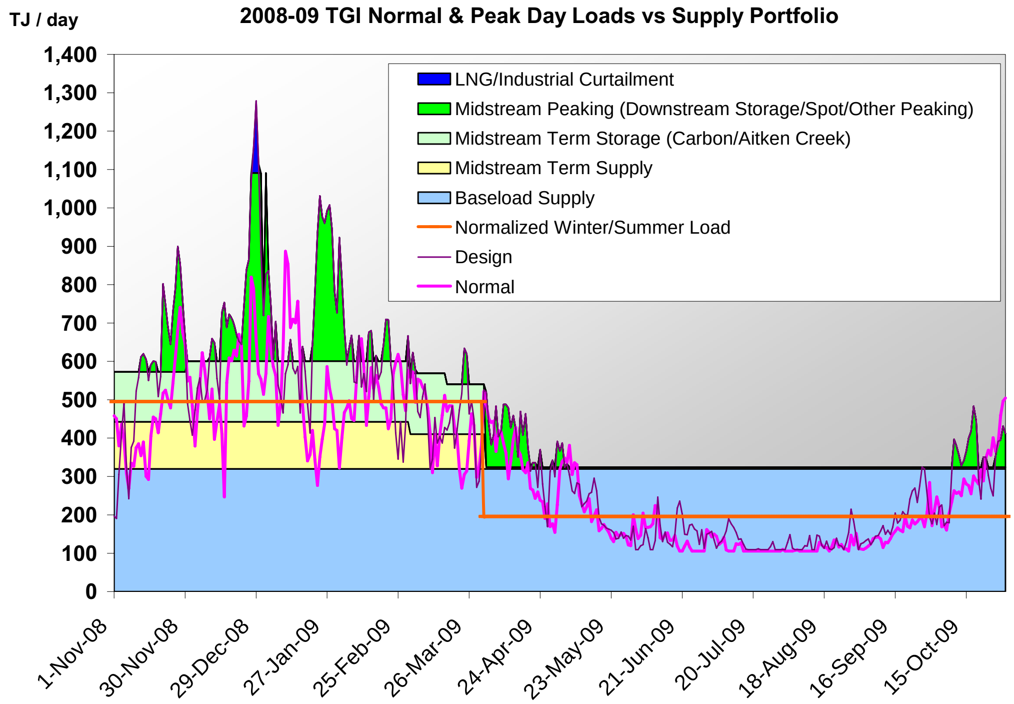
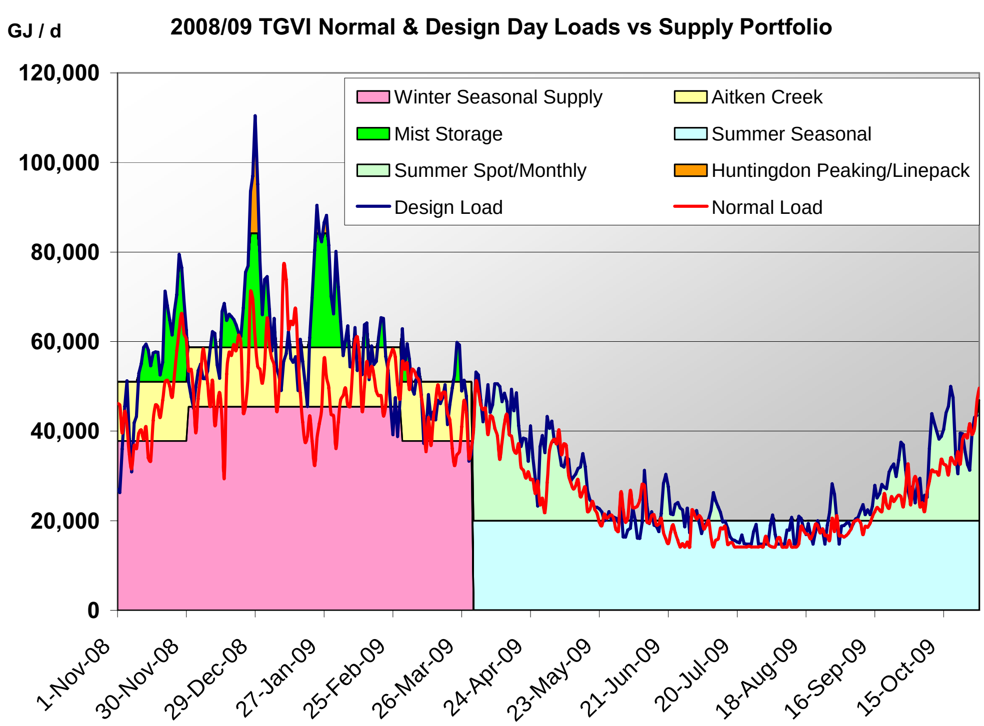


Figure 6-3 2008-09 Supply Portfolio for TGVI



The baseload and summer-seasonal components in Figure 6-2 and Figure 6-3 highlight the effectiveness of pipeline assets to meet constant demand. Pipeline resources broaden access to gas supplies from producing regions and offer greater assurance that supply can be contracted over the long term. TGI holds firm transportation capacity on Westcoast T-South, and on TransCanada's B.C. and Alberta pipelines to meet baseload requirements. The gas supply portfolio also contains firm transportation capacity on Northwest Pipeline which is primarily used for gas delivery to and from the Mist and Jackson Prairie storage facilities to the Huntingdon market area. TGI holds firm capacity on Southern Crossing Pipeline which allows the flow of Kingsgate or Alberta gas supply to the Lower Mainland.

6.2.3 Managing Commodity Price Uncertainty (Price Risk Management)

The procurement of gas supplies in a competitive, wholesale market place has inherent market price risk. Ensuring natural gas rates remain competitive with other energy sources is fundamental to retaining existing load and adding economic new load. Both TGI and TGVI develop diversified procurement strategies and utilize a price risk management plan to manage commodity price risk in order to facilitate competitive natural gas rates.

Price Risk Management at Terasen Gas must also consider Marketer involvement in retail sales. Since 2007, TGI customers have had the ability to purchase their supply directly from marketers at fixed prices. TGI maintain the responsibility of managing the midstream infrastructure

The focus of the price risk management plans is to improve the likelihood that natural gas remains competitive with electricity, and to moderate the impact of gas price volatility on customer rates. Through annual submissions of utility Price Risk Management Plans to the BCUC, Terasen Gas re-examines the price risk management objectives and strategy to ensure the plan is aligned to changing pricing and contracting environments.

The gas supply plan adopts a diversified resource acquisition strategy to maintain supply reliability and moderate commodity price uncertainty. Volatility in natural gas prices is managed by maintaining access to liquid trading hubs, acquiring a variety of storage and transportation resources, and using different pricing structures and contract terms. Terasen Gas considers access to appropriate natural gas infrastructure and minimizing reliance on any one price point a critical element of ensuring the long term competitiveness of natural gas rates.

6.2.4 Long Term Supply Planning Strategy

The longer term contracting strategy aims to maintain reliable cost competitive natural gas deliveries to meet future demand. The focus is to assess the impact of changing supply, demand, and pricing dynamics on gas procurement strategies, and to foster the development of a cost-effective, diversified gas supply portfolio. Terasen Gas' service regions are part of the broader Pacific Northwest market. As such, the TGI and TGVI gas supply portfolios rely on storage and pipeline infrastructure situated in the I-5 corridor to meet the load requirements. Similar to other regional utilities, the growing competition for infrastructure, limited resource options, and continued growth in energy demand are the primary challenges facing Terasen Gas' long term resource acquisition strategy.

In recognition of the influence of regional dynamics on individual utility supply portfolios, longer term planning is conducted as a regional effort to ensure sustainability of natural gas resources in the PNW. Terasen Gas actively works in partnership with the NWGA to develop a consensus industry study giving perspective of the region's current and projected natural gas supply and delivery capabilities, as well as customer demand projections and its drivers for the PNW. The key findings of the 2007 NWGA Outlook Study include:

- Regional demand for natural gas will continue to grow and change in load shape; primarily driven by gas-fired generation and greater numbers of residential customers.
- Regional production areas will increasingly be accessed by other North American markets and form an integral part of meeting continental demand growth; effectively increasing competition for supply in the PNW.
- Regional natural gas pipeline and storage capabilities, although adequate to meet near-term demand, is expected to reach capacity limits early in the next decade. The efficient and effective utilization of energy combined with increased access to new and existing supplies will be fundamental to moderating future gas prices.

These findings by the NWGA reflect the expected contracting environment in the region and directly impacts long term resource strategy for Terasen Gas. Of significance to the Terasen Gas supply portfolios, is the potential impact of a resource constrained regional market and increased competition for supply.

Figure 6-4 and Figure 6-5 indicate the mix of resources required to meet projected deign year demand for TGI and TGVI respectively. The requirement of incremental resources is best served by a combination of market area storage and pipeline capacity. Furthermore, enhancing diversity in the resource mix and increasing access to broader markets, such as Alberta, is considered essential to sustaining long-term reliable cost competitive supply.

Figure 6-4 TGI Long Term Supply Portfolio Requirements

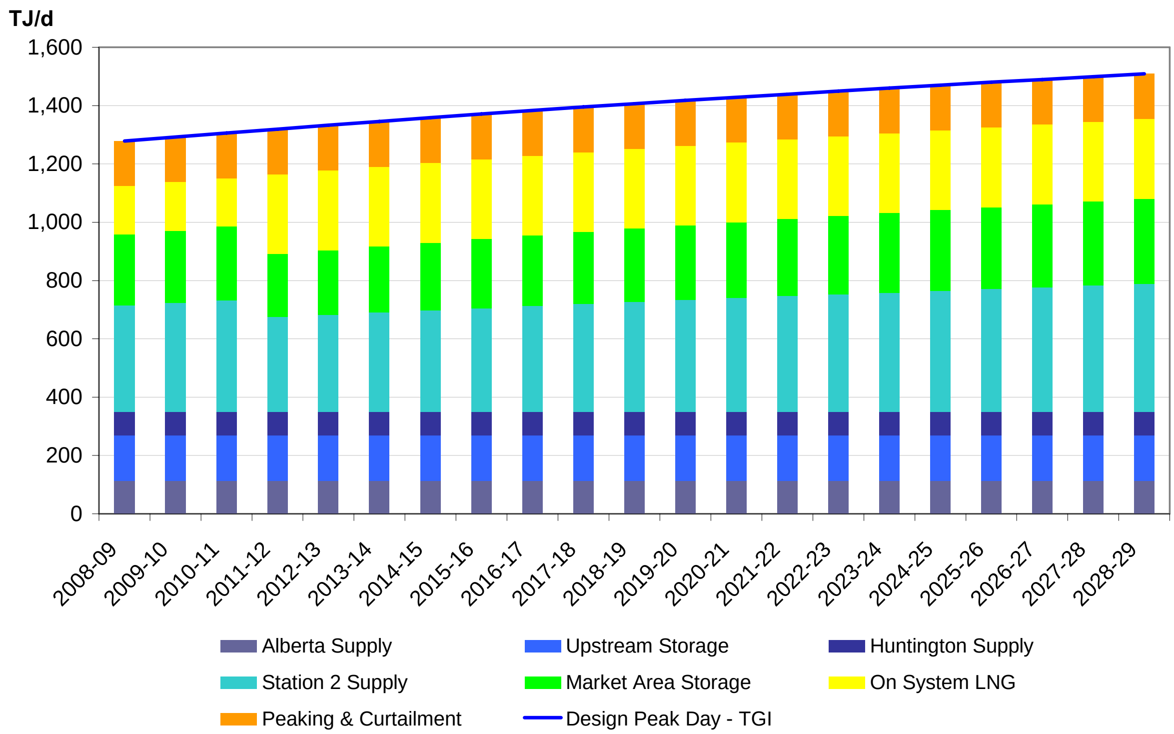
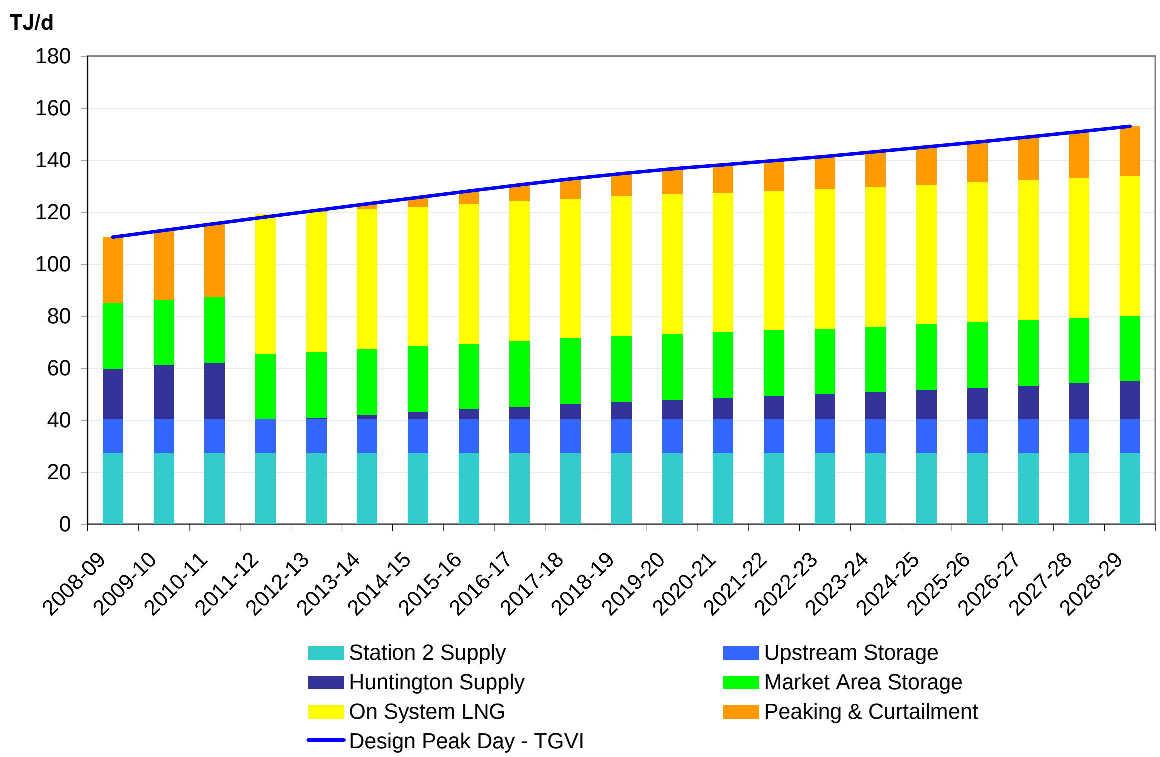


Figure 6-5 TGVI Long Term Supply Portfolio



Terasen Gas has very little certainty regarding long term cost and availability of storage assets. Market area storage is critical to maintaining peaking capability and cost-effective management of weather-dependent demand. Historically, Terasen Gas has purchased a significant portion of its regional storage needs from other PNW utilities who have earned returns on those facilities. As demand grows in their own service areas, these utilities will now be seeking to retain more of the capacity at these facilities for their own use. The majority of Terasen Gas' contracts for these facilities are short term in nature and therefore vulnerable to both renewal and price risks.

The Terasen Gas existing portfolios combined contain approximately 250 TJ/day of market area storage from Mist and Jackson Prairie storage facilities, which is primarily accessed through displacement contracts on the NWP system. Regional pipeline infrastructure constraints or addition of supply and infrastructure which change physical gas flows on the NWP system can potentially impede the ability to use storage displacement contracts. For example, without access to storage displacement contracts, Terasen Gas would need to contract for incremental firm redelivery NWP transportation capacity.

Another long term challenge relates to the significant reliance on supply and infrastructure at Station 2. The continued competition for northern B.C. supply has implications on the cost of Station 2 commodity purchases – the greater the competition for supply, the higher the Station 2 premium relative to the Alberta market price. The increased competition for supply is evident in the $0.25/GJ change in Station 2 winter premium from 2006 to 2008. Although a $0.25/GJ movement in Station 2 prices appears small, the cost implications for the Terasen Gas supply portfolios are significant. For example, TGI currently sources approximately 85% of baseload gas supply from Station 2.

Terasen Gas continues to monitor industry and regional developments that may affect long term gas procurement strategies. In addition to the requirement for incremental resources to meet future demand, access to natural gas infrastructure that enables supply source diversity is important to maintaining reliable cost effective service. The long term supply strategy will continue to build a gas supply portfolio that has a balanced mix of storage and transportation resources, enhances supply diversification, and actively procures cost competitive resource options.

6.2 Regional Supply Resources

6.3.1 Production Areas – Supply Update

The PNW sources natural gas supply from two major producing regions; the Western Canadian Sedimentary Basin straddling B.C. and Alberta, and the Rocky Mountain area in the mid-western U.S. Combined, the two production areas contain approximately 99 trillion cubic feet ("Tcf") of proven reserves and an ultimate resource potential of 500Tcf[18].

[18] As of December 31, 2005 – see Appendix C, NWGA Outlook Study p.9-10.

While natural gas production in Alberta is slightly declining, production in both B.C. and the U.S. Rockies is growing. In the past decade, B.C. production has increased by approximately 50%[19], contributing to stable Canadian production levels. In the Rockies basin, production has doubled over the same time period[20]. Although the continued growth in western production means supply is sufficient to meet long term needs in the PNW, the rapid addition of new pipeline capacity connecting these production areas to alternate North American markets is expected to intensify the competition for supply.

Over the longer term, access to alternate supply including northern frontier gas (Mackenzie, Alaska), unconventional resources, and import LNG is considered critical to meet future North American demand. Renewed interest in pipeline proposals to access Mackenzie and Alaska gas suggest these supplies could enter the market in approximately 10 years. The potential for domestic supply is vast when Canadian unconventional gas resources are considered. B.C. alone has significant and diverse supply resources including coal bed methane and tight/shale gas reserves of approximately 84Tcf and 550Tcf respectively[21]. Recent exploration in the Montney and Horne River Basins in northeast B.C. indicates possible massive reserves and the potential for shale gas to become a significant supply source, although the full extent of these resources is not yet fully understood. Appendix L provides additional detail on estimates of conventional and future reserves.

6.3.2 Planning for Regional Supply Infrastructure

6.3.2.1 Trends Affecting Resource Development in the PNW

A number of new trends and supply issues are emerging in the utilization of and planning for infrastructure in the PNW, resulting in a number of new infrastructure projects being proposed. Terasen Gas needs to monitor these trends and investigate its own regional resource planning options to meet the needs of its customers and interests of its stakeholders. Detailed descriptions of the following trends and their impact on the PNW supply resources are contained in Appendix L.

Similar to electricity supply, regional price disconnects can arise if transmission disruptions occur during high demand periods. Both the electricity and natural gas industries are challenged to ensure that the timing of infrastructure expansion leads demand.

Increasingly constrained regional infrastructure

The 2007 NWGA Outlook Study (Appendix C) identified that while regional infrastructure is being utilized very efficiently and currently meets the regions capacity needs, growing demand for both residential use and electricity generation is causing increasing capacity constraints in the existing infrastructure. This finding takes into account the characteristic weather

[19] BC Ministry of Energy Mines & Petroleum Resources and National Energy Board

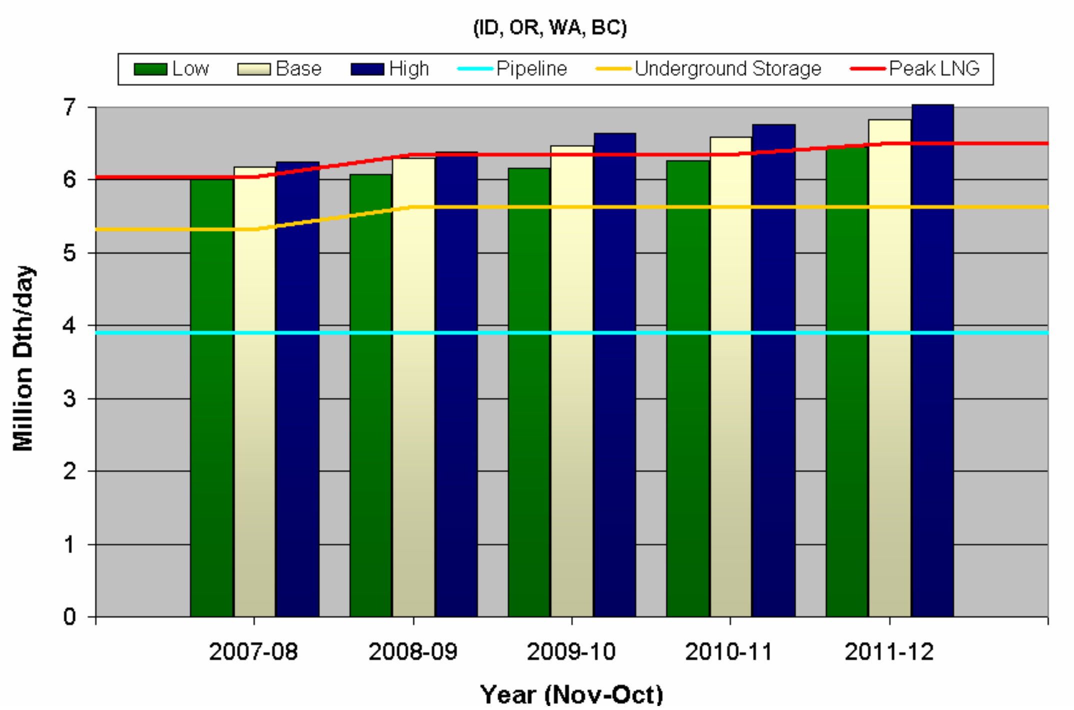
[20] US Energy Information Administration

[21] See Appendix C, NWGA Outlook Study p. 12.

dependency on peak day demand for these growing markets and the expectation that peak demand will grow more sharply than demand on a more typical day. Figure 6-6 shows that the regional infrastructure's ability to meet peak winter demand will be constrained by the end of the decade.

The current capability of regional infrastructure to meet peak day demand also assumes that there are no service outages or reductions anywhere in the system. If pipeline disruptions or compression failures were to occur during a region-wide peak demand period, regional capacity could fall below demand. Also, if a peak day were to occur near the end of a prolonged cold period during which storage withdrawals were necessary, regional storage delivery capacity could be reduced.

Figure 6-6 PNW Total Firm Peak Day Demand – Capacity Balance



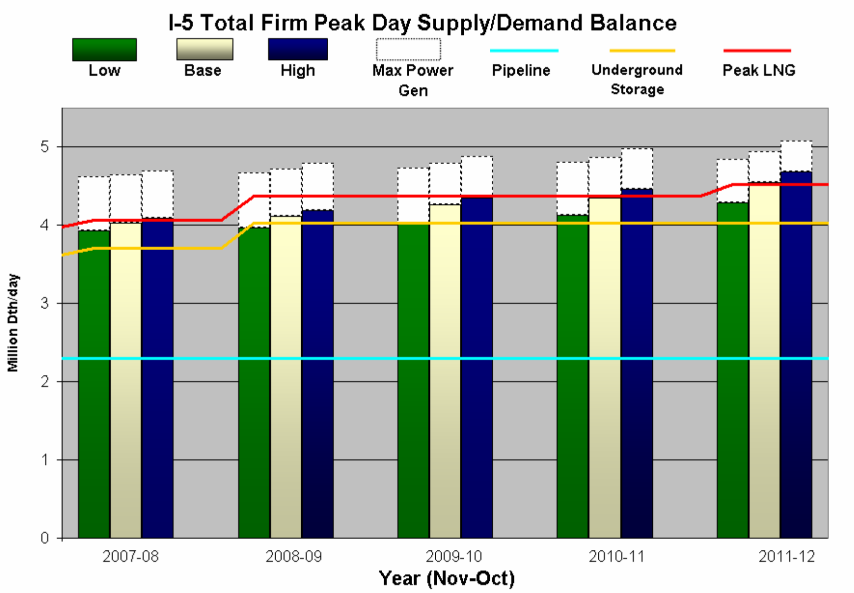
(Source: NWGA)

Over the longer term, the market will respond to these imbalances by increasing production and / or building required infrastructure, resulting in a reduction in regional price disconnects and price volatility. The increase in BC and Rockies production and an increase in regional infrastructure proposals as discussed later in the Chapter, are evidence that the market is beginning to respond to both growing North American demand and regional resource constraints.

Focus on Issues

Added constraints from regional generation demand

The regional supply / demand balance analysed in the 2007 NWGA Outlook Study includes demand from all firm natural gas fired electricity generation in the PNW. Not all existing generation facilities in the Region, however, hold firm electricity delivery contracts with customers or firm gas supply contracts. Electricity supply disruptions or other market forces in western North America could cause these resources to come on-line and compete for gas supply. The graph below shows the supply demand balance in the I-5 corridor if all gas fired generation in the Region (shown as Max. Power Gen.) were required to run. Demand then exceeds the capacity of regional infrastructure in all growth scenarios.

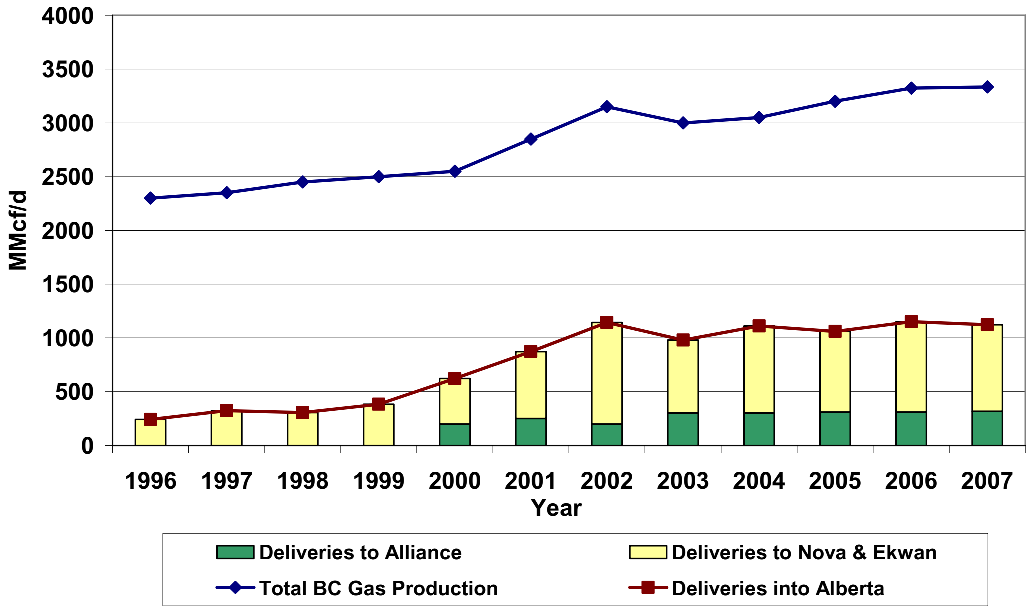


Since peak demand for both electricity and natural gas in the PNW is weather dependent, peak demand is expected to occur at approximately the same time. This uncontracted need for limited supply can create volatile market conditions by driving up spot prices and creating risk of supply shortage during peak demand periods. The addition of either base load resources (pipeline) and/or peaking resources (storage) within the region would help to alleviate this risk.

Diversion of Northern B.C. Supply

Increasingly, access to northern B.C. gas supply is being made available to markets in eastern North America and California through the development of new pipeline resources that can take northern B.C. production into the Alberta market. The result of these developments has been a reduction in contracted capacity and an increase in the use of interruptible capacity on Westcoast Pipeline.

Figure 6-7 B.C. Production and Flows into Alberta



Sources: BC Ministry of Energy Mines & Petroleum Resources, National Energy Board, TransCanada and Alliance

Increasing Demand from Gas Fired Electricity Generation

The marginal source of electricity generation in the PNW is natural gas, fueling either combined cycle base load plants or single cycle peaking plants. This growing reliance on gas-fired generation is expected to continue since regional electric utilities in the U.S. currently view natural gas as the preferred strategy to:

- minimize emission related cost risks associated with base load coal resources, and
- allow integration of more intermittent wind resources to meet targets under new renewable portfolio standards.

Electric utilities are now competing with gas utilities more than ever for limited regional gas supply infrastructure. As this trend continues, electricity and natural gas market prices will continue to converge. The need for integrated infrastructure planning becomes paramount to ensuring adequate resources in the region for delivering natural gas to meet requirements of both energy markets.

Increased Sourcing from the Rocky Mountain Supply Basin

Historically, Rockies gas has served western markets, including the PNW and California. With production growth exceeding take-away capacity growth, Rockies gas has been able to reach only a confined market. This limited market has created gas on gas competition which has kept prices low relative to the Sumas trading point where B.C. sourced production enters the PNW. U.S. utilities that have access to Rockies gas therefore maximize its use as a resource in their supply portfolio. The result is full capacity utilization of existing infrastructure delivering Rockies gas and use of other sources of supply to serve peaking demand and demand growth.

A further consequence of the competition for Rockies gas is the increase of westward gas flow to the I-5 corridor and northward toward the Sumas Huntingdon trading point using the existing regional pipelines. The increase in west and north flow is altering the more traditional southward flows on the William's Northwest Pipeline ("NWP") between Portland and the Huntingdon-Sumas trading point. This shift is increasing the likelihood of operational constraints on NWP and potentially impacting the utilization and contracting of other regional resources, including storage facilities and the Westcoast pipeline from northern B.C.

Reduced Supply 'Cushion' from Fuel Switching Capability of Regional Industry

The western energy crisis of 2000 and 2001 was a catalyst for permanent closures in both the aluminum and forest products industries throughout the western U.S. Portions of the western forest products industry have continued to struggle economically since that time, with continued closures of mills and other plants. Chapter 2 highlights the changing make-up of regional gas demand.

These large gas users typically had fuel switching capabilities and their supply could be curtailed during periods of high demand and constrained system capacity. Though seldom implemented, this capability provided an additional cushion in system capacity design. Regional demand is again approaching pre-crisis levels; however, this lost industrial load has been replaced with residential and electricity generation demand, both of which are weather sensitive demand. Not only has the Region lost some of the industrial curtailment 'cushion' historically depended on for supply capacity, but the growing demand today is also 'peakier'. These characteristics need to be considered in planning for new regional infrastructure.

6.3.2.2 Regional Infrastructure Development Proposals

Regional infrastructure projects being proposed to bring new supply sources and / or diversify supply for the PNW include new transmission pipelines, new or existing regional storage facilities and import facilities that can accept LNG imports from overseas. A number of pipelines under development or in proposal stages will also provide other markets with access to Rockies supply. Not all of these projects are expected to proceed; however, completion of one or more of the proposed projects has the potential to increase price volatility at the Huntingdon-Sumas trading point, thereby impacting Terasen Gas customers. Table 6-1 provides the proponents, supply – market interconnects and volume / energy details for each of these projects. These projects and their specific implications for supply in the PNW are more fully discussed in Appendix L.

Table 6-1 Proposed Natural Gas Pipeline Infrastructure Projects

Access to Rocky Mountain Production				
Pipeline Projects	**Market**	**Supply Source**	**Project Specifics**	**In-Service Timing**
Bison Pipeline **-** Northern Border Pipeline Company	US Midwest Chicago	Rockies	400 – 660 MMcf/d from Powder River Basin to Morton County North Dakota	2010
Bronco Pipeline - Spectra Energy	California	Rockies	1 Bcf/d from Rockies to Malin, Oregon	2011
Pathfinder Pipeline - TransCanada	US Midwest	Rockies	1.2 Bcf/d from Wamsutter Wyoming to Ventura and Chicago	2010
Rockies Alliance Pipeline - Alliance Pipeline & Questar	US Midwest, Central Canada	Rockies	1.2 – 1.8 Bcf/d from Rockies to Ventura and Chicago trading hubs	2011
Rockies Express Pipeline - Kinder Morgan, Sempra Energy, ConocoPhillips	US Midwest, Eastern	Rockies	1.8 Bcf/d from Rio Blanco County Colorado to Monroe County Ohio	2009
Ruby Pipeline - El Paso, Bear Energy, PG&E	California, Nevada, PNW	Rockies	1.2 Bcf/d (potentially 2 Bcf/d) from Opal Wyoming to Malin Oregon	2011
Sunstone Pipeline - Williams & TransCanada	California, Nevada, PNW	Rockies	1.2 Bcf/d from Opal Wyoming to Stanfield Oregon	2011
Access to LNG Import				
Pipeline Projects	**Market**	**Supply Source**	**Project Specifics**	**In-Service Timing**
Pacific Connector Gas Pipeline - Williams, Fort Chicago (Canada), PG&E	California, Nevada, PNW	Import LNG	1Bcf/d from proposed Jordon Cove import LNG terminal Coos bay Oregon to Malin Oregon	2011
Pacific Trails Pipeline - Galveston LNG & Pacific Northern Gas	Alberta	Import LNG	1 Bcf/d bi-directional pipe from proposed Kitimat LNG B.C. to Summit Lake B.C. connecting to existing	2010
Palomar Pipeline West **-** Oregon Pipeline	PNW	Import LNG	1 – 1.5 Bcf/d from proposed Oregon LNG import terminal Warrenton Oregon to Molalla Oregon	2012

Continued on next page.

New Supply for the Pacific Northwest				
Pipeline Projects	**Market**	**Supply Source**	**Project Specifics**	**Proposed In-Service Date**
Blue Bridge Pipeline - Williams & Puget Sound Energy	PNW	Rockies Alberta	~0.5 Bcf/d from Stanfield Oregon to points north along NWP existing pipeline corridor to PNW market	2011
Palomar Pipeline - TransCanada & Northwest Natural	PNW Western US	WSCB Rockies Import LNG	1.4Bcf/d bi-directional connecting NWN distribution system at Molalla Portland to GTN system in central Oregon, and to proposed Bradwood Landing LNG pipeline	2011

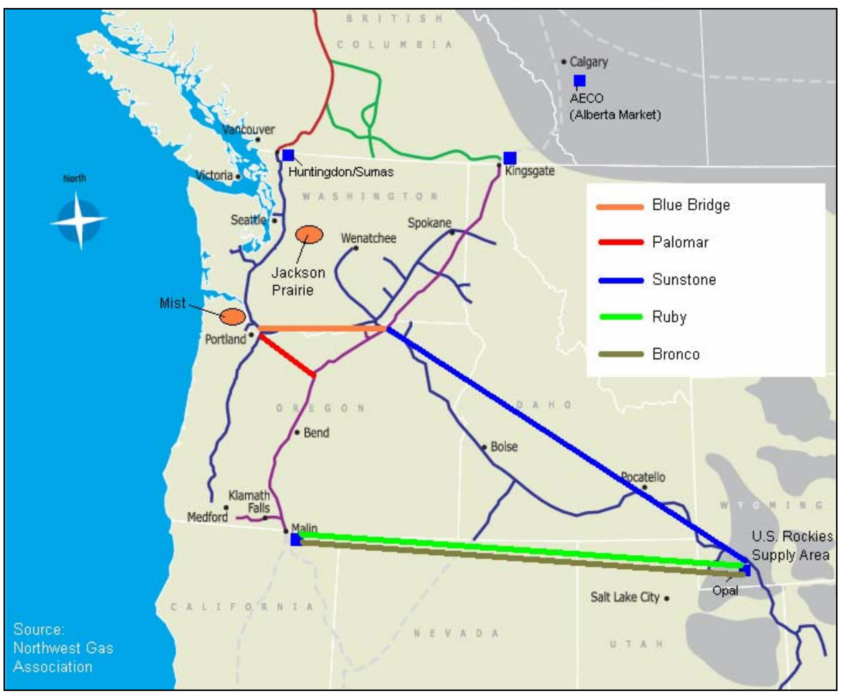
Increased Access to U.S. Rockies Production

The development of new pipelines to access Rockies production is highly competitive, intending to move large volumes of gas. Completing any two of these major projects would likely change Rockies pricing. The impact for the PNW is expected to be increased competition for supply and consequent increases in Rockies commodity prices.

Supply Diversification for the PNW

Three of the current pipeline proposals – these located within the PNW - aim to help alleviate the reliance on a single source of natural gas transmission service and offer the opportunity for diverse, cost-competitive supply. Each proposal has the potential to access incremental Alberta supply or Rockies production. Figure 6-8 provides a schematic representation of the supply regions and market interconnects that will result.

Figure 6-8 Current Regional Pipeline Proposals



Natural Gas Import Facilities

Import LNG has the potential to add a new source of supply to the PNW that would augment WCSB and Rockies production. Another driver of natural gas pipeline proposals in the PNW is the need for transmission associated with proposed import facilities in the region.

Regional Storage Projects

The NWGA analysis of resource requirements for peak day and extended winter demand throughout the region indicates the long term need for storage resources to meet the region's higher projected growth in weather sensitive demand. Utilities that currently own all or portions of existing facilities, and with whom Terasen Gas currently contracts for service, are expected to retain more of the capacity to meet their own needs as demand throughout the region grows. Recent investments to increase the region's storage capacity include expansions at Jackson Prairie and Mist storage facilities, and the approval to develop the Mt. Hayes storage facility on Vancouver Island. With growing demand, these projects have not fully satisfied the Region's future need for storage resources.

6.3.3 Terasen Gas On-System Resource Alternatives

In examining its response to these regional trends, Terasen Gas currently has two resource options available on its own system. In addition to helping solve regional capacity, diversity and reliability constraints, each of the Terasen Gas alternatives will ensure that these regional benefits reach its own customers and further improve the optimization of Terasen Gas' existing infrastructure.

6.3.3.1 Expansion of Southern Crossing Pipeline

This project would provide bi-directional gas flows between Terasen Gas' existing Southern Crossing Pipeline at Oliver, B.C. and the Huntingdon-Sumas trading point in the Lower Mainland on the B.C. - Washington border. Since Southern Crossing connects with TransCanada's BC System in south-eastern B.C., which delivers gas from the Alberta market hub, the proposed Inland Pacific Connector ("IPC") pipeline would connect supply availability between the Alberta and Huntingdon-Sumas trading points. The project will thus improve the diversity of supply available at Huntingdon Sumas. In addition, this project would improve the region's capability to use displacement to diversify supply options for shippers throughout the region.

Figure 6-9 shows the potential routing of IPC. Alternatively, this project could be interconnected with the Westcoast Pipeline, with the potential to further optimize both systems. Additional background and description of IPC is provided in Appendix M.

Figure 6-9 Proposed IPC Route Alternatives

6.3.3.2 Lower Mainland Regional Storage Facility

Another alternative available to Terasen Gas is the development of a new storage facility in the Lower Mainland. Such a facility would allow re-delivery during extreme or extended cold weather events, essentially providing an additional shaped supply resource. Since the facility would be located north of the Huntingdon-Sumas trading point, it would help to alleviate the risk of increasing prices and price volatility that a number of the other regional proposals could create. This facility would also allow Terasen Gas to utilize and optimize its own existing infrastructure.

A new storage facility in the Lower Mainland could also have important benefits for Terasen Gas customers that some of the other regional resource alternatives cannot provide. Approval of the Mt. Hayes facility was predicated in part on the renewal and cost risk associated with re-contracting for firm transportation and storage on the regions existing infrastructure. With increasing competition for the limited supply resources in the region, the risk of availability and cost increases to retain access to regional resources could continue to grow. In the event that displacement capacity on the NWP system is decreased or if supply on the Westcoast Pipeline becomes more expensive to source, additional storage near major load centres could become more critical. Given the weather dependent demand characteristics of Terasen Gas' customer base, additional cost-effective storage resources will be a valuable asset in Terasen Gas' supply portfolio alternatives.

6.3.3.3 Participation in Regional Resource Projects in another Jurisdiction

A third alternative for Terasen Gas in response to the wide range of current infrastructure proposals is to participate in a project or projects outside of its service territory that would ensure regional supply benefits for its own customers. Some of the regional resource projects being put forward could result in the exclusion of B.C. gas customers from the benefits associated with alleviating capacity constraints and improving supply diversity. Other projects could enhance regional supply availability and diversity for B.C. In addition to exploring resource alternatives connected to its own infrastructure, Terasen Gas may wish to participate in other regional projects in some way that will help ensure the success of projects that benefit B.C. customers.

6.3.4 Regional Infrastructure Conclusions and Recommendations

Sustained growth in natural gas demand and increasing regional production continue to change procurement strategies of utilities and the competitive environment for pipeline and storage access in the PNW. Constraints on regional pipeline and storage infrastructure are expected to impact the market by the end of the decade if new and diversified resources are not constructed. These constraints will make the PNW more vulnerable to price volatility and supply reliability concerns caused by changes in supply-demand balances relative to the Alberta market, where excess gas supply is drawn eastward and south. Terasen Gas needs to participate in or support the development of resources that provide optimal benefits for the entire region, including its own service territories, in order to ensure that those facilities consider the needs of Terasen Gas' customers.

Three alternatives exist for Terasen Gas to participate in regional resource development:

- connecting the Alberta and Huntingdon Sumas trading points via the IPC pipeline proposal,
- constructing additional gas storage facilities near the load centre in the Lower Mainland to provide shaped supply resources to the region and thereby avoid seasonal price volatility, and
- participate in another regional resource that will provide similar benefits throughout the PNW, including the Terasen Gas service territories.

Terasen Gas recommends further investigation into each of these alternatives in the near term in order to determine the appropriate longer term strategy for its participation in regional resource development.

7 ALTERNATIVE ENERGY OPPORTUNITIES

The energy planning landscape and trends described in Chapter 2 – growing demand, increasing energy costs and concerns about carbon emissions – have led to renewed interest in a wide range of clean and efficient energy alternatives. Terasen Gas has been developing proposals and opportunities to use the infrastructure and existing resources it already has in place to develop a number of potential alternative energy initiatives. These initiatives are important steps in helping to meet the policies of the B.C. Energy Plan and other provincial and regional energy objectives and in improving the efficiency and optimization of energy infrastructure in B.C.

Although the proposed initiatives discussed in this Chapter do not form part of a traditional resource planning portfolio for Terasen Gas, they do respond to the changing planning environment. The opportunities and initiatives discussed below include both demand and supply side resources. Terasen Gas has chosen to discuss them separately from other resources due to the unique nature and early stages of their development. This discussion provides stakeholders with examples of the types of activities Terasen Gas is undertaking to ensure that natural gas is being used as the right fuel in the right applications to help meet Provincial energy and carbon emission objectives.

7.1 Natural Gas Clean Transportation Opportunities

The 2007 BC Energy Plan ("Energy Plan") sets out a strategy for reducing greenhouse gas emissions and reducing human impacts on the climate. Transportation is a major contributor to climate change and air quality concerns. The use of conventional transportation fuels such as gasoline, diesel, propane and bunker fuel oil accounts for about 39% of B.C.'s GHG emissions[22], the single largest source of greenhouse emissions in the province.

Given its economic and environmental benefits over traditional fuels, natural gas can play a significant role in helping meet the GHG goals set out in the BC Energy Plan 2007 and the air quality goals of the Ministry of Environment. Examples of current technologies and initiatives in other jurisdictions provide an indication of the benefits that can be achieved in B.C. Terasen Gas is working with others in the NGV industry to identify and develop important new NGV initiatives here in B.C. that will help reduce carbon emissions and pollution.

This section describes a number of both near-term and long-term opportunities for the adoption of natural gas vehicles ("NGV") within the transportation industry. Near-term opportunities are defined those where the:

1) technology is proven and commercially available;
2) transition to natural gas technology for the end user is economically and environmentally viable; and
3) technology is supported.

[22] BC Ministry of Environment – based on 2004 data

Terasen Gas has identified near-term opportunities to shift from conventional fuels to NGV technology in a wide range of transportation sector applications such as heavy-duty truck fleets, port materials handling equipment, bus fleets, refuse haulers and port electrification.

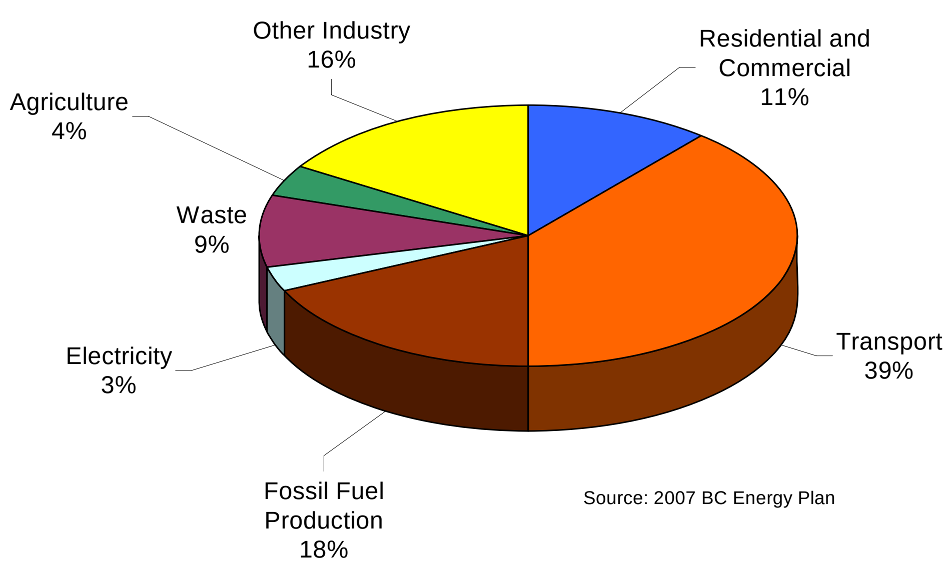
Long-term opportunities are those in which natural gas transportation technology exists, but is not yet commercially proven or available. Terasen Gas believes there are opportunities where natural gas technologies can be adopted in the transport sector for marine passenger vessels and in new light-duty return-to-home fleet or passenger vehicle technology.

The potential natural gas load growth discussed in these examples has not been included in the Terasen Gas demand forecasts due to the uncertainties that remain in capturing this market. As demonstration projects and first adopters in the province show success Terasen Gas expects that markets will begin to grow. As that occurs, Terasen Gas will endeavour to include load growth expectations from this market into its demand forecasts

Air Quality Benefits of Implementing NGV Technology

Figure 7-1 indicates that the single largest source of greenhouse gas in B.C. is the transport sector. Terasen Gas believes that this sector provides the greatest opportunity for greenhouse gas reductions.

Figure 7-1 B.C. Greenhouse Gas Emissions by Sector



Data from Natural Resources Canada indicates heavy-duty natural gas vehicles emit 15-30 % less GHG emissions than their diesel counterparts. Light-duty vehicles emit almost 30% less

GHG emissions compared to their gasoline equivalents. Natural gas vehicles also emit 50-80% less air quality contaminants such as NOx, SOx and particulate matter[23].

Economic Benefits of Implementing NGV Technology in BC

In terms of fuel costs, natural gas refueling prices at the pump in B.C. are currently up to 50% less than the gasoline equivalent[24]. The recently imposed carbon tax will also affect traditional petroleum fuels to a greater degree than natural gas. This operational cost savings can help to offset fleet conversion costs and in the long run can continue to provide operational efficiencies.

In terms of industry development, the Lower Mainland hosts a cluster of NGV technology expertise and businesses, including Terasen Gas, Westport Innovations, Cummins Westport, Clean Energy, Eco Fuels, MaxQuip, IMW Industries and Powertech Labs. Canadian companies are recognized worldwide as being leading providers of natural gas vehicle technologies and services. Implementing NGV technologies in B.C. will help to develop and support the long-term viability and health of this important industry. Figure 7-2 shows examples of natural gas fuel applications in heavy duty trucks and transit vehicles.

Figure 7-2 Examples of Natural Gas Fuel Technology in Heavy Duty Trucks

Class 8 LNG Truck

CNG Refuse Truck

CNG Articulated Bus

7.1.1 Near-Term Opportunities

7.1.1.1 Ports and Shipping Industry Applications

Heavy Duty Trucks

As a result of the new BC Energy Plan and specific goals in the Pacific Gateway Plan, the Ministry of Transportation ("MOT") and the Climate Change Secretariat are searching intensely for ways to clean up the emissions in British Columbia's Ports. Interest is growing in initiatives that are unfolding in California around truck and ship emissions as opportunities in British Columbia.

23 Emission comparisons cited here are available from NRCan GHGenius modeling software available at: http://www.oee.nrcan.gc.ca/transportation/tools/greenhouse-gas-info.cfm?attr=16

24 Based on March 26,2008 gasoline price of $1.20 /litre and CNG pump prices of $0.63 / GLE

San Pedro Bay Ports, operating in the Ports of Los Angeles and Long Beach, have developed an aggressive Clean Air Action Plan ("CAAP") which calls for the replacement of more than 16,000 old Class 8 diesel trucks with several thousand new trucks that operate using LNG fuel technology. The plan includes this and other clean fuel initiatives to meet specifications for reduced particulate matter ("PM") and nitrogen oxide ("NOx") emissions. This movement to cleaner LNG trucks, featuring LNG fuel systems developed and manufactured here in B.C. by Westport Innovations Inc., will result in significantly decreased greenhouse gasses, NOx and particulate emissions. Westport's LNG fuel system is the only alternative fuel technology currently qualified for financial support under the ports' clean truck program.
In the Port of Vancouver, Class 8 trucks are used for transporting containers to and from cargo ships to various hubs throughout the Lower Mainland for distribution throughout North America via rail or long-haul transport. The incremental cost of purchasing a Class 8 heavy-duty truck is approximately $75,000, however; the incremental cost can be offset by fuel savings and the environmental benefits.[25] The near-term business proposal for Class 8 heavy-duty trucks to operate on LNG is for short-haul point-to-point routes where a refueling station is located at one of the points. This is due to the infrastructure investment needed for refueling.

There are currently over 4,000 Class 8 trucks that frequent the Ports of Vancouver, 1,500 of these are regular visitors. Each truck uses approximately 2000 GJ / yr[26]. Terasen Gas believes that with government and industry support a market could be developed starting with a pilot project of 10 trucks, ramping up to 250 -500 trucks over the next 10 years with an estimated consumption is 500,000-1,000,000/GJ per year.

Materials Handling Equipment: Forklifts and Shunt Trucks

Most forklift fleets today use propane as an energy source; however, natural gas is a viable and cleaner alternative. Natural gas as CNG produces fewer emissions, is safer to handle, and is cheaper to operate. In the past five years over 1500 forklifts in the Province of Ontario have converted from propane to natural gas to capture fuel cost savings and air quality benefits[27].

A potential market exists in B.C. for the conversion of propane forklift and shunt trucks (container movers in shipping ports – see Figure 7-3) fleets to CNG. The conversion process includes converting the equipment to use CNG and installing compression and refuelling facilities at the customer premise. Third party vendors are available to provide both the conversion and compression services at either a capital cost to the customer or through a lease back program. By choosing a lease option, the customer will often see immediate savings. The customer may also be eligible for grants to help offset conversion costs. On average, third party vendors report a 15-40% savings on fuel costs for end users that have adopted CNG for their forklift fleets. Current Original Equipment Manufacture ("OEM") products are also available for both equipment types.

[25] U.S. DOE Alternative Fuel Price Report, October 2006.

[26] Information obtained through discussions with industry representatives.

[27] ibid

Figure 7-3 Shunt Truck

Terasen Gas estimates that a market opportunity exists for approximately 300-500 CNG forklifts and shunt trucks. On average each unit uses approximately 200 GJ/year, resulting in a market potential of approximately 60,000-100,000 GJ/year.

Focus on solutions

Natural Gas Fork Lifts

Terasen Gas with its technology partner FuelMaker is converting 100 forklifts from propane fuel to natural gas, for a trans-load shipping operator located in the Lower Mainland. On average a forklift consumes as much natural gas as a house or as much gas as two cars. Not only are forklifts cheaper to operate on natural gas than propane, but they produce well over 50% less smog and 90% less carbon monoxide, yielding great environmental, health, and safety benefits as most forklifts operate indoors.

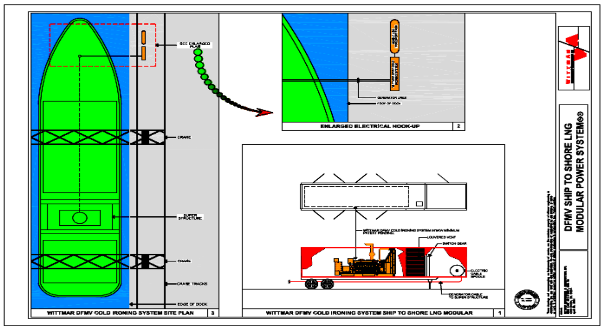
Cold Ironing

In 2004, the Greater Vancouver Regional District (now Metro Vancouver) identified that by 2006 marine activities would become the single largest producer of smog forming pollutants (NOx+SOx+VOC+PM2.5+NH3) in the Lower Fraser Valley.[28] By 2025, marine activities are anticipated to produce approximately three times more smog than light-duty vehicles.[29]

The primary contributor of air pollutants in British Columbia associated with marine activities occurs from ships while idling in port. When transport ships load and unload while in port - on average a two day process - they continue to burn their own fuel source, often bunker fuel, to run auxiliary engines and power electrical equipment such as navigation, ventilation, refrigeration, and other appliances. Providing shore power for ships (cold-ironing) is a possible solution to the emissions concerns resulting from marine activity. The Port of Oakland has recently completed testing, whereby generators that can run on either LNG or CNG to power the ships while in port. Figure 7-4 provides an illustration of the LNG cold-ironing process and a picture of the proof of concept demonstration at the Port of Oakland.

28 http://www.portvancouver.com/the_port/docs/Air_Quality_Management_in_the_GVRD.pdf
29 Ibid.

Figure 7-4 LNG Cold-Ironing Schematic and In-use Photo



Source: Clean Air Logix

Tests at the Port of Oakland indicate reductions of 94-100% in NOx, SOx, and PM10, and CO and CO2 reductions of 43% and 57% respectively, per 24 hour port call (see Table 7-1). This technology is now included in California regulations for shore power alternatives for ships.

Table 7-1 Pollutant Reductions: Port of Oakland - LNG Cold-Ironing

APL POLLUTION REDUCTION EFFORTS AND RESULTS

	Statistics for a 24 Hour Port Call in Oakland				
	2006	2007	LATE 2007		
Fuel Type	2.5% Sulfur Diesel	0.5% Sulfur Diesel	Wittmar DFMV Cold Ironing w/ RML	Reduction	%
NOx	1059 Pounds	1059 Pounds	56 Pounds	94.71	%
CO	79 Pounds	79 Pounds	34 Pounds	56.96	%
PM10	29 Pounds	15 Pounds	0.02 Pounds	99.93	%
SOx	358 Pounds	72 Pounds	0 Pounds	ELIMINATED	
CO2	42,651 Pounds	42,651 Pounds	24,430 Pounds	42.72	%
Fuel Consumption	1,906 Gallons of Diesel	1,906 Gallons of Diesel	2,813 Gallons of RML		

Source: Clean Air Logix, Port of Oakland, Proof of Concept

Terasen Gas continues to closely monitor the developments in California shore power initiatives. Terasen Gas believes that in the next five years there is a potential for three generators at the Port of Vancouver. The estimated consumption would be 300,000 GJ/ year for all three units.

7.1.1.2 Transit Buses

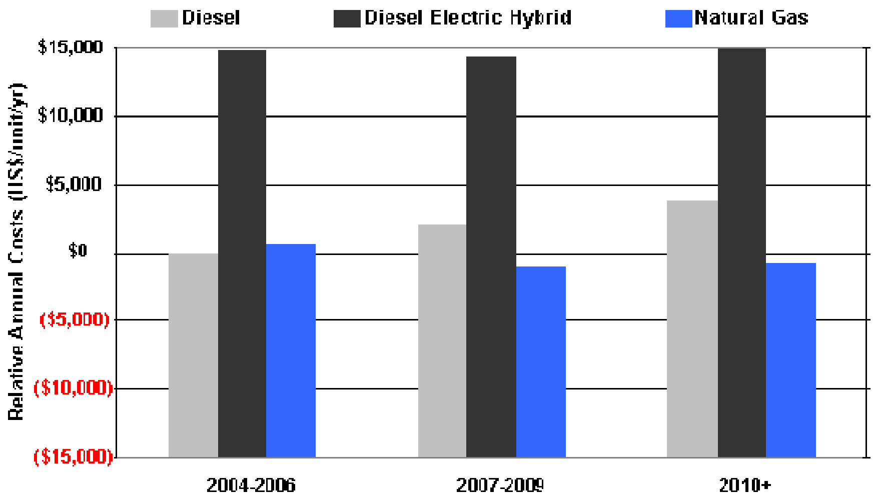
Commercially available OEM engines exist that allow transit buses to operate on CNG. Cummins Westport's ISLG 2007 natural gas engine is already certified to meet 2010 Environmental Protection Agency (EPA) and California Air Resources Board (CARB) emissions standards. This engine is the cleanest heavy-duty commercial technology available.

The incremental cost of purchasing a CNG powered bus over its diesel counterpart is approximately $50,000[30]. The incremental cost is offset by the environmental benefits and

30 ibid

lower fuel costs. Figure 7-5 illustrates estimated annual capital and operating cost of CNG buses against diesel and diesel electric hybrid buses.

Figure 7-5 Annual Capital and Operating Costs



The City of Los Angeles has more than 2000 CNG buses, accounting for 94% of their total fleet. In B.C., there are currently 75 CNG buses, (4% of fleet) which operate out of the Port Coquitlam transit hub and are operated by Coast Mountain Bus Company. In January 2008, the Premier of British Columbia in conjunction with the Minister of Transportation announced a $14 billion transportation plan that called for 1500 new clean technology buses. CNG is among the five technologies being considered for this plan.

Given the current policy direction for clean transportation technology, Terasen Gas anticipates there are opportunities over the next seven years, for an additional 150 CNG buses. An additional 150 buses would result in a total of 300,000 GJ/year or 2,000 GJ per bus per year. The total estimated number of transit buses in B.C. greater than 2200.

7.1.1.3 Refuse Trucks

Refuse trucks operating on CNG use the same engine technologies as transit buses. The use characteristics of these vehicles are similar to that of bus fleets. As a result, the economic and environmental benefits of operating a refuse fleet on CNG are similar to those of operating bus fleets on CNG.

Smithtown, Long Island, NY, a suburb of New York City, has recently replaced its entire refuse fleet of 24 trucks to CNG. Smithtown has reported a significant reduction in operating costs, a

20% reduction in greenhouse gas emissions, quieter trucks operating in residential neighbourhoods, and improved breathing conditions for operators.[31]

The most significant challenge with adopting CNG is fleet portability. Many B.C. municipalities outsource their waste hauling contracts through a bid process with contract periods ranging for 3-5 years. If an operator loses a contract in an area after adopting a CNG fleet, it may be costly to move the refueling systems if they have to re-deploy their fleet to another jurisdiction.

With government incentives, and continued municipality commitment to reduce greenhouse gas emissions, this challenge can be overcome. Terasen Gas anticipates that one or two pilot projects can be developed to include approximately 25 CNG refuse trucks using approximately 35,000 GJ/yr or 1,400 GJ per truck per year.

7.1.2 Long-Term Opportunities

7.1.2.1 Light-Duty Fleet & Passenger Vehicles

The successful business model for light-duty fleet and passenger vehicles is similar to the model for heavy-duty trucks. Due to limited refueling infrastructure, vehicles must either operate as a return-to-home fleet with dedicated refueling or operate within an area with retail refueling infrastructure. A significant hurdle in pursuing return to home fleets is the lack of OEM vehicles available in Canada. Terasen Gas believes the majority of CNG fleets over the next 3-5 years will be as a result of converting existing gasoline vehicles to bi-fuel vehicles (run both on natural gas and gasoline).

Vehicles converted in B.C. are predominately converted using a standard EPA approved kit. Depending on the vehicle type, conversions cost approximately $4,000-$7,000[32], and customers are eligible for grants of up to $2500 under Terasen Gas' Rate Schedule 6. The cost of conversion can be offset by the reduced commodity cost of natural gas versus gasoline. Terasen Gas is not aware of any significant fleet conversions to CNG bi-fuel. However, if a lifecycle emission analysis approach similar to that adopted in California is adopted in B.C. there may be significant opportunity to develop a CNG vehicle market for couriers, taxis, delivery vehicles and other light-duty fleets.

Terasen Gas believes that any success in this CNG market segment would have to be driven by CNG OEM engine manufacturers. Terasen Gas is, however, closely following the recent successes of the natural gas powered Honda Civic GX in California and New York State, and is closely monitoring the OEM CNG vehicles manufactured in Europe.

31 http://www.nytimes.com/2006/07/30/opinion/nyregionopinions/30LIunderwood.html?_r=1&ref=nyregionopinions&oref=slogin

32 ibid

7.1.2.2 Marine Passenger Vessels

Current technology exists to build ships that can operate on LNG instead of diesel. Given the current energy planning environment and emphasis on greenhouse gas reduction, Terasen Gas believes that in the long term an opportunity may arise to use LNG to operate passenger vessels in British Columbia. Terasen Gas efforts to make LNG available to truck fleets will provide valuable experience as the potential for operating fleet vessels in B.C. is more closely examined.

7.1.3 Standing Tariff for the Sale of LNG

To help open the market for LNG as a fleet fuel, Terasen Gas expects to apply for the approval of a standing tariff for the sale of LNG from its Tilbury LNG peakshaving facility within the coming year. Initially, the tariff would allow for up to 1040 GJ per day (11,700 gallons of LNG) to be sold to customers within the Terasen Gas service territory from the Tilbury facility. As the market for LNG in the fleet transportation sector grows, Terasen Gas will build the necessary infrastructure to support its growth. Infrastructure may include 50,000 to 80,000 gallon storage tanks at Tilbury to facilitate moderate growth and a new LNG facility at either the existing Tilbury site or an alternative location if the market demand justifies the investment.

7.1.4 Natural Gas Vehicle Grants

Under Rate Schedule 6, TGI offers promotional grants towards the cost to purchase factory-built natural gas vehicles, or the cost to convert vehicles to natural gas. The amount of the grant is up to $10/GJ, based on estimated consumption over a one year period, up to a maximum total grant by vehicle type as outlined in Table 7-2.

Table 7-2 Rate Schedule 6 Vehicle Grants

Vehicle Description	GVW (Pounds)	Maximum Grant
Light Duty	< 10,000	$ 2500
Medium Duty	< 17,000	$ 5,000
Heavy Duty	>17,000	$10,000

Terasen Gas may also fund Special Demonstration project grants for innovative applications of natural gas used in vehicles that can be used to demonstrate the technology and promote natural gas as a fuel source for the particular application. The total funds available under the Special Demonstration project grants are $100,000 per year.

7.2 Alternative Supply - Opportunities to Capture Energy from Waste

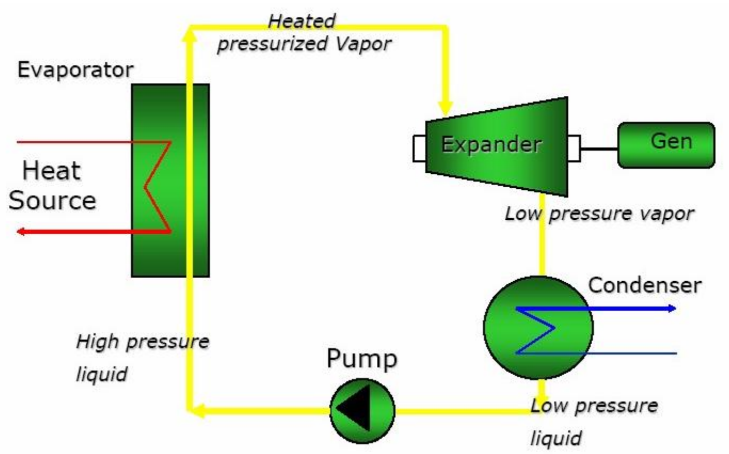
Terasen Gas' initiatives in alternative energy supplies support the 2007 BC Energy Plan objectives of energy conservation and efficiency, innovation to create clean and renewable energy, and developing leadership in clean energy generation. Terasen Gas is examining opportunities that leverage existing gas infrastructure to increase the production of clean energy, and improve the transportation and use of energy in B.C. Two innovative opportunities to capture usable, clean and renewable energy from waste that Terasen Gas is pursuing are the capture of waste heat from compressor station operation and the capture of biogas (natural gas) from waste produced in agricultural processes, sewage treatment plants and potential landfill sources.

7.2.1 Waste Heat Recovery Electricity Generation

TGVI is evaluating a potential project for capturing waste energy from the exhaust heat of compressor units at its Coquitlam Compressor Station to generate electricity. The existing Coquitlam Compressor Station increases pipeline pressure to transport natural gas from the Lower Mainland to the Sunshine Coast and Vancouver Island. These compressor units are driven by natural gas fired turbines. The exhaust from the turbines is vented to the atmosphere at a relatively high temperature (about 950 ^{o}F) and this waste heat could be captured and transformed into electricity with existing technology. Since this heat energy is currently being lost as part of ongoing operations, there will be no carbon or other emissions that result from the electricity production.

Generating electricity from recovered heat employs two separate technologies. Heat recovery technology captures the waste heat and transfers it a heating fluid through heat exchangers. The heated fluid then drives a turbine, or expander, which is coupled to a generator. Figure 7-6 explains the process schematically. Appendix N provides a more detailed description of the both the heat recovery and generation processes.

Figure 7-6 Waste Heat Recovery and Generation Schematic



Project Benefits

The electricity generated is a clean energy since it is captured from waste heat with no additional use of fuel. Since the electricity produced at the site can be delivered to the grid through existing distribution lines that currently service the facility, new transmission lines can be avoided. Other environmental impacts such as noise, line of sight, and water quality issues are avoided as the project will be developed within an existing facility. The project will provide an overall balance of energy efficiency, environment & economy.

This potential project is expected to generate about 3.2 MW of electrical power capacity and approximately 15,000 to 18,700 MWh per year of clean energy – enough to meet the electrical demand for 1,500 to 1,800 homes in the Lower Mainland. At this level of power generation, the project will qualify for sales to BC Hydro under the Standing Offer Program. Income from electricity sales would offset the project costs to the benefit of TGVI ratepayers.

A number of other benefits for TGVI and the province can be realized. The project will:

- help meet the BC Energy Plan objectives of self sufficiency and net zero GHG emissions;
- displace over 13,510 tonnes[33] CO2e of GHG emissions per annum compared to imported electricity;
- optimize the energy used to deliver natural gas to TGVI and improving overall energy efficiency in the province;
- provide electricity in close proximity to B.C.'s largest load centre with a peak seasonal generation profile that matches the needs of BC Hydro's winter peak demand; and
- use known engineering principles and proven technologies to ensure project success.

Terasen Gas will continue to examine the technical and economic requirements of this project as well as sources of potential funding to assist with its implementation. Discussions with BC Hydro are underway to ensure the project can meet the specifications of the Standing Offer Program, and appropriate applications will be brought forward as the project's technical and economic feasibility become certain.

7.2.2 Biogas Upgrading

Another opportunity that Terasen Gas is investigating to reduce carbon emissions, increase energy efficiency and optimize existing energy infrastructure is the potential for new, green sources of natural gas. Biogas – methane produced through the processing of animal and other organic wastes – has potential to be brought into the Terasen Gas pipeline system, mixed with other more traditional supplies of natural gas and sold to customers as a more sustainable, lower impact alternative. Biogas can be combined with traditional natural gas supplies to create cleaner and lower GHG intensive energy alternatives.

[33] Based on GHG emission factor of 855 tonne CO2e/GWh for a 560 MW greenfield thermal coal plant at the Hat Creek site, as stated in BC Hydro 2006 IEP, Appendix F, 2005 Resource Options Report

Biogas is primarily manufactured through the process of anaerobic digestion of plant and animal waste. At this time, Terasen Gas has identified three alternative sources of potential biogas resources in B.C. that it might be able to access: methane produced by anaerobic digestion from agricultural waste and / or crop and animal processing industries, methane produced as a natural by-product in municipal sewage treatment systems and methane produced within solid waste landfill sites as waste materials break down beneath the soil.

7.2.2.1 Agricultural Biogas

British Columbia's agricultural system appears to be sufficiently large enough to develop opportunities for biogas production and upgrading. Terasen Gas is currently in the early stages of gathering information and talking with industry experts to help understand the magnitude and challenges of the biogas opportunity.

A recent study commissioned by the B.C. BioProducts Association identified 2,500 terajoules annually of economically viable biogas produced from agricultural waste available in the Fraser Valley region of British Columbia. This represents enough energy to displace the annual natural gas usage in 25,000 B.C. homes.

7.2.2.2 Methane Produced at Municipal Wastewater Treatment Plants

Biogas is also produced through anaerobic digestion as part of the treatment process at many municipal wastewater treatment plants. As such these plants are potential suppliers of biogas. Similar to biogas produced from agricultural waste, the biogas from wastewater treatment plants would require upgrading to meet pipeline quality standards.

Although the total potential biogas available from sewage treatment plants in B.C. has not yet been quantified, Metro Vancouver has determined that its sewage treatment plants alone have the potential to produce 740,000 GJ of pipeline quality carbon neutral gas or enough gas to heat 7,400 homes. Terasen Gas is currently working with Metro Vancouver on a potential demonstration project at the Lions Gate Treatment Plant to demonstrate the viability of upgrading biogas to pipeline quality gas that can be injected into the Terasen Gas system. The Company also continues to evaluate other biogas potential across B.C.

7.2.2.3 Landfill Gas

The B.C. Bioenergy Strategy released by the provincial government in February 2008 indicated that the government will develop legislation to phase in requirements for methane capture at landfills, the source of about nine per cent of B.C.'s greenhouse gas emissions. This methane could be used for clean energy. With the requirement to capture the methane produced at landfill sites there is an opportunity to upgrade the landfill gas to pipeline quality and inject it into the gas delivery infrastructure. Terasen Gas will continue to assess the feasibility of incorporating landfill gas production areas from across the Province into B.C.'s natural gas supply.

Developing Biogas Supply

Terasen Gas has applied for funding under the Innovative Clean Energy (ICE) Fund to develop a biogas upgrading demonstration project at Metro Vancouver's Lions Gate Waste Water Treatment Plant.

The project would provide enough carbon neutral gas to displace the natural gas usage of over 100 homes and CO2e reduction equivalent to removing 165 passenger vehicles from the road.

7.2.2.4 Developing Biogas as an Alternative Supply

One of the primary concerns for gas utilities interested in the potential of biogas is the quality and heat content of the gas produced. Terasen Gas is working with the agricultural and municipal waste sectors, as well as biogas upgrading equipment manufacturers to develop a biogas upgrading project in which the lessons learned could be used to develop future large scale projects. Such projects could help reduce the greenhouse gas emissions by capturing the methane, upgrading it and using the upgraded product as an energy source rather than being flared or vented into the atmosphere.

Terasen Gas is also evaluating various options as to how biogas will be incorporated into its supply portfolio. Current options under investigation include, using the carbon neutral gas to offset greenhouse gas emissions from compressor and other operating equipment, provide customers an opportunity to pay a premium to purchase biogas as an alternative fuel source, or incorporate the biogas into the core gas supply portfolio. Terasen Gas' objectives are to continue evaluating the biogas potential and if feasible, to help develop this new potential industry sector to allow for biogas sales, offering customers as a more sustainable augmentation to natural gas supply that will allow for a reduction in the overall carbon footprint.

7.3 Alternative Energy Systems

Alternative energy systems for space and water heating have been discussed in Chapter 2 and Appendix D in relation to the competitive position of natural gas. However, natural gas can also be an important component of these types of systems in serving both individual homes and neighbourhoods through district energy systems. Development of these technologies can also lead to the growth of distributed electricity generation facilities and technologies, which can help to meet Provincial objectives for electricity sustainability and the development of new clean and efficient sources of supply.

Terasen Gas recognizes that alternative energy systems and technology have become a part of the energy planning landscape in B.C. and that there is no single solution to meeting the growing demand for energy in the province. Hence, utilities need to examine all of the ways that both new and traditional technologies can be combined to create a diverse and robust energy portfolio for B.C and the Region.

Heat Pumps / Geo-exchange Systems

Ground source heat pumps ("GSHP") are a form of geo-exchange system. These systems can be installed in single family applications, multi-family developments and district energy systems (discussed below). Air source heat pumps are another space heating and cooling technology, although more applicable for single family applications. Both types of systems are typically installed along with a secondary or back-up energy system that is typically either an electric or a natural gas system. These systems continue to gain popularity in B.C. due to their high efficiency and more recently to home owner desires to reduce their end-use carbon footprint.

As the name implies, geo-exchange or geo-thermal systems use heat pump technology to exchange heat energy between ground, groundwater or surface water resources and the living or working environment in buildings. There also appears to be growing interest in some urban areas for heat pump technology that utilizes waste heat from other municipal systems such as sewers and sewage treatment. Geo-exchange systems are most often used for building heating and cooling and hot water and the conditions for successfully implementing this technology are very regional and site specific.

More and more, developers and community planners appear to be looking to hybrid systems that combine geo-exchange technology with other forms of both new and traditional energy technologies. These systems can be designed with building use and regional weather characteristics in mind to provide an optimal mix of energy efficiency, reduced emissions, system reliability and life cycle costs. Potential opportunities exist to leverage natural gas infrastructure to employ a range of hybrid systems for single family homes, multi-family developments and communities. Terasen Gas continues to examine the potential for such systems in its service regions where they can benefit customers, help to optimize existing infrastructure and address government policies on energy and climate change.

High-Efficiency District Energy Systems

High efficiency gas boiler technology can be combined with hydronic heating systems to improve system efficiency, reliability and life cycle costs even further. Hydronic heating systems - the circulating of heated water from a centralized source to facilitate the distribution of space heating and hot water – are a long-established and proven technology. Combined with geo-exchange and / or high efficiency gas boiler technology, these systems can provide reliable and cost-effective distribution of energy for multi-unit developments or even multi-use communities, at some of the highest possible efficiencies. The Lonsdale Energy Corporation in North Vancouver provides an example of effectively implementing this type of distributed systems by supplying an entire mixed use, downtown area of the Municipality. New high density residential, community centre and business customers continue to be added to this highly efficient system that is expected to serve 3 million square feet of building space within 10 years.[34]

District energy technology is also one way of combining natural gas with other emerging renewable technologies to create a highly efficient, sustainable and reliable mixed energy platform for growing communities. As new, renewable sources of energy are developed for a community, they can be easily exchanged within the existing district energy infrastructure, making the mixed energy platform flexible to future technologies.

Dockside Green set to become North America's first greenhouse gas neutral community.

At Dockside Green in Victoria B.C., a biomass gasification energy system is being employed to deliver energy to the community. The system creates low-cost heat through a thermo-chemical process known as 'starved air combustion'. This ultra-clean technology transforms locally sourced wood waste – municipal tree trimmings, mill scraps, pine-beetle damaged lumber – into energy. The process provides sufficient heat to create clean 'syngas'. Burned in a boiler just like natural gas, syngas will create heat for space and hot water needs for the 1.3 million square feet of Dockside Green's residential, office, retail and industrial space. In future, a sewer waste heat recovery system may also supplement the biomass system and utilize an otherwise wasted energy source.

New Metering Technologies

Growth in hydronic systems and district energy technologies is also creating a need for investment in new metering technologies in the same way that the need for individual metering in multi unit dwellings. Measuring the flow of heat and other energy to individual users in a district energy system is essential for the fair and efficient distribution of the resource and the energy costs. Terasen Gas recently received approval to develop and implement a thermal metering pilot project to assess the distribution of energy use in multi unit developments that use hydronic heating. BC Hydro has received approval for funding advanced Smart Meter technologies to improve efficiencies and help manage electricity demand. Continued investment in metering technology improvements will improve energy efficiency overall, lower the total carbon footprint in B.C. and the PNW and address Provincial energy policies.

[34] Visit the City of North Vancouver's web site at www.cnv.org for more information on Lonsdale Energy Corporation.

Distributed Generation

Small scale power generation systems and equipment located at or near the end-use is a growing choice in some regions of North America. Used primarily in commercial, industrial or institutional applications, these systems can provide peak shaving and fuel switching benefits as well as improvements in power quality and reliability for sensitive applications and remote locations.

Distributed generation equipment typically relies on traditional fuels such as natural gas at relatively high efficiencies and low emissions. However, technology advancements are allowing the use of alternate fuels such as lower quality recovered gas from industrial processes and biogas from landfills, wastewater treatment and agricultural operations. In B.C., many of the potential sources of biogas would be insufficient on their own to drive micro-turbine generators, however, when combined with pipeline supplied gas this type of generation can significantly reduce GHG emissions over the venting of biogas directly into the atmosphere.

Distributed generation provides some potentially significant benefits to the regional energy mix in circumstances where the generation facility is close to the electrical distribution network. Excess generation capacity can be supplied to the electrical distribution grid. BC Hydro, for example, does enter net metering arrangements with this type of Independent Power Producer, which can use the excess power sales to further offset energy costs. Where sufficient generation capacity can be supplied in this way, distributed generation has the potential to partially offset the need for new electrical transmission and distribution infrastructure. Natural gas can also play an important role in combined heat and power technology, which generates electricity and utilizes waste heat energy in highly efficient distributed generation applications.

Looking further into the future, improvements renewable energy technologies such as wind, run-of-river, and solar alternatives could add to the growth in distributed generation in locations where strict emission controls are in place or desired by the community. New systems, small enough and quiet enough to work in the home are being developed in Europe. Incentives from federal, provincial and local municipal governments as well as some utilities for pilot projects and implementing new technologies might speed the growth of distributed generation. Terasen Gas is ideally positioned to investigate viability of distributed generation in clean energy applications using its existing infrastructure and expertise.

7.4 Alternative Energy Conclusions

These opportunities are just a few of the emerging solutions to meet the provinces growing demand for energy and reduce the provinces carbon footprint. As a forward thinking energy utility, Terasen Gas will continue to identify alternative energy opportunities that improve efficiencies, facilitate renewable technology development and reduce carbon emissions. Where these opportunities benefit customers, help meet B.C. energy policies and utilize or optimize existing energy infrastructure, Terasen Gas will continue to investigate and pursue them.

In the transportation sector, replacing conventional transportation fuels such as diesel and gasoline provide a significant opportunity to help the province reduce greenhouse gas emissions associated with the transportation sector. The technology is proven and immediately available. To help facilitate the development of a market for natural gas in the transportation sector, Terasen Gas is undertaking a number initiatives including:

- the development of a standing tariff for the sale of LNG for use in the transportation sector,
- the provision of grants to help offset the incremental cost of natural gas vehicles,
- new technology demonstration grants, and
- working with industry partners and government lobby efforts for policy and incentive legislation.

Potential new load resulting from these initiatives is not yet considered in Terasen Gas' demand forecast; however, as markets for NGV technology in B.C. develop, the trends in load growth will be monitored and included.

Other alternative opportunities that are emerging for Terasen Gas include developing biogas projects as an alternative and renewable natural gas supply; capturing waste heat from natural gas compressors to produce electricity; and developing the use of alternative energy systems and advanced metering technologies. Terasen Gas will continue to investigate opportunities to develop these alternative, renewable supplies over the coming months for potential inclusion in utility system resource additions and supply portfolios.

8 STAKEHOLDER CONSULTATION

Stakeholder needs and concerns are critical to resource planning. More than simply facilitating open communication, effective stakeholder consultation provides insights that can impact the entire planning process, from trends that influence demand forecasting and DSM analysis through to the development of an action plan for implementing preferred planning solutions. Terasen Gas has a record of conducting effective stakeholder consultation programs and continues to do so in preparing this plan.

Terasen Gas considers stakeholder consultation for resource planning to be an ongoing process and an element of many stakeholder activities we undertake for a broad range of purposes. In addition to conducting planned events to share information and gather feedback specific to the Resource Plan, information from other community, customer and stakeholder engagement informs the planning process. In many cases, Terasen Gas has been able to combine focused discussion of resource planning issues with other community and energy industry consultation. For example, consultation efforts in support of Terasen Gas' new EEC Application (Appendix H), provided an opportunity to talk to stakeholders about energy planning issues affecting the Resource Plan and vice versa. Stakeholder input on previous resource plans also continues to influence the development of the current plan.

A modest increase in the level of interest in Terasen Gas' Resource Plan among stakeholders has been noted. Though not statistically evaluated, a higher attendance from a broader range of stakeholders has been noted during the 2008 Resource Plan Workshops than for previous plans. Terasen Gas attributes this increase to a growing level of interest and knowledge in energy issues resulting from rising energy costs, energy security and climate change concerns and the work that all B.C. utilities have been doing to educate stakeholders and the broader public.

Regional energy planning issues are also at the forefront of the planning landscape in B.C., since energy supplies and transmission resources are linked across political boundaries and other jurisdictions are now facing similar challenges to those in this province. Terasen Gas has sought to understand the energy challenges and alternatives in neighbouring jurisdictions and consider the implications for planning across the region. Consultation therefore continues to include participation from organizations in other parts of the PNW and Terasen Gas participation in regional activities outside of B.C.

Terasen Gas has continued to nurture relationships with municipalities and First Nations throughout its service territories and have included these important stakeholders in resource planning consultation activities. Representatives have regularly participated in various municipal association conferences and in 2008 have distributed Resource Planning Update newsletters to these and other stakeholders. Terasen Gas conducts ongoing First Nations consultation pursuant to the company's statement of principles and commitment to respect the social, economic and cultural interests of First Nations[35].

[35] Visit http://www.terasengas.com/_AboutUs/OurCommitments/AboriginalRelations/default.htm for more information.

8.1 Resource Plan Stakeholder Workshops and Presentations

In addition to ongoing discussions with a range of stakeholder groups, Terasen Gas held resource planning specific workshops and presented stakeholder information through the winter and spring of 2008 as shown in Table 7-3.

Table 7-3 Summary of Resource Plan Specific Stakeholder Events

Event & Date	Issues Presented / Discussed	Audience	Attendees / Respondents
Stakeholder workshop / presentation Lower Mainland **February 12, 2008**	- Background to Resource Planning - Terasen Gas service and value initiatives - Energy Efficiency and Conservation - - Supply needs and market challenges - Trends and issues in demand for natural gas - Potential alternative clean and renewable energy opportunities being examined by Terasen Gas	Email and mail invitations were sent to stakeholders and stakeholder groups including: - customers & business - municipal & provincial government & BCUC - environmental and energy related non government organizations (NGO) - Interveners who regularly participate in Terasen Gas filings - Other energy utilities in B.C and the PNW.	33 people attended including customer, government, BCUC, utilities, NGO and Intervenor representatives
Customer Advisory Council meeting and Resource Plan Stakeholder workshop Lower Mainland **April 29th, 2008**	- Energy planning issues and challenges including 2007 B.C. Energy Policy, potential climate change and energy legislation, and regional planning issues - Customer service issues - Carbon Tax Implications - Upcoming Regulatory Calendar - Resource planning process and objectives - Gas competitiveness in B.C. - Demand forecasts and future scenarios - Resource Development needs and opportunities - Draft Action Plan and next steps	Email invitations were sent to over 700 individuals representing: - customers & business - municipal & provincial government & BCUC - environmental and energy related non government organizations (NGO) - Interveners who regularly participate in Terasen Gas filings - Other energy utilities in B.C and the PNW.	61 confirmed attendees including customer, government, BCUC, utilities, NGO and Intervenor representatives
Presentation to the Southern Interior Local Government Association Vernon, B.C. **May 1, 2008**	An overview of B.C. and regional energy planning issues, gas demand and supply trends, potential resource requirements and issues, and alternative energy opportunities at Terasen Gas	Municipal Mayors, Councillors and staff	100 to 150 representatives

Event & Date	Issues Presented / Discussed	Audience	Attendees / Respondents
Presentation to the North Central Municipal Association Prince George, B.C. **May 8, 2008**	An overview of B.C. and regional energy planning issues, gas demand and supply trends, potential resource requirements and issues, and alternative energy opportunities at Terasen Gas	Municipal Mayors, Councillors and staff	100 to 150 representatives

Issues raised by stakeholders during the 2008 workshops and presentations generally followed the pattern of topics presented by Terasen Gas staff. These issues included:

- Regional implications of energy choices being made in B.C. and elsewhere in the PNW;
- Implications of the B.C. carbon tax, proposed cap and trade mechanisms and other climate change related policies and regulations;
- Land prices, geographic limitations and social perceptions are having a large impact on choices in housing type;
- Risks to supply upstream of the Terasen Gas transportation and distribution systems;
- New infrastructure proposals to provide new access to gas production areas and trading markets and the implication for BC customers;
- New EEC programs and strategy under development by Terasen Gas and the imperative that increased EEC programming be implemented;
- Competitiveness of natural gas against other fuels and other energy system alternatives – stakeholders wanted to see a more thorough analysis of natural gas systems against heat pumps, for example;
- How energy use trends and new energy policies and legislation might affect demand for natural gas;
- How can gas service be provided to communities beyond the edge of Terasen Gas' current service limits;
- Is there long-term viability risk to the utility as a result of climate change concerns and potential drastic GHG emission reduction steps; and
- Is Terasen Gas encountering perceptions that it is not viewed as part of the solution to B.C.'s energy and climate change challenges?

8.2 Consultation with Other Energy Utilities

Terasen Gas maintains open, consultative communications with other energy utilities in B.C. and the PNW. Since the 2005 and 2006 Resource Plans, Terasen Gas has continued to participate in the consultation opportunities and regulatory process of both BC Hydro and Fortis BC. Terasen Gas participates on Puget Sound Energy's Integrated Resource Planning Advisory Group, which provides and opportunity for dialogue with a number of utilities and energy industry representatives regarding regional issues.

8.3 Customer Advisory Consultation

TGI's 2008 spring Customer Advisory Council meeting was combined with Terasen Gas' second Resource Planning Stakeholder Workshop on April 29th. This provided an opportunity for customer representatives to discuss specific business issues affecting customers as well as the energy planning issues addressed in the Resource Plan. It also provided the context in which Terasen Gas was able to provide information on the implications of B.C.'s new Carbon Tax, Terasen Gas' new EEC strategy and upcoming regulatory submissions.

8.4 Business and Energy Industry Consultation

Terasen Gas took a number of business and industry opportunities to discuss the role of natural gas in B.C.'s energy planning landscape. Specific events included participating as a panel member at Canadian Institute of Energy discussions on DSM programming in March, 2008 and Right Fuel Symposium in May, 2008[36]. Terasen Gas representatives also presented information on planning issues at the BC Natural Gas Symposium hosted by the Canadian Institute in May, 2008. On regional energy planning issues, Terasen Gas also participates in stakeholder consultation activities hosted by the Northwest Power and Conservation Council, the Pacific Northwest Economic Region, the Canadian Gas Association and the Northwest Gas Association and other organizations on an ongoing basis. Various resource planning related issues were also discussed within the following presentations made by senior Terasen Gas staff:

- February 25, 2008 - BC Chamber of Commerce Energy Summit
- March 12, 2008 - BC Power Summit
- April 17, 2008 - Developer Conference (Kelowna)
- April 29, 2008 - Customer Advisory Council
- May 22, 2008 - Gaining Ground Summit (Victoria)
- May 28, 2008 – Canadian Gas Association

8.5 Future Consultation Opportunities for Stakeholders

Terasen Gas will continue to share Resource Planning information and recommendations with stakeholders throughout its service territories and more broadly within the PNW. Planning for continued consultation with targeted and interested groups concerning potential infrastructure

[36] www.cienergy.org

projects will be developed and implemented through the remainder of 2008 and into 2009. Consultation activities will also be conducted in regard to additional or next generation EEC programming that might be brought forward between now and the next Resource Plan filing, likely in mid-2010. Terasen Gas representatives will also continue to participate in energy related stakeholder opportunities hosted by other utilities and organizations in B.C. and the PNW.

9 ACTION PLAN

The Action Plan describes the activities that Terasen Gas intends to pursue over the next four years based on the information and recommendations provided in this Resource Plan.

1. *Implement the new EEC programs and continue research and planning for future EEC programming.*

Once BCUC Approval has been received for the additional EEC funding, Terasen Gas will proceed with implementing the new programming. The May, 2008 EEC application also includes undertaking a new CPR, which Terasen Gas will also initiate. Terasen Gas will continue to monitor EEC program trends across B.C. and across North America to identify further opportunities beyond the current application to intensify EEC activities in accordance with Provincial directives.

2. *Participate in FortisBC and BC Hydro resource planning processes.*

In order to understand the interrelated resource needs of each utility Terasen Gas will continue to participate as a stakeholder in the resource planning activities of both FortisBC and BC Hydro. The FortisBC Resource Plan is expected to confirm the preferred resource portfolio for meeting future electricity demand in the Okanagan and southern interior region of B.C. This portfolio is expected to have implications for TGI's resource requirements on the ITS. BC Hydro's 2008 LTAP was released in June, 2008 and Terasen Gas is continuing to review and assess its full implications for planning at Terasen Gas.

3. *Influence provincial and regional energy and climate related policy development.*

Terasen Gas will continue to liaise with policy makers and energy planners in the B.C. and the Region to ensure that the benefits and importance of natural gas in both the provincial and regional energy mix are a high priority.

4. *Continue monitoring and evaluating system expansion needs in the Okanagan area.*

TGI has identified an approaching constraint in the Okanagan area of the ITS. TGI will work with FortisBC to confirm the potential for demand from a new gas fired peaking facility in this area to accelerate the timing of ITS expansion requirements. If the new peaking facility is included in FortisBC's preferred resource portfolio, TGI will fully examine the available resource alternatives. Demand requirements from such a facility could result in the need to submit a CPCN for facility expansion in the near-term.

5. *Prepare and submit CPCN applications for near-term distribution system requirements.*

Terasen Gas will continue to plan for and prepare CPCN applications for the replacement of two compressor units at TGVI's V1 compressor station in Coquitlam and the rehabilitation of TGI's crossing of the South Arm of the Fraser River.

6. *Monitor and investigate the development of regional pipeline and storage infrastructure alternatives.*

Terasen Gas will continue to liaise with those parties proposing new regional resources in order to more fully establish and evaluate Terasen Gas alternatives and opportunities. This activity will include continued investigation into resource alternatives available to Terasen Gas to develop on-system resources in response to regional gas supply and resource trends. Namely, Terasen Gas will continue to investigate the potential for expanding / extending Southern Crossing Pipeline service from the interior region into the Lower Mainland, as well as the potential benefits of increasing on-system natural gas storage in the Lower Mainland. This activity also includes consideration of participation in other regional resource proposals that can ensure similar benefits for Terasen Gas customers.

7. *Identify and pursue innovative clean energy initiatives and funding for made in B.C. solutions in natural gas vehicles, biogas development, waste heat, advanced metering technologies and other alternative energy uses, supplies and systems.*

Terasen Gas will continue to identify and pursue a range of clean energy alternatives that will help improve the overall efficiency of energy use in B.C. and reduce GHG emissions in both B.C. and the Region.

GLOSSARY

AC – air conditioning.

AFUDC – allowance for funds used during construction.

Annual demand – the cumulative daily demand for natural gas over an entire year.

Bcf – billion cubic feet.

BCH – BC Hydro.

BCUC (British Columbia Utilities Commission) – the BCUC is the provincial body regulating utilities in British Columbia.

BTUH – British thermal units per hour.

CAAP – Clean Air Action Plan – developed to significantly reduce health risks posed by air pollution from port related sources at San Pedro Bay and the Ports of Los Angeles and Long Beach in California.

CAFÉ – Customer Attachment Front End information system – implemented by Terasen Gas.

CIAC – contributions in aid of construction.

CMHC – Canada Mortgage & Housing Corporation.

CNG – compressed natural gas.

Cogeneration – in this document, cogeneration refers to the generation of both electrical and thermal power simultaneously by utilizing the waste heat from a gas turbine to generate steam.

Commission – see BCUC.

Compression, compressor station – the application of increased pressure to a natural gas pipe system to create gas flow. Higher levels of compression can be applied to increase the carrying and storage capacity of the pipe. Increased pressure is applied through a compressor station constructed along the pipeline.

COP – coefficient of performance.

Core, core customers, and core market – residential, commercial and small industrial customers that have gas delivered to their home or business (bundled sales). Terasen Gas purchases natural gas and delivers it to the customer in a bundled sales rate. Core Market customers typically use a significant portion of their gas requirements for heating applications, resulting in weather sensitive demand.

CPCN (Certificate of Public Convenience and Necessity) – a Certificate of Public Convenience and Necessity (a “CPCN”) is a certificate obtained from the British Columbia Utilities Commission under Section 45 of the Utilities Commission Act for the construction and/or operation of a public utility plant or system, or an extension of either, that is required, or will be required, for public convenience and necessity.

CPR (Conservation Potential Review) – a study completed to identify opportunities for energy savings across gas and electrical energy delivery infrastructures and improvements to overall energy utilization efficiency.

CTS – Coastal Transmission System.

Curtailment – the planned interruption of gas supply to interruptible customers during periods of high demand for natural gas – usually during extreme cold weather events.

Daily demand – the amount of natural gas consumed by Terasen Gas’ customers throughout each day of the year.

DC – Destination Conservation.

Demand forecast – a prediction of the demand for natural gas into the future for a given period and under a specified set of expected future conditions.

Demand side, Demand Side Management (DSM) – defined as “any utility activity that modifies or influences the way in which customers utilize energy services”. From Terasen Gas’ perspective, the primary objectives of DSM are to increase the overall economic efficiency of the energy services it provides to customers and maintain the competitive position of natural gas relative to other energy sources.

Design-day, design hour demand (see also: peak day) – the maximum expected amount of gas in any one day or hour required by customers on the TGI system. Since Core customers' demand is primarily weather dependent, design-day or design-hour demand is forecasted based upon a statistical approach called Extreme Value Analysis, which provides an estimate of the coldest day weather event expected with a 1 in 20 year return period. For transportation customers, the design-day is equivalent to the firm contract demand. (See also: peak day).

Dth – deca therm – approximately equal to 1 GJ.

EBP – Efficient Boiler Program.

EEC – Energy Efficiency Conservation.

EES – earth energy system.

EER – energy efficiency ratio.

EGD – Enbridge gas distribution.

EIA – section of the U.S. Department of Energy (DOE) providing statistics, data, analysis on resources, supply, production, consumption for all energy sources.

EPA – Electricity Purchase Agreement.

ETO – Energy Trust of Oregon.

GDP – gross domestic product.

GHG – greenhouse gas.

GJ – Gigajoule – a measure of energy equivalent to one billion joules. One joule of energy is equivalent to the heat needed to raise the temperature of one gram (g) of water by one degree Celsius (ºC) at standard pressure (101.325 kPa) and standard temperature (15ºC).

GLE – gasoline litre equivalent.

GLJ – GLJ Petroleum Consultants Ltd. is a private petroleum industry consultancy serving clients who require independent advice relating to the petroleum industry, including the preparation of natural gas and oil price forecasts on a quarterly basis.

GSHP – ground source heat pumps - a form of geo-exchange system.

GTN – Gas Transmission Northwest.

GWh – giga-watt hours.

HDD – Heating degree day – a measure of the coldness of the weather experienced. The number of heating degree days for a given day is calculated based on the extent to which the daily mean temperature falls below a reference temperature, 18 degrees Celsius.

HSPF – heating seasonal performance factor.

Huntingdon/Sumas – gas flow regulating stations on either side of the British Columbia / US border through which much of the regional gas supply is traded

I-5 Corridor – the natural gas regional market area served by infrastructure located along Interstate 5 in the north western US. The I–5 Corridor includes B.C.'s Lower Mainland and Vancouver Island, Western Washington and Western Oregon.

ICP – Island Cogeneration Project – a cogeneration plant located at Elk Falls, Campbell River supplying electricity and thermal energy on Vancouver Island.

IEP – Integrated Electricity Plan – BC Hydro's 2006 Integrated Resource Plan.

ILM transmission project – interior to Lower Mainland electrical transmission project being developed by BCTC to serve BC Hydro Lower Mainland load.

IMP – Integrity Management Plans.

IPP – Independent Power Producers.

IP system – intermediate pressure - pipeline operating pressure between 100 and 30 psig.

Interruption – see curtailment.

IRP – Integrated Resource Plan – see Section 1 for a detailed description of Resource Planning. An integrated resource plan is a document that details the resource planning process and outcomes that guide a utility in planning to serve its customers over the long term.

ITS – Interior Transmission System.

JPS – Jackson Prairie Storage.

JV – Joint Venture – see Vancouver Island Gas Joint Venture.

KKpa – kilopascals.

kW (kilowatt) – One thousand watts; the commercial unit of measurement of electric power. A kilowatt is the flow of electricity required to light 10 100-watt light bulbs.

kWh (kilowatt hour) – One thousand watts used for a period of one hour; the basic unit of measurement of electric energy. On average, residential customers in B.C. use about 10,000 kWh per year.

LNG (Liquefied natural gas), LNG storage – natural gas stored under high pressure turns to liquid form. Approximately 600 times as much natural gas can be stored in its liquid state than in its typical gaseous state; however, specialized storage facilities must be constructed.

LNG Import Terminals – terminals that receive lliquefied natural gas that is shipped in large tankers from overseas. LNG Import terminals are considered supply resources not storage resources.

Load – the total amount of gas demanded by all customers at a given point in time.

Looping – the twinning of sections of gas supply transportation pipe to improve storage and flow characteristics within the service area.

LP – low pressure.

LTAP – BC Hydro's Long Term Acquisition Plan which identifies the preferred resources, both supply and demand that the utility intends to acquire over the long-term to serve the growing demand for electricity in BC.

MFD – multi family dwelling.

MMCF – 1 million cubic feet.

MMcfd – 1 million cubic feet per day.

MOP – maximum operating pressure.

MoT – Ministry of Transportation.

MW (mega watt) – One million watts; one thousand kilowatts. A unit commonly used to measure both the capacity of generating stations and the rate at which energy can be deliver delivered.

NGV – natural gas vehicles.

Normal demand (also called annual demand) – when considering historical normal demand, this is the actual demand experience that has been adjusted to account for weather that has been colder/warmer than normal. The expected demand during a year of normal weather conditions. When considering forecast normal demand, this is the expected demand under normal weather conditions. Normal weather conditions are based on a rolling 10 year average of heating degree days experienced during each of the 10 years.

NPCC – Northwest Power and Conservation Council.

NPS – nominal pipe size.

NWGA – NorthWest Gas Association is a trade organization of the Pacific Northwest natural gas industry. Its members include six natural gas utilities, including Terasen Gas, serving communities in Idaho, Oregon, Washington and British Columbia, and three interstate pipelines that move natural gas from supply basins into and through the region.

NWN – Northwest Natural – a gas utility operating in the Pacific Northwest Region.

NWP – Northwest Pipeline.

OEM – original equipment manufacture.

OGC – Oil and Gas Commission of BC.

PBR – performance based regulation.

Peak day, peak demand, peak day demand – the maximum expected amount of gas in any one day or hour required by customers on the TGI system. Since Core customers' demand is primarily weather dependent, design-day or design-hour demand is forecasted based upon a statistical approach called Extreme Value Analysis, which provides an estimate of the coldest day weather event expected with a 1 in 20 year return period. For transportation customers, the design-day is equivalent to the firm contract demand. (See also: design-day)

PG & E – Pacific Gas & Electric Company.

PGE – Portland General Electric.

PJ – petajoule – equal to 1000 terajoules or 10^6 gigajoules.

PM – particulate matter.

PNW – Pacific Northwest Region.

PNWER – Pacific Northwest Economic Region.

Portfolio, resource portfolio, supply portfolio – selected supply and / or demand resources that, when grouped together, can meet the future demand and supply needs of a service area.

PPF – public purpose fund.

PSE – Puget Sound Energy.

psig – pounds per square inch gauge.

PUC – Public Utility Commission.

Rate volatility – the amount to which natural gas rates fluctuate and the frequency of those fluctuations.

Resources – demand side and supply side means available to meet forecasted energy needs. Examples of supply side resources within the context of the Resource Planning process are Pipeline Looping, Compression and Storage. Examples of demand side resources are industrial customer curtailment and load management programs for residential and commercial customers.

REUS – Residential End Use Study.

SCADA System Upgrade – supervisory control & date acquisition.

SCGT – simple cycle gas turbine.

SCP – Southern Crossing Pipeline.

SEER – Seasonal Energy Efficiency Ratio - used to rate the efficiency of heat pumps and air conditioning units.

SFM – single family dwelling.

SH – supplemental heat.

Tcf – trillion cubic feet.

TCPL – TransCanada Pipeline.

TGI – Terasen Gas Inc.

TGVI – Terasen Gas Vancouver Island.

TGW – Terasen Gas Whistler.

TJ – terajoule – equal to 1000 gigajoules.

Transportation customers – customers who purchase natural gas directly from producers or brokers and pay the utility a fee to deliver the gas from the city gate to the meter at their facilities.

UCA Act – Utilities Commission Amendment Act.

UEC – unit energy consumption.

VIGJV (Vancouver Island Gas Joint Venture) – a joint venture of industrial customers (primarily large mills) on Vancouver Island who contract for transportation services as a single entity.

WCSB – Western Canadian sedimentary basin.

APPENDIX A

Bill 15 – Utilities Commission Amendment Act
Excerpt from the Utilities Commission Act - Section 44 & 45
BCUC Resource Planning Guidelines

APPENDIX A-1
Bill 15 – Utilities Commission Amendment Act

2008 Legislative Session: 4th Session, 38th Parliament
THIRD READING

Certified correct as passed Third Reading on the 8th day of April, 2008
Ian D. Izard, Q.C., Law Clerk

HONOURABLE RICHARD NEUFELD
MINISTER OF ENERGY, MINES AND PETROLEUM RESOURCES

BILL 15 — 2008
UTILITIES COMMISSION AMENDMENT ACT, 2008

HER MAJESTY, by and with the advice and consent of the Legislative Assembly of the Province of British Columbia, enacts as follows:

1 Section 1 of the Utilities Commission Act, R.S.B.C. 1996, c. 473, is amended by adding the following definitions:

"demand-side measure" means a rate, measure, action or program undertaken

(a) to conserve energy or promote energy efficiency,

(b) to reduce the energy demand a public utility must serve, or

(c) to shift the use of energy to periods of lower demand;

"government's energy objectives" means the following objectives of the government:

(a) to encourage public utilities to reduce greenhouse gas emissions;

(b) to encourage public utilities to take demand-side measures;

(c) to encourage public utilities to produce, generate and acquire electricity from clean or renewable sources;

(d) to encourage public utilities to develop adequate energy transmission infrastructure and capacity in the time required to serve persons who receive or may receive service from the public utility;

(e) to encourage public utilities to use innovative energy technologies

(i) that facilitate electricity self-sufficiency or the fulfillment of their long-term transmission requirements, or

(ii) that support energy conservation or efficiency or the use of clean or renewable sources of energy;

(f) to encourage public utilities to take prescribed actions in support of any other goals prescribed by regulation;

"transmission corporation" has the same meaning as in the *Transmission Corporation Act*; .

2 Section 2 (4) is amended by striking out "1 to 3 and 5 to 13" ***and substituting*** "1 to 13"***.***

3 Section 3 is repealed and the following substituted:

Commission subject to direction

3 (1) Subject to subsection (3), the Lieutenant Governor in Council, by regulation, may issue a direction to the commission with respect to the exercise of the powers and the performance of the duties of the commission, including, without limitation, a direction requiring the commission to exercise a power or perform a duty, or to refrain from doing either, as specified in the regulation.

(2) The commission must comply with a direction issued under subsection (1), despite

(a) any other provision of

(i) this Act, except subsection (3) of this section, or

(ii) the regulations, or

(b) any previous decision of the commission.

(3) The Lieutenant Governor in Council may not under subsection (1) specifically and expressly

(a) declare an order or decision of the commission to be of no force or effect, or

(b) require the commission to rescind an order or a decision.

4 Section 5 is amended

(a) by adding the following subsection:

(0.1) In this section, **"minister"** means the minister responsible for the administration of the *Hydro and Power Authority Act.* ,

(b) in subsection (3) by adding "British Columbia or" ***after*** "enactment of", ***and***

(c) by adding the following subsections:

(4) The commission, in accordance with subsection (5), must conduct an inquiry to make determinations with respect to British Columbia's infrastructure and capacity needs for electricity transmission for the period ending 20 years after the day the inquiry begins or, if the terms of reference given under subsection (6) specify a different period, for that period.

(5) An inquiry under subsection (4) must begin

(a) by March 31, 2009, and

(b) at least once every 6 years after the conclusion of the previous inquiry,

unless otherwise ordered by the Lieutenant Governor in Council.

(6) For an inquiry under subsection (4), the minister may specify, by order, terms of reference requiring and empowering the commission to inquire into the matter referred to in that subsection, including terms of reference regarding the manner in which and the time by which the commission must issue its determinations under subsection (4).

(7) The minister may declare, by regulation, that the commission may not, during the period specified in the regulation, reconsider, vary or rescind a determination made under subsection (4).

(8) Despite section 75, if a regulation is made for the purposes of subsection (7) of this section with respect to a determination, the commission is bound by that determination in any hearing or proceeding held during the period specified in the regulation.

(9) The commission may order a public utility to submit an application under section 46, by the time specified in the order, in relation to a determination made under subsection (4).

5 Section 22 is repealed and the following substituted

Exemptions

22 (1) In this section:

"eligible person" means a person, or a class of persons, that

(a) generates, produces, transmits, distributes or sells electricity,

(b) for the purpose of heating or cooling any building, structure or equipment or for any industrial purpose, heats, cools or refrigerates water, air or any heating medium or coolant, using for that purpose equipment powered by a fuel, a geothermal resource or solar energy, or

(c) enters into an energy supply contract, within the meaning of section 68, for the provision of electricity;

"minister" means the minister responsible for the administration of the *Hydro and Power Authority Act*.

(2) The minister, by regulation, may

(a) exempt from any or all of section 71 and the provisions of this Part

(i) an eligible person, or

(ii) an eligible person in respect of any equipment, facility, plant, project, activity, contract, service or system of the eligible person, and

(b) in respect of an exemption made under paragraph (a), impose any terms and conditions the minister considers to be in the public interest.

(3) The minister, before making a regulation under subsection (2), may refer the matter to the commission for a review.

6 Section 43 (1) is repealed and the following substituted:

(1) A public utility must, for the purposes of this Act,

(a) answer specifically all questions of the commission, and

(b) provide to the commission

(i) the information the commission requires, and

(ii) a report, submitted annually and in the manner the commission requires, regarding the demand-side measures taken by the public utility during the period addressed by the report, and the effectiveness of those measures.

(1.1) The authority, in addition to providing the information and reports referred to in subsection (1), must provide to the commission, in accordance with the regulations, an annual report comparing the electricity rates charged by the authority with electricity rates charged by public utilities in other jurisdictions in North America, including an assessment of whether the authority's electricity rates are competitive with those other rates.

7 The following sections are added:

Long-term resource and conservation planning

44.1 (1) In this section, **"demand increase"** means the greater of

(a) the difference between

(i) the sum of the estimate referred to in subsection (4) (b) and a prescribed amount, if any, and

(ii) the demand the authority would serve during the period referred to in subsection (4) (b) if the demand in each year of that period remains equal to the demand referred to in subsection (4) (a), and

(b) zero.

(2) Subject to subsection (4), a public utility must file with the commission, in the form and at the times the commission requires, a long-term resource plan including all of the following:

(a) an estimate of the demand for energy the public utility would expect to serve if the public utility does not take new demand-side measures during the period addressed by the plan;

(b) a plan of how the public utility intends to reduce the demand referred to in paragraph (a) by taking cost-effective demand-side measures;

(c) an estimate of the demand for energy that the public utility expects to serve after it has taken cost-effective demand-side measures;

(d) a description of the facilities that the public utility intends to construct or extend in order to serve the estimated demand referred to in paragraph (c);

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

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

(g) any other information required by the commission.

(3) The commission may exempt a public utility from the requirement to include in a long-term resource plan filed under subsection (2) any of the information referred to in paragraphs (a) to (f) of that subsection if the commission is satisfied that the information is not applicable with respect to the nature of the service provided by the public utility.

(4) A long-term resource plan filed under subsection (2) by the authority before the end of the 2020 calendar year must include, in addition to everything referred to in subsection (2) (a) to (g), all of the following:

(a) a statement of the demand for electricity the authority served in the year beginning on April 1, 2007, and ending on March 31, 2008;

(b) an estimate of the total demand for electricity the authority would expect to serve in the period beginning on April 1, 2008, and ending on March 31, 2021, if no new demand-side measures are taken during that period;

(c) a statement of the demand-side measures the authority would need to take so that, in combination with demand-side measures taken by the government of British Columbia or of Canada or a local authority, the demand increase would be reduced by 50% by 2020.

(5) The commission may establish a process to review long-term resource plans filed under subsection (2).

(6) After reviewing a long-term resource plan filed under subsection (2), the commission must

(a) accept the plan, if the commission determines that carrying out the plan would be in the public interest, or

(b) reject the plan.

(7) The commission may accept or reject, under subsection (6), a part of a public utility's plan, and, if the commission rejects a part of a plan,

(a) the public utility may resubmit the part within a time specified by the commission, and

(b) the commission may accept or reject, under subsection (6), the part resubmitted under paragraph (a) of this subsection.

(8) In determining under subsection (6) whether to accept a long-term resource plan, the commission must consider

(a) the government's energy objectives,

(b) whether the plan is consistent with the requirements under sections 64.01 and 64.02, if applicable,

(c) whether the plan shows that the public utility intends to pursue adequate, cost-effective demand-side measures, and

(d) the interests of persons in British Columbia who receive or may receive service from the public utility.

(9) In accepting under subsection (6) a long-term resource plan, or part of a plan, the commission may do one or both of the following:

(a) order that a proposed utility plant or system, or extension of either, referred to in the accepted plan or the part is exempt from the operation of section 45 (1);

(b) order that, despite section 75, a matter the commission considers to be adequately addressed in the accepted plan or the part is to be considered as conclusively determined for the purposes of any hearing or proceeding to be conducted by the commission under this Act, other than a hearing or proceeding for the purposes of section 99.

Expenditure schedule

44.2 (1) A public utility may file with the commission an expenditure schedule containing one or more of the following:

(a) a statement of the expenditures on demand-side measures the public utility has made or anticipates making during the period addressed by the schedule;

(b) a statement of capital expenditures the public utility has made or anticipates making during the period addressed by the schedule;

(c) a statement of expenditures the public utility has made or anticipates making during the period addressed by the schedule to acquire energy from other persons.

(2) The commission may not consent under section 61 (2) to an amendment to or a rescission of a schedule filed under section 61 (1) to the extent that the amendment or the rescission is for the purpose of recovering expenditures referred to in subsection (1) (a) of this section, unless

(a) the expenditure is the subject of a schedule filed and accepted under this section, or

(b) the amendment or rescission is for the purpose of setting an interim rate.

(3) After reviewing an expenditure schedule submitted under subsection (1), the commission, subject to subsections (5) and (6), must

(a) accept the schedule, if the commission considers that making the expenditures referred to in the schedule would be in the public interest, or

(b) reject the schedule.

(4) The commission may accept or reject, under subsection (3), a part of a schedule.

(5) In considering whether to accept an expenditure schedule, the commission must consider

(a) the government's energy objectives,

(b) the most recent long-term resource plan filed by the public utility under section 44.1, if any,

(c) whether the schedule is consistent with the requirements under section 64.01 or 64.02, if applicable,

(d) if the schedule includes expenditures on demand-side measures, whether the demand-side measures are cost-effective within the meaning prescribed by regulation, if any, and

(e) the interests of persons in British Columbia who receive or may receive service from the public utility.

(6) If the commission considers that an expenditure in an expenditure schedule was determined to be in the public interest in the course of determining that a long-term resource plan was in the public interest under section 44.1 (6),

(a) subsection (5) of this section does not apply with respect to that expenditure, and

(b) the commission must accept under subsection (3) the expenditure in the expenditure schedule.

8 Section 45 (6.1) and (6.2) is repealed.

9 Section 46 is amended

(a) in subsection (3) by striking out "The commission" ***and substituting*** "Subject to subsections (3.1) and (3.2), the commission"***, and***

(b) by adding the following subsections:

(3.1) In deciding whether to issue a certificate under subsection (3), the commission must consider

(a) the government's energy objectives,

(b) the most recent long-term resource plan filed by the public utility under section 44.1, if any, and

(c) whether the application for the certificate is consistent with the requirements imposed on the public utility under sections 64.01 and 64.02, if applicable.

(3.2) Section (3.1) does not apply if the commission considers that the matters addressed in the application for the certificate were determined to be in the public interest in the course of considering a long-term resource plan under section 44.1.

10 Section 58 is amended by adding the following subsections:

(2.1) The commission must set rates for the authority in accordance with

(a) the prescribed requirements, if any, and

(b) the prescribed factors and guidelines, if any.

(2.2) A requirement prescribed for the purposes of subsection (2.1) (a) applies despite

(a) any other provision of

(i) this Act, including, for greater certainty, section 58.1, or

(ii) the regulations, except a regulation under section 3, or

(b) any previous decision of the commission.

(2.3) Subsections (2.1) (a) and (2.2) are repealed on March 31, 2010.

(2.4) Despite subsection (2.3), a requirement prescribed for the purposes of subsection (2.1) (a) that is in effect immediately before March 31, 2010, continues to apply after that date as though subsection (2.2) were still in force, unless the prescribed requirement is amended or repealed after that date.

11 The following section is added:

Rate rebalancing

58.1 (1) In this section, **"revenue-cost ratio"** means the amount determined by dividing the authority's revenues from a class of customers during a period of time by the authority's costs to serve that class of customers during the same period of time.

(2) This section applies despite

(a) any other provision of

(i) this Act, or

(ii) the regulations, except a regulation under section 3 or 125.1 (4) (f), or

(b) any previous decision of the commission.

(3) The following decision and orders of the commission are of no force or effect to the extent that they require the authority to do anything for the purpose of changing revenue-cost ratios:

(a) 2007 RDA Phase 1 Decision, issued October 26, 2007;

(b) order G-111-07, issued September 7, 2007;

(c) order G-130-07, issued October 26, 2007;

(d) order G-10-08, issued January 21, 2008,

and the rates of the authority that applied immediately before this section comes into force continue to apply and are deemed to be just, reasonable and not unduly discriminatory.

(4) Nothing in subsection (3) prevents the commission from setting rates for the authority, but the commission may not set rates for the authority for the purpose of changing the revenue-cost ratio for a class of customers.

(5) Subsection (4) is repealed on March 31, 2010.

(6) Nothing in subsection (3) prevents the commission from setting rates for the authority, but the commission, after March 31, 2010, may not set rates for the authority such that the revenue-cost ratio, expressed as a percentage, for any class of customers increases by

more than 2 percentage points per year compared to the revenue-cost ratio for that class immediately before the increase.

12 Section 61 (2) is amended by adding "rescinded or" ***after*** "must not be"***.***

13 The following Part is added:

PART 3.1 — ENERGY SECURITY AND THE ENVIRONMENT

Electricity self-sufficiency

64.01 (1) The authority must

(a) by the 2016 calendar year, achieve electricity self-sufficiency according to the prescribed criteria, and

(b) maintain, according to the prescribed criteria, electricity self-sufficiency in each calendar year after achieving it.

(2) A public utility, in planning for

(a) the construction or extension of generation facilities, and

(b) energy purchases,

must consider the government's goal that British Columbia be electricity self-sufficient by the 2016 calendar year and maintain self-sufficiency after that year.

Clean and renewable resources

64.02 (1) To facilitate the achievement of the government's goal that at least 90% of the electricity generated in British Columbia be generated from clean or renewable resources, a person to whom this section applies

(a) must pursue actions to meet the prescribed targets in relation to clean or renewable resources, and

(b) must use the prescribed guidelines in planning for

(i) the construction or extension of generation facilities, and

(ii) energy purchases.

(2) This section applies to

(a) the authority, and

(b) a prescribed public utility, if any, and a public utility in a class of prescribed public utilities, if any.

Standing offer

64.03 (1) In this section, **"eligible facility"** means a generation facility that

(a) either

(i) has only one generator with a nameplate capacity of 10 megawatts or less or has more than one generator and the total nameplate capacity of all of them is 10 megawatts or less, or

(ii) meets the prescribed requirements, and

(b) either

(i) is a high-efficiency cogeneration facility, or

(ii) generates energy by means of a prescribed technology or from clean or renewable resources,

but does not include a prescribed generation facility or class of generation facilities.

(2) The authority must establish and maintain a standing offer

(a) during the times prescribed by and in accordance with the regulations, if any, and

(b) on the terms and conditions, if any, approved by the commission under subsection (3),

to enter into an energy supply contract for the purchase of electricity from eligible facilities.

(3) Subject to regulations made for the purposes of subsection (2) (a), the commission, by order and on application by the authority, may approve terms and conditions for the purposes of subsection (2) (b) if the commission considers that the terms and conditions are in the public interest.

(4) The commission may not issue an order under section 71 (3) with respect to a contract entered into in accordance with the regulations made for the purposes of subsection (2) (a), and exclusively on the terms and conditions referred to in subsection (2) (b), of this section.

Smart meters

64.04 (1) In this section:

"private dwelling" means

(a) a structure that is occupied as a private residence, or

(b) if only part of a structure is occupied as a private residence, that part of the structure;

"smart meter" means a meter that meets the prescribed requirements, and includes related components, equipment and metering and communication infrastructure that meet the prescribed requirements.

(2) Subject to subsection (3), the authority must install and put into operation smart meters in accordance with and to the extent required by the regulations.

(3) The authority must complete all obligations imposed under subsection (2) by the end of the 2012 calendar year.

(4) If a public utility, other than the authority, makes an application under the Act in relation to advanced meters, the commission, in considering that application, must consider the government's goal of having advanced meters and associated infrastructure in use with respect to customers other than those of the authority.

(5) The authority may, by itself, or by its engineers, surveyors, agents, contractors, subcontractors or employees, enter on any land, other than a private dwelling, without the consent of the owner, for a purpose relating to the use, maintenance, safeguarding, installation, replacement, repair, inspection, calibration or reading of its meters, including smart meters.

14 Section 71 (2) is repealed and the following substituted:

(2) The commission may make an order under subsection (3) if the commission, after a hearing, determines that an energy supply contract to which subsection (1) applies is not in the public interest.

(2.1) In determining under subsection (2) whether an energy supply contract is in the public interest, the commission must consider

(a) the government's energy objectives,

(b) the most recent long-term resource plan filed by the public utility under section 44.1, if any,

(c) whether the energy supply contract is consistent with requirements imposed under section 64.01 or 64.02, if applicable,

(d) the interests of persons in British Columbia who receive or may receive service from the public utility,

(e) the quantity of the energy to be supplied under the contract,

(f) the availability of supplies of the energy referred to in paragraph (e),

(g) the price and availability of any other form of energy that could be used instead of the energy referred to in paragraph (e), and

(h) in the case only of an energy supply contract that is entered into by a public utility, the price of the energy referred to in paragraph (e).

(2.2) Subsection (2.1) (a) to (c) does not apply if the commission considers that the matters addressed in the energy supply contract filed under subsection (1) were determined to be in the public interest in the course of considering a long-term resource plan under section 44.1.

(2.3) A public utility may submit to the commission a proposed energy supply contract setting out the terms and conditions of the contract and a process the public utility intends to use to acquire power from other persons in accordance with those terms and conditions.

(2.4) If satisfied that it is in the public interest to do so, the commission, by order, may approve a proposed contract submitted under subsection (2.3) and a process referred to in that subsection.

(2.5) In considering the public interest under subsection (2.4), the commission must consider

(a) the government's energy objectives,

(b) the most recent long-term resource plan filed by the public utility under section 44.1,

(c) whether the application for the proposed contract is consistent with the requirements imposed on the public utility under sections 64.01 and 64.02, if applicable, and

(d) the interests of persons in British Columbia who receive or may receive service from the public utility.

(2.6) If the commission issues an order under subsection (2.4), the commission may not issue an order under subsection (3) with respect to a contract

(a) entered into exclusively on the terms and conditions, and

(b) as a result of the process

referred to in subsection (2.3).

15 Section 88 (4) is amended by striking out "a matter that is subject" ***and substituting*** "a person, or a person in respect of a matter, who has been exempted under"***.***

16 Section 108 (b) is amended by adding "responsible for the administration of the *Hydro and Power Authority Act*" ***after*** "minister"***.***

17 The following sections are added:

Minister's regulations

125.1 (1) In this section, **"minister"** means the minister responsible for the administration of the *Hydro and Power Authority Act*.

(2) The minister may make regulations respecting the government's energy objectives, as defined in section 1, including, without limitation, regulations as follows:

(a) defining a word or phrase used in the definition;

(b) prescribing actions and goals for the purposes of paragraph (f) of the definition;

(c) establishing factors or guidelines the commission must use in considering the government's energy objectives, including guidelines regarding the relative priority of the objectives referred to in paragraphs (a) to (f) of the definition.

(3) A regulation under subsection (2) may be made with respect to the government's energy objectives generally or with respect to their application in any particular case.

(4) The minister may make regulations as follows:

(a) making declarations for the purposes of section 5 (7);

(b) respecting exemptions under section 22;

(c) respecting reports to be provided to the commission by the authority under section 43 (1.1), including, without limitation, respecting the jurisdictions with which comparisons are to be made, the rate classes to be considered, the factors to be used in making the comparisons and conducting the assessments, and the meaning to be given to the word "competitive";

(d) prescribing, for the purposes of paragraph (a) (i) of the definition of "demand increase" in section 44.1 (1), an amount representing an increase in resource requirements of the authority not related to an estimated increased demand referred to in section 44.1 (4) (b);

(e) for the purposes of section 44.1 and 44.2,

(i) prescribing rules for determining whether a demand-side measure, or a class of demand-side measures, is adequate, cost-effective or both,

(ii) declaring a demand-side measure, or a class of demand-side measures, to be cost effective and necessary for adequacy,

(iii) prescribing rules or factors a public utility must use in making the estimate referred to in section 44.1 (2) (a), and

(iv) prescribing rules or factors the authority must use in making the estimate referred to in section 44.1 (4) (b);

(f) prescribing requirements for the purposes of section 58 (2.1) (a);

(g) prescribing factors and guidelines for the purposes of section 58 (2.1) (b), including, without limitation, factors and guidelines to encourage

(i) energy conservation or efficiency,

(ii) the use of energy during periods of lower demand,

(iii) the development and use of energy from clean or renewable resources, or

(iv) the reduction of the energy demand a public utility must serve;

(h) defining a term or phrase used in section 58.1 and not defined in this Act;

(i) identifying facts that must be used in interpreting the definition in section 58.1;

(j) defining a term or phrase used in Part 3.1 and not defined in that Part;

(k) prescribing criteria respecting self-sufficiency for the purposes of section 64.01 (1) (a) and (b);

(l) prescribing targets for the purposes of section 64.02 (1) (a), guidelines for the purposes of section 64.02 (1) (b) and public utilities and classes of public utilities for the purposes of section 64.02 (2) (b);

(m) for the purposes of section 64.03, respecting eligible facilities, including prescribing generation facilities and classes of generation facilities, and respecting the standing offer to be established and maintained under that section;

(n) for the purposes of section 64.04, respecting smart meters and their installation, including, without limitation,

(i) the types of smart meters to be installed, including the features or functions each meter must have or be able to perform, and

(ii) the classes of users for whom smart meters must be installed, and requiring the authority to install different types of smart meters for different classes of users;

(o) prescribing standard-making bodies for the purposes of section 125.2 (1) and matters for the purposes of section 125.2 (3) (d);

(p) prescribing owners, operators, direct users, generators and distributors, or classes of any of them, for the purposes of section 125.2 (8).

(5) In making a regulation under this section, the minister may

(a) make regulations of specific or general application, and

(b) make different regulations for different persons, places, things, measures, transactions or activities.

Adoption of reliability standards, rules or codes

125.2 (1) In this section:

"reliability standard" means a reliability standard, rule or code established by a standard-making body for the purpose of being a mandatory reliability standard for planning and operating the North American bulk power system, and includes any substantial change to any of those standards, rules or codes;

"standard-making body" means

(a) the North American Electric Reliability Corporation,

(b) the Western Electricity Coordinating Council, and

(c) a prescribed standard-making body.

(2) For greater certainty, the commission has exclusive jurisdiction to determine whether a reliability standard is in the public interest and should be adopted in British Columbia.

(3) The transmission corporation must review each reliability standard and provide to the commission, in accordance with the regulations, a report assessing

> (a) any adverse impact of the reliability standard on the reliability of electricity transmission in British Columbia if the reliability standard were adopted under subsection (6),
>
> (b) the suitability of the reliability standard for British Columbia,
>
> (c) the potential cost of the reliability standard if it were adopted under subsection (6), and
>
> (d) any other matter prescribed by regulation or identified by order of the commission for the purposes of this section.

(4) The commission may make an order for the purposes of subsection (3) (d).

(5) If the commission receives a report under subsection (3), the commission must

> (a) make the report available to the public in a reasonable manner, which may include by electronic means, and for a reasonable period of time, and
>
> (b) consider any comments the commission receives in reply to the publication referred to in paragraph (a).

(6) After complying with subsection (5), the commission, subject to subsection (7), must adopt the reliability standards addressed in the report if the commission considers that the reliability standards are required to maintain or achieve consistency in British Columbia with other jurisdictions that have adopted the reliability standards.

(7) The commission is not required to adopt a reliability standard under subsection (6) if the commission determines, after a hearing, that the reliability standard is not in the public interest.

(8) A reliability standard adopted under subsection (6) applies to every

> (a) prescribed owner, operator and direct user of the bulk power system, and
>
> (b) prescribed generator and distributor of electricity.

(9) Subsection (8) applies to a person prescribed for the purposes of that subsection despite any exemption issued to the person under section 22 or 88 (3).

(10) The commission may make orders providing for the administration of adopted reliability standards.

(11) The commission, on its own motion or on complaint, may

(a) rescind an adoption made under subsection (6), or

(b) adopt a reliability standard previously rejected under subsection (7)

if the commission determines, after a hearing, that the rescission or adoption is in the public interest.

(12) The commission, without the approval of the minister responsible for the administration of the *Hydro and Power Authority Act*, may not set a standard or rule under section 26 of this Act with respect to a matter addressed by a reliability standard assessed in a report submitted to the commission under subsection (3) of this section.

Consequential Amendments and Transition

Insurance Corporation Act

18 Section 44 of the Insurance Corporation Act, R.S.B.C. 1996, c. 228, is amended by striking out "other than sections 22, 23 (1) (a) to (d) and (2), 25 to 38, 40, 41, 45 to 57, 59 (2) and (3), 60 (1) (b) (ii) and (2) to (4), 97, 98, 106 (1) (k), 107 to 109 and 114 and Parts 4 and 5 of that Act," ***and substituting*** "other than sections 3, 5 (4) to (9), 22, 23 (1) (a) to (d) and (2), 25 to 38, 40, 41, 43 (1) (b) (ii), 44.1, 44.2, 45 to 57, 59 (2) and (3), 60 (1) (b) (ii) and (2) to (4), Part 3.1, 97, 98, 106 (1) (k), 107 to 109 and 114, Parts 4 and 5 and sections 125.1 and 125.2 of that Act,"***.***

Water Utility Act

19 Section 4 (b) of the Water Utility Act, R.S.B.C. 1996, c. 485, is amended by striking out "other than sections 28, 29 and 45 (2), (3), (5) and (6)," ***and substituting*** "other than sections 28, 29, 44.1, 44.2, 45 (2), (3), (5) and (6), 58 (2.1) and (2.2) and 58.1, Part 3.1 and sections 125.1 and 125.2,"***.***

Transition

20 (1) For greater certainty, a regulation made under section 3 of the

Utilities Commission Act, as that section read immediately before the date section 3 of this Act comes into force, if that regulation was in effect immediately before that date, remains in effect and is deemed to be a regulation under section 3 of the *Utilities Commission Act* as that section reads immediately after section 3 of this Act comes into force.

(2) An exemption under section 22 of the *Utilities Commission Act*, as that section read immediately before the date section 5 of this Act comes into force, if that exemption was in effect immediately before that date, remains in effect and is deemed to be an exemption under section 22 of the *Utilities Commission Act* as that section reads immediately after section 5 of this Act comes into force.

Commencement

21 The provisions of this Act referred to in column 1 of the following table come into force as set out in column 2 of the table:

Item	Column 1 **Provisions of Act**	Column 2 **Commencement**
1	Anything not elsewhere covered by this table	The date of Royal Assent
2	Section 11	March 31, 2008

APPENDIX A-2

Utilities Commission Act - Section 44 & 45

Excerpt from the Utilities Commission Act - Section 44 and 45

Duty to keep records

44 (1) A public utility must have in British Columbia an office in which it must keep all accounts and records required by the commission to be kept in British Columbia.

(2) A public utility must not remove or permit to be removed from British Columbia an account or record required to be kept under subsection (1), except on conditions specified by the commission.

Certificate of public convenience and necessity

45 (1) Except as otherwise provided, after September 11, 1980, a person must not begin the construction or operation of a public utility plant or system, or an extension of either, without first obtaining from the commission a certificate that public convenience and necessity require or will require the construction or operation.

(2) For the purposes of subsection (1), a public utility that is operating a public utility plant or system on September 11, 1980 is deemed to have received a certificate of public convenience and necessity, authorizing it

(a) to operate the plant or system, and

(b) subject to subsection (5), to construct and operate extensions to the plant or system.

(3) Nothing in subsection (2) authorizes the construction or operation of an extension that is a reviewable project under the *Environmental Assessment Act*.

(4) The commission may, by regulation, exclude utility plant or categories of utility plant from the operation of subsection (1).

(5) If it appears to the commission that a public utility should, before constructing or operating an extension to a utility plant or system, apply for a separate certificate of public convenience and necessity, the commission may, not later than 30 days after construction of the extension is begun, order that subsection (2) does not apply in respect of the construction or operation of the extension.

Excerpt from the Utilities Commission Act - Section 45

(6) A public utility must file with the commission at least once each year a statement in a form prescribed by the commission of the extensions to its facilities that it plans to construct.

~~(6.1) A public utility must file the following plans with the commission in the form and at the times required by the commission:~~

> **~~(a) a plan of the capital expenditures the public utility anticipates making over the period specified by the commission;~~**
>
> **~~(b) a plan of how the public utility intends to meet the demand for energy by acquiring energy from other persons, and the expenditures required for that purpose;~~**
>
> **~~(c) a plan of how the public utility intends to reduce the demand for energy, and the expenditures required for that purpose.~~**

~~(6.2) After receipt of a plan filed under subsection (6.1), the commission may~~

> **~~(a) establish a process to review all or part of the plan and to consider the proposed expenditures referred to in that plan,~~**
>
> **~~(b) determine that any expenditure referred to in the plan is, or is not at that time, in the interests of persons within British Columbia who receive, or who may receive, service from the public utility, and~~**
>
> **~~(c) determine the manner in which any expenditures referred to in the plan can be recovered in rates.~~**

(7) Except as otherwise provided, a privilege, concession or franchise granted to a public utility by a municipality or other public authority after September 11, 1980 is not valid unless approved by the commission.

(8) The commission must not give its approval unless it determines that the privilege, concession or franchise proposed is necessary for the public convenience and properly conserves the public interest.

Excerpt from the Utilities Commission Act - Section 44 and 45

(9) In giving its approval, the commission

(a) must grant a certificate of public convenience and necessity, and

(b) may impose conditions about

(i) the duration and termination of the privilege, concession or franchise, or

(ii) construction, equipment, maintenance, rates or service,

as the public convenience and interest reasonably require.

APPENDIX A-3
BCUC Resource Planning Guidelines

BRITISH COLUMBIA UTILITIES COMMISSION

Resource Planning Guidelines

Issued: December 2003

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PURPOSE AND SCOPE OF THE RESOURCE PLANNING GUIDELINES

The Commission's mandate to direct and evaluate the resource plans of energy utilities is intended to facilitate the cost-effective delivery of secure and reliable energy services. The Resource Planning Guidelines (the "Guidelines") outline a comprehensive process to assist the development of such plans.

The Utilities Commission Act ("UCA") was amended in 2003 to provide the Commission with a mandate to implement the policy actions of the Provincial Government's November 2002 energy policy, "Energy For Our Future: A Plan For BC" ("Energy Plan"). Amendments to Section 45 of the UCA expand upon and clarify the planning requirements of utilities and the Commission's role to review filed plans to determine whether expenditures are in the public interest and whether associated rate changes are necessary and appropriate. The additions to Section 45 of the UCA are as follows:

45 (6.1) A public utility must file the following plans with the commission in the form and at the times required by the commission;

- (a) a plan of the capital expenditures the public utility anticipates making over the period specified by the commission;
- (b) a plan of how the public utility intends to meet the demand for energy by acquiring energy from other persons, and the expenditures required for that purpose;
- (c) a plan of how the public utility intends to reduce the demand for energy and the expenditures required for that purpose.

(6.2) After receipt of a plan filed under subsection (6.1), the commission may:

- (a) establish a process to review all or part of the plan and to consider the proposed expenditures referred to in the plan;
- (a) determine that any expenditure referred to in the plan is, or is not at that time, in the interests of persons within British Columbia who receive, or who may receive, service from the public utility, and
- (b) determine the manner in which expenditures referred to in the plan can be recovered in rates.

On the basis of subsection 6.1, the Commission will require that any resource plans filed under paragraph 6.1, (a), (b) and (c) be prepared in accordance with the Guidelines.

The Commission requires consideration of all known resources for meeting the demand for a utility's product, including those which focus on traditional and alternative supply sources (including "BC Clean Electricity" as referred to in the Energy Plan), and those which focus on conservation of energy and Demand Side Management ("DSM").[1] Resource planning is intended to facilitate the selection of cost-effective resources that yield the best overall outcome of expected impacts and risks for ratepayers over the long run. The process aids in defining and

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[1] *Demand Side Management* may be defined as a deliberate effort to decrease, shift or increase energy demand. Utilities develop DSM programs to encourage customers to enact DSM measures. Because of measurement difficulties and uncertainty about consumer behavior, DSM programs should be evaluated before and after implementation to determine their full impacts.

assessing market-based costs and benefits, while also entailing the assessment of tradeoffs between other expected impacts that may vary across alternative resource portfolios. Such impacts may be associated with objectives such as reliability, security of supply, rate stability and risk mitigation, or specific social or environmental impacts. In sum, a resource planning process that assesses multiple objectives and the tradeoffs between alternative resource portfolios is key to the development of a cost-effective resource plan for meeting demand for a utility's service.

In most circumstances, Certificates of Public Convenience and Necessity ("CPCN") applications should be supported by resource plans filed pursuant to Section 45 of the UCA. The Commission expects that resource plans will help facilitate the review of utility revenue requirements and rate applications.

The Guidelines do not alter the fundamental regulatory relationship between the utilities and the Commission. The Guidelines do not mandate a specific outcome to the planning process, nor do they mandate specific investment decisions. The Guidelines provide general guidance regarding Commission expectations of the process and methods for utilities to follow in developing plans that reflect their specific circumstances. More specific directions regarding resource plans will be provided to utilities on a utility to utility basis. Further directions may address issues regarding the elements of the resource plan or the underlying methodology. The Commission will review resource plans in the context of the unique circumstances of the utility in question. For this reason, the Guidelines do not distinguish between the circumstances of small and large utilities or between transmission and distribution utilities, nor do they prescribe specific planning horizons or approaches to resource acquisition. Although the Guidelines are not prescriptive in that sense, after review of a resource plan the Commission expects to be prescriptive on a utility by utility basis, as necessary, to facilitate cost-effective delivery of a reliable and secure supply that meets demand for a utility's service.

RESOURCE PLANNING GUIDELINES

1. Identification of the planning context and the obj ectives of a resource plan

Key underlying issues and assumptions that inform the planning context should be identified and discussed (e.g., reliability and security issues, risk factors, major uncertainties). Objectives include, but are not limited to: adequate and reliable service; economic efficiency; preservation of the financial integrity of the utility; equal consideration of DSM and supply resources; minimization of risks; compliance with government regulations and stated policies; and consideration of social and environmental impacts.[2]

2. Development of a range of gross (pre-DSM) demand forecasts

In making a demand forecast, it is necessary to distinguish between demographic, social, economic and technological factors unaffected by utility actions, and those actions the utility can take to influence demand (e.g. rates, DSM programs). The latter actions should not be reflected in the utility's gross demand forecasts.[3] More than one forecast would generally be required in order to reflect uncertainty about the future: probabilities or qualitative statements may be used to indicate that one forecast is considered more likely than others. The energy end-use categories[4] used to analyze DSM programs should be compatible with those used in demand forecasting, so that at any point a consistent distinction can be made between demand with and without DSM on an end-use category-specific basis. Thus, the gross demand forecast should be structured in such a way that the savings, load shifting or load building due to each DSM resource can be allocated to specific end-uses in the demand forecast.

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[2] Bonbright, Danielsen and Kamerschen, (Principles of Public Utility Rates, 1988, Ch.8, p.165) suggest that the rates set by utility commissions invariably involve some discretionary judgment about the extent to which broader social principles should influence ratemaking. Because of social and environmental impacts, the rates charged by utilities may be allowed to deviate from those that would result from a rate determination based exclusively on financial least cost. The objectives to be addressed may be identified by the utility, intervenors, or government. The BC Utilities Commission interprets its jurisdiction as extending only to consideration of environmental and social impacts that are likely to become financial costs in the foreseeable future.

[3] In other words, gross forecasts represent an attempt to simulate markets in which the utility did nothing to influence demand. Of course, this is not entirely possible. Utilities will continue to require rate increases and existing DSM programs will affect demand as will already ordered rate design changes. However, the assumptions made with respect to these factors in estimating future gross demand should be clearly specified so that the effects of these assumptions may be distinguished from the effects of future utility actions designed to influence demand.

[4] The term *End-use categories* is intended to mean energy consumption by categories of end-user, such as industrial, commercial, or residential. Guideline No. 2 does not prescribe *end-use forecasting* or *end-use modeling*, but rather requests that forecast outputs and DSM results be organized and checked according to end-use categories.

3. Identification of supply and demand resources

Feasible[5] individual supply and demand resources, both committed and potential, should be listed. Individual resources are defined as indivisible investments or actions by the utility to modify energy and/or capacity supply, or modify (decrease, shift, increase) energy and/or capacity demand.

4. Measurement of supply and demand resources

Each supply-side and demand-side resource must be measured against the objectives established under Guideline No. 1. This includes identifying utility and customer costs (life cycle costs, impact on rates, etc.), associated risks, and lost opportunities.[6] Characterizing the feasible supply and demand resources could also include reporting how these resources perform[7] relative to specific social and environmental objectives. This can facilitate a more comprehensive understanding of the tradeoffs between objectives as they may be associated with various supply and demand resources. Supply and demand resource cost estimates should represent the full costs of achieving a given magnitude of the resource. These cost estimates may be represented as supply curves; i.e. graphs showing the unit costs associated with different magnitudes of the resource.

5. Development of multiple resource portfolios

For each of the gross demand forecasts, several plausible resource portfolios should be developed, each consisting of a combination of supply and demand resources needed to meet the gross demand forecast. The gross demand forecasts and the resource portfolios should cover the same period, generally 15 to 20 years into the future.

6. Evaluation and selection of resource portfolios

For each of the gross demand forecasts, the set of alternative resource portfolios that match the forecast are assessed against the objectives. Analysis of the tradeoffs between portfolios and how they perform under uncertainty will facilitate determining which portfolio performs best relative to the stated objectives. This process will lead to the selection of a set of preferred resource portfolios, each portfolio matching one of the gross demand forecasts.[8]

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[5] Feasible resource options are defined as those options consistent with the objectives of the resource planning process, as established under Guideline No. 1. For example, government policy may rule out a particular technology or form of energy.

[6] *Lost opportunities* are opportunities that, if not exploited promptly, are lost irretrievably or rendered much more costly to achieve. Examples can include cogeneration opportunities that are available but not taken when renovating a pulp and paper mill, or additional insulation that is not installed in a new house.

[7] Performance measures may be quantitative or qualitative.

[8] Guidelines No. 4 through No. 6 may require an iterative process to account for any interdependencies.

7. Development of an action plan

The selection process in Guideline No. 6 provides the components for the action plan. The action plan consists of the detailed acquisition steps for those resources (from the selected resource portfolio) which need to be initiated over the next four years in order to meet the most likely gross demand forecast. The action plan should include a contingency plan that specifies how the utility would respond to changed circumstances, such as changes in loads, market conditions or technology and resource options. For resources with considerable uncertainty, the action plan should incorporate an experimental design and monitoring plan to allow for hindsight evaluation of associated market impacts and full resource costs.

8. Stakeholder input

Although utility management is responsible for its resource planning and resource selection process, utilities should normally solicit stakeholder input during the resource planning process. Methods could include stakeholder collaboratives, information meetings, workshops, and issue papers seeking stakeholder response. Utilities are encouraged to focus such efforts on areas of the planning process where it will prove most useful and to choose methods that best fit their needs.

9. Regulatory input

To streamline the regulatory process, utilities are encouraged to seek review and comment from Commission staff during the various phases of resource plan preparation.

10. Consideration of government policy

A resource plan filed in accordance with the UCA and these Guidelines should be consistent with government policy, as it is expressed in legislation (e.g. efficiency standards) or in specific policy statements and directives. Emerging policy issues, such as increased control of emissions, may be addressed as risk factors.

11. Regulatory review

Upon receipt of a resource plan filed pursuant to Section 45, paragraph 6.1, the Commission will establish a review process, as necessary, pursuant to Section 45, paragraph 6.2. A review may provide, as the Commission considers appropriate, opportunities for written and/or oral public comment.

APPENDIX B

Terasen Gas Discussion Paper
Regional Energy Policy Issues

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DISCUSSION PAPER - REGIONAL POLICY ISSUES

1 INTRODUCTION

Global climate change, energy policy and environmental concerns attributable to human energy use have become topics of daily public discussion in recent years in many different forums. Recently in British Columbia the provincial government has made a number of strong public commitments in the areas of energy policy and climate change. These commitments have been supported with the issuance of policy statements and in many cases with the passing of legislation. Further policy statements, legislation and regulation are anticipated from all levels of government in Canada and the U.S.

The effects of human-induced greenhouse gas ("GHG") emissions on climate change and the mitigation of these effects are the central drivers of these energy and environmental policies. The use and combustion of fossil fuels (coal, oil, gasoline, natural gas, etc.) is a leading source of GHG emissions caused by human activity. Land use changes (e.g. from forest to agricultural use or rural to urban) also contribute to atmospheric GHG levels by reducing/changing carbon absorption capabilities of the land. Certain agricultural activities and practices such as the raising of animals for meat, dairy and poultry products are also measurable contributors to atmospheric GHG levels.

Natural gas is a major source of energy in BC accounting for approximately 21% of end use energy consumption.[1] This is approximately the same share of the end use energy market in the province as electricity. Natural gas production and consumption accounts for approximately 34% of the provincial greenhouse gas emissions[2]. As a fossil fuel the future role of natural gas in the BC energy mix comes into question in light of the public policy pronouncements on energy and climate change. Although the combustion of natural gas produces the lowest GHG emissions of any fossil fuel and negligible levels of other pollutants, such as nitrogen oxides, sulfur oxides and particulates[3], compared to the combustion of other fossil fuels and biomass, natural gas is often grouped together with other fossil fuels without any recognition of these attributes. This paper will support the premise that natural gas is part of the solution and that continued use of natural gas,

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[1] BC NRCan End Use Database, BC Stats

[2] The BC Energy Plan: A Vision for Clean Energy Leadership, February 2007, page 20

[3] GHG and other emissions for fossil fuels are available from the NRCan GHGenius modeling software at: http://www.oee.nrcan.gc.ca/transportation/tools/greenhouse-gas-info.cfm?attr=16

particularly in direct end-use applications, will assist in the achievement of public policy goals. This paper will also identify the differences on these issues from one jurisdiction to the next in the Pacific Northwest and show how British Columbia's contribution in the region can be improved with natural gas playing a key role.

2 PLANNING ENVIRONMENT – REGIONAL RESOURCE PLANNING OUTLOOK

The key components of the utility resource planning process include the forecast demand and the available resources to meet projected load. Terasen Gas Inc.'s ("TGI") participation in the Pacific North West ("PNW") regional energy market means gas procurement activities are conducted in a competitive environment where access to and the cost of gas supply, storage and transportation are driven by regional supply and demand balances. This section provides an overview of emerging trends in natural gas supply and demand in the region.

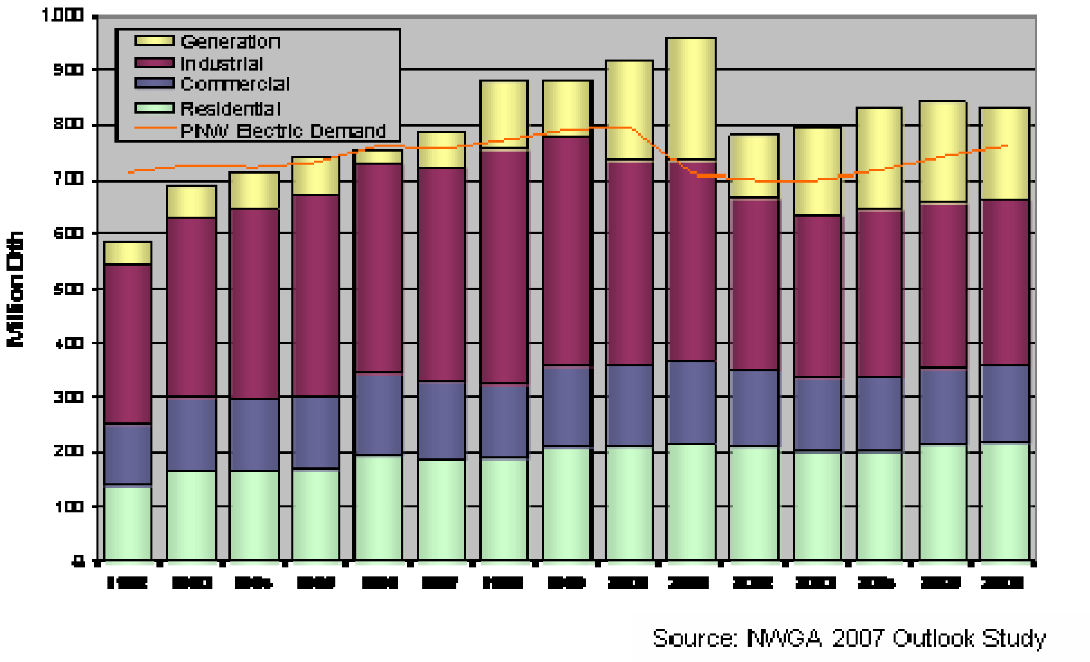
2.1 Regional Energy Needs

2.1.1 Trends in Natural Gas Demand

Strong economic growth continues to increase demand for natural gas in the PNW. The region's total gas consumption has exhibited consistent growth with the Northwest Gas Association ("NWGA") projecting an annual average growth of 1.9% and a cumulative projected growth rate of 7.2% by 2012[4]. Figure 2-1 depicts the historical demand for natural gas in the PNW. The chart shows regional gas consumption is climbing back to levels experienced prior to the 2000/01 energy crisis. Recent past and expected future growth is primarily being driven by the residential and power generation sectors.

[4] NWGA 2007 Outlook Study

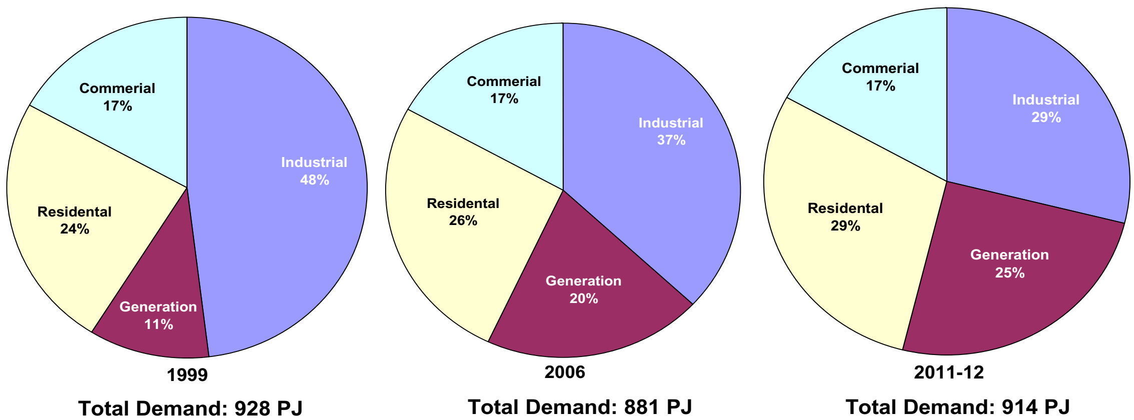
Figure 2-1 Continued Growth in PNW Demand (Source: NWGA 2007 Outlook)



The fundamental change in regional demand relates to the changing customer mix and consequent increase in weather-dependent load. Figure 2-2 compares the historical customer share of annual regional load to future expectations based on NWGA 2007 Outlook demand projections. The chart shows that the residential and electricity generation sectors are projected to make up 54% of total annual demand in 2011/12 compared to 35% in 1999.

The permanent reduction in industrial demand combined with higher growth rates in residential and generation demand imply future regional peak demand is expected to increase more rapidly than baseload demand. The continued growth in customer additions and consequent increase in peak day and annual energy demand is a common projection in the integrated resource plans of regional utilities.

Figure 2-2 Changing to a Weather-Dependent Highly Variable Load

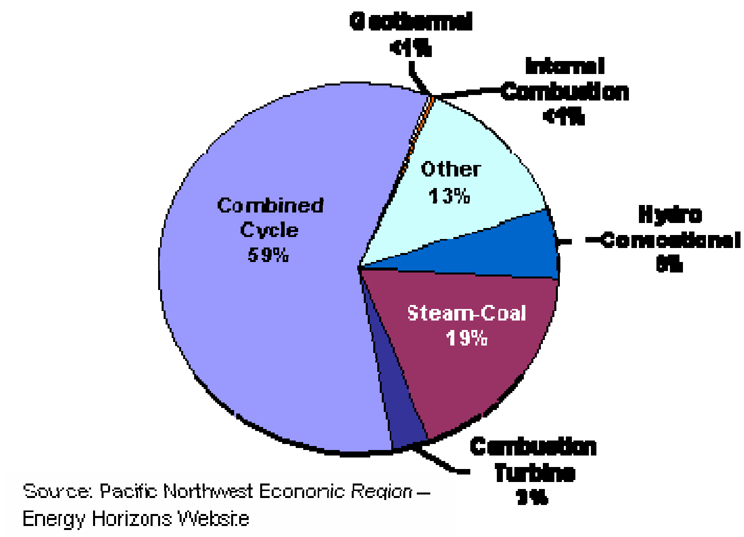


Source: NWGA 2007 Outlook Study

The use of natural gas for electric generation in the region is expected to increase. The NWGA expects natural gas to play a significant role under new energy policies targeting greenhouse gas emission reductions. Electric utilities are challenged by the limited availability of commercial cost-effective utility scale resources that meet reliability, cost effective, and environmental standards. It is anticipated natural gas-fired generation will be used for wind integration, to meet incremental capacity and energy needs, and to mitigate risks associated with using baseload coal resources.

Figure 2-3 provides a summary of generation resources expected to be added during 2005 - 2014. The addition of incremental resources, of which 58% is natural gas-fired generation, imply future resource deficiencies and convergence of energy markets as electric utilities increasingly rely on natural gas and associated infrastructure to meet their resource requirements.

Figure 2-3 Gas-Fired Generation Part of Meeting New Energy Policies



3 SUPPLY UPDATE

3.1 Production

The PNW has access to supply from the Western Canadian Sedimentary Basin ("WSCB") and the US Rocky Mountains ("Rockies"). These production basins represent a significant supply source in North America having approximately 99 trillion cubic feet ("Tcf") of proven reserves and an ultimate resource potential of 500 Tcf[5].

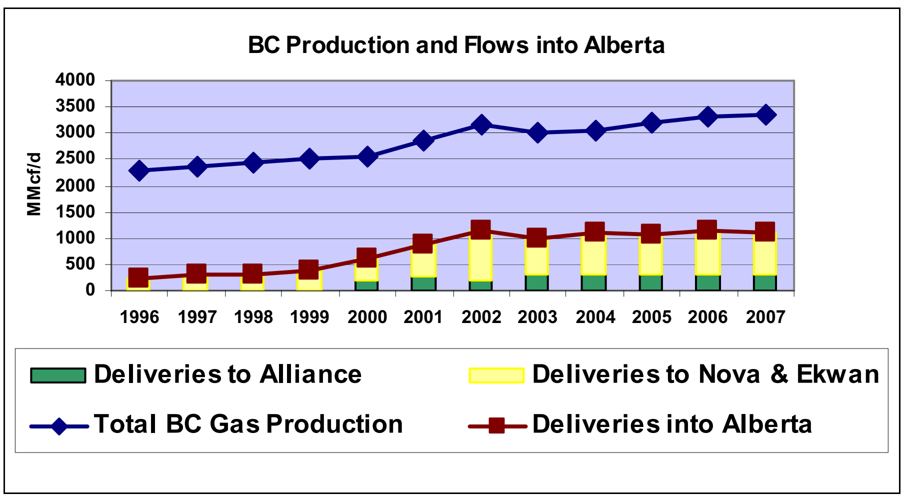
The growth in western production has generated increased competition for supply from other North American markets. While recent pipeline infrastructure developments such as Alliance and Rockies Express ("REX") provide producers opportunities to access alternative markets to maximize returns, regional PNW utilities are challenged to secure long term cost-effective supply resources. Figure 3-1 shows the historical growth in British Columbia gas production and increased supply to the Alberta market. This diversion of gas to Alberta affects supply liquidity at the western trading points of Station 2 and Huntingdon / Sumas, and changes the costs and utilization of existing regional infrastructure.

[5] As of December 31, 2005 – see Appendix C, NWGA Outlook Study p.9-10.

Production from the Rockies continues to increase as illustrated in Figure 3-2. The significant growth in production combined with lagging pipeline development has resulted in regional utilities south of the Canada/US border shifting their gas procurement from Northern BC to the Rockies. The greater reliance on Rockies production to meet PNW demand affects pipeline flows which in turn has long term implications on access to resources at Huntington.

Although the region has sufficient supply to meet immediate needs, incremental supply is required to meet long term growth in North American natural gas demand. Figure 3-3 provides Energy Information Administration's ("EIA") outlook[6] of the supply mix to meet future US demand. It shows the growth in future natural gas demand is expected to be met with LNG imports, Alaskan and Canadian Frontier gas, and non-conventional resources. While LNG imports are expected to be the marginal supply resource in the US and several facilities have been proposed in the region, the role of LNG imports in the PNW market is uncertain.

Figure 3-1 Diversion of BC Production Growth to Alberta/Eastern Markets



Data compiled from:

1. BC Ministry of Energy Mines and Petroleum Resources (Total BC Gas Production & Flows into Alberta)
2. BC Flows to Nova (TransCanada) and Information from TransCanada
3. BC Flows to Alliance (Daily Throughput Report from Alliance Pipeline website)

[6] EIA 2007 Annual Energy Outlook

Figure 3-2 Increased Rockies Production

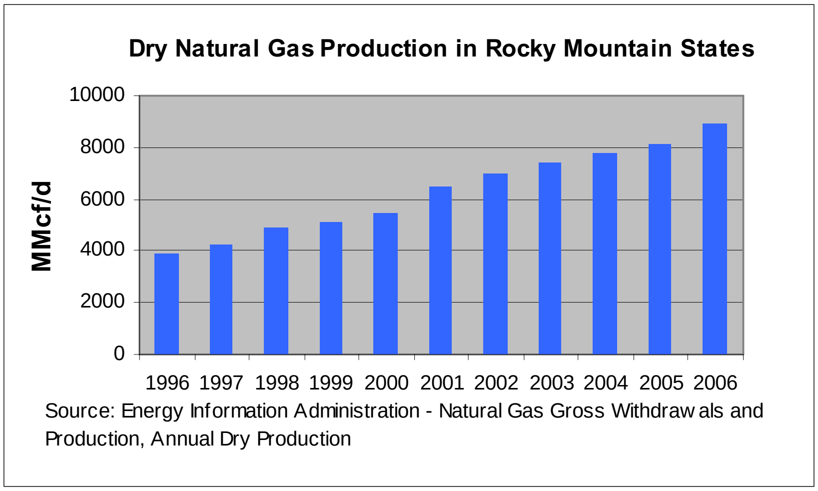
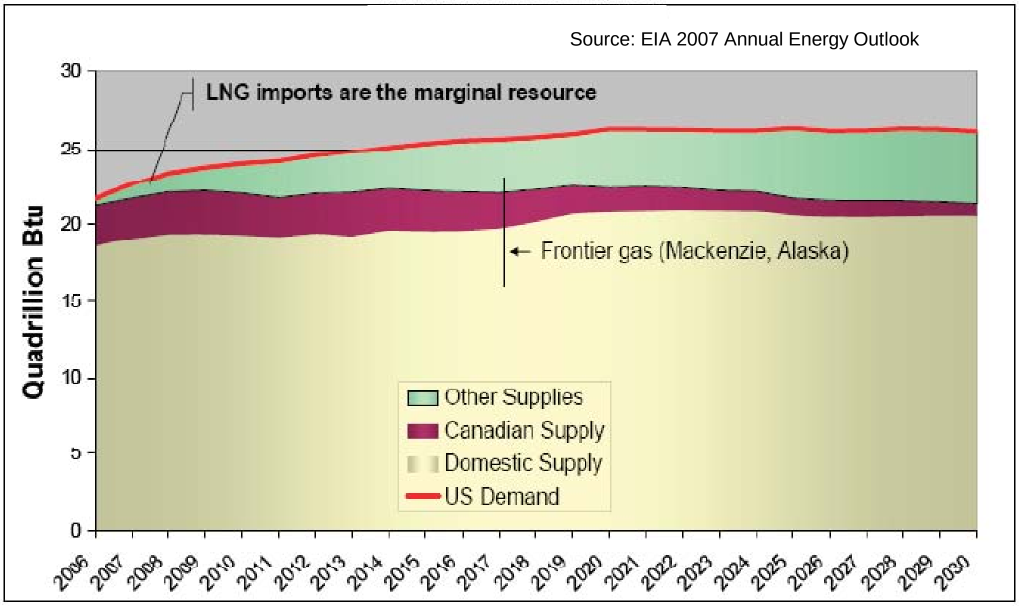


Figure 3-3 LNG imports the Major New Supply Source



LNG (green area) will play a vital role in serving future U.S. demand as cumulative U.S. and Canadian supplies grow only slightly or hold steady. Alaskan gas will provide much-needed domestic supply boost after 2017.

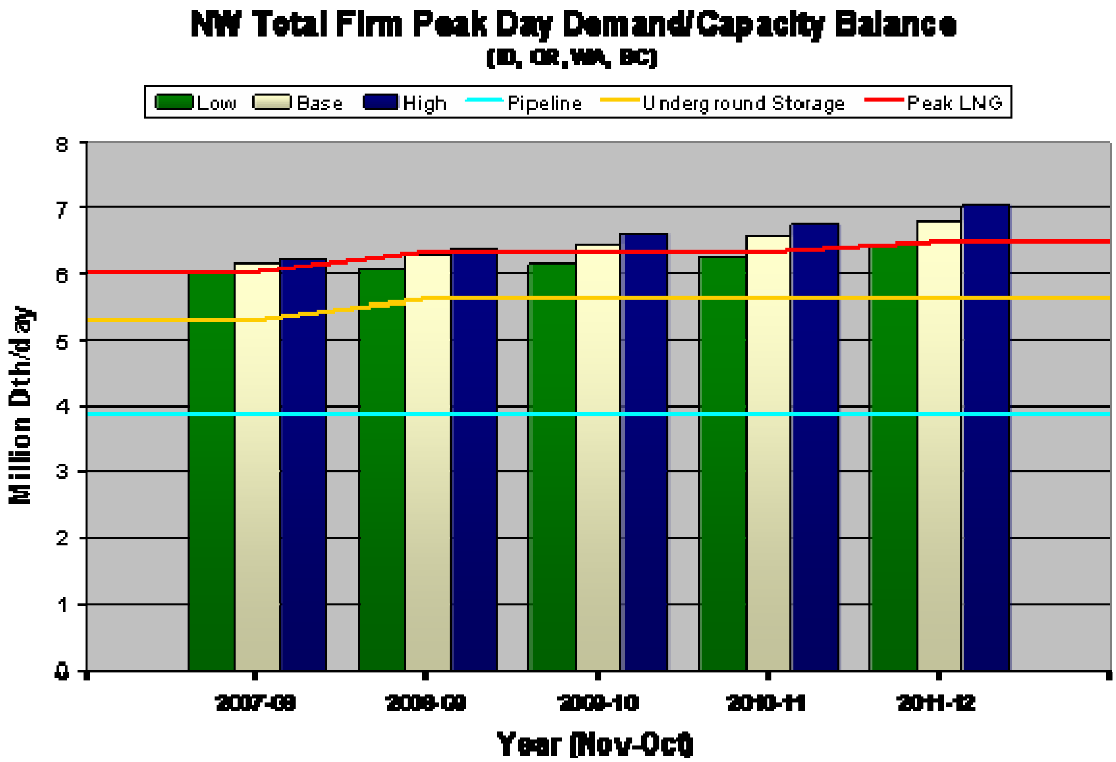
3.2 Regional Infrastructure

The region's natural gas pipeline and storage infrastructure is operating near capacity limits under extreme demand peaks. Figure 3-4 shows the region's infrastructure is expected to be constrained to meet peak day demand and sustained high winter demand by the end of this decade, as projected by NWGA.

The western energy crisis of 2000 and 2001 was a catalyst for permanent closures in both the aluminum and forest products industries throughout the western U.S. Portions of the western forest products industry have continued to struggle economically since that time, with continued closures of mills and other plants.

These large gas users typically had fuel switching capabilities and their supply could be curtailed during periods of high demand and constrained system capacity. Though seldom implemented, this capability provided an additional cushion in system capacity design. Regional demand is again approaching pre-crisis levels; however, this lost industrial load has been replaced with residential and electricity generation demand, both of which are weather sensitive demand. Not only has the Region lost some of the industrial curtailment 'cushion' historically depended on for supply capacity, but the growing demand today is also 'peakier'. These characteristics need to be considered in planning for new regional infrastructure.

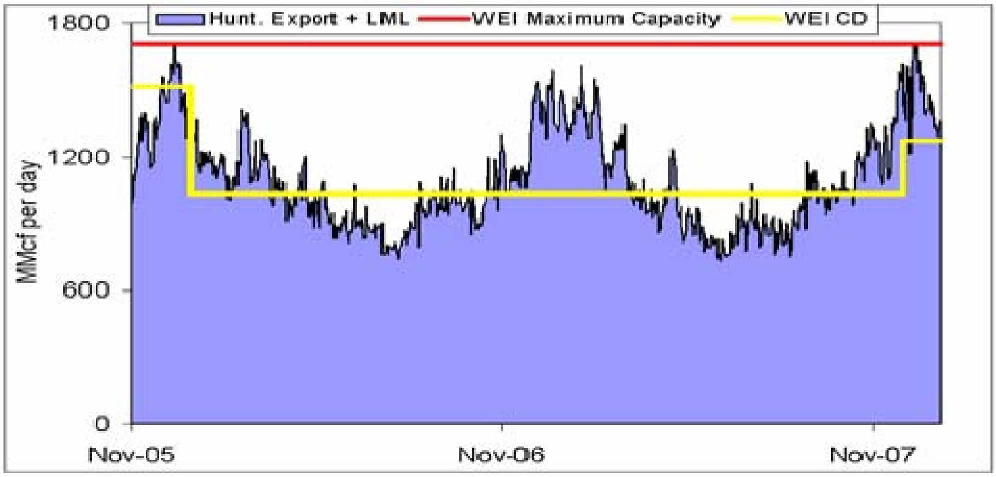
Figure 3-4 Regional Infrastructure Constrained Under Peak Demand Growth Projections



Source: NWGA 2007 Outlook Study

This tight supply-demand balance combined with projected growth in highly variable weather-dependent load, and changing contracting patterns on Canadian upstream pipelines (for entry into alternative markets) creates long term uncertainty in access and cost of existing regional infrastructure. Figure 3-5 demonstrates the difference between utilization and contracted capacity on the Spectra - Westcoast pipeline system. Although contracted firm pipeline capacity declined in 2005, utilization was near maximum limits during peak winter demand in the past three years.

Figure 3-5 Regional Infrastructure Fully Utilized Under Peak Demand



Source: Spectra Energy

The requirement for appropriate natural gas infrastructure to the meet growing and changing nature of demand and facilitate long term resource diversification continues to be viewed as the key challenge of regional utilities. The importance of encouraging infrastructure development that maximizes supply alternatives and fosters alignment of supply-side resources to regional demand with the intent of moderating future gas prices is highlighted by NWGA in its 2007 Outlook Update. Infrastructure development that satisfies this objective will mitigate price volatility and avoid regional price disconnects to the overall benefit of gas consumers in the region.

4 TRENDS IN UTILITY RESOURCE PROCUREMENT STRATEGY

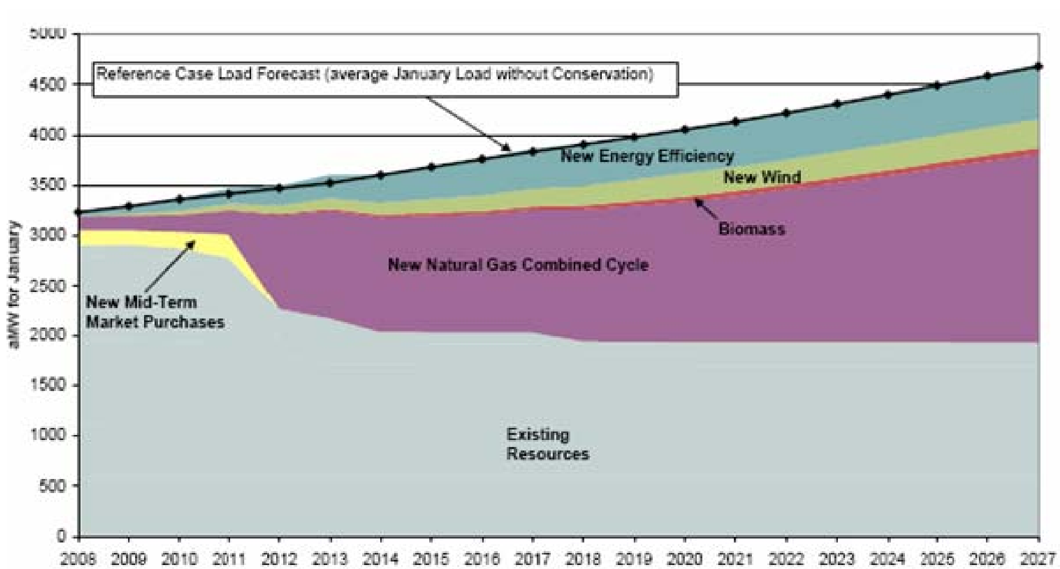
4.1 Drivers of Utility Portfolio Planning

Regional utilities share similar objectives and challenges in the development of a resource portfolio to meet the continued growth in energy demand. Regional electric and natural gas utilities face significant future needs for incremental resources and increasing uncertainty in selecting a supply portfolio that provides the right balance between reliability, cost, environmental concerns and risk. The key issues affecting resource selection strategies include meeting the expected demand growth and adapting to the changing nature of demand, new environmental regulations, uncertainty and limited future supply options.

The demand for energy in the region is changing. Higher growth in weather-dependent demand is expected to result in increased winter peaking demand, the need for sustained peaking capacity, and the emergence of dual season peaking as summer cooling load grows. The integrated resource plans of regional utilities indicate capacity and energy deficits in the following decade.

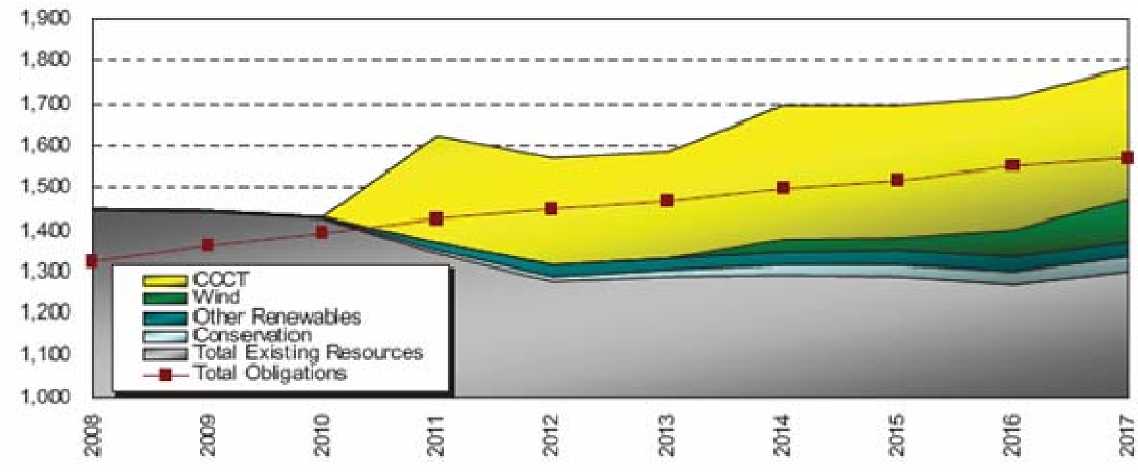
The choice of resources is also affected by environmental regulations. Legislation on renewable portfolio standards and greenhouse gas emissions change the viability of incremental supply options and the risk profile of resource strategies. Figure 4-1 and Figure 4-2 show the preferred electric resource strategy of two regional utilities (Puget Sound Energy and Avista Energy) to meet future demand under the new environmental laws. It shows the resource mix is made up of renewable resources, conservation and gas-fired generation. The significant contribution of natural gas to meet baseload and intermediate electric needs arises from the limited availability and operational challenges of cost effective utility scale renewable resource options and higher economic risks associated with coal emissions.

Figure 4-1 Puget Sound Energy 2007 IRP - Preferred Resource Strategy



Source: PSE 2007 IRP

Figure 4-2 Avista Loads & Resources Energy Forecast with Preferred Resource Strategy (aMW) – 2007 IRP



Source: Avista Energy 2007 IRP

Figure 4-1 and Figure 4-2 also highlight the importance of a diversified resource mix to meet the reliability and cost-effectiveness planning criteria. The integrated resource plans of regional natural gas utilities emphasize the need for long term supply diversification for purposes of maintaining service reliability and improving access to competitive alternatives. Diversity in supply sources and resource options ensures natural gas remains cost competitive at both the individual utility and regional portfolio levels.

5 CLIMATE CHANGE AND UTILITY RESOURCE PLANNING

Climate Change can be defined as the variation in the earth's global climate or in regional climate over time. It involves changes in the variability or average state of the atmosphere over durations ranging from decades to millions of years. These changes can be caused by dynamic processes on earth, external forces including variations in sunlight intensity, and more recently by human activities. In recent usage, especially in the context of environmental policy, the term "climate change" often refers to changes in modern climate conditions.

In a recent analysis conducted by the research firm TNS Canadian Facts, 91 per cent of Canadians agree that climate change is a serious concern and 89 per cent say that immediate action is needed[7]. This survey is an example of how Canadians view the environmental issues as a topic for governments to deal with now and in the future. The environment and its place on the issues list for Canadians have changed in recent years. For many Canadians, the environment ranks along side health care and the economy as the most important issues for government to deal with in setting public policy.

Rising GHG levels are implicated as the primary cause of global warming attributable to the "greenhouse effect". The rise of carbon dioxide levels in the atmosphere is being attributed to human activity, in particular the consumption of fossil fuels. Consumption of fossil fuels is deeply entrenched in the daily lives of people across the planet. It touches every aspect of modern life from daily transportation needs to electricity consumption in our homes to being a source of raw materials and energy in the manufacturing of products we consume. If governments, following the demands of the public, want to reduce the output of GHG emissions, they will need to develop public policy and regulations that will change individual behaviour and support the development of new technologies that reduce GHG emissions.

GHG emissions, however, cannot be addressed solely within the boundaries of any single political jurisdiction. Instead, to optimize and find solutions that reduce overall GHGs, emission sources and solutions must be examined on a regional or even global basis. The cross-jurisdictional impacts of policies and planning, therefore, need to be addressed. A piecemeal approach in which each jurisdiction develops it own policies, action plans, tax regimes and programs in isolation will be unlikely to result in an optimal solution on GHG emissions overall. An uncoordinated approach on GHG emissions is also likely to have other undesirable impacts on the state and provincial economies by affecting trade and investment patterns and the relative competitiveness of goods and service produced in one jurisdiction relative to its neighbours.

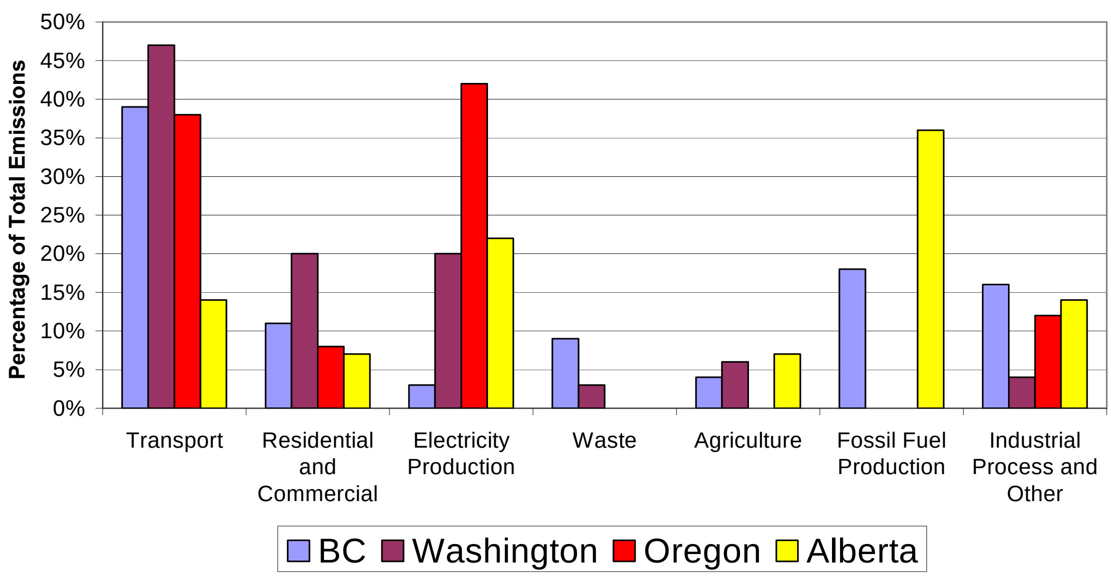
GHG emissions from human activities can be grouped into categories or sectors such as: residential, commercial, industrial, fossil fuel production, electricity generation, transportation, agriculture, and waste. These categories/sectors are used to report and help define the output of GHG emissions for states and provinces, but more importantly they give governments an idea of what regulations or initiatives are needed to reduce GHG output given the mix of GHG sources for any particular state or province. For example, given the information in Figure 5-1, it is clear that BC's greatest source of GHGs emitted within provincial boundaries comes from the transportation sector. Thus, if BC wants to reduce GHG output in the province a good place to start would be to

[7] TNS Canadian Facts. Global Warming and Green Energy Public Release. July 2007

develop regulations and policies that target the reduction of GHG emissions from the transportation sector.

In addition to transportation, another sector that differentiates provinces and states from one another in terms of GHG output is how electricity is generated in that jurisdiction. In Figure 5-1 the electricity production category clearly illustrates these differences. For example, Oregon produces 40-45% of its GHG emissions in this category; whereas BC produces less than 5% of its GHG output from electricity generation. The reason for this rests with the fact that BC electricity production comes primarily from hydro resources (see Figure 5-2 “Energy Sources for Power Generation (% Share)”). This is an example of how the mix of GHG emissions sources from a state or province can differ due to the particular natural resources available there. BC has abundant hydro resources available whereas Oregon does not. Oregon must look to alternative generation sources other than hydro to meet the state’s electricity demand. Oregon has a much higher proportion of natural gas and coal fired generation creating higher emissions in this category.

Figure 5-1 GHG Emissions by Sector (BC, Washington State, Oregon, Alberta)

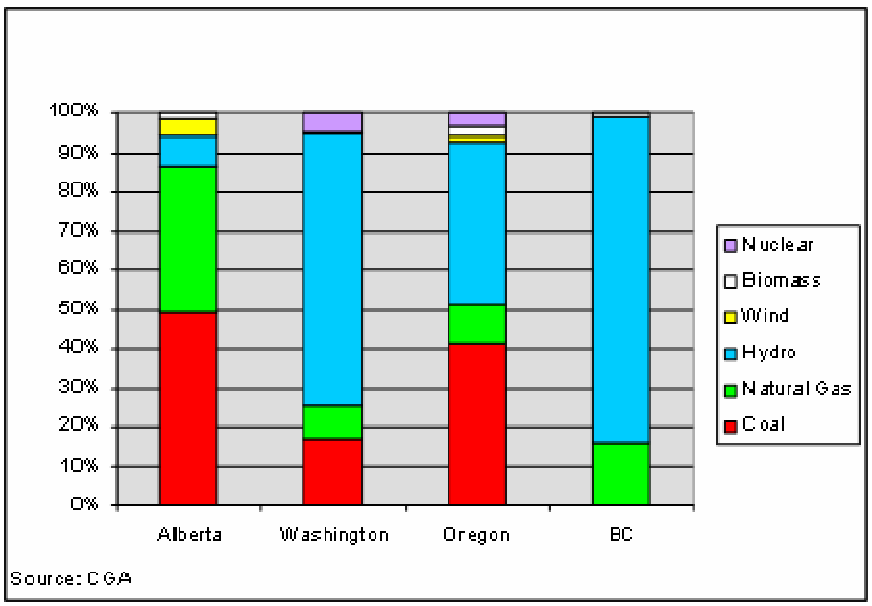


Source: Data is available to the public from various provincial and state government web sites and documents.

Note: If a column is missing for a particular state/province it means the number is zero for the category for that state/province. In some cases the number being zero may have to do with how that state or province classifies and reports the GHG output.

Policies and regulations regarding electricity production differ by state or province. In Oregon or Alberta, policies could, for example, be developed that support the movement from coal-based electricity production to natural gas-fired generation. This would reduce GHG emissions output by 50% for the same amount of electrical output. In BC however, very little domestic electricity production comes from natural gas fired facilities, and none comes from coal. Therefore BC's policies or regulations would need to be quite different in order to reach similar percentage reduction targets. This example shows how, if targets are developed by examining emissions only within a province's or state's boundaries, the public policies in one jurisdiction would be expected to differ from another jurisdiction due to differing sources of the GHG emissions. (See Figure 5-2 "Energy Sources for Power Generation" for more details of how electricity is produced in the Pacific Northwest.) This example also shows that what is considered appropriate in one jurisdiction, may well not be in another from a public perception point of view. In Oregon's case, natural gas is and is perceived to be the "greener" solution than coal. In BC, however, there are no coal-fired generation facilities so natural gas-fired generation is compared to perceived greener hydro-based generation.

Figure 5-2 Energy Sources for Power Generation (% Share)



Source: Canadian Gas Association
Note: BC energy power generation is based on capacity where as the others are based on energy sold.

A second point in this area is that Oregon and Washington could make significant strides towards meeting their GHG reduction targets as part of the Western Climate Initiative ("WCI") by switching from coal-fired generation to natural gas-fired generation. Currently, the total combined GHG output from Oregon and Washington is 155 million tonnes, of which 45 million tonnes comes from coal-fired electricity generation.[8] By converting to natural gas-fired generation, the two states combined would reduce GHG output by 22 million tonnes, which translates into 14% reduction. This is almost enough to meet their WCI reduction target of 15%.[9]

An emerging area of interest in the PNW and elsewhere in North America for achieving GHG reductions as well as broad-based energy efficiency and economic benefits pertains to the promotion of the direct use of natural gas at the end use. Using natural gas in high efficiency end-use applications such as high efficiency furnaces and water heaters is more efficient than using natural gas to fire electricity generation which is then used to for home heating and domestic hot-water. Direct use of natural gas therefore also reduces GHG emissions since natural gas-fired generation is currently the PNW marginal, regional resource. Direct use also avoids future expansion of the electric transmission and distribution systems.

Several direct use studies are being undertaken in the PNW. For example, the Washington Utilities and Transportation Commission recently initiated a review process on the implications and benefits of the direct use of natural gas and fuel switching opportunities in Washington. The Northwest Power and Conservation Council ("NWPCC") is conducting a study on the direct use of natural gas and the economic benefits of fuel switching for inclusion in its 6th Power Plan for the Pacific Northwest Region. The NWPCC conducted a similar study in 1994 and expects the current study to identify significant regional energy savings, economic benefits and GHG reductions as the earlier study did. The BCUC recognized the potential regional benefits of direct use of natural gas in B.C. in its October 26, 2007 decision on BC Hydro's 2007 Rate Design Application. At page 191 of that decision the following statement is made: "The Commission Panel agrees with Terasen that the use of natural gas (as opposed to electricity) for space and water heating in B.C. will make additional energy available to displace coal or gas-fired generation at the margin in the Pacific Northwest."

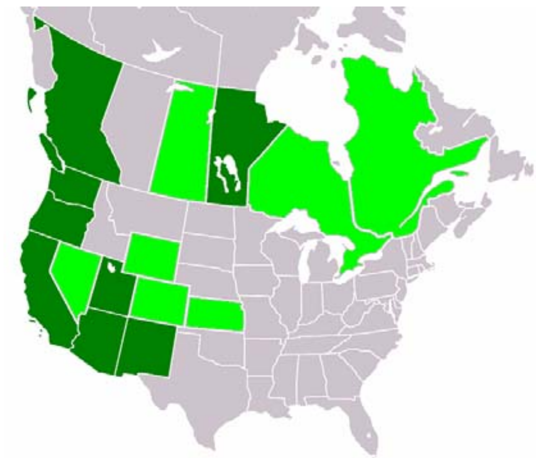
The Western Climate Initiative ("WCI") was formed by 5 US State governments (Washington, Oregon, California, Arizona and New Mexico) in February 2007 to address the growing public concern around climate change and to develop regional strategies to

[8] Washington's Greenhouse Gas Emissions: Source and Trends, December 2006 (Revised 2/12/07) and Inventory and Forecast of Oregon's Greenhouse Gas Emissions, October 31,2007

[9] Western Climate Initiative, "Statement of Regional Goal", August 22, 2007

deal with climate change. In the spring of 2007, Utah and two Canadian provinces (Manitoba and BC) joined the organization. Members of this organization are committed to reduce GHG output by 15% below 2005 levels by 2020 as a minimum[10].

Figure 5-3 WCI: Members and Observers:



Members are in dark green, observers are in light green. Source: WCI web site

One of the interesting issues in the setting up of an organization such as WCI is how this regional initiative will fit into an overall North American or global solution. These states and provinces are working to set goals and policies for their region, but how these regional goals and policies will fit in with the federal, state/provincial, and global polices to reduce GHG emissions is another matter. The potential for conflicting polices could result in the marketplace being sent the wrong signals to promote GHG reductions and lead to suboptimal investment decisions by industry and business. As an example, in recent years California has been leading an initiative along with 19 other U.S. states to implement new and tougher state regulations to limit greenhouse gas emissions from cars. To put these standards into law and enforce them, the states must receive a waiver from the federal U.S. Environmental Protection Agency ("EPA"). To date, this waiver has not been granted by the EPA and on January 2, 2008 the State of California filed a law suit against the EPA in this matter. The result is that there is no new emissions standard in place for GHG reductions from cars and it may be some time before the states and the EPA can come to terms on what the arrangements should be to put this into effect.

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[10] Western Climate Initiative, "Statement of Regional Goal", August 22, 2007

Many states and province see that there is political goodwill in being ahead of the curve in setting climate change goals, but there is also an economic reality to this trend. This comes from the diversity between jurisdictions on how GHG emissions are produced. If left to a federal body to set policies and regulations, there may be a greater economic cost to pay than if a policy is set locally. For example, in Alberta over 35% of GHG emissions come from the production of fossil fuel that is either consumed within Alberta or exported for consumption elsewhere (see Figure 5-1*)*.

Different policies established to reduce emissions output in this sector may lead to economic impacts on Alberta and the government of Alberta that are quite different than other policies. The Canadian Association of Petroleum Producers ("CAPP") have recommended policies in the past in such documents as the Tax Competitiveness Measure that was submitted in June 2005 to the Saskatchewan Business Tax Review Committee, that promotes the idea of taxing consumption. If this CAPP policy was adopted, the consumers of the fossil fuels would pay the cost associated with the GHG emission for fossil fuel produced from Alberta.

The cost of this tax under the proposed CAPP policy would be spread across all consumers of the Alberta-produced fossil fuel. This is in contrast to having the GHG taxed at source. By taxing at source, the economic impact is felt more in the province of Alberta. Fossil fuel producers in Alberta may end up not investing capital back into Alberta, which in the long term would impact the royalties paid to the Alberta government. This demonstrates how a GHG policy could have undesirable effects on an economy and helps to explain why state or provincial governments do not want to give up control of setting GHG policy.

5.1 Policies and Developments in Other Jurisdictions

Below is a brief description of some of the public policies and regulations for Alberta, Oregon, Washington, California and BC, on how these governments intend to reduce GHG emissions in their state or province. These public policies and regulations are in addition to the commitments these states and provinces have made as members of the WCI, except for the province of Alberta, which is not a member of the WCI.

Alberta:

Alberta is the largest emitter of GHGs in Canada at about 230 million tonnes per year[11], as compared to BC which is fourth at about 67 million tonnes per year. The reasons why Alberta has such a large GHG output comes from the fact that Alberta is a large producer of oil and natural gas in North America and the fact that a large part of Alberta's electricity production comes from coal or natural gas. In Alberta, 72% of GHG output comes from electrical production, fossil fuel production and industrial sectors based on 2004 data.

As early as October 2002, the Alberta government laid out a goal of decreasing GHG emissions intensity to 50% below 1990 levels by 2020. The Alberta government is expected to release a new five year plan in the first part of 2008.

Alberta is the first jurisdiction in North America to have regulations in place to reduce greenhouse gas emissions under the Climate Change and Emissions Management Act. An example of this regulation is that all Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emission intensity by 12 per cent. The facilities have three ways to meet their reductions. They can make operating improvements, buy Alberta based carbon credits or contribute ($15/tonne) to the Climate Change and Emissions Management Fund. By putting this type of regulation forward, Alberta is targeting the areas that can contribute the most to reducing GHG output in the province, which are the heavy emitters: electrical generating plants, large industrial plants, and oil and gas plants.

The Alberta government also has set a target to reduce GHG from government operations by 26% below 1990 levels. Some of the ways that the Alberta government is trying to accomplish this goal are:

1) New government buildings are constructed under Silver Leadership in Energy and Environmental Design ("LEED") standard.
2) 90% of the electricity that is consumed at government facilities comes from green power sources.

Alberta is also making commitments in terms of funding for various renewable and alternative energy sources. For example, for 2007 provincial funding for biofuel initiatives was increased to $41 millions from $ 5 million the previous year.

[11] http://www.ec.gc.ca/pdb/ghg/inventory_report/2004_report/ta12_18_e.cfm

Oregon:

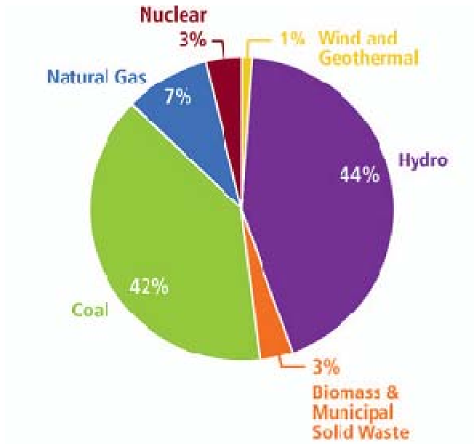
Over the last five years Oregon has started several initiatives to reduce GHG emissions. One of those initiatives is the Oregon Low Emission Vehicle Program which introduces strict emissions standards for new vehicles. Oregon was the eleventh state to adopt California's standards. The rules aim to decrease emissions that cause ground–level ozone, promote zero-emissions vehicles and reduce GHG emissions. The Oregon Department of Transportation can deny registration to new vehicles that do not comply with the standards, which will take full effect in model year 2016. By that time, it is expected that the program will bring about GHG reductions of 30% from vehicles and will have improved average vehicle fuel efficiency significantly.[12] A second initiative of Oregon's is the development of Greenhouse Gas Mandatory Reporting Rules.

In August 2007 Oregon signed into law the creation of a permanent Global Warming Commission. The goal of this commission is to coordinate state and local efforts to reduce GHG emissions. At this time, Oregon has also put into law its goal of reducing GHG emissions by 10% below 1990 levels by 2020.

One of Oregon's key initiatives is to reduce its GHG output from electricity production. Coal and natural gas electricity generation account for 49% of Oregon's electricity production.[13] As an example, shifting from coal-fired generation to natural gas-fired generation in Oregon would decrease GHG output by 50% for every unit of production moved from coal to natural gas. To help in this area, Oregon has mandated that by 2025, 25% of Oregon's electricity supply will come from renewable sources.

[12] State of Oregon, Governor's Vehicle Emission Workgroup Report, November 2005, Page 24
[13] Inventory and Forecast of Oregon's Greenhouse Gas Emissions, October 31, 2007

Figure 5-4 Oregon Electrical Production by Source (2003):



Source: State of Oregon Energy Plan 2005-2007

Washington:

Washington, like Oregon has been addressing climate change for a number of years. The Washington State Energy Office issued a report call “Greenhouse Gas Mitigation Options for Washington State” in April, 1996 that outlined the principle that no single program can stabilize and/or reduce the output of GHGs in Washington State. The State must undertake a broad range of mitigation programs. To this end, Washington Sate has taken significant action to address climate change and they include:

1) 2005 Clean Car Act – requiring certain automobiles to meet tougher emission standards beginning with 2009 models
2) Requiring fuel suppliers to ensure that 2% of the fuel they sell is biodiesel or ethanol
3) Implementing the best energy efficiency standards for appliances
4) Passing a clean energy initiative to increase the amount of energy conservation and efficiency and renewable resources in the state’s electricity systems
5) Purchasing hybrid and low emission vehicles for state use

The two biggest initiatives to reduce greenhouse gas emission in Washington are in the transportation sector (45% of total GHG output) and electricity generation (20% of total GHG output).[14]

On the transportation side, Washington is working with other sates to implement new and tougher state regulations to limit greenhouse gas emissions from cars.

In November, 2006 voters of Washington passed the Clean Energy Initiative, an act relating to requirements for new energy sources. This act states that by 2020 sources of electricity constructed after March 31, 1999 at least 15% of these new sources of electricity generation must come from renewable sources.

California:

California is moving ahead on meeting GHG reduction targets in a number of ways, but California is seen as a leader on two fronts when it comes to GHG reduction.

First, California has had a renewable portfolio standard for electricity production since passing legislation in September 2002, four to five years before Oregon and Washington introduced their renewable portfolio standards. Also, the renewable standard legislation target of 20% by 2010 is more aggressive than Washington's target of 15% by 2020 and Oregon's target of 25% by 2025.

California has also been evaluating the acquisition of renewable electricity resources from outside its own borders. A June 26, 2008 article in the Vancouver Sun entitled "California utility looks to BC for green power; PG&E predicts province will have a huge electricity surplus", indicates that California is possibly turning to British Columbia to meet its renewable requirements. This is an example of how solutions may need to cross political boundaries to achieve better results in GHG mitigation and environmental benefits for the region.

Secondly, California has been leading a group that includes 19 other states to be granted authority from the US Federal government to put state laws in place on reducing GHG emissions from cars. Currently, this matter is before the courts.

Others initiatives that California has identified in an April 20, 2007 report entitled "Proposed Early Actions to Mitigate Climate Change in California" are:

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[14] State of Washington, Department of Community, Trade and Economic Development,2007 Biennial Energy Report, January 2007

1. Low Carbon Fuel Standard
2. Improved landfill methane capture
3. Strengthen light duty vehicle standards
4. Heavy duty vehicle emission reductions
5. Port Electrification

Consistent with the state's GHG emission output profile California is very focused on reducing GHG emission from the transportation and electricity sectors.

5.2 British Columbia

2007 BC Energy Plan

On Feb 27, 2007 the BC Provincial Government released the BC Energy Plan: A Vision for Clean Energy Leadership. The BC Energy Plan lays out 55 policy actions with the intent of ensuring a secure, reliable, and affordable energy supply for all British Columbians, while maintaining our environmental responsibilities. This made in BC solution sees the province moving to eliminate or offset greenhouse gas emissions for all new projects in the growing electricity sector, end flaring from oil and gas producing wells, and putting in place a plan to make BC electricity self-sufficient by 2016.

The highlights of the 55 policy actions are as follows:

- Set ambitious conservation targets, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.
- Ensure a coordinated approach to conservation and efficiency is actively pursued in BC.
- Encourage utilities to pursue cost effective and competitive demand side management opportunities.
- Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation.
- Implement Energy Efficiency Standards for Buildings by 2010.
- Ensure self-sufficiency to meet electricity needs by 2016, including "insurance".
- Establish a standing offer for clean electricity projects up to 10 megawatts.
- Public ownership of BC Hydro and the BC Transmission Corporation.

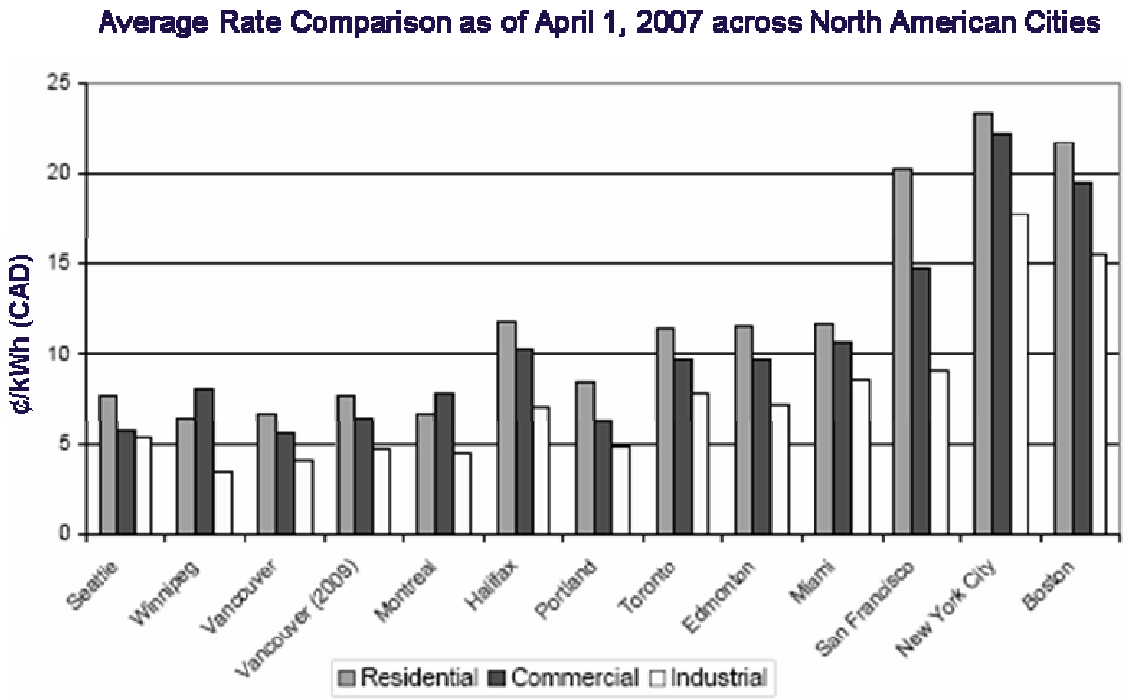
- All new electricity generation projects will have zero net greenhouse gas emissions.
- Zero net greenhouse gas emissions from existing thermal generation power plants by 2016.
- Zero greenhouse gas emissions from any coal thermal electricity facilities.
- Ensure clean or renewable electricity generation continues to account for a least 90 per cent of total generation.
- Review the BC Utilities Commission's roles in considering social and environmental costs and benefits.
- Establish the Innovative Clean Energy Fund to support development of clean power and energy efficiency technologies in the electricity, alternatives energy, transportation, and oil and gas sectors.
- Eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half by 2011.
- Best coalbed gas practices in North America.
- Continue to work to lift the federal moratorium on offshore exploration and development and reiterate the intention to simultaneously lift the provincial moratorium.
- Pursue regulatory and fiscal competitiveness in support of being among the most competitive oil and gas jurisdiction in North America.
- Support the growth of British Columbia's oil and gas service sectors.
- Implement a five per cent renewable fuel standard for diesel and gasoline.

With the Energy Plan outlining these policies the provincial government of BC has laid a forward path for the province in terms of energy supply and energy efficiency. Thus, it is important for British Columbians to understand the appropriate uses of different forms of energy and utilizing the right fuel, for the right activity at the right time so that the goals of this plan can be reached.

<u>Electricity in British Columbia</u>

In BC, one marked difference from other Pacific Northwest jurisdictions is the small difference between the retail prices of natural gas compared with retail electricity rates. Natural gas commodity pricing for consumers in BC is market-based; whereas a large percentage of the costs making up electrical rates is based on the low embedded costs of BC Hydro's Heritage generation facilities. BC Hydro's electrical rates are among the lowest in North America (see Figure 5-5).

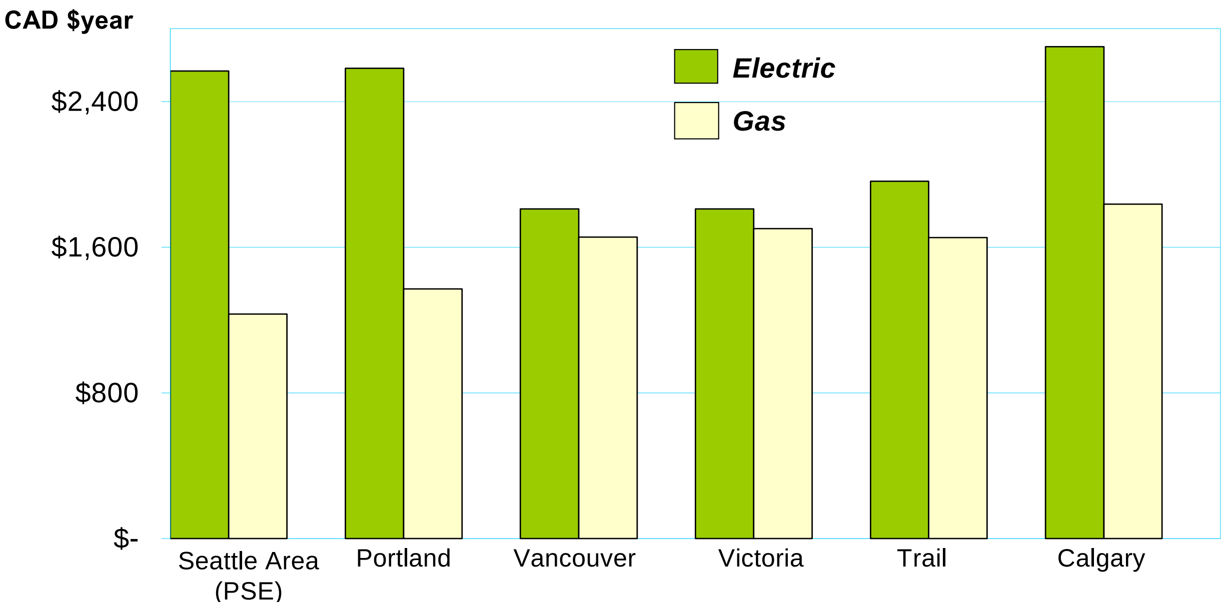
Figure 5-5 Comparing Electric Rates in BC with Cities in Other Jurisdictions:



Source: BC Hydro F2009-F2010 Revenue Requirements Application p. 1-4

The relative cost for residential consumers of natural gas and electricity for BC and neighbouring PNW jurisdictions is displayed in the chart below. The current competitive challenge for natural gas versus electricity in BC relative to other jurisdictions is clearly evident from this chart.

Figure 5-6: Annual Residential Bill Comparisons in the PNW: Electricity vs. Gas



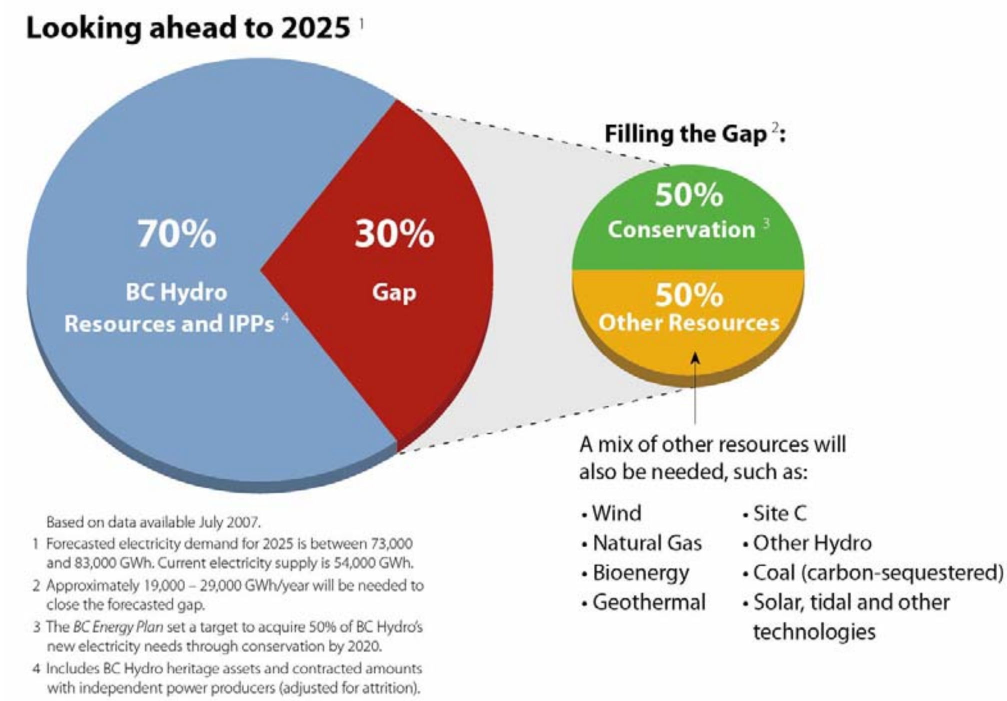
ASSUMPTIONS:
Annual Bill - 110 GJ/year
1 USD - 1.03 CAD Bank of Canada USD Conversion Rate
1 GJ = 9.4782 Therms and 277.78 kWh
The electric rates are 90% efficiency adjusted
Rates include all applicable riders
Other utilities' rates are estimates only

In recent years electricity demand in B.C. has surpassed the supply from Heritage resources and BC Hydro has been a net importer of power from neighbouring jurisdictions as well as contracting for increasing amounts of supply from independent power producers within BC. Going forward an increasing load – resource gap as well as the legislated requirement for electricity self-sufficiency in B.C. will require BC Hydro to acquire additional supply from independent power producers at much higher prices than its embedded costs. As well, BC Hydro and BC Transmission Corporation will need to add new infrastructure to the generation, transmission, and distribution assets to meet the needs of the province.

BC Hydro states in the Peace River Site C Hydro Project report released in December 2007 that by 2025, based on existing resources in its supply portfolio, BC Hydro will be resource short by 19,000 to 29,000 GWh per year (see Figure 5-7). Meeting these resource and infrastructure requirements will cause upward pressure on BC Hydro's rates in the future. For example, on January 10, 2008 the BC Transmission Corporation filed its current Ten Year Capital Plan that set out planned capital spending of $5.1 billion. BC Hydro, in its F2009 / F2010 Revenue Requirements Application, identifies increased capital spending to provide for growth and to refurbish or replace aging assets in its system as a key driver of its requested two-year rate increase.

BC Hydro will also need new supply resources to fill the load-resource gap to 2025. If Site C is one of the options selected to supply a portion of this growing shortfall, BC Hydro has indicated on its website that the early cost estimate for Site C is between $5 - $6.6 billion dollars (Peace River Site C Hydro Project webpage – Frequently Asked Questions). Whether from Site C or smaller independent power projects the cost of new supplies are substantially greater than the average cost of BC Hydro's existing electricity supply. Such cost additions are two examples of how BC Hydro customer rates will be impacted. Site C is expected to provide about 4,600 GWh per year of electricity. Thus, based on the range of BC Hydro's resource requirements, BC Hydro will need to secure enough supply-side or demand-side resources to provide the equivalent of 4 to 6 projects the size of Site C.

Figure 5-7 BC Hydro Supply Position in 2025:



Source: BC Hydro, Peace River Site C Hydro Project: An Option to Help Close BC Growing Electricity GAP; Stage One Review of Project Feasibility, December 2007

How these costs are to be recovered from customers in the future will be dictated by BC Hydro's approved rate design. In 2007, BC Hydro had its first Rate Design hearing since 1991. The BCUC decision on October 26, 2007 dictated some important changes in how BC Hydro's cost will be allocated to rate classes going forward. The key change in cost allocation methodology required by the Commission is that generation and transmission demand-related costs must allocated to the customer classes in a manner that reflects a stronger linkage to the winter peaking nature of the BC Hydro system. The Commission also required BC Hydro to undertake rate rebalancing to move the class revenue-to-cost ratios to 1:1 over three years but this rebalancing requirement was overturned by the Utilities Commission Amendment Act ("UCAA"). Under the UCAA the Commission cannot require rate rebalancing to change rate class revenue-to-cost ratios for BC Hydro before March 31, 2010. After that date rate rebalancing adjustments will be limited to increases in the revenue-to-cost ratios of a maximum of 2% per year. In general the results of the RDA Decision cause a shifting of costs from commercial/industrial rate classes to residential rates in keeping with the principle of cost causation.

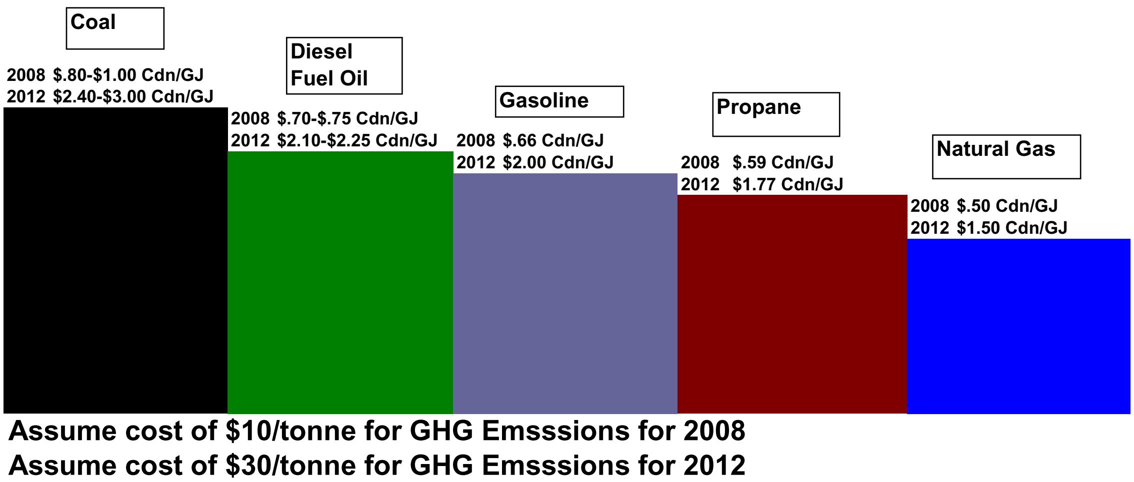
Another matter of debate in the BC Hydro 2007 Rate Design proceeding was the implications of electric space and water heating on energy demand and peak capacity growth in BC Hydro's system and the related implications for GHG emissions. One view advanced in the proceeding was that with the clean electricity and provincial self-sufficiency stipulations in the Energy Plan that using electricity for space and water heating in B.C. would reduce GHG emissions locally. The Terasen Utilities advanced the view that GHG emissions and climate change mitigation are issues that extend beyond the provincial boundaries and should be looked at from a regional perspective. The BCUC recognized the potential regional benefits of using natural gas (and alternative energies) for space and water heating in B.C. in its October 26, 2007 Rate Design Decision. At page 191 of that decision the following statement is made: "The Commission Panel agrees with Terasen that the use of natural gas (as opposed to electricity) for space and water heating in B.C. will make additional energy available to displace coal or gas-fired generation at the margin in the Pacific Northwest." However, the BCUC considered the matter of fuel choice for space and water heating to be a matter of government policy and declined to make a determination in this regard.

In February 2008 BC Hydro filed an application for a residential inclining block rate structure in keeping with its own plans and in response to another requirement of the BCUC Decision on the 2007 Rate Design Application. This rate structure will charge a higher rate for consumption above a specified threshold and is intended to promote conservation. BC Hydro intends to develop other rate proposals in the residential and general service rate classes in order to promote conservation. The UCAA also mandates smart meters for all of BC Hydro's customers by 2012. The availability of smart metering infrastructure will assist in the development and implementation of conservation rate structures. In general, these conservation rate structures will send price signals to customers about the higher costs of new long-term power supply. Conservation rates for electricity will also provide a more appropriate balance between natural gas and electricity rates in the province.

BC Carbon Tax and Other Legislation Changes

On February 19, 2008 the B.C. provincial government as part of the 2008 Budget announced that effective July 1, 2008 all fossil fuel combustion emissions in BC will be subject to a carbon tax. This carbon tax will start at \$10/tonne of GHG and increase by \$5/tonne each year to \$30/tonne by 2012. Figure 5-8 illustrates the cost per GJ of different fossil fuel based their different GHG emissions profile at \$10/tonne and \$30/tonne.

Figure 5-8 GHG Emission Cost Profile



One energy source that is absent from this emission cost profile is electricity. That is because electricity costs related to a carbon tax depends on the mix of how that electricity is produced. In most jurisdictions the electricity is produced from a variety of sources thus the unit cost associated with carbon tax would vary depending on the supply mix to produce the electricity. In BC, approximately 15% of the electricity consumed in BC is imported electricity produced from other jurisdictions. Whether and how the carbon tax will be administered for this imported power is not clear at this time.

Table 5-1 shows the cost that would be needed to be recovered in BC Hydro revenue requirement if this imported electricity was subject to the carbon tax assuming a carbon tax of $10/tonne.

Table 5-1 Estimated Carbon Tax Cost for Electricity Imported by BC Hydro

GWH's Sold in 2007	Assume 15% Imported	Coal GHG tonne/GWH	GHG Tonnes	$Cdn/Tonne	Total $$$
52,911	7,937	855	6,785,836	$10	$67,858,358
		Natural Gas GHG tonne/GWH		**$Cdn/Tonne**	**Total $$$**
		450	3,571,493	$10	$35,714,925

This example shows that different public policies across different states or provinces can have an impact on how the energy is priced to the end user, which in turn gives the wrong price signal to the consumer, which may impact their behaviour in how they consume energy. Also, this action might result in more GHG emissions for the region as a whole than if policies and regulatory structures aimed at reducing GHG emissions were established on a more regional basis.

In moving the policy items outlined in the 2007 Energy Plan forward the BC Provincial Government in the spring 2008 Legislative Session have introduced the following bills:

1. Bill 15 – Utilities Commission Amendment Act
2. Bill 16 - Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act
3. Bill 18 – Greenhouse Gas Reduction (Cap and Trade) Act
4. Bill 31 – Greenhouse Gas Reduction (Emission Standards) Statutes Amendment Act
5. Bill 27 – Local Government (Green Communities) Statutes Amendment Act, 2008
6. Bill 37 – Carbon Tax Act

The intent of these Bills is to codify various policy items in the 2007 Energy Plan into law within British Columbia. Each of these bills received Royal Assent and was enacted by the end of the spring 2008 Legislative Session.

6 CONCLUSIONS

Climate change and energy are subjects of enormous global importance in the present times. The combustion of fossil fuels provides a large percentage of the overall global energy consumption at the end use and for conversion to another form of energy (i.e., electricity). The combustion of fossil fuels is also the largest contributor to the increasing level of atmospheric GHGs which in turn is considered to be the major contributor to global climate change.

Natural gas is the cleanest burning fossil fuel, producing lower GHG emissions and much lower levels of other pollutants, such as nitrogen oxides and particulates, relative to other fossil fuels. From a regional perspective natural gas is seen as an important part of the future energy resource mix and a contributor to the meeting the climate change mitigation and GHG reduction objectives in various jurisdictions. In electricity production natural gas-fired generation is a preferred resource option to displace coal-fired generation and to provide firm backup to the intermittent renewable generation resources such as wind, small hydro and solar. The direct use of natural gas for residential and commercial applications is also expected to be an important contributor regionally to increased energy efficiency, economic benefits and GHG reductions.

In British Columbia the abundant potential for renewable sources of electricity generation have placed the province in a different set of circumstances. Some have concluded by looking at B.C. in isolation that electricity should be used for space and water heating in the province and displace the use of natural gas in these applications. There are a number of shortcomings of this logic:

- It tends to underestimate or ignore the environmental and social impacts associated with large-scale expansion of renewable power in BC (e.g. the proliferation of transmission lines to connect the renewable resources to the grid, disruption of land use and aquatic systems, etc.)
- It does not recognize that the quantities of end use energy in the province are similar in magnitude for gas and electricity. Any significant shifting from natural gas to electricity would require enormous investment in generation resources and expansion and reinforcement of the electricity grid.
- If natural gas (and alternative energy sources) are used for space & water heating in the province more renewable B.C. electricity will be made available for export to offset fossil-fuel based generation in neighbouring jurisdictions and reduce GHG emissions regionally,
- It undervalues the economic benefits for the province of using the right fuel in the right use. The BC 2007 Energy Plan includes a number of policy actions aimed at responsible expansion of natural gas production in the province. The BC 2007 Energy Plan also promotes energy conservation and efficiency, the development of alternative energy technologies and using the right fuel in the right use. The efficient direct use of natural gas in BC supports all these objectives and will avoid the misuse of the province's valuable electricity resources in lower value end uses such as space and water heating.

It is acknowledged that the topics of Energy Planning and Climate Change discussed in this paper are highly complex and involve large numbers of stakeholders in government, industry and society in general. The intent of this discussion paper has been to show that energy planning and GHG mitigation strategies need to be developed giving consideration to regional issues and perspectives. A further purpose is to demonstrate that natural gas is an important part of the solution, both regionally and within British Columbia.

APPENDIX C

Northwest Gas Association Outlook Study

NWGA
NORTHWEST GAS ASSOCIATION

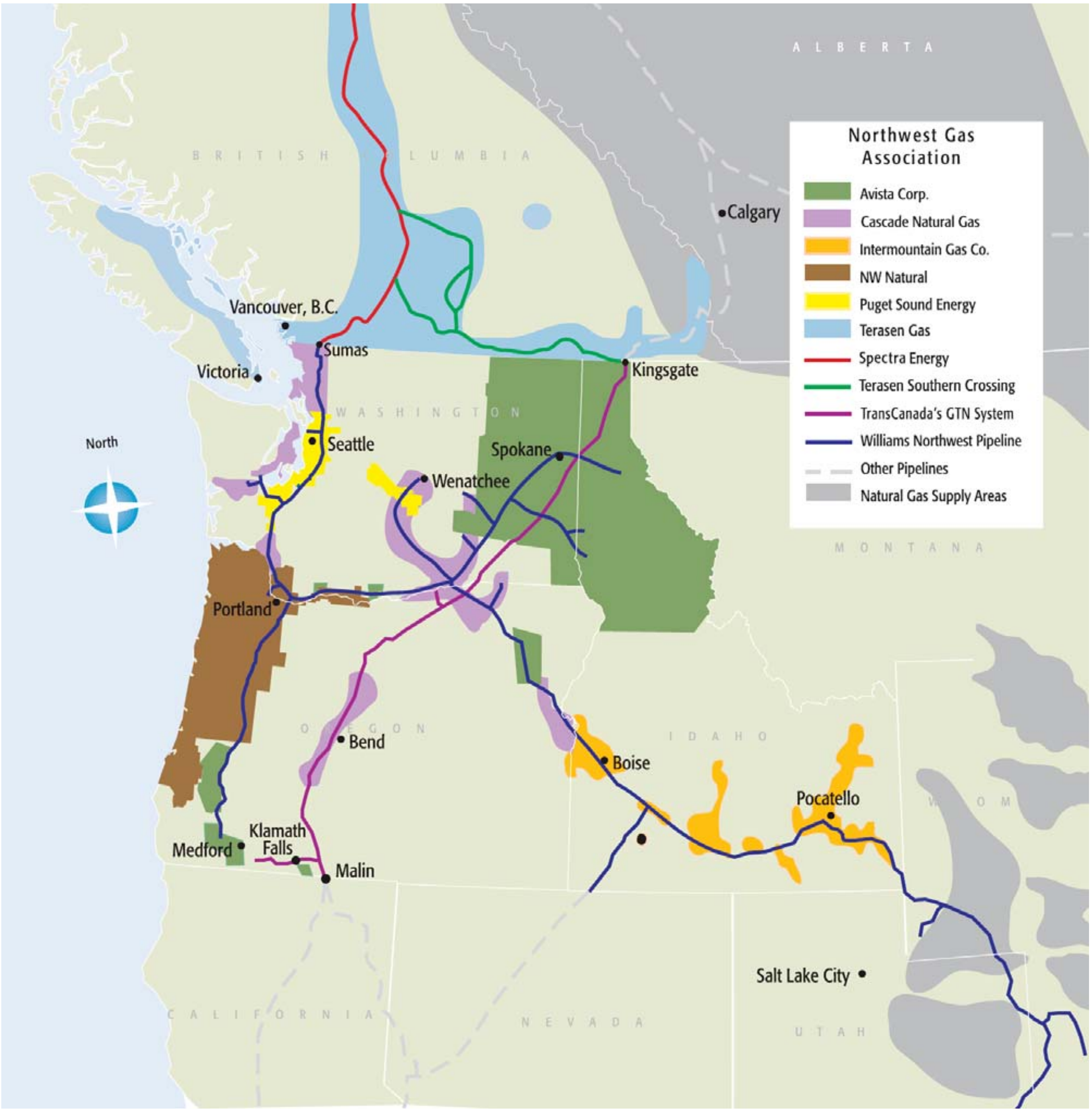
NORTHWEST GAS OUTLOOK

Natural Gas Demand, Supply and Service Capacity in the Pacific Northwest

FOR YEARS 2007 – 2012

PUBLISHED
FALL 2007

MAP OF NWGA MEMBER COMPANIES



NWGA MEMBERS

Avista	(800) 227-9187	www.avistautilities.com
Cascade Natural Gas Corporation	(206) 624-3900	www.cngc.com
Intermountain Gas Company	(208) 377-6000	www.intgas.com
NW Natural	(503) 226-4211	www.nwnatural.com
Puget Sound Energy	(425) 454-6363	www.pse.com
Spectra Energy Transmission	(604) 691-5500	www.spectraenergy.com
Terasen Gas	(800) 773-7001	www.terasengas.com
TransCanada GTN System	(503) 833-4000	www.gastransmissionnw.com
Williams' Northwest Pipeline	(801) 583-8800	www.williams.com

ABOUT THE NORTHWEST GAS ASSOCIATION

The NWGA is a trade organization of the Pacific Northwest natural gas industry. It seeks to meaningfully shape policies to help increase the diversity, abundance and dependability of natural gas supply and infrastructure available to serve the Pacific Northwest. Its members include six natural gas utilities serving communities throughout Idaho, Oregon, Washington and British Columbia, and three transmission pipelines that transport natural gas from supply basins into and through the region.

Avista Utilities (www.avistautilities.com) – Serves 306,000 natural gas customers in three Western states including northern Idaho, eastern Washington and parts of southwestern and northeastern Oregon.

Cascade Natural Gas Corporation (www.cngc.com) – Serves approximately 250,000 residential, commercial and industrial natural gas customers in 93 communities in Oregon and Washington.

Intermountain Gas Company (www.intgas.com) – Serves nearly 300,000 residential, commercial and industrial customers in 23 counties and 75 cities in southern Idaho, generally along the Snake River through southern Idaho.

NW Natural (www.nwnatural.com) – Serves 635,000 customers in Oregon and southwest Washington, including the Portland-Vancouver metropolitan area, the Willamette Valley, the northern Oregon coast and portions of the Columbia River Gorge.

Puget Sound Energy (www.pse.com) – The Pacific Northwest's largest energy utility provides electric and/or natural gas service to more than 1.2 million customers primarily in Washington State's Puget Sound region.

Spectra Energy Transmission. (www.spectraenergy.com) – Delivers gas to markets in British Columbia (BC) and the Pacific Northwest via a 1,600-mile pipeline transmission system stretching from Fort Nelson in northeast BC and Gordondale at the BC/Alberta border to the BC/U.S. border at Huntingdon/Sumas. Spectra's system is capable of transporting approximately 1.7 billion cubic feet (Bcf) of Canadian gas to key markets daily.

Terasen Gas (www.terasengas.com) – The largest distributor of natural gas in the Pacific Northwest and the third largest gas utility in Canada, serving more than 900,000 customers in 125 communities across British Columbia..

TransCanada Gas Transmission Northwest (www.gastransmissionnw.com) – Serves markets in California and Nevada, delivers gas in the Pacific Northwest directly to customers off its mainline system and to local distribution companies in Idaho, Oregon and Washington. The GTN system is capable of transporting approximately 2.9 Bcf of Canadian and domestic gas per day.

Williams Northwest Pipeline (www.williams.com) – Serves the Pacific Northwest and other western states with a 3,900-mile bi-directional system that extends from the Colorado/New Mexico state border to the U.S./Canadian border in the state of Washington. The system is capable of delivering up to 3.4 Bcf of peak-day gas from key supply points such as the Rockies, San Juan Basin and Western Canada Sedimentary Basin. Northwest also has working natural gas storage capacity of approximately 12.4 Bcf.

TO OUR READERS:

Understanding the technical side of this report.

Throughout this report we have used terminology specific to the natural gas industry. This includes the most common units of energy used to describe natural gas a measure of volume, and therms a measure of energy (or heat). When discussing the specifics of natural gas demand, supply or capacity, we have tried to be consistent about using the same unit of energy throughout a related section.

Here are some basic definitions for the various units of energy discussed to help our readers make comparisons should the need arise. While the energy content of natural gas varies according to its specific composition, we have generally used the value of 1,030 British thermal units (Btus) per cubic foot of natural gas when making conversions.

Btu	British thermal unit – a measure of energy content (non-metric).
1 Btu	The energy required to increase the temperature of one pound of water one degree Fahrenheit under standard (defined) conditions.
MMBtu	One million Btus – the typical unit by which natural gas is bought and sold (*e.g.* "the spot price of natural gas is $7.00 per MMBtu").
J	Joule – a measure of energy content (metric).
1 J	The energy required to lift a small apple (102 grams) one meter against Earth's gravity.
cf	Cubic foot – a measurement typically used to describe natural gas volumes, as in reserves, deliveries, storage levels, *etc*.
1 cf	Approximately 1,030 Btus; the energy content of natural gas varies by its source. This document uses 1,030 Btus/cf as a general rule.
Mcf	1,000 cubic feet. Equivalent to 1.03 MMBtu.
MMcf	1 million cubic feet. Equivalent to 1.03 MDth.
Bcf	1 billion cubic feet. Equivalent to 1.03 MMDth.
Tcf	1 trillion cubic feet.
Therm	A unit of heat equal to 100,000 Btus.
Dth	Decatherm; Equivalent to 10 therms, 1 million Btus or 0.975 Mcf.
MDth	1,000 Decatherms. Equivalent to 0.975 MMcf.
MMDth	1 million Decatherms. Equivalent to 0.975 Bcf.
W	Watt – a measure of electrical energy.
kw	Kilowatt or 1,000 watts.
kWh	Kilowatt-hour, a measurement of electrical energy used over time. (Ten 100w light bulbs burning for one hour would use 1 kWh.)
1 kWh	3,413 Btus.
hp	Horsepower – a measure of mechanical energy. One horsepower equals 550 foot-pounds per second.
1 hp	746 watts.
hp-hr	Horsepower-hour.
1hp-hr	2,545 Btus.

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EXECUTIVE SUMMARY

This report, compiled annually by the Northwest Gas Association (NWGA) and its members, provides a consensus industry perspective of the Pacific Northwest's current and projected natural gas demand, supply, delivery capability and prices. For purposes of this report, the Pacific Northwest is defined as Idaho, Oregon, Washington and British Columbia (BC). This forecast covers the period beginning November 1, 2007 and ending October 31, 2012.

Information and data for the report were provided by NWGA member companies and drawn from various public and internal planning documents (*e.g.*, integrated resource plans, least-cost plans, *etc.*), then compiled, analyzed and agreed to by a group of market specialists representing each of the NWGA member companies and encompassing a variety of disciplines. Regional, national and continental statistics were obtained from a variety of sources, including the Energy Information Administration (EIA), Northwest Power and Conservation Council (NWPCC), National Energy Board (NEB) – Canada, Statistics Canada and others as cited.

By sharing factual information about the dynamics of the regional natural gas industry, the Association hopes to:

• Build a broad-based awareness of the natural gas industry – including the vital role it can play in mitigating climate change – throughout the region.

• Cultivate a common outlook as industry participants work through the challenges of ensuring a reliable supply of natural gas to serve growing regional demand.

• Encourage discussion about region-wide energy issues beyond natural gas, including a better understanding of the potential impacts of various fuel choices on the local economy and global environment and the need for more integration in energy planning.

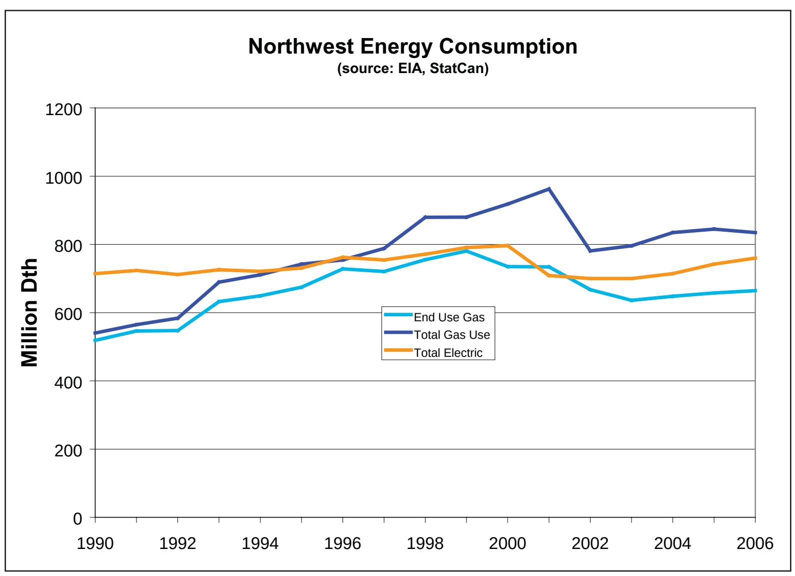
• Promote public policies and industry and consumer actions that will ensure the wise and most cost-effective use of natural gas.

Understanding the natural gas market and how best to use this valuable resource is particularly important today as the region joins with energy users across the globe to address climate change. As the cleanest burning fossil fuel, natural gas is already playing a central role in emerging policies and energy industry initiatives to protect our environment.

THE ROLE OF NATURAL GAS IN THE NORTHWEST

Natural gas serves an important role in the Pacific Northwest's energy market. Here is a look at the numbers:

- Natural gas burned directly for residential space and water heat, and for commercial and industrial processes (*i.e.* "end use") accounts for more than 40 percent of the total energy consumed in the region in the form of electricity and natural gas. The number jumps to almost 50% when including natural gas used to generate electricity.



- According to the Northwest Power and Conservation Council (NPCC), natural gas fuels almost one quarter of the Northwest's power generation capability.
- The number of natural gas customers in the region grew by nearly 13 percent between 2000 and 2005, despite a regional economic downturn and commodity price increases.

HOW RECENT HISTORY SHAPED TODAY'S MARKET

The western energy crisis of 2000-2001, together with the 9/11 terrorist attacks, the subsequent downturn in capital markets and a soft economy significantly changed the energy market in the Pacific Northwest. Not surprisingly, the Pacific Northwest's overall economy also changed, in some cases permanently. For instance, skyrocketing power costs spurred mergers, acquisitions and plant closures, which eliminated thousands of high-paying jobs in the aluminum and other industries.

Electricity and natural gas prices have since stabilized in the region, although at sustained higher levels. Unemployment rates have declined as the region continues to generate new jobs. More recently, sustained high crude oil prices have continued to boost the cost of heating oil and gasoline.

As a result, consumers are spending more of their budgets on energy for heating, transportation and manufacturing. This has provided incentives to develop more efficient technologies and conserve energy use – already evidenced by declining natural gas and electricity consumption per customer. And now, greater awareness of the impact of our energy use on the Earth's climate is further shaping government policies, industry initiatives and consumer habits.

On the following pages, this report looks at what this new energy paradigm means for future natural gas demand, supply, infrastructure and prices as the industry adapts to market changes.

SUMMARY OF KEY CONCLUSIONS

The Pacific Northwest regional natural gas market is robust. In the short run the industry faces a number of challenges – including increased competition for supplies; growing demand; lagging development of new supplies and the potential for higher prices triggered by a tight demand/supply balance. The prospects remain bright over the longer term. As the cleanest burning fossil fuel, natural gas will play a significant role in addressing what has emerged as one of the top priorities for regional public policy-makers: climate change.

BLUE BRIDGE TO
A GREEN WORLD

As the cleanest burning fossil fuel with abundant supplies across the globe, natural gas will play a vital role in mitigating climate changes.

The natural gas industry is committed to do its part by encouraging the wise and appropriate use of natural gas, acquiring necessary supply and building needed infrastructure to sustain a balanced market and stabilize prices. **However, policymakers can have a significant impact on the availability and price of natural gas in the future** based on whether and how swiftly they can work together to address critical issues facing natural gas consumers today. They will play a pivotal role in how effectively this resource can be harnessed to help address climate change. To that end, we hope this report can inform and guide policymakers' efforts.

Here is a summary of key conclusions drawn from the data and discussion contained in this report:

DEMAND

- Regional demand for natural gas will grow over the next five years, paced by demand for gas-fired electrical generation and continued growth in the number of residential customers.
- Recently adopted climate change policies will drive additional demand for natural gas because its clean-burning attributes are vital in helping to reduce carbon emissions.

- Relatively higher natural gas prices and energy efficiency efforts continue to limit growth in industrial demand for natural gas.

- Weather-dependent gas demand – *e.g.*, space heating in the winter or natural gas-fired electrical generation to power air conditioning during the summer – continues to grow more rapidly than baseload demand. This change in the region's "load shape" has implications for future infrastructure investments needed to serve higher short-term spikes in demand.

SUPPLY

- Other regions of North America will increasingly access gas supplies from production areas upon which the Northwest depends.

- To meet future regional and continental demand growth – particularly in response to climate change policies – North America will require new incremental supplies. Sources of additional natural gas are plentiful and include liquefied natural gas (LNG) imported from overseas and new supply sources closer to home such as Alaskan gas, Canadian frontier gas (Mackenzie River Delta), offshore resources and unconventional resources such as coal-bed methane, shale and biogas.

- Escalating exploration and development costs, exploration and drilling restrictions and regulatory hurdles impede development of new incremental natural gas resources.

CAPACITY

- Existing natural gas pipeline and storage capabilities are adequate to serve regional needs for the next five years under normal conditions. Extreme peaks in demand, however, could approach the capacity limits of the region's infrastructure.

- As the competition for existing supplies increases and market options grow for natural gas producers, large consumers in the region (*e.g.*, local distribution companies, power generators, and industrial customers) will require additional upstream transport capacity to ensure sustained access to available Canadian and Rockies supplies.

- Market-area storage is important to serve weather-driven peak demand (typically very cold days) that are only sustained for a few days at a time. This is especially true as weather sensitive demand in the region (*e.g.* residential heating, electric generation) is growing more rapidly than the region's baseload demand which occurs regardless of the weather.

- Lead times for adding infrastructure are long and rapidly escalating pipe costs, personnel shortages, and environmental, regulatory and permitting hurdles may impede the development of new incremental capacity within the region.

- The region has historically added new infrastructure when needed. Currently, several new pipelines are under consideration, most of them to transport potential LNG to market. These proposed facilities would add supply diversity and incremental capacity to the region's existing natural gas infrastructure.

PRICES

- Like most commodities, natural gas prices reflect the relative balance between supply and demand. Increased demand for natural gas – driven in part by regional climate change policies – and more competition from other North American markets will only tighten the region's demand/supply balance.

- In addition to ensuring that energy is utilized as efficiently and effectively as possible, policymakers must explore and encourage increased access to new and existing supplies.

- Average U.S. wholesale (wellhead) prices for natural gas more than doubled between 2002 and 2005 then stabilized last year – dropping more than 10 percent from $7.33 per thousand cubic feet in 2005 to $6.42 in 2006 according to the U.S. Energy Information Administration (EIA)[1]. The price decline was due to temperate weather conditions and an absence of supply disruptions from seasonal events like hurricanes. This decline prompted a number of Northwest utilities to file for decreases in their purchased gas adjustments in the fall of 2007.
- The EIA projects that the average U.S. wholesale price of natural gas in 2007 will rebound to $7.45 per Mcf and resume an upward trend due to increasing demand, declining traditional supplies, a growing reliance on new and more expensive sources of supply and sustained high crude oil prices.[2]

[1] *U.S. Energy Information Association, Natural Gas Prices - http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm*
[2] *U.S. Energy Information Administration, Short Term Energy Outlook, August 7, 2007*

REGIONAL NATURAL GAS DEMAND

KEY CONCLUSIONS

1. Natural gas consumption in the region (measured by energy content, or decatherms - Dth) is expected to grow an average of 1.9 percent per year, with a cumulative projected growth rate of 7.2 percent through 2012 (see data table A.1., Appendix page 29). Most of this increase reflects an anticipated rebound in demand by electrical generation as well as continued growth in residential demand.
2. The region's peak demand is growing more rapidly than its baseload demand. This has significant implications for the type of new capacity most appropriate to serve the region's needs.
3. The number of natural gas customers continues to grow in the Pacific Northwest, although the use per customer is lower than in the late '90s and continues to decline. New construction complying with efficiency-minded development codes and consumer response to higher natural gas prices, including better weatherization, more efficient appliances and equipment and more conscientious energy use have all contributed to lower per-customer use of natural gas.
4. New energy policies to mitigate climate change are increasingly driving demand for natural gas both regionally and continentally because its clean-burning attributes are recognized as an important tool in reducing carbon emissions.
5. In the face of climate change, we must ensure now more than ever that we are using natural gas resources in the most efficient ways possible. Because natural gas emits fewer greenhouse gases (GHG) than other fossil fuels, it will increasingly be used to generate electricity. But it is most efficient when burned for home space and water heating, cooking, or to fuel vehicles, and we need to encourage those uses.

A CLOSER LOOK

RECENT DEMAND[3]

Events at the beginning of this decade continue to influence natural gas demand in the Pacific Northwest. A significant and immediate decrease in the region's industrial energy consumption caused by the energy crisis of 2000-2001 was followed by several years of a sluggish economy and warmer winter weather. In 2005, for example, aggregate deliveries to all market sectors (customer types) were 6 percent less than they were in 2000 (See Figure 1). From 2002 through 2006, however, aggregate demand grew by 9.2 percent; an indicator that steady growth in all but the industrial sector has resumed since the energy crisis .

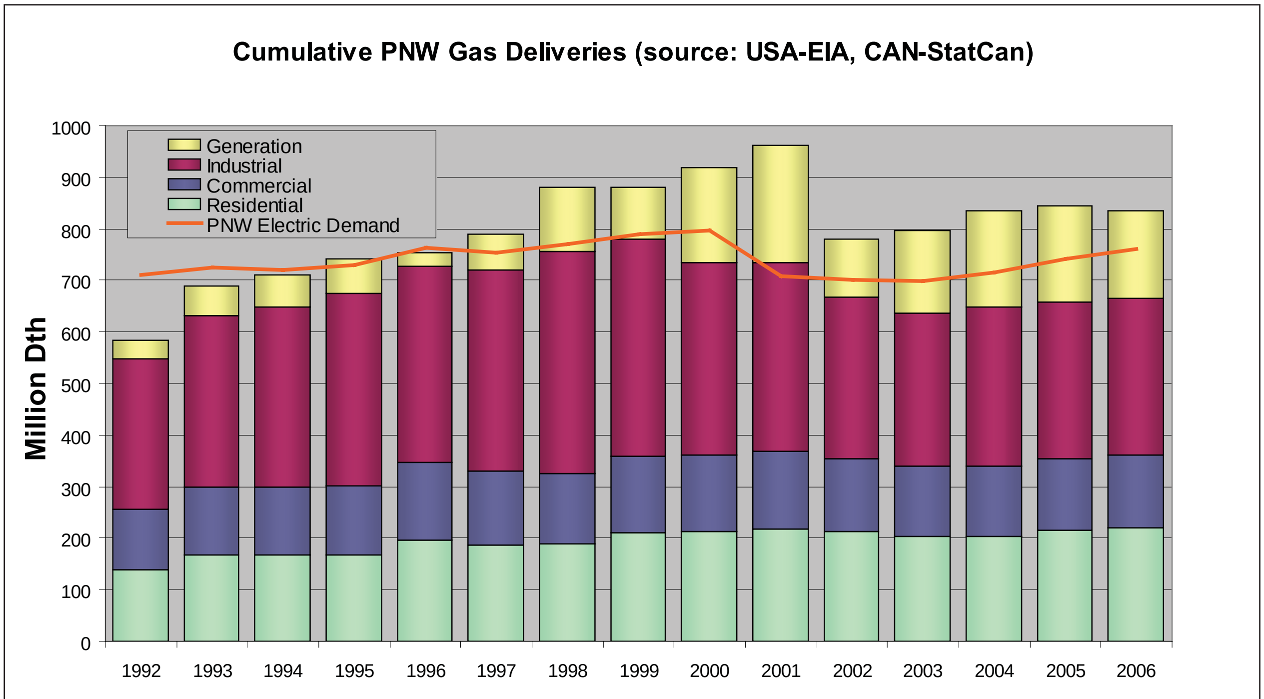
Here is how consumption has changed since that period for different customer groups:

Residential and commercial consumers used 1.5 percent less natural gas in 2005 than in 2000. During the same period, however, the actual number of residential and commercial customers grew by almost 13 percent (NWGA member survey, Spring 2007). While mild weather was a part of the equation, reduced per-person usage reflects greater investment in energy efficient appliances and conservation practices since the energy crisis.

Industrial consumption of natural gas remains at a much lower level – 20 percent less in 2005 than in 2000 (a 45 percent drop from its historical high recorded in 1998). Because energy costs can be a large part of operating costs, the industrial sector is very price-sensitive. Industrial consumers were especially hard hit during the earlier energy crisis – in some cases, permanently closing plants and merging operations – and those changes, along with aggressive implementation of energy conservation measures, have permanently changed the region's industrial base.

[3] *Unless otherwise noted, U.S. historical demand data is drawn from the Energy Information Administration (EIA); Canadian data from Statistics Canada.*

FIGURE 1. PNW NATURAL GAS DEMAND - 1992-2006



Source: NWGA

Power generation demand has been volatile reflecting the many variables that can affect it (*e.g.*, relative weather severity, availability of hydropower, costs of natural gas and oil). According to the EIA, the use of natural gas to fuel the region's electrical generators reached its peak in 2001 at a time when electricity prices were high because of the energy crisis and market conditions created demand for generation from gas-fired units. The very next year saw a combination of abundant hydropower, dampened electricity demand and stronger wholesale natural gas prices, resulting in a 50 percent drop in the amount of gas used to generate electricity. In 2005, the volume of gas fueling electric generation was 18 percent lower than its high point in 2001 but had rebounded, growing an average of almost 18 percent a year from the 2002 low point.

More than 20 percent of the region's electricity generating capability is fueled by natural gas. The region's 57 gas-fired generation facilities are capable of delivering in excess of 6,400 megawatts (MW) of power.[4] Of that total, almost 3,800 MWs have been added since 2001. Electricity generated by these facilities serves the Northwest as well as California and the desert southwest. Three more gas-fired plants with the capability of delivering almost 900 MWs are currently anticipated or under construction.

FUTURE DEMAND PROJECTIONS

Natural gas demand in the Pacific Northwest is projected to grow 1.9 percent annually, for a total of 7.2 percent through 2012, given normal weather conditions and expected economic and population growth (called "base case"). This projection continues a slight downward trend (the 2005 and 2006 Outlook reports projected 9.3 percent and 8.1 percent cumulative growth, respectively, over five years), and also represents a shift in market forces behind that growth. Whereas demand growth by residential/commercial customers eclipsed that of gas-powered electric generation facilities in recent years, changing energy policies and relatively stable gas prices have spurred an increase in anticipated generation demand.

Still, expected demand growth among residential consumers continues to play a large role. This partly reflects a growth in the number of consumers – due to an expanding economy and population – as well as the higher cost of alternative energy sources, such as electricity and heating oil. Since natural gas is a good value for home heating, it

[4] *Power Plants in the Pacific Northwest, NWPCC, July 2007.*

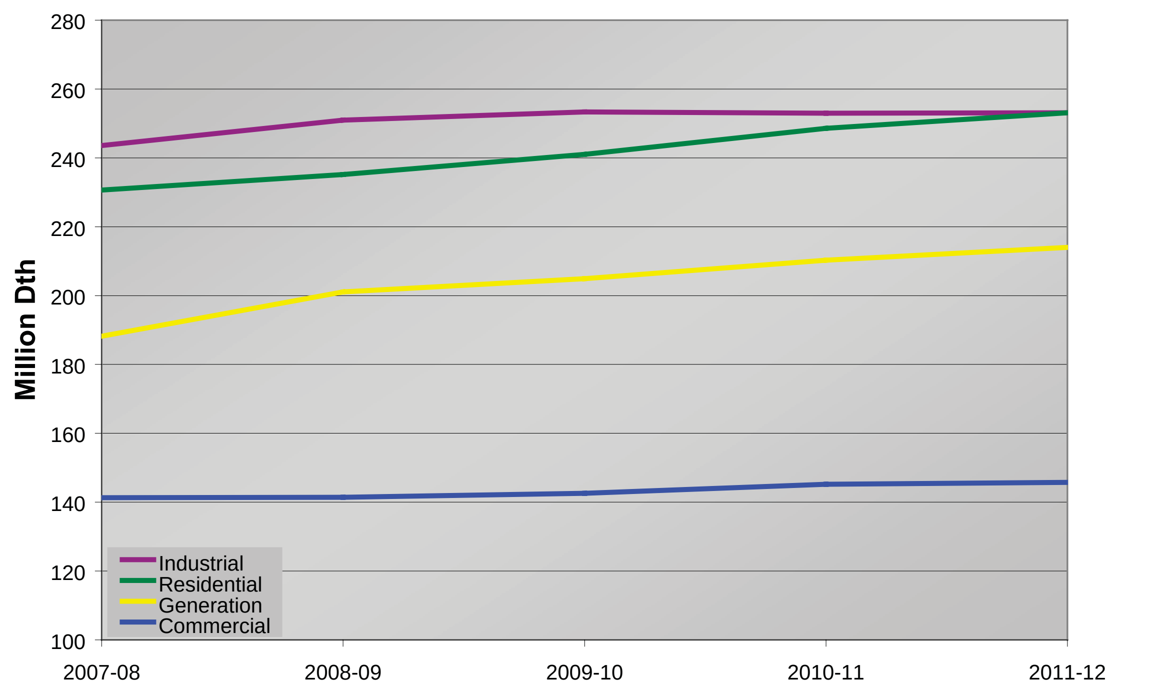
remains the fuel of choice for space and water heat in most new single-family home construction, and many older electric furnaces and water heaters are being replaced with natural gas units. Forecast growth in demand for each customer group under a number of growth scenarios is shown in Table 1.

TABLE 1. PROJECTED REGIONAL DEMAND GROWTH THROUGH 2012

	Low Growth Case		Base (expected) Case		High Growth Case	
	Average Annual	Cumulative	Average Annual	Cumulative	Average Annual	Cumulative
Total	1.3%	4.8%	1.9%	7.2%	2.2%	8.5%
Residential	1.7%	6.4%	2.3%	8.9%	3.1%	11.5%
Commercial[5]	0.3%	1.1%	0.8%	3.0%	1.1%	4.1%
Industrial	0.8%	3.0%	1.0%	3.8%	1.3%	5.1%
Generation	2.1%	8.0%	3.3%	12.1%	3.2%	11.8%

Industrial consumption, while still proportionally larger than other customer groups, continues to show effects of the earlier energy crisis and weak economy and is growing very slowly. As shown in Figure 2, total residential customer demand is expected to surpass industrial demand by 2011. Figure 3 shows projected total annual demand growth for each of the next five years.

FIGURE 2. PROJECTED DEMAND BY SECTOR - BASE CASE , 2007-2012



Source: NWGA

[5] *The drop in commercial demand from the 2006 Outlook study largely reflects customers switching to an industrial customer class*

FIGURE 3. PROJECTED DEMAND GROWTH BASE CASE 2007-2012

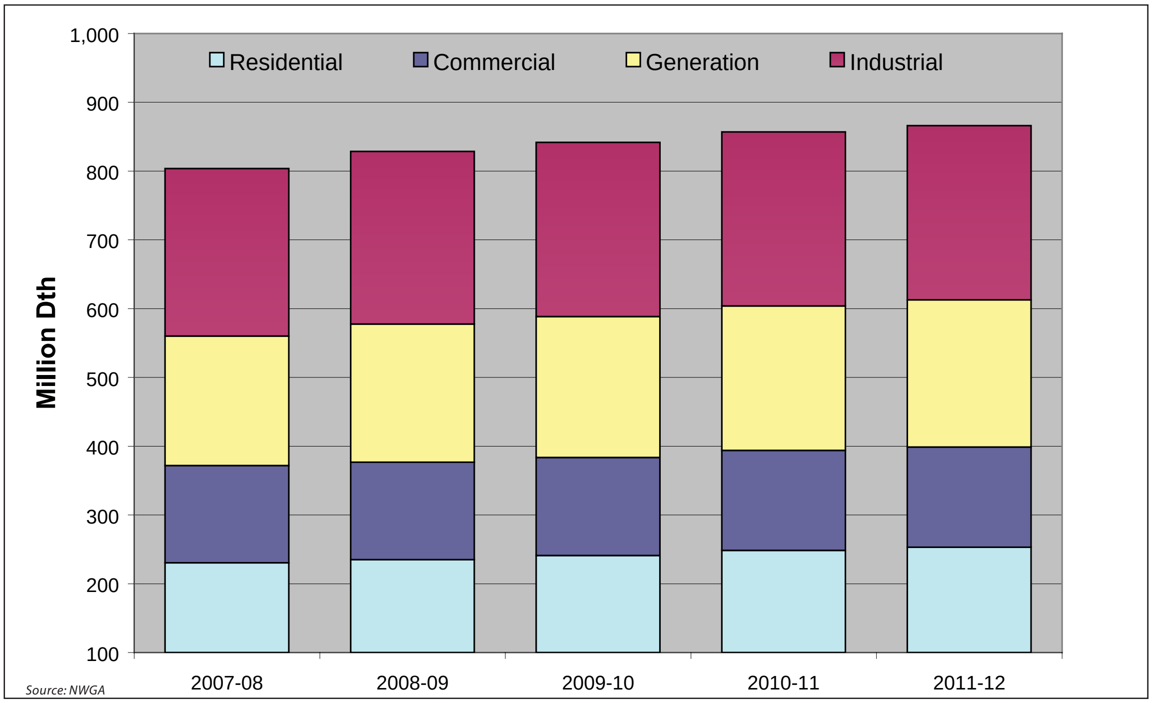
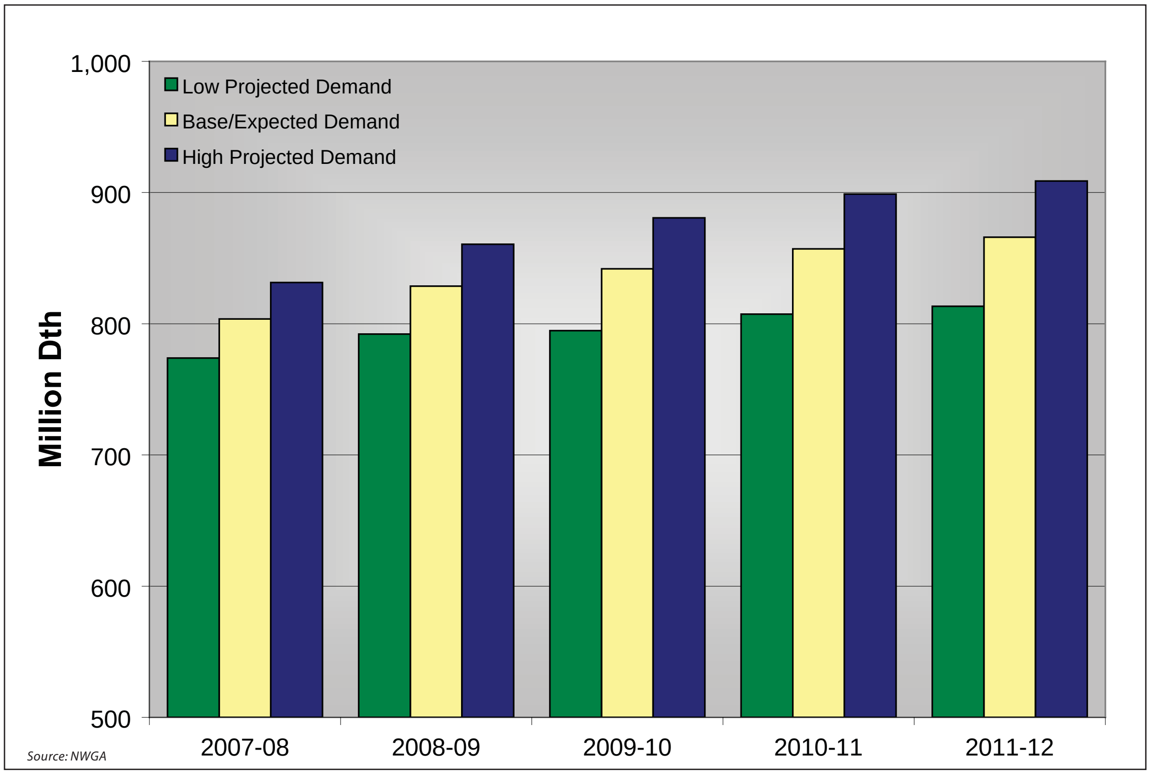


Figure 4 shows projected annual demand under each of the three growth scenarios: base-case, low-growth and high-growth. Low-growth assumes slower than expected economic growth while high-growth considers a more rapid economic expansion and greater requirements for gas-fired electrical generation. Projected gas prices also figure prominently in the respective forecasts. The low case reflects higher than expected natural gas prices, and the high case lower than expected prices.

FIGURE 4. PROJECTED ANNUAL DEMAND BY GROWTH CASE, 2007-2012



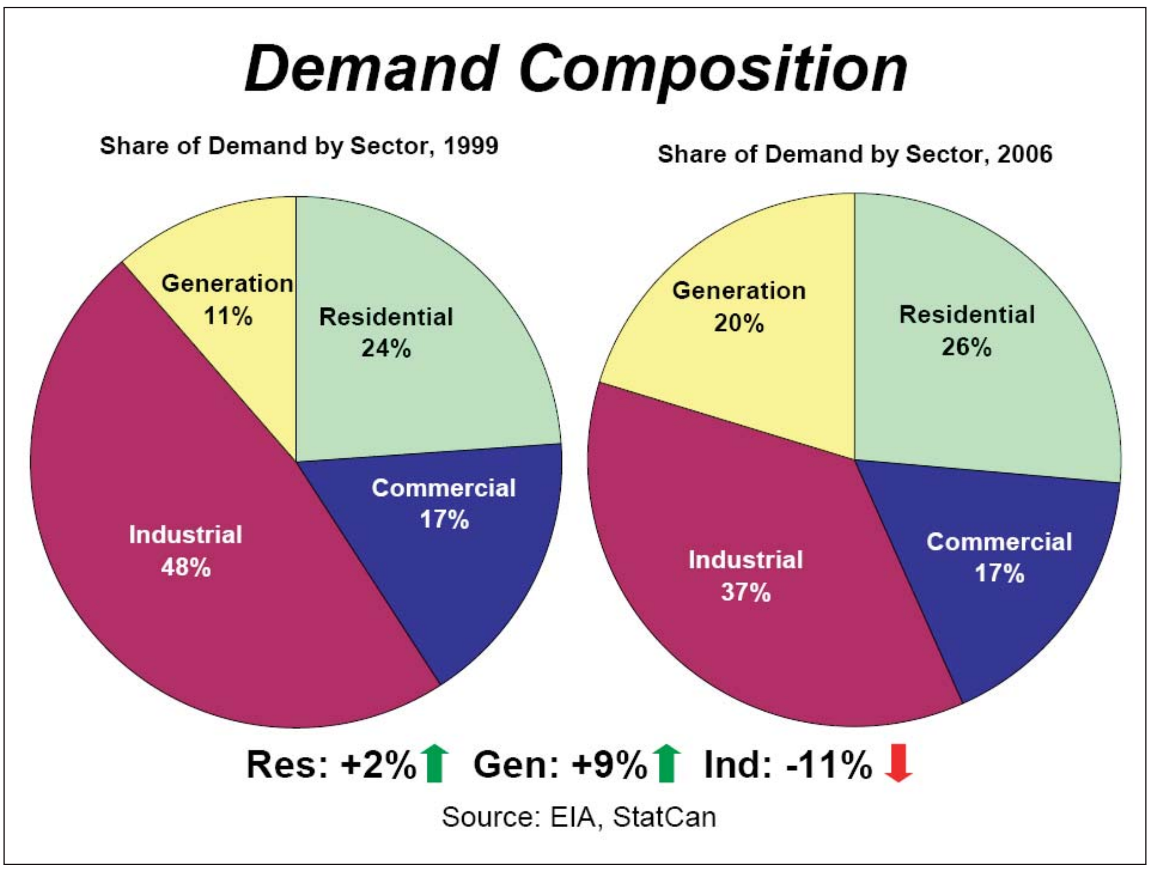
TRENDS IN DEMAND GROWTH

While the region's natural gas consumption continues to grow, the nature of that consumption has changed in recent years. Increased energy conservation efforts triggered by rising energy prices have not only slowed the rate of demand growth, but changed customer demand profiles and composition (Figure 5). Year-round or baseload demand (*e.g.*, industrial processes only nominally affected by weather, including chemical processing, kilns to dry lumber, or boilers for food processing) are growing more slowly than demand triggered by weather or other short-term factors (*e.g.*, home heating).

And new energy policies aimed at reducing carbon emissions will likely intensify this trend. The region requires additional electric resources to serve expected growth in baseload demand as well as weather-driven demand in the summer (air conditioning) and winter months (electric baseboard heating). Emissions standards recently enacted throughout the region dictate that any new generation must meet or improve upon the emissions from the best available natural gas-fired generation technology.

This change has important implications for the natural gas industry since it affects the region's overall capacity and purchasing requirements to serve potentially more seasonally peaking customer demand. For instance, pipelines are usually built to serve baseload demand, while storage facilities are typically the most cost-effective method of meeting short-term surges in demand. (For more information on the region's pipeline and storage facilities, see the Regional System Capacity section later in this document.)

FIGURE 5. CHANGE IN LOAD COMPOSITION 1999 ACTUAL -2006 ACTUAL



WHAT THIS MEANS

How can the region's growing natural gas demand – now encouraged by environmental mandates – best be met? Encouraging even more efficient use of this vital resource while simultaneously working to expand access to new supplies will help. (The need to expand supplies is discussed in the following Regional Supply section.)

ENCOURAGING WISE USE OF NATURAL GAS

Demand for natural gas is something nearly every consumer can influence. With proper information and often at minimal expense, consumers can take a variety of steps to reduce their usage and monthly bills. Customers have already significantly curbed regional demand – often with technical and/or financial help from energy efficiency programs offered by gas and electric utilities or other entities – by installing more efficient furnaces and appliances, programmable thermostats and better weatherizing their homes and businesses.

However, more can be done. The American Council for an Energy Efficient Economy (ACEEE) estimates that widespread adoption of cost-effective energy efficiency measures throughout the U.S. alone could lower projected national gas usage by 10 percent by 2020 and cut the wholesale price of natural gas by 25 percent. Such measures will have maximum impact if they encourage direct uses of natural gas at the burner tip for home heating, water heating, stovetops, even vehicles. Consequently, policymakers should also focus on encouraging high-efficiency end-use natural gas applications.

> Right Fuel, Right Use:
>
> Direct use of natural gas – for home and water heating, cooking, and to power vehicles – is the most environmentally beneficial and cost-effective way to use it

HELPING UTILITIES HELP CUSTOMERS

Traditional rate structures recover fixed costs on a volume basis and therefore provide little incentive for natural gas utilities to invest funds that promote energy efficiency programs. In fact, such programs dilute the earnings of energy companies unless accompanied by regulatory solutions. Simply put, the less gas consumers use, the less revenue a utility receives for its fixed costs required to provide natural gas transportation and distribution services.

To overcome this disincentive for utilities to promote and acquire cost effective conservation, regulators throughout the U.S. and Canada have begun to evaluate and adopt various

HOW NEW ENERGY POLICIES ARE DRIVING NATURAL GAS DEMAND

As policymakers address climate change and enact laws that shape how we use energy, the impact on regional energy markets will be extensive. Because it is efficient and clean-burning compared to other fossil fuels, natural gas will play a vital and growing role as governments mandate greenhouse gas (GHG) emission reductions and other measures designed to mitigate environmental impacts.

The U.S. and Canadian federal governments are already developing aggressive policies to encourage emission reductions. In the U.S., for example, some $35 billion in tax incentives has been invested to promote cleaner energy sources and emission-reducing technologies. Several proposals have been introduced in the past year, all aimed at enacting even more comprehensive remedies. While differing in details, all call for reducing U.S. emissions (usually by 80 percent) by a certain deadline (usually 2050).

In Canada, the federal government has released its Regulatory Framework for Air Emissions, which requires industrial emitters to reduce their emission intensities at an increasing rate beginning in 2010, with an overall goal of 38 percent reduction by 2020 and 60-70 percent reduction by 2050.

Regionally, Pacific Northwest policymakers in the U.S. and Canada are already blazing trails to reduce GHG emissions. In the U.S., Washington and Oregon both enacted standards requiring significant proportions of electricity to be generated by renewable resources. Both states also adopted standards that limit the emission of greenhouse gases by any new electric generation resources to those of state-of-the-art gas-fired generation technology. Idaho enacted a temporary moratorium on mercury emissions, precluding the construction of any new coal-fired generation in the state.

In addition to Canadian federal actions, British Columbia (BC) issued its new Energy Plan in the spring of 2007, which calls for reducing GHG emissions to 2000 levels by 2016 and by 33 percent from current levels by 2020. The goal is for clean or renewable electricity generation to account for at least 90 percent of total generation. BC is aiming to be carbon-neutral by 2010. Similarly, the Province of Alberta, one of the first provinces to require large industrial facilities to report their GHG emissions (beginning in 2002), has put in place GHG emission intensity targets effective July 1, 2007, and is working on a more comprehensive climate change action plan to be issued later this fall.

The Western Climate Initiative, a collaboration launched in 2007 between six Western states (including Oregon and Washington), BC and Manitoba, has additionally agreed to an overall regional (aggregate) goal of reducing GHG by 15 percent below 2005 levels by 2020.

innovative rate structures. One example, called "decoupling," separates the direct link between the volume of gas sold and recovery of authorized fixed costs, usually by establishing a rate structure that allows a utility to recover its fixed costs regardless of how much gas it distributes. Adoption of creative rate structures such as decoupling, as well as tax credits and other incentives, would make utilities indifferent to lower gas sales volumes and likely encourage investment in technology and programs that further promote energy efficiency.

EMERGING/ALTERNATIVE USES OF NATURAL GAS

One known significant source of carbon and pollutant emissions is fuel burned for transportation. Not surprisingly, the high cost of crude oil and growing political and environmental concerns about its use have spurred consumer interest in vehicles powered by electricity, biodiesel and natural gas.

Here is a brief look at how natural gas is being used or considered for vehicle and mass transit programs throughout the Pacific Northwest.

NATURAL GAS POWERED FLEETS

Natural Gas Vehicle (NGV) technology is the most advanced and widely used newer and environmentally friendly transportation fuel solution. California claims the honor as North America's biggest user of NGVs, with a large network of fueling stations and incentives for adopting the technology for both passenger and commercial vehicles.

NGV technology has also gained a foothold in the Pacific Northwest, primarily for large fleet and mass transit applications. For example, Pierce Transit in Tacoma, Wash., has the largest and likely longest-serving natural gas bus fleet in the region, boasting more than 20 years of NGV experience and a present-day natural gas bus fleet exceeding 250 vehicles. Several taxicab fleets in Washington have also converted to natural gas. In BC, the Greater Vancouver Transit Authority recently purchased 50 buses fueled by compressed natural gas (CNG) – bringing its NGV fleet to 75 – and continues to test newer CNG/hydrogen blended technology. And Valley Regional Transit, the bus system for greater Boise, Idaho, currently has 27 dedicated CNG buses using 40,000 MMBtus of natural gas annually. In addition, most regional gas utilities use CNG for some or all of their service vehicles.

The heavy-duty natural gas engine is currently the cleanest commercial engine available and already meets 2010 EPA standards. This gives natural gas an advantage for enabling large-scale, step reductions in transportation emissions by fleet vehicles.

GREEN PORTS

Another promising adaptation is the use of natural gas to generate on-site, shore-side electricity for ships in ports. Instead of relying on diesel or oil-powered shipboard generators, docked ships could plug into shore-based liquefied natural gas (LNG) fueled generators. Called "cold-ironing," this practice is being examined by California and other jurisdictions as one means to reduce emissions from the shipping industry. Having LNG available at ports also provides an opportunity for port vehicles to run on the fuel, reducing port emissions as well. The Port of Oakland is currently undertaking a pilot study that may lead to other, similar projects in the Pacific Northwest.

NATURAL GAS FUELED FERRIES

As with large commercial and industrial vehicles, natural gas offers a cleaner, lower-emitting fuel alternative to diesel engines on pedestrian and vehicle ferries. Already operating in other parts of the world, this natural gas and dual-fuel technology holds promise for our region as well. In BC, the Greater Vancouver Transit Authority already has experience operating two short-run, dual-fuel (diesel/compressed natural gas) ferries on an inland waterway. Studies are now being conducted to explore the use of LNG for new or existing coastal ferry runs and may result in future pilot projects in the region.

Additional information on natural gas demand and influencing factors can be found in the NWGA white paper *Natural Gas Demand in the Pacific Northwest*, Fall 2006. The role natural gas can play in mitigating climate changes is discussed further in the white paper *Natural Gas and Climate Change in the Pacific Northwest*, Fall 2007. Both are posted on the NWGA website www.nwga.org.

REGIONAL NATURAL GAS SUPPLY

KEY CONCLUSIONS

1. The Pacific Northwest market benefits from its proximity to two large gas-producing regions – the Western Canada Sedimentary Basin (WCSB), consisting of an expansive area covering northeast British Columbia (BC), much of Alberta and part of Saskatchewan; and the U.S. Rocky Mountains, including primarily Colorado, Utah and Wyoming – see Figure 6.

2. However, the region is increasingly competing for those resources with other North American markets. New pipelines built in recent years provide access to these supplies by growing markets in the Midwest and Northeast, and proposed pipelines will sustain the trend. For example, the Rockies Express (REX) Pipeline under construction by Kinder Morgan is expected to ship 1.8 Bcf/day of gas from the Rockies to Ohio, and several pipelines have been proposed to spur off of REX to transport Rockies gas further east.

3. With U.S. and Canadian natural gas demand expected to grow nearly 20 percent by 2030,[6] and declining and/or restricted supplies elsewhere on the continent, we will soon need additional natural gas resources to serve both the Pacific Northwest and the rest of North America.

4. Liquefied natural gas (LNG) imports will play a vital role in meeting future demand and are expected to make up almost 20 percent of U.S. supply by 2030, according to the EIA. Besides LNG imports, access to Alaskan gas, Canadian frontier gas, development of offshore gas supplies and non-conventional resources such as coal-bed methane reserves, shale gas and biogas will all play important roles serving future demand.

5. To ensure supply can keep pace with demand, we must build on recent efforts to encourage exploration, development and production in these areas and re-examine the restrictions on offshore drilling.

The Pacific Northwest currently relies on natural gas produced in the WCSB and the U.S. Rockies. About half of the gas consumed in the region comes from the portion of the WCSB located in northeast BC.

FIGURE 6 - PRODUCTION AREAS IN THE PNW

6 EIA, International Energy Outlook 2007, May, 2007.

A CLOSER LOOK

Total annual natural gas production in the WCSB and Rockies, currently about 25 billion cubic feet per day (Bcf/d), could approach 27 Bcf/d by 2012 according to some estimates,[7] due primarily to growth in the Rockies. Figures 7 and 8 illustrate forecasts for production in each of the aforementioned areas. As indicated, WCSB production is expected to decline overall. However, production in the Northeast BC sector of the WCSB will experience strong growth in production. The average of Rockies production forecasts indicates an increase of almost 20 percent (about 4 percent annually) over the forecast period.

In all, the two production areas contain about 99 trillion cubic feet (Tcf)[8] of proven reserves (a "working inventory" of natural gas that can be economically recovered using today's technologies), or more than a third of North America's total proven reserves. The combined ultimate resource potential (best estimate of total resources) of the Rockies and the WCSB exceeds 500 Tcf.

FIGURE 7. WCSB GAS PRODUCTION FORECAST[9]

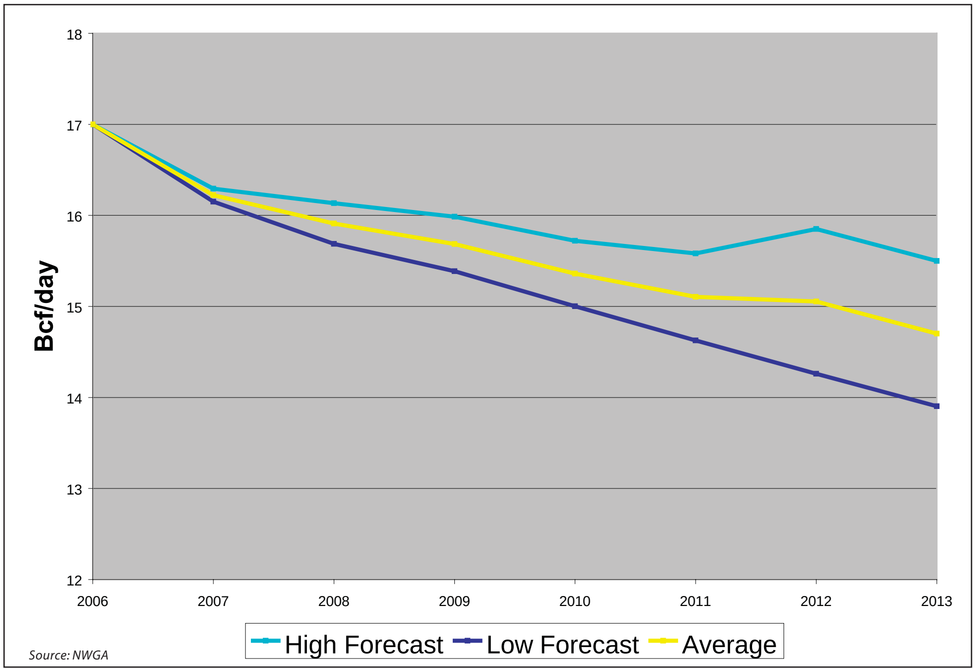
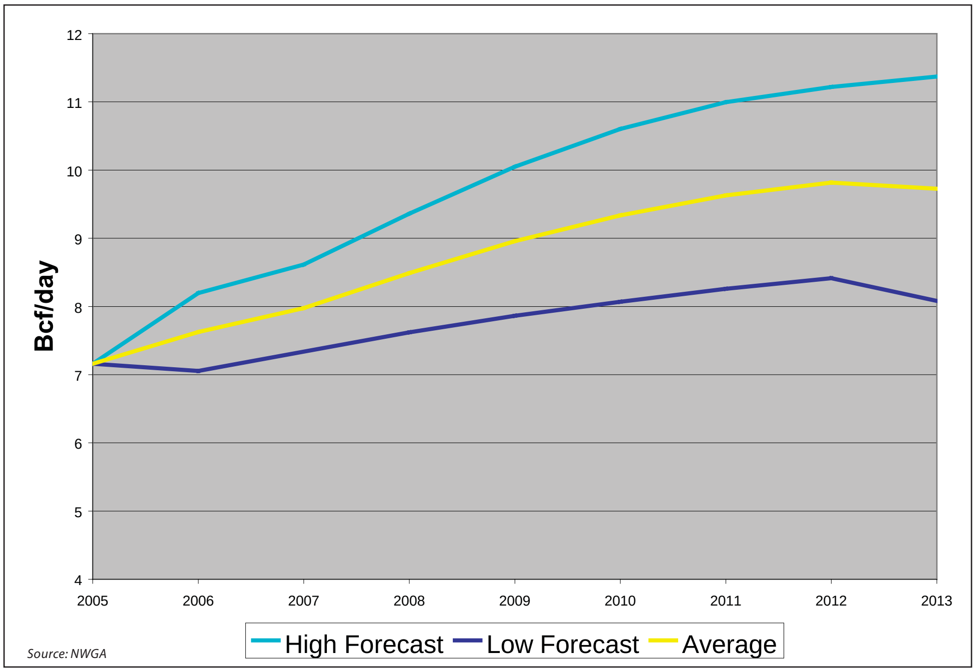


FIGURE 8. ROCKIES GAS PRODUCTION FORECAST

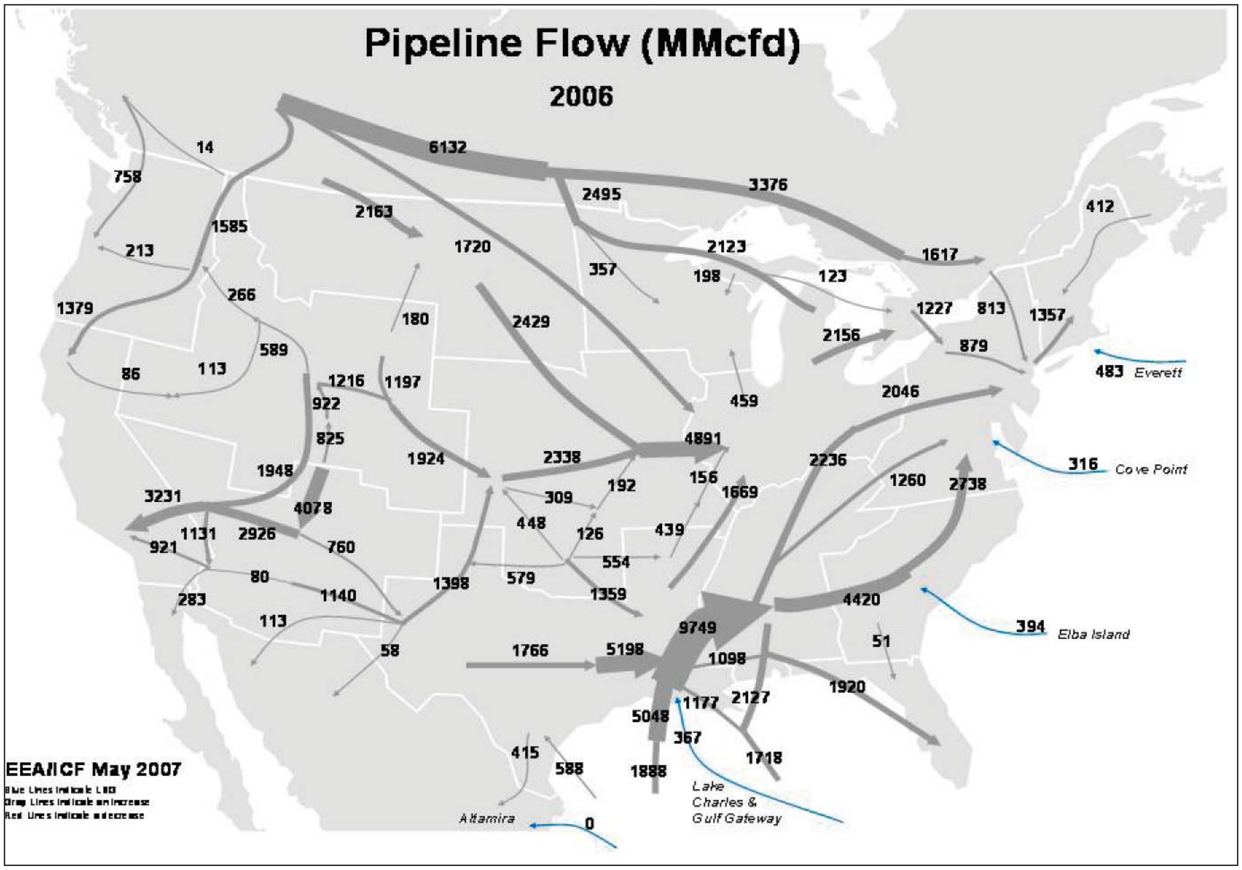


[7] WoodMac Rockies + Spectra Energy WCSB
[8] As of 12/31/2005: EIA for WY, CO, UT (44.665 Tcf); StatCan table 153-0014 for AB, BC, SK (53.868 Tcf)
[9] The "High" and "Low" data points represent commercially available projections from proprietary sources.

While ample supply resources still exist to serve the region, we need to consider our longer-term needs. Several barriers have prevented the industry from pursuing development in new production areas or expanding capacity out of existing production areas. Barriers include personnel shortages, increasing pipe costs, permitting issues and regulatory hurdles.

Furthermore, as already noted, the Pacific Northwest is increasingly competing with the rest of North America for supply from these western producing regions. (See Figure 9.) For example, Canada is expected to export less gas to the U.S. as its own needs grow. In addition, as pipelines increasingly link production areas with the larger continental market, the regional market is more influenced by the continental demand and supply balance.

FIGURE 9. NORTH AMERICAN NATURAL GAS FLOWS



WHAT THIS MEANS

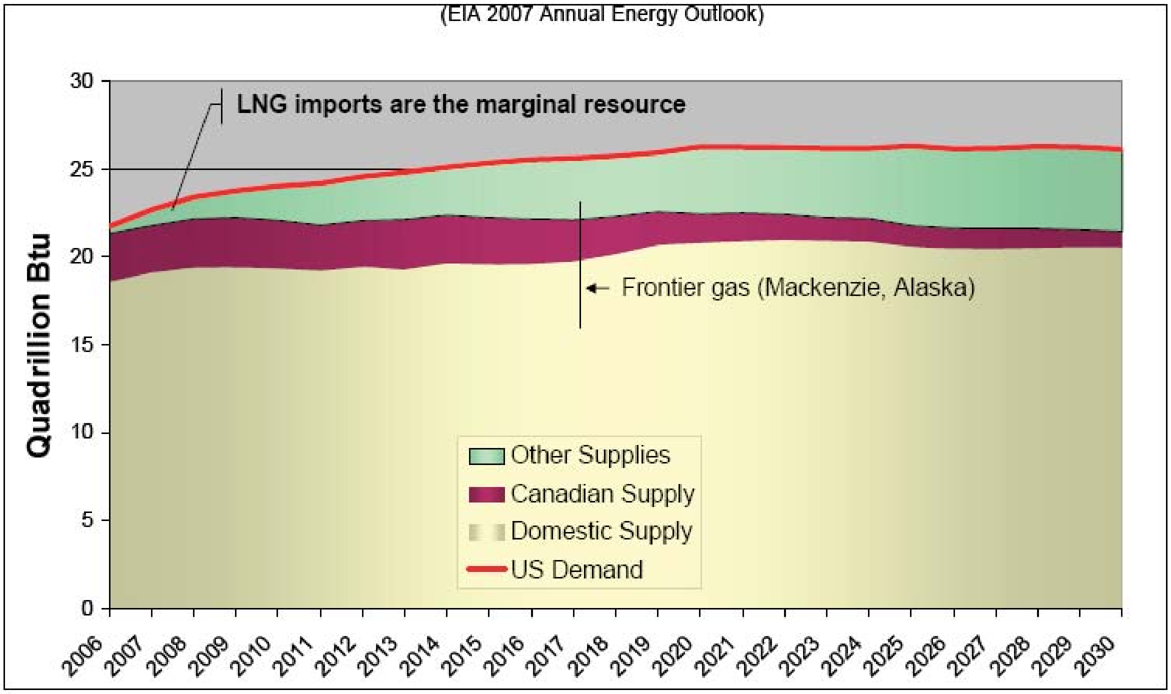
Meeting future demand in North America cannot be achieved solely by expanding production in our traditional supply areas. Besides enhanced energy conservation efforts (discussed in the previous Regional Demand section), it will require accessing Alaskan, Canadian Mackenzie River delta and offshore sources, developing unconventional resources, building additional export capacity from producing areas and importing more natural gas from around the globe.

THE IMPORTANT ROLE OF LNG

While production from mature gas supply sources is waning and new continental development is restricted, global natural gas supplies are abundant and can be shipped as LNG anywhere in the world. According to the 2007 BP Statistical Review of World Energy, the world contains almost 6,500 Tcf of proved natural gas reserves (those reserves known to exist and economically recoverable at today's prices with today's technology)-more than 60 years of gas at the world's current rate of consumption.

As shown in Figure 10, imported natural gas supplies will serve a growing role in the continental and regional energy picture. The EIA projects that LNG imports must increase from less than 1 Tcf in 2004 to more than 4.5 Tcf by 2030 in order to meet projected demand – enough to serve almost 20 percent of U.S. natural gas consumption.

FIGURE 10. PROJECTED MIX OF RESOURCES NEEDED TO MEET FUTURE DEMAND



LNG (green area) will play a vital role in serving future U.S. demand as cumulative U.S. and Canadian supplies grow only slightly or hold steady. Alaskan gas will provide much-needed domestic supply boost after 2017.

Recent technological improvements have made the cost of LNG imports more competitive, spurring interest in expanding or building new LNG import terminals throughout North America. In the U.S. alone, a number of terminals have been expanded, and the first new terminal in 20 years began service in March 2005. Dozens of new terminals have been proposed, including three in Oregon and two in British Columbia (see Figure 11).

Building an LNG receiving terminal in the Pacific Northwest could provide significant benefits to the region. A regional import terminal would promote supply diversity and reliability; would result in lower shipping costs helping to preserve the region's low-cost energy advantage; and may result in millions of dollars in economic benefits annually from new high-paying jobs.

Building new energy infrastructure like an LNG import facility can be compared to the investments our region made in hydropower several decades ago – an endowment that continues to pay dividends today. A regional LNG terminal could leave a similar legacy while simultaneously helping to enhance our environment. (Discussion of the region's existing and proposed infrastructure, including proposed LNG import terminals as well as transmission and distribution pipelines and storage facilities, follows in the next section.)

OTHER SOURCES OF NEW SUPPLY

Besides LNG, the region will rely on supply from the following areas to meet future demand.

- **Frontier gas supplies.** The Mackenzie River Delta (Canada) and the Alaska North Slope have enough proven natural gas reserves to satisfy North American natural gas demand for more than a decade. Alaskan gas, projected to come online in 2017, will be the single largest potential domestic source of relief for North American gas consumers. Through the Alaska Gas-line Inducement Act (AGIA) signed into law this year, the state is currently seeking requests for proposals (RFPs) and expects to select a construction partner by next year. Meanwhile, the Mackenzie Gas Project's proposed 1220-kilometer pipeline to deliver natural gas from Canada's Northwest Territories to North American markets could be functional as early as 2014.[10]

- **Offshore resources.** More than 130 Tcf of offshore natural gas resources in North America are currently off-limits to development because of federal offshore drilling moratoria – 80 Tcf off U.S. shores and 50 Tcf in Canada (including 40 Tcf off the coast of British Columbia).[11] Both nations are reviewing their offshore oil and natural gas exploration and production policies.

- **Coal bed methane (CBM) reserves.** Extracted from coal seams, CBM is already being produced in significant quantities in the U.S. According to the EIA, in 2001 it accounted for about 7 percent of U.S. annual natural gas production and its potential has barely been tapped. For example, BC's 2007 Energy Plan encourages development of unconventional resources, including 84 Tcf of coal bed gas. A pilot drilling program being proposed by a consortium of companies from Calgary, Alberta, was recently announced for BC's Peace River area, thought to contain up to 2.3 Tcf of gas. This project is reported to be the first of its kind in BC.

FIGURE 11. PROPOSED LNG IMPORT

- **Shale gas.** Shale or "tight" gas is natural gas that exists in rock formations with low porosity and/or permeability. BC alone has an estimated 550 Tcf of tight/shale gas reserves, and exploration activity has picked up recently. In the U.S., the Barnett Shale play in Texas is already producing substantial quantities of natural gas.

[10] *www.mackenziegasproject.com/index.asp*

[11] *Interstate Oil and Gas Compact Commission, Untapped Potential: Offshore Oil and Gas Resources Inaccessible to Leasing, March 2006.*

- **Other non-conventional resources.** Other natural gas resources are also increasingly accessible. In the lower 48 states, according to the EIA, overall unconventional resource production will increase from 8.0 Tcf in 2005 to 10.2 Tcf in 2030, when it will account for approximately 50 percent of projected domestic U.S. natural gas production. Recovery of these resources, and the exploration of others (see "Alternative Sources: Biogas" below), will be assisted by the development of new discovery, drilling and extraction technologies.

ALTERNATIVE SOURCES: BIOGAS

As concern about climate change has grown across North America, so too has interest in biogas development. Generally captured from solid waste landfill sites or produced in anaerobic digesters, biogas has traditionally been limited to smaller-scale electricity generation or industrial process projects.

In particular, projects that produce electricity from methane sourced from agricultural waste, dubbed "Cow Power" in some regions, have been growing in number and scale. Some U.S. producers have been successful in selling "Cow Power" or "Moo-thane" as a premium, green electricity product at a somewhat higher rate than conventional thermally generated electricity.

More recently, interest is growing in the development of biogas from agricultural wastes, municipal sewage treatment plants and landfill sites for injection into natural gas transportation and distribution systems. The ability to store this energy resource and to use it in highly efficient direct-use applications are potential advantages over using it to generate electricity. Uncertainties remain, however, in the need for and ability to economically meet gas quality standards as well as the cost of pressurizing the gas for injection into a pipeline.

Still, a number of initiatives are underway. Some U.S. gas utilities are accepting processed biogas while many others are examining requirements for a wide range of potential projects. In the Pacific Northwest, several utilities are participating in a national study to develop pipeline quality standards and biogas processing requirements for pipeline injection. In Canada, the BC Bio-Products Association is conducting a feasibility study for a state-of-the-art agricultural biogas production facility, including an assessment of whether to inject the processed gas into the pipeline system or use it to generate electricity.

While biogas is considered only a micro-scale potential source of supply in meeting overall demand for natural gas, industry and governments are re-examining its potential costs and benefits. Many of the hurdles experienced in the past in developing biogas projects still exist, but changing environmental policies, insights from past lessons learned, and socioeconomic incentives to capture the green benefits of biogas are enticing the natural gas industry to search for economic and technical solutions for pipeline injection.

Natural gas supply is discussed further in the NWGA White Paper, *Natural Gas Supply in the Pacific Northwest*, January 2006, posted on the NWGA website www.nwga.org.

KEY CONCLUSIONS

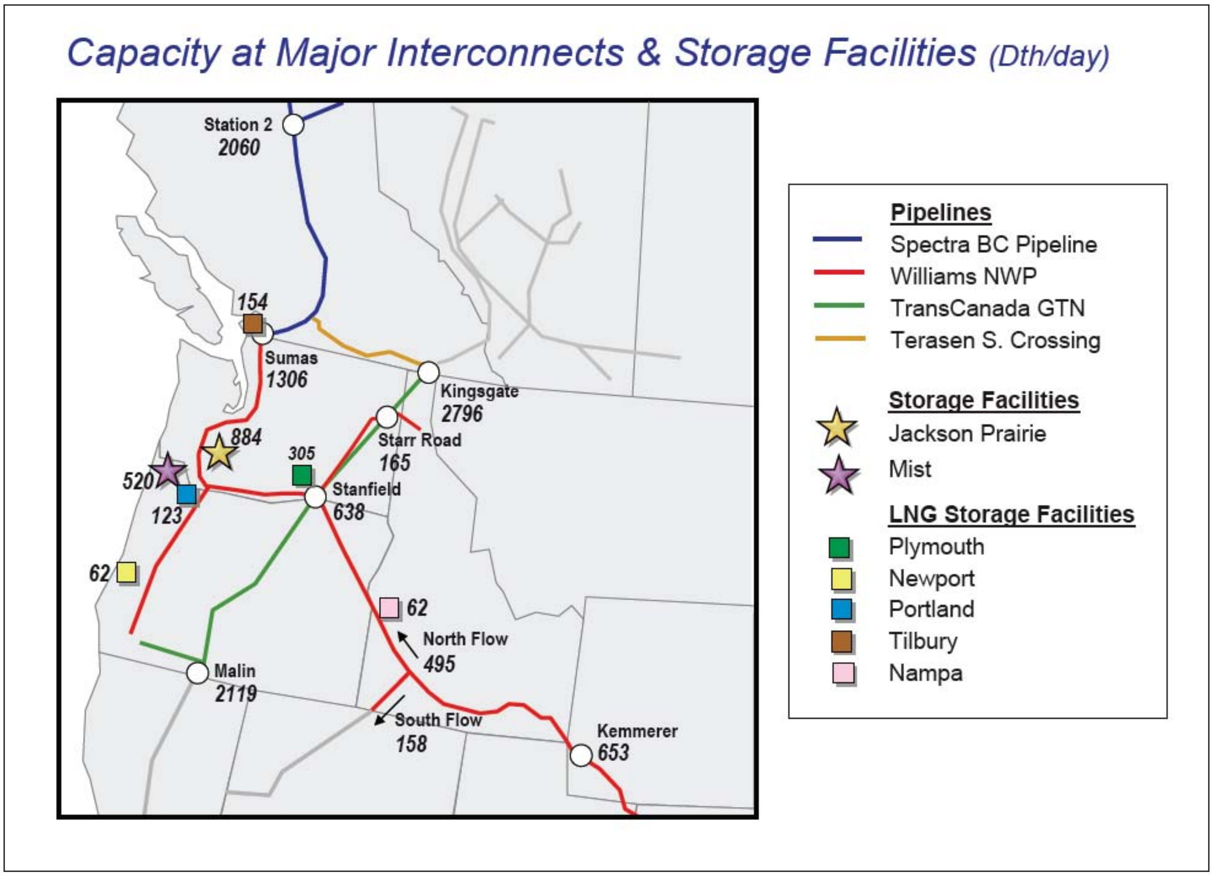
1. Under expected conditions, existing natural gas pipeline and storage capacities and planned storage expansions are adequate to serve regional needs through this study period (2012). Projected peak day demand approaches the capacity of the region's infrastructure, which is being used very efficiently and has little redundancy.
2. The changing nature of the region's demand for natural gas (peak demand growing faster than baseload demand) means we must continue to closely monitor infrastructure adequacy. Because stored gas is generally a more cost-effective means of meeting seasonal and peak market needs, the industry has already responded by expanding the region's gas storage capacity.
3. New pipelines to serve the region are now under consideration. Several would link proposed LNG import terminals to the region's existing natural gas infrastructure and are contingent on construction of those terminals. If built, they would add supply diversity and incremental capacity to the region's existing natural gas infrastructure.
4. Contracting patterns on the region's Canadian upstream pipelines also continue to change. Gas producers and marketers historically held much of the capacity on these pipelines. For a variety of reasons, these shippers relinquished significant volumes of capacity in recent years. Demand-side interests in the region have stepped in to acquire some of the available capacity in order to ensure continued access to reliable gas supplies at upstream trading hubs. The remaining un-contracted capacity on upstream pipelines is available to flow gas on an interruptible basis in response to market demand in the region.
5. As climate change policies drive additional regional demand for natural gas – especially for new, large-scale electric generation – the industry will closely monitor and respond to the adequacy of the region's infrastructure to deliver gas, particularly during extreme weather events.
6. The region's natural gas providers and its generators of electricity should work to enhance coordination through various industry forums. Regional demand and supply forecasts like the Northwest Gas Market Outlook (NWGA) and the Northwest Regional [Electricity] Forecast produced by the Pacific Northwest Utilities Conference Committee are vital tools in the effort.

A CLOSER LOOK

The region's 44,000-mile network of transmission and distribution pipelines is designed to meet the baseload demand requirements of the Pacific Northwest on an ongoing basis, while underground and LNG storage assets provide a cost-effective means of meeting intermittent weather-driven needs (*e.g.*, winter heating demand). Together, pipelines and storage give the industry flexibility in serving dynamic customer demand.

Figure 12 shows the current delivery capacity of pipelines and storage facilities serving the region in MDth/day (thousand decatherms per day). The region's pipeline operators all completed major pipeline expansions in the 1990s through 2003 and storage expansions are ongoing today.

FIGURE 12. KEY INFRASTRUCTURE SERVING THE PACIFIC NORTHWEST



In addition to potential opportunities to expand or extend existing pipelines from Spectra, Williams, TransCanada and Terasen, there are now four new transmission pipelines proposed in the region, three solely to connect proposed LNG import terminals to the region's infrastructure:

- The 110-mile eastern segment of the proposed Palomar Pipeline is designed to connect NW Natural's distribution system in Molalla to the GTN system near Madras (Palomar is an equal partnership of TransCanada and NW Natural). Another 110-mile segment would extend west from Molalla to the proposed Bradwood Landing LNG pipeline.
- The 221-mile Pacific Connector Gas Pipeline – a joint venture of Williams Pipeline, Fort Chicago (Canada) and Pacific Gas & Electric (PG&E – California) – would extend from the proposed Jordan Cove LNG terminal in Coos Bay across southwest Oregon to the California border at Malin to serve the Pacific Northwest and California markets.
- Oregon LNG proposes to construct a 117-mile pipeline to connect its proposed LNG terminal in Warrenton, Oregon, to the existing Williams Northwest Pipeline system near Molalla.
- The 291-mile Pacific Trails Pipeline - jointly advanced by Galveston LNG and Pacific Northern Gas - will connect the proposed Kitimat LNG terminal in BC's Bish Cove to Spectra Energy Transmission's pipeline system at Summit Lake.

It is important to note that construction of pipelines serving proposed LNG import terminals is contingent on approval of the terminals themselves. In all, seven LNG import terminals have been proposed in the region.

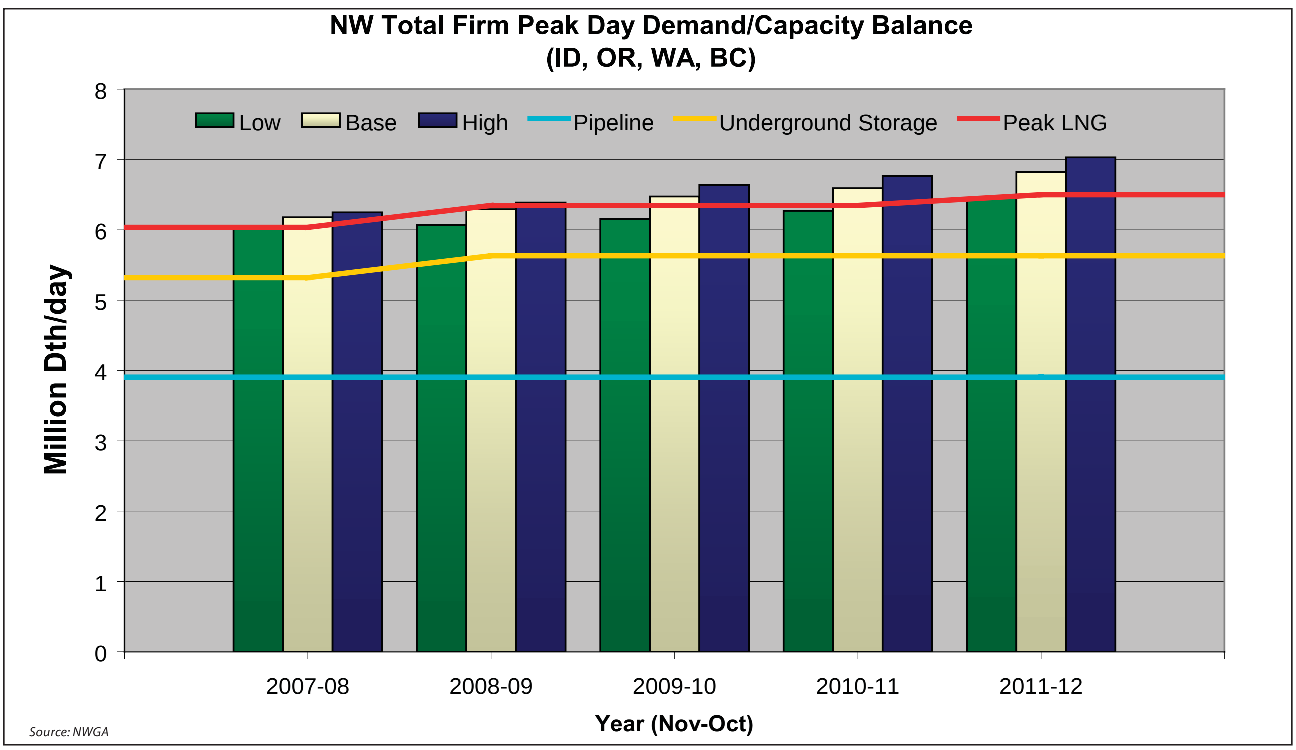
Two are inactive, while five are currently proceeding through various local, state and federal regulatory approval processes. The five active projects, shown earlier in Figure 12, include those of Kitimat LNG in Northwest British Columbia; WestPac LNG on Texada Island in the Strait of Georgia; Bradwood Landing on the Columbia River near Clatskanie, Oregon; Oregon LNG in Warrenton, Oregon; and Jordan Cove LNG in Coos Bay, Oregon. The market will ultimately dictate which of these projects are built.

Finally, discussions to expand westward access to Rockies production have recently accelerated. One project is the Bronco Pipeline, a 650 mile interstate natural gas system proposed by Spectra Energy Gas Transmission. Another project is Ruby Pipeline, a 680-mile natural gas transmission pipeline proposed by El Paso and Bear Energy. If built, either of these pipelines would access existing and future production in Wyoming, Utah and Colorado and interconnect with several pipelines en route to the key west coast physical and financial trading point of Malin, Oregon.

PEAK DAY ANALYSIS

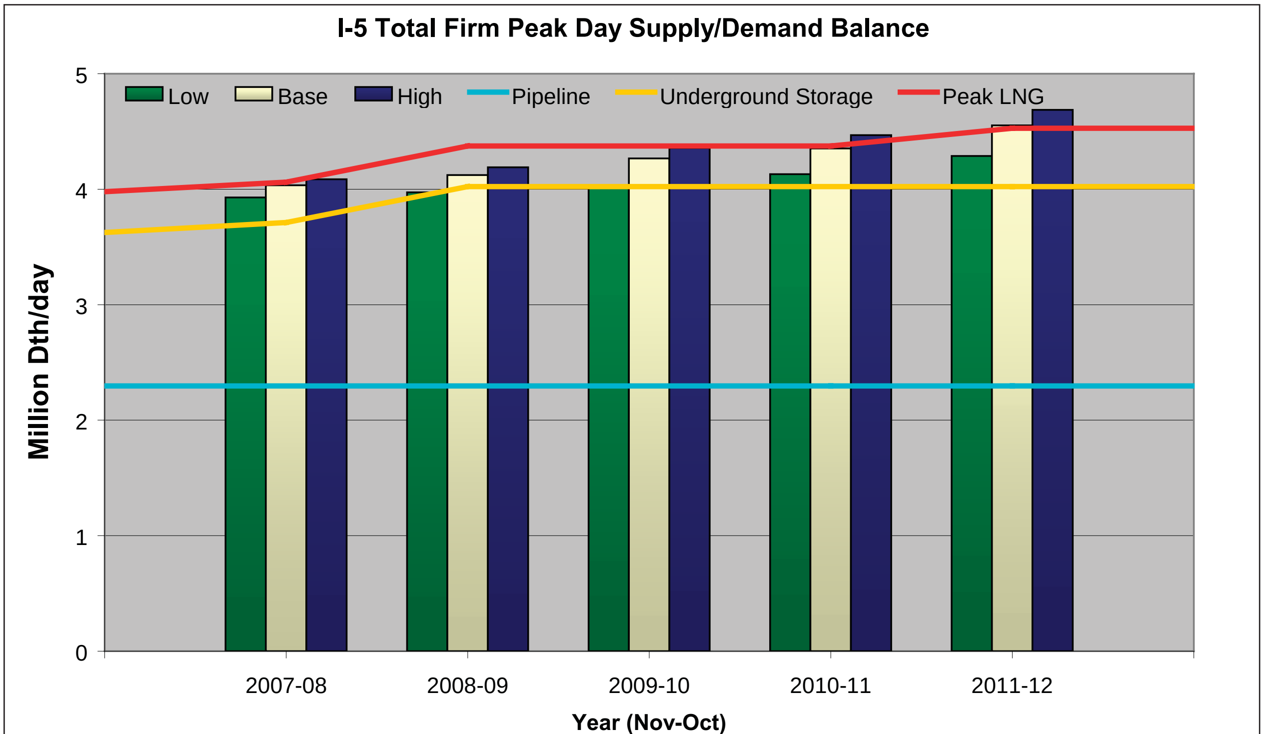
Currently, pipelines and storage facilities serving the region are capable of delivering more than 6.0 million Dth/day at peak capacity and will have been expanded to more than 6.5 million Dth/day by the end of the forecast period. If the coldest days planned for by each NWGA member (called peak or design days) all occurred simultaneously, one can see in Figure 14 that the region's capacity falls short. However, since weather patterns tend to roll across the Northwest, it is very unlikely that the entire region would experience design days simultaneously. Figure 13 demonstrates that the system is not overbuilt and that the region is expanding storage capacity to serve intermittent, weather-driven demand.

FIGURE 13. PIPELINE AND STORAGE CAPACITY TO MEET REGIONAL PEAK DEMAND



While still improbable, it is more likely that the I-5 Corridor (map delineating the region on page 17) could experience extremely cold weather all at once. It is therefore important to examine capacity levels needed in the event design days occur coincidentally across this sub-region. Figure 14 demonstrates that capacity is adequate assuming that all infrastructure is available and working, and that storage expansions are occurring to serve the growth in weather-driven demand.

FIGURE 14. CAPACITY OF PIPELINES AND STORAGE TO MEET I-5 CORRIDOR PEAK DEMAND



Source: NWGA

Extreme weather is more likely to affect only parts of the region and usually in succession, not simultaneously. Nevertheless, it is important to note that should a capacity shortage occur, it is extremely unlikely that residential and commercial service would be affected. However, there is a chance that industrial customers without firm service agreements could face service curtailments.

I-5 CORRIDOR EXTENDED WINTER ANALYSIS

The NWGA also conducted analyses of winter-long supply and demand for normal, moderately cold, and low-hydro years in the I-5 Corridor. The temperature in a moderately cold year differs depending on the specific region but occurs 15 percent of the time, or once every seven or eight years. A low-hydro year is one in which lower than average stream flows reduce hydroelectric generation and increase demand for gas-fired electric generation. The low-hydro year in this analysis was based on data from 2001.

For each of the scenarios, both base case and high growth case demand were plotted against pipeline capacity, underground storage and peaking resources such as LNG storage to gauge the adequacy of deliverability capacity. The high demand case was used in order to test the "worst case." (While the probability of these scenarios occurring at the same time is low, the Western energy crisis in 2000-2001 demonstrates that it is not impossible.)

The shapes of the curves were derived using analyses performed in 2004 and updated with the latest forecast of core, industrial and power generation demand included in the Demand section of this update. The shape of core and power generation demand are different for a moderately cold year than for a normal or low-hydro year, while that for industrial demand is the same in all cases.

Results of the base case analyses demonstrated that if the I-5 Corridor's delivery capacity remains available at present levels, with no interruption of deliverability over the winter, existing resources would be sufficient to meet base case demand, as well as expected demand in moderately cold or low-hydro circumstances, through 2012. (See Figures 15-16.)

FIGURE 15. 2011-2012 WINTER ANALYSIS (BASE CASE DEMAND) – MODERATELY COLD YEAR

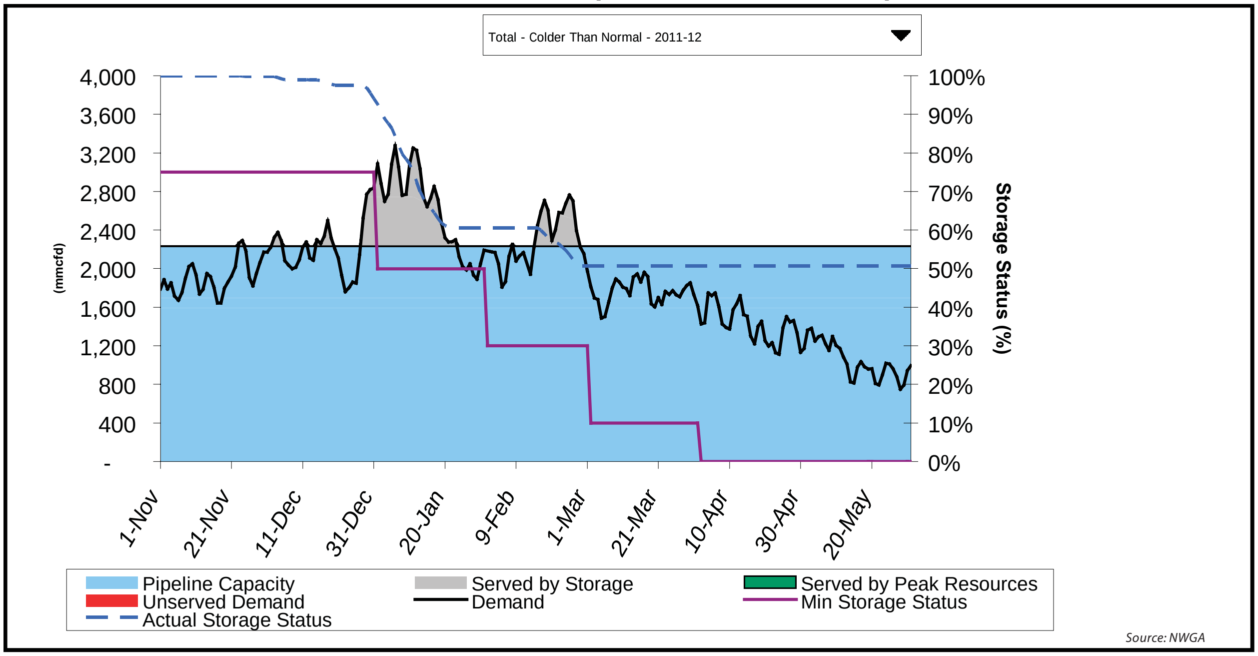
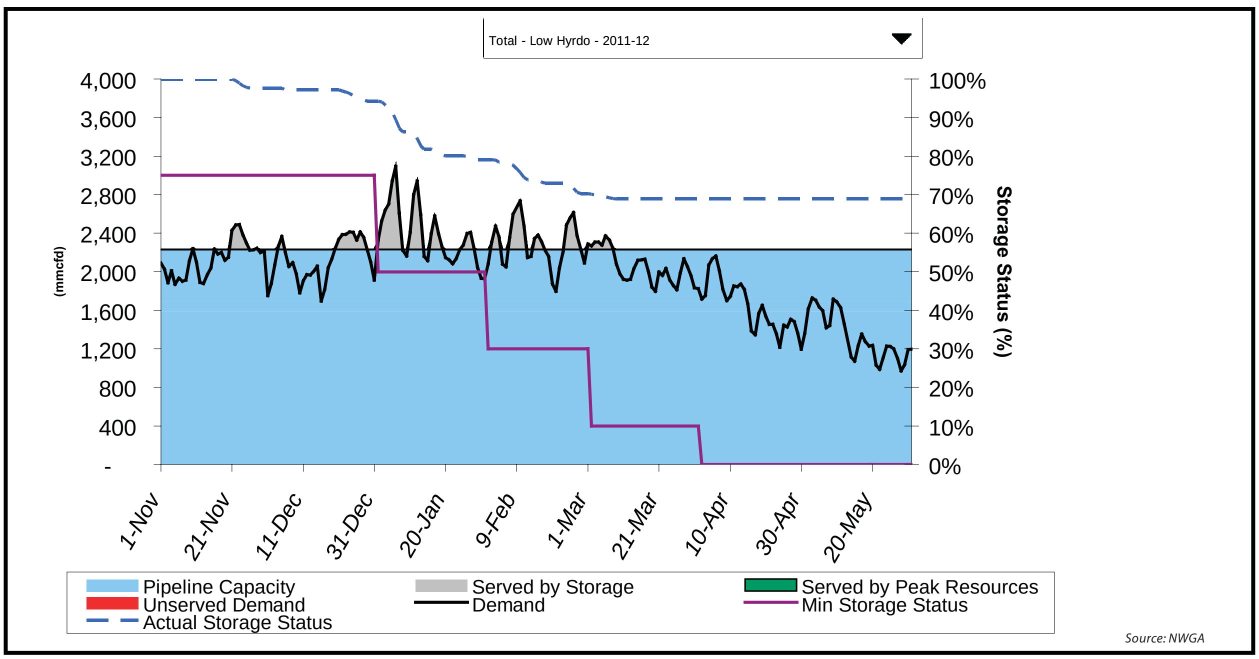


FIGURE 16. 2011-2012 WINTER ANALYSIS (BASE CASE DEMAND) – LOW HYDRO YEAR



Results of the high-growth demand case analyses indicate adequate capacity exists throughout the forecast period to serve natural gas demand in a low-hydro year. However, there is a potential for unserved demand during the 2011-12 heating year under the moderately cold scenario. (See Figures 17 and 18.) Potential consequences of unserved demand include significant price volatility and the curtailment of interruptible industrial demand. As mentioned previously, it is very unlikely that residential and commercial customers would experience service interruptions under any scenario.

FIGURE 17. 2011-2012 WINTER ANALYSIS (HIGH DEMAND) – MODERATELY COLD YEAR

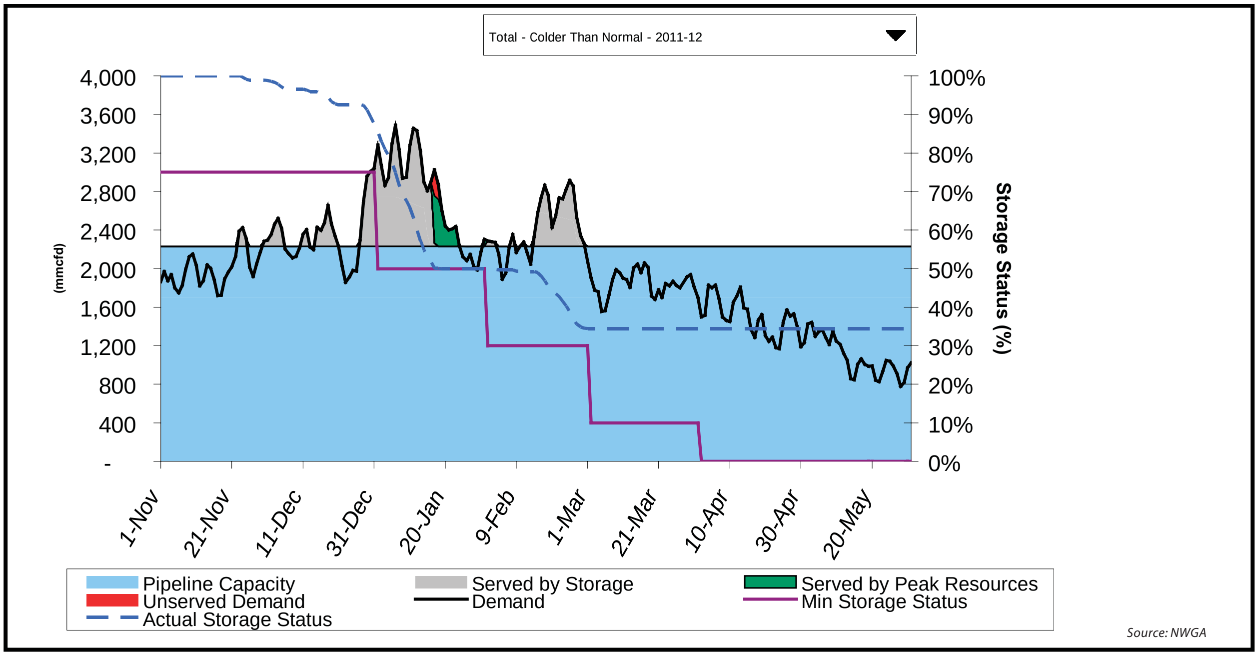
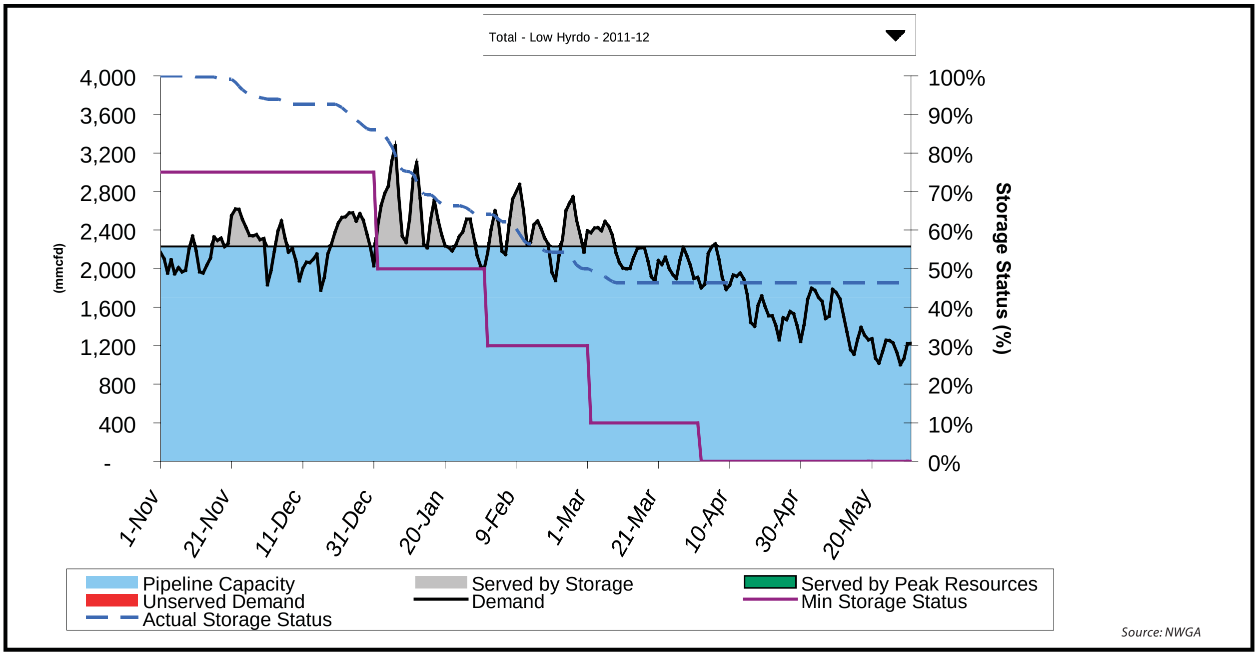


FIGURE 18. 2011-2012 WINTER ANALYSIS (HIGH DEMAND) – LOW HYDRO YEAR



It is important to emphasize that the only scenarios that produced results demonstrating a potential capacity deficit were the ones that utilized the higher than expected demand growth projections. While unlikely to occur, they are worth discussing because they can help the region weigh the cost of future added capacity against the perceived need for that capacity – whether under normal circumstances or unusually severe scenarios.

TRENDS IN PIPELINE CAPACITY CONTRACTING

Construction of new pipeline capacity from Western Canada and the Rockies to Midwest gas markets and beyond in recent years has provided gas producers a greater array of market options for their production. Accordingly, the volume of capacity held by producer/marketer shippers on Canadian upstream pipelines serving the Pacific Northwest has declined. Local gas companies and large end-use customers have been compelled to purchase gas and to contract directly for pipeline capacity from trading hubs situated closer to production areas. This represents a significant change, as many of these entities historically purchased gas from suppliers at major border export points like Sumas, Washington.

As a result of this transition in capacity ownership from suppliers to consumers, there is currently un-contracted capacity on the upstream pipelines that bring Canadian gas to the region. For example, 25.6% of Spectra Energy's T-South pipeline, which moves gas from production areas in Northeast BC to Vancouver and to the U.S. Pacific Northwest at Sumas, Washington, is currently un-contracted. Likewise, 20 percent of TransCanada's GTN pipeline, which moves gas from production areas in Alberta to the Inland Northwest and through to California markets at Malin, California, is un-contracted.

It is important to note that Canadian supplies remain available to the region – regardless of who owns the transport capacity – though it may be shipped on an interruptible rather than a firm basis. For instance, natural gas demand in portions of the region was driven up by cold weather on January 17, 2007. At the time, the T-South pipeline operated near its peak capacity on the south end of the system at the Huntingdon/Sumas delivery area. A considerable volume of gas flowed on an interruptible transport basis during the event, demonstrating that supply and capacity is available to serve the market when demand is high.

In order to mitigate the risk of curtailment that exists with interruptible transport capacity, local gas companies, industrial users and generators of electricity that require a reliable supply of gas must arrange for firm pipeline capacity from key upstream trading locations or contract for firm supply from a third party who will assume the obligation of ensuring delivery.

STORAGE CAPACITY AND EXPANSIONS

With peak demand growing more rapidly than baseload demand in the region, storage capacity is increasingly important. Currently, the region is served by more than 39 million Dth of working gas capacity (gas available to the marketplace – see Table 2) in underground natural gas storage facilities and over 5 million Dth of capacity in aboveground LNG peaking storage facilities (not to be confused with the larger scale LNG import facilities discussed earlier), for a total regional storage capacity of over 44 million Dth. Along with pipeline capacity, this is enough to serve the entire region for almost a week under all except the most extreme conditions.

To meet growing peak demand, several storage expansions are now underway or proposed. For example, NW Natural continues to expand its Mist gas storage field in northwest Oregon, drilling a St. Helens reservoir earlier this year and adding new injection and withdrawal wells. Completed in November of 2007, the project expanded Mist's storage capacity from 14.5 million Dth to 16.3 million Dth. The expansion also increased throughput to 530 MDth of gas per day, up almost 15 percent from about 450 MDth per day.

In addition, the Jackson Prairie Partners (Avista, Puget and Williams Northwest Pipeline) are expanding the Jackson Prairie storage facility in southwest Washington. The working capacity of the facility will grow from 19.0 million Dth to 25.6 million Dth by 2010. This project has been underway since August 2002 and has already increased the working capacity by about 4 million Dth. The JP Partners are also increasing the withdrawal capability of the facility from 884 MDth/d to 1,196 MDth/d by November 2008.

Meanwhile, Terasen Gas continues the planning and development of an LNG storage facility to serve peak demand on Vancouver Island for operation by the winter of 2011-12. In November of 2007, Terasen Gas received regulatory approval for this project from its utilities commission. This facility will supplement the several LNG storage facilities that already serve the region with peaking capacity.

TABLE 2. EXISTING PACIFIC NORTHWEST STORAGE AND LNG FACILITIES

PNW STORAGE FACILITIES

Facility	Owner	Type	Capacity* (MDth)	Max Withdrawal (MDth/day)
Jackson Prairie, WA	Avista, PSE, NW Pipeline	Underground	23,216	884 **
Mist, OR	NW Natural	Underground	15,943	520 **
	Underground Subtotal		39,159	1,404
Plymouth, WA	NW Pipeline	LNG	2,371	305
Newport, OR	NW Natural	LNG	1,000	60
Portland, OR	NW Natural	LNG	600	120
Tilbury, BC	Terasen Gas	LNG	616	154
Nampa, ID	Intermountain Gas	LNG	588	60
Swarr Station, WA	PSE	LPG***	130	10
Gig Harbor, WA	PSE	LNG	31	3
	LNG/LPG Subtotal		5,336	712
	TOTAL STORAGE (as of Sept., 2007)		**44,495**	**2,116**

* Working gas capacity; gas that can be used to serve the market.
** Represents start of season or full rate; storage withdrawal rates vary with working gas volumes.
*** LPG = Liquid Propane Gas and Air mixture

Source: NWGA

WHAT THIS MEANS

Much like arteries in the human body, the region's natural gas pipelines serve a living, breathing market that is never static. Storage facilities serve as energy reserves to be called upon as needed. Together, the system keeps natural gas flowing to customers.

The natural gas infrastructure serving the region is adequate for now. Climate change policies and other factors that may drive additional weather-related demand make good planning vital. Delays can be costly so public agencies must be equipped to respond quickly by implementing streamlined permitting and siting processes. A 2005 study by the Interstate Natural Gas Association of America (INGAA) Foundation found that a delay of just three years in the creation of adequate natural gas infrastructure (including LNG terminals) would cost the Oregon economy $11.1 billion and Washington $9.7 billion, or a total of $20.8 billion.[12]

[12] *INGAA Foundation, Discussion of Effects of Long-Term Gas Commodity and Transportation Contracts on the Development of North American Natural Gas Infrastructure, 2005.*

KEY CONCLUSIONS

1. After rising steadily for four years, natural gas prices dropped in the past two years due to mild weather conditions, no major disruptions in supply, and a record amount of imported LNG.[13] Over the next year, prices are expected to remain stable, presuming no extreme weather conditions or disruptions in supply. (Weather is a major driver of gas use and prices in the short term.)

2. However, given that commodity prices reflect the balance between demand and supply, and unless new supply can keep pace with forecasted increasing demand (*e.g.* new electric generation, Canadian oil sands development), the price of natural gas is expected to rise in the long term.

3. Demand growth driven by new climate change policies will likely exacerbate the already tight demand/supply balance across North America over the next five years, resulting in the continuation of natural gas price volatility. The timing of new supply resources reaching the energy market will play a significant role in continental and regional prices over the longer term.

4. Still, the Pacific Northwest continues to benefit from lower prices than other regions and gas continues to be a good value relative to other energy options, particularly for heating and other direct uses.

5. Public policy makers and industry decision-makers will have a significant impact on natural gas prices in the coming decades based on whether and how swiftly they work together to address critical issues facing natural gas consumers: access to supply, critical infrastructure additions and climate change.

A CLOSER LOOK

While natural gas prices continued to moderate in 2007, due largely to a combination of weather-related factors such as moderate demand due to mild winters and summers and no hurricane-driven disruptions of Gulf Coast supplies, they are unlikely to return to the lows of prior decades. As discussed in the Regional Supply section, the Pacific Northwest is increasingly competing for natural gas from nearby producing regions with the larger North American market. Accordingly, regional gas consumers now pay prices for natural gas that more closely reflect those of the broader market and are subject to price movements that occur in those markets, particularly the energy intensive U.S. Northeast and Southwest.

FIGURE 19. NATURAL GAS FORECAST COMPARISON

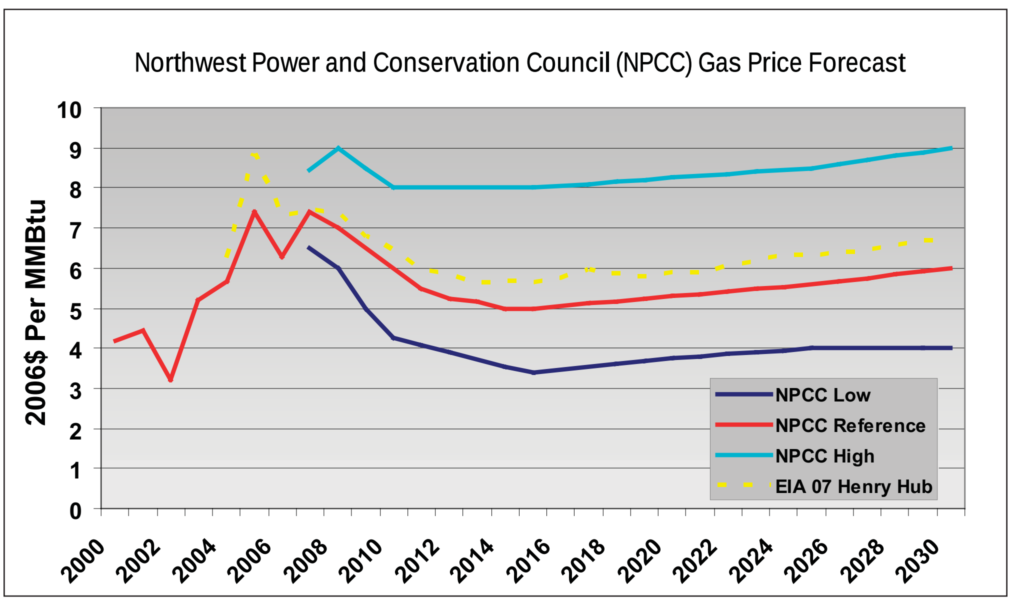


Figure 19 shows the most recent natural gas price forecast used by the Northwest Power and Conservation Council (NPCC) in its power planning efforts. The band bounded by the low and high price estimates

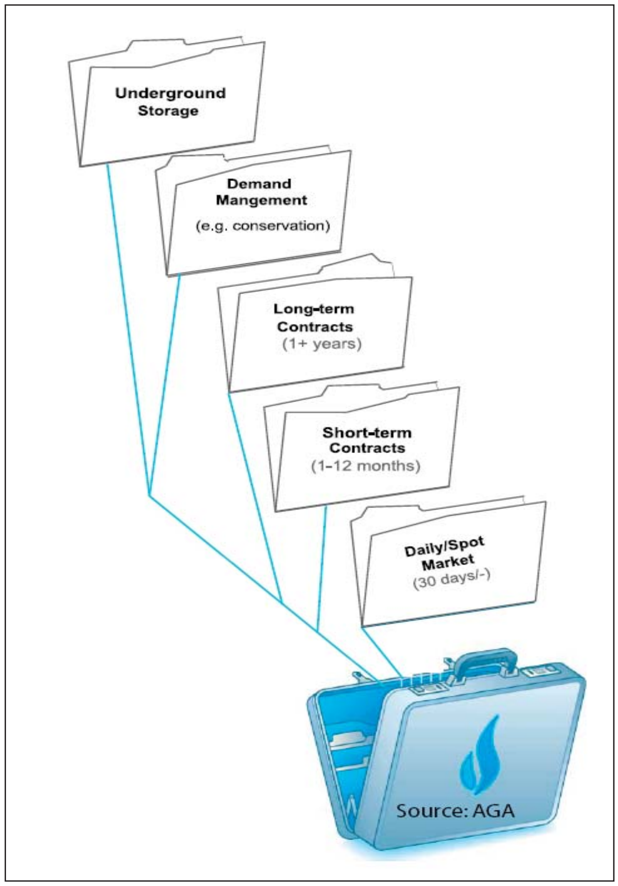
[13] *Per the Daily Oil Bulletin, Oct. 2, 2007, U.S. imports of LNG in July 2007 alone were 72 percent greater than the same month a year earlier, representing an all-time high, according to the EIA.*

describes the range of possible prices for natural gas forecast by the NPCC. The red line represents the base gas price forecast used in NPCC models for projecting the reference or expected mix of various sources of future electrical generation in the Pacific Northwest (*e.g.*, gas-fired combined cycle turbines, wind energy, coal, *etc.*). The yellow dashed line reflects the projections of the U.S. Energy Information Administration as forecast in its 2007 Annual Energy Outlook

A complex interplay of factors contributes to energy price volatility. In the next few years, for example, new energy policies aimed at reducing greenhouse gas emissions are expected to boost demand for natural gas. How this affects prices will depend on whether access to supply is adequately expanded to meet the new demand.

Natural gas end-users such as utilities and power generators work to manage price drivers as much as possible through portfolio management activities that mix short and long-term purchases, balance risk and ultimately acquire the requisite resources for regional customers at reasonable prices. Figure 20 illustrates a typical portfolio of resources.

FIGURE 20. INDUSTRY PRICE MANAGEMENT TOOLS



WHAT THIS MEANS

Strategic planning by the natural gas industry cannot, itself, overcome the price squeeze being felt by Pacific Northwest and other North American customers. Public policies and the regulatory environment heavily influence the industry's ability to operate effectively – either expediting market flexibility or posing serious hurdles that can skew the demand/supply balance – and therefore can play a huge role in future gas prices.

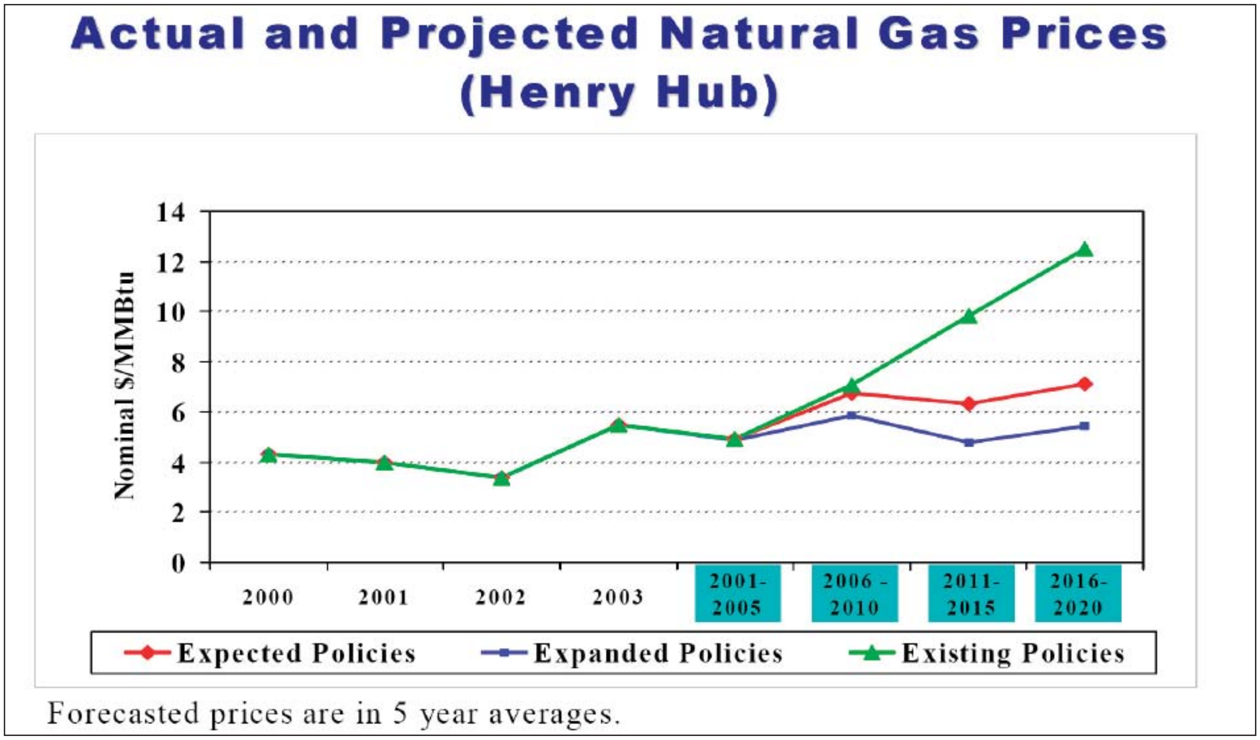
IMPACT OF PUBLIC POLICY ON NATURAL GAS PRICES

Two recent studies looked at the effects public policy choices (or lack of them) could have on future natural gas prices. An American Gas Foundation (AGF) study issued in February 2005 – Natural Gas Outlook to 2020 – analyzed future U.S. natural gas prices based on three alternative public policy scenarios: existing, expected and expanded.

The existing, or status quo, scenario described in the 2005 AGF study assumed continuing restrictions on off-shore and Rocky Mountain drilling, no functional Alaskan pipeline and no new LNG terminals. The expected scenario assumed a more diverse natural gas supply, with major contributions from Alaska (no earlier than 2017) and imported LNG, but continued drilling restrictions. Finally, the expanded scenario assumed new supplies from Alaska and LNG and development of limited resources off the East Coast and Gulf of Mexico and in the Rockies.
The expanded policy scenario could save consumers more than $500 billion over the expected scenario between 2005 and 2020, the study found (see Figure 21). It notes, however, that both the expected and expanded scenarios require significant changes in public policy.

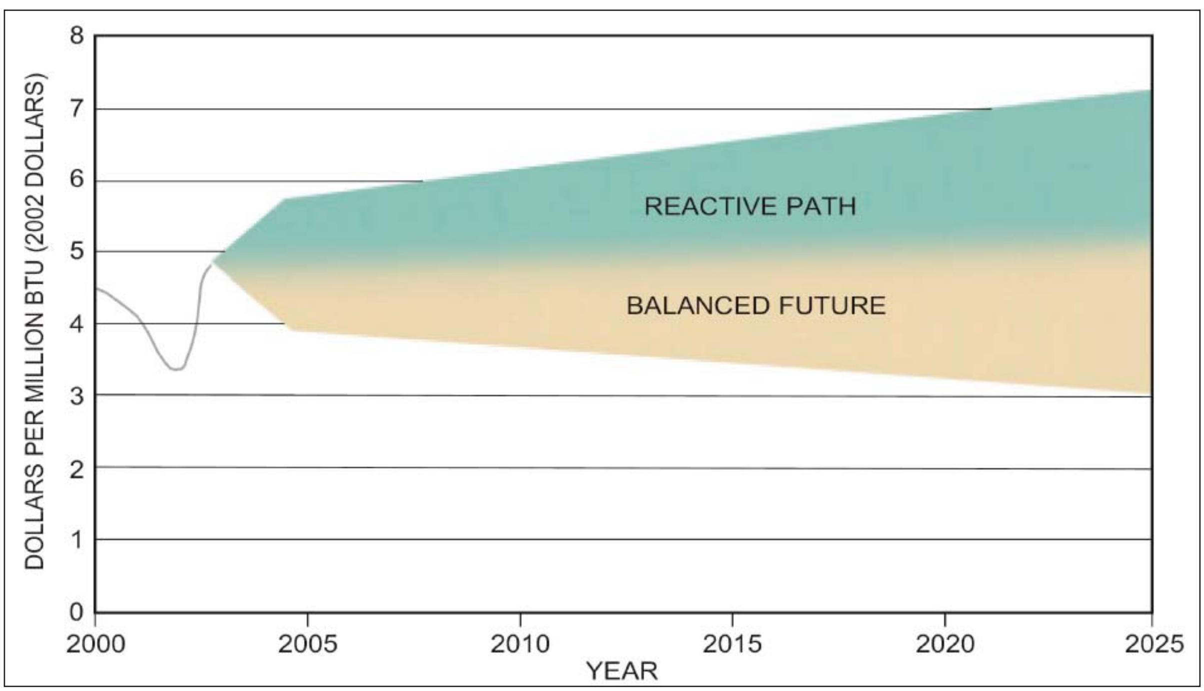
Similarly, in its 2003 Natural Gas Study, the National Petroleum Council (NPC) identified two policy scenarios: a "reactive path" and a "balanced future." The reactive (or minimal action) path assumed some action is taken to increase efficiency and conservation, enable the Alaskan gas pipeline, overcome siting opposition to LNG terminals and allow increased drilling in the Rockies. Supply and demand would continue to be tight, the NPC found, resulting in higher and more volatile prices.

FIGURE 21. AGF FUTURE GAS PRICES: THREE PUBLIC POLICY SCENARIOS[14]



The NPC's recommended "balanced future" scenario assumed more aggressive steps to maximize supply and infrastructure development and fuel-switching flexibility, resulting in lower price projections. Such actions could save energy consumers up to $1 trillion in natural gas costs over the next two decades, the study found (see Figure 22).

FIGURE 22. NPC – POLICY IMPACT ON FUTURE GAS PRICES



[14] Figures 21 and 22 both reference (or million Btu) on the Y axis. One MMBtu is equivalent to one decatherm, the energy unit referenced throughout the rest of this document.

RECENT PUBLIC POLICY ACTIONS

Recent policy initiatives in both the U.S. and Canada mean we have already taken some important first steps to expand supply. The U.S. Energy Policy Act of 2005 provided a fresh blueprint for the supply, delivery and efficient use of natural gas and other forms of energy – directly benefiting homeowners and commercial consumers who have struggled with rising energy prices since 2000. The Act encourages more natural gas production in the U.S., increasing imports of LNG, and promoting research on promising new sources of natural gas, such as coal-bed methane and methane hydrates. It encourages expansion of natural gas pipelines and the construction of more underground natural gas storage facilities. And the Act promotes innovative technologies, such as natural gas fuel cells, to encourage more efficient use. By separate action earlier in 2005, Congress also enacted provisions to expedite construction of the Alaska Gas Pipeline, which will connect readily available stores of natural gas to the consuming regions of North America.

In addition, British Columbia implemented aggressive natural gas supply strategies that produced results. Royalty relief, road construction in remote areas and other incentives spurred natural gas production gains in targeted areas. However, Alberta recently introduced changes to its royalty regime that are less favorable to producers, potentially threatening the viability of some production in the area.

But maintaining and even enacting new, more favorable policies will not resolve the supply/demand imbalance overnight. Demand can change quickly – and will, in response to new climate change policies – but it takes years for new natural gas production (and pipelines to deliver it) to reach the market. The licensing and construction of new infrastructure like LNG import terminals, production, storage and pipelines is a three- to five-year effort.

Moderating future gas prices will require additional proactive steps by the industry and policy makers on both sides of the equation – not only reshaping demand in more efficient and environmentally friendly ways – but encouraging development of and access to additional supply from diverse sources.

REGIONAL PERCEPTIONS OF SUPPLY AND PRICES

A May 2007 survey of 47 Pacific Northwest opinion leaders commissioned by the NWGA[14] found that 53 percent believe the price of natural gas will rise in the next year, with even more (68 percent) believing it will rise over the next five years. They also indicated they are moderately concerned about rising gas prices (ranking it 6.2 on a scale of 1 to 10.)

At the same time, 62 percent of survey respondents thought the region has access to adequate natural gas supplies for the next 10 years and indicated, on the same 1-to-10 scale, that natural gas supply is one of their least concerns (ranking 5.3. Only the availability of electricity, at 4.9, was ranked of less concern). The small number of leaders who were concerned about adequate supplies mainly worried about limitations in infrastructure.

However, if adequate supplies and infrastructure are developed over the next decade to meet growing demand, there will be less pressure on prices. But the reason price increases are expected is because demand is growing faster than supply. Development of and access to new resources, therefore, should be of greater concern among regional policymakers.

Survey respondents were asked their preferences to ensure adequate future supplies, with the largest group (28 percent) favoring reduction in usage (conservation/energy efficiency measures), followed by increased access to worldwide supplies of LNG (19 percent), building a new pipeline to Alaska (17 percent), opening currently restricted areas of the U.S. to energy development (15 percent) and developing more offshore access to energy supplies in the U.S. and Canada (15 percent).

[14] *More than 500 individuals were invited to participate in this online survey including legislators, regulators, other government officials and business leaders from BC, ID, OR, and WA.*

Additional information on prices, including key price drivers, can be found in the September 2005 white paper, *Natural Gas Prices in the Pacific Northwest*, posted on the NWGA website www.nwga.org.

IMPLICATIONS (ACTIONS NEEDED)

Based on the data collected for, and conclusions drawn from, the 2007-2012 Outlook study, we can identify several important actions that can help to balance the region's demand and supply of natural gas and stabilize prices, as well as help the region transition to a more "green" energy future. Some of these are the responsibility of gas industry members, but customers, public interest groups, policy makers and regulators are all key stakeholders in this energy market, with important roles to play.

IMPROVING REGIONAL UNDERSTANDING AND AWARENESS

Fostering a better understanding of natural gas – its implications for the regional economy, contributions to the way of life enjoyed by the people of the Pacific Northwest, and its unique environmental attributes – is a top priority for the industry. Recognizing that natural gas can play a significant role in reducing greenhouse gas emissions regionally and globally, policymakers are increasingly enacting measures to expand its use. This growing awareness provides a tremendous opportunity to "get the word out" about natural gas. At the same time, we must be sure we are conserving this valuable resource wherever possible, promoting its highest and best use, and working to expand supply to meet the greater demand.

ENSURING THE BEST USE OF THIS VALUABLE RESOURCE

To maximize its environmental and economic benefits, we must be sure we are encouraging the most effective and efficient use of natural gas. This means:

- Promoting more "direct" use. As already noted, natural gas is most efficient when used directly to heat homes and water, or to fuel a vehicle for instance. It makes the most sense for the industry and public policy to emphasize those uses.
- Supporting expanded use of natural gas to generate electricity. Given its clean burning attributes, natural gas is definitely a more "green" choice than other fossil fuels for producing electricity. Only renewable energy sources such as solar and wind power have fewer emissions than natural gas, and they are not yet produced at sufficient scale to provide major sources of firm power. As electric generators increasingly factor natural gas into their future resource needs, the electric and gas interests in the region must be sure to integrate their planning efforts to ensure sufficient supply and capacity exists to meet all of the future energy needs of the Pacific Northwest.
- Increasing the use of natural gas as a transportation fuel to replace more polluting, higher carbon intensity fuels such as oil and diesel in applications like fleet vehicles, heavy equipment, ferries and other shipping activities including cold-ironing in ports.
- Encouraging development of energy efficiency technology and conservation measures. The many efficiency tax credits included in the U.S. Energy Policy Act and similar Canadian initiatives are evidence that energy efficiency is increasingly being encouraged as the right, not merely a "green," choice. In addition to encouraging consumers to retrofit heating systems, replace appliances and weatherize homes and businesses, public policy can raise building code energy efficiency standards and boost investment in new energy efficiency technologies, such as advanced meters that can support "time-of-use" (TOU) rate structures. Innovative technologies like these give consumers the ability to more closely manage their energy usage.
- Developing innovative rate structures such as "decoupling" so that utilities are not financially punished for encouraging energy efficient choices and behavior. Such approaches adopted throughout the Northwest are already proving effective.

SECURING SUPPLIES FROM DIVERSE SOURCES

Ensuring that the Pacific Northwest is served with an adequate mix of natural gas supplies and infrastructure is vital for the region to sustain a growing economy. Since the process of building new natural gas supply and delivery facilities can take upwards of five years, we must work with regulators and engage policymakers and the public ***now*** to promote the acquisition of long-term supply and transportation capacity for the region. This means:

- Building the infrastructure necessary to receive and transport imported LNG. Building one or more LNG import terminals on the West Coast will help maintain a stable supply of natural gas benefitting natural gas consumers and the overall economy.
- Encourage new natural gas pipeline infrastructure to access prolific domestic production areas and regional storage expansions to serve peak demand.
- Accessing new gas reserves across North America by loosening restrictions on exploration and land uses and by encouraging infrastructure construction.
- Aligning regulatory processes with system planning efforts to overcome costly delays. To access global LNG supplies, for example, we need to encourage coordination among local, state and federal agencies to streamline the siting/permitting process for import terminals.
- Encouraging research and development of unconventional resources such as methane hydrates and bio-gas from landfill and dairy operations.
- Educating the public about the risks and benefits of resource and infrastructure development including pipelines, storage facilities, exploration in offshore and other currently restricted areas and LNG import terminals.

Recently, federal, state and local policy initiatives have taken first steps in three important directions: promoting more efficient use of all energy sources, encouraging development of new energy sources (including natural gas and renewable energy sources), and reducing our carbon footprint. These are a solid foundation, but are only a starting point. Partnering public policy, regulatory innovation and consumer education will create a powerful force in the mission to promote the highest and best use of natural gas, balance demand and supply, and stabilize prices for current and future consumers. The industry will continue its considerable efforts in this area, and expects to participate fully in all efforts to craft environmentally friendly and economically sensible new energy policies.

APPENDIX

Data Tables

2007 Natural Gas Outlook
Annual Demand Summary (Dth) - Base Case

Region/Sector	2007-08	2008-09	2009-10	2010-11	2011-12
BC Lower Mainland & Van. Island	**146,686,227**	**147,562,643**	**150,091,503**	**151,262,065**	**152,552,380**
Residential	57,402,509	58,152,197	58,907,979	59,709,426	60,547,599
Commercial (Sales)	36,614,501	36,543,315	36,734,569	36,956,914	37,243,949
Industrial (Transport & Interruptible)	35,629,714	35,870,280	36,023,147	36,169,917	36,335,024
Power Generation	17,039,503	16,996,851	18,425,808	18,425,808	18,425,808
W. Washington	**239,570,980**	**254,470,758**	**257,435,259**	**263,522,554**	**264,203,475**
Residential	70,797,674	72,497,907	74,816,253	77,794,343	78,998,909
Commercial (Sales)	42,011,133	42,180,265	42,505,245	43,307,707	43,342,247
Industrial (Transport)	56,336,202	58,584,806	59,370,087	59,379,244	59,235,022
Power Generation	70,425,970	81,207,780	80,743,674	83,041,259	82,627,297
W. Oregon	**148,625,436**	**150,429,845**	**151,631,215**	**151,862,266**	**153,124,607**
Residential	37,809,504	38,613,534	39,708,614	40,883,184	42,148,676
Commercial (Sales)	23,369,741	23,130,163	22,988,933	22,965,298	22,941,172
Industrial (Transport & Interruptible)	69,196,191	70,436,148	70,683,668	69,763,784	69,784,759
Power Generation	18,250,000	18,250,000	18,250,000	18,250,000	18,250,000
BC Interior	**55,597,868**	**55,679,408**	**55,961,512**	**56,301,400**	**56,706,339**
Residential	18,090,259	18,311,486	18,540,468	18,790,227	19,063,824
Commercial (Sales)	9,632,577	9,484,269	9,517,548	9,581,066	9,680,635
Industrial (Transport & Interruptible)	27,875,032	27,883,653	27,903,496	27,930,106	27,961,880
Power Generation	-	-	-	-	-
E. Washington & N. Idaho	**72,441,869**	**75,557,595**	**78,000,678**	**80,567,469**	**81,779,447**
Residential	18,509,226	18,906,158	19,542,344	20,479,912	20,701,551
Commercial (Sales)	14,045,390	14,199,253	14,580,998	15,311,875	15,240,385
Industrial (Transport & Interruptible)	24,877,115	27,016,095	27,785,540	27,994,315	28,046,025
Power Generation	15,010,138	15,436,088	16,091,795	16,781,366	17,791,486
E. Oregon & Medford	**85,979,289**	**89,213,894**	**92,163,546**	**95,650,621**	**98,391,139**
Residential	7,289,331	7,441,001	7,782,786	8,445,789	8,332,257
Commercial (Sales)	5,276,194	5,289,702	5,424,719	5,790,338	5,560,581
Industrial (Transport & Interruptible)	7,691,954	9,031,353	9,314,805	9,374,187	9,321,538
Power Generation	65,721,809	67,451,838	69,641,237	72,040,307	75,176,763
S. Idaho	**54,824,744**	**55,751,472**	**56,604,032**	**57,883,756**	**59,189,156**
Residential	20,729,880	21,246,955	21,730,267	22,507,366	23,288,330
Commercial (Sales)	10,364,933	10,606,937	10,845,311	11,278,736	11,742,187
Industrial (Transport & Interruptible)	21,988,143	22,141,431	22,284,111	22,353,311	22,414,297
Power Generation	1,741,789	1,756,149	1,744,343	1,744,343	1,744,343
PNW Annual Demand - Base	**803,726,411**	**828,665,614**	**841,887,746**	**857,050,130**	**865,946,543**
Residential	230,628,383	235,169,237	241,028,711	248,610,248	253,081,146
Commercial (Sales)	141,314,469	141,433,905	142,597,324	145,191,935	145,751,156
Industrial (Transport & Interruptible)	243,594,350	250,963,766	253,364,854	252,964,865	253,098,544
Power Generation	188,189,209	201,098,706	204,896,857	210,283,083	214,015,698

Table A2. Annual Demand by Region and Sector, High Growth Case

Northwest Gas Association
2007 Natural Gas Outlook
Annual Demand Summary (Dth) - High Case

Region/Sector	2007-08	2008-09	2009-10	2010-11	2011-12
BC Lower Mainland & Van. Island	**157,005,684**	**158,892,627**	**163,077,565**	**164,797,934**	**167,425,832**
Residential	63,623,084	65,389,085	67,401,158	68,923,743	70,953,603
Commercial (Sales)	40,713,383	40,636,411	41,227,453	41,278,467	41,711,397
Industrial (Transport & Interruptible)	35,629,714	35,870,280	36,023,147	36,169,917	36,335,024
Power Generation	17,039,503	16,996,851	18,425,808	18,425,808	18,425,808
W. Washington	**242,338,182**	**258,406,974**	**261,984,553**	**268,872,352**	**270,134,145**
Residential	71,808,292	74,033,046	76,774,746	80,303,929	82,004,975
Commercial (Sales)	42,918,494	43,658,816	44,119,737	45,055,530	45,154,565
Industrial (Transport)	56,645,426	58,967,332	59,806,396	59,931,634	59,807,307
Power Generation	70,965,970	81,747,780	81,283,674	83,581,259	83,167,297
W. Oregon	**153,255,528**	**155,107,204**	**156,457,578**	**156,830,231**	**158,254,848**
Residential	40,825,901	41,687,727	42,919,666	44,231,665	45,645,462
Commercial (Sales)	24,569,230	24,307,027	24,175,727	24,165,555	24,155,370
Industrial (Transport & Interruptible)	69,610,397	70,862,450	71,112,185	70,183,010	70,204,016
Power Generation	18,250,000	18,250,000	18,250,000	18,250,000	18,250,000
BC Interior	**59,120,512**	**59,317,865**	**60,136,514**	**59,638,149**	**60,048,137**
Residential	19,993,157	20,287,926	21,026,749	21,026,444	21,435,715
Commercial (Sales)	11,252,323	11,146,286	11,206,269	10,681,599	10,650,542
Industrial (Transport & Interruptible)	27,875,032	27,883,653	27,903,496	27,930,106	27,961,880
Power Generation	-	-	-	-	-
E. Washington & N. Idaho	**74,479,047**	**77,756,709**	**81,768,515**	**86,019,046**	**87,167,668**
Residential	18,848,074	19,257,409	20,345,561	21,653,220	21,988,337
Commercial (Sales)	14,366,698	14,515,361	15,164,954	16,124,326	16,248,729
Industrial (Transport & Interruptible)	25,030,212	27,171,825	27,956,320	28,184,962	28,238,868
Power Generation	16,234,063	16,812,115	18,301,679	20,056,538	20,691,734
E. Oregon & Medford	**90,358,196**	**93,701,760**	**96,669,429**	**100,323,956**	**101,732,541**
Residential	7,302,556	7,429,406	7,881,945	8,659,649	8,623,054
Commercial (Sales)	5,336,896	5,357,302	5,563,219	5,993,523	5,793,543
Industrial (Transport & Interruptible)	7,848,677	9,185,067	9,468,985	9,533,319	9,473,592
Power Generation	69,870,067	71,729,986	73,755,279	76,137,466	77,842,352
S. Idaho	**54,873,272**	**57,380,029**	**60,655,745**	**62,335,304**	**64,035,277**
Residential	20,728,114	21,129,163	22,118,837	23,151,504	24,221,053
Commercial (Sales)	10,364,546	10,534,987	11,105,081	11,677,217	12,239,642
Industrial (Transport & Interruptible)	22,038,824	23,959,730	25,687,484	25,762,240	25,830,238
Power Generation	1,741,789	1,756,149	1,744,343	1,744,343	1,744,343
PNW Annual Demand - High	**831,430,422**	**860,563,168**	**880,749,898**	**898,816,972**	**908,798,448**
Residential	243,129,178	249,213,762	258,468,661	267,950,154	274,872,200
Commercial (Sales)	149,521,570	150,156,190	152,562,440	154,976,217	155,953,789
Industrial (Transport & Interruptible)	244,678,282	253,900,336	257,958,014	257,695,188	257,850,925
Power Generation	194,101,392	207,292,880	211,760,783	218,195,413	220,121,534

Table A3. Annual Demand by Region and Sector, Low Growth Case

Northwest Gas Association
2007 Natural Gas Outlook
Annual Demand Summary (Dth) - Low Case

Region/Sector	2007-08	2008-09	2009-10	2010-11	2011-12
BC Lower Mainland & Van. Island	**138,234,413**	**136,888,834**	**130,093,782**	**131,140,050**	**132,300,776**
Residential	52,199,886	52,807,967	53,488,093	54,211,757	54,968,481
Commercial (Sales)	33,365,310	33,316,889	33,499,824	33,698,789	33,962,736
Industrial (Transport & Interruptible)	35,629,714	33,767,128	33,901,620	34,025,259	34,165,314
Power Generation	17,039,503	16,996,851	9,204,245	9,204,245	9,204,245
W. Washington	**234,831,760**	**247,271,965**	**249,735,752**	**254,786,517**	**254,370,108**
Residential	68,990,412	69,514,759	71,112,929	73,139,641	73,473,391
Commercial (Sales)	39,877,933	38,856,409	39,382,241	40,029,151	39,865,645
Industrial (Transport)	55,597,445	57,753,017	58,556,908	58,636,466	58,463,774
Power Generation	70,365,970	81,147,780	80,683,674	82,981,259	82,567,297
W. Oregon	**144,114,108**	**145,761,460**	**146,860,945**	**146,982,317**	**148,103,136**
Residential	34,897,471	35,578,024	36,565,696	37,623,774	38,754,249
Commercial (Sales)	22,183,745	21,922,898	21,789,412	21,763,158	21,732,526
Industrial (Transport & Interruptible)	68,782,891	70,010,537	70,255,837	69,345,385	69,366,361
Power Generation	18,250,000	18,250,000	18,250,000	18,250,000	18,250,000
BC Interior	**53,034,634**	**52,899,822**	**53,155,700**	**53,464,260**	**53,831,882**
Residential	16,313,346	16,480,329	16,686,413	16,911,196	17,157,433
Commercial (Sales)	8,846,281	8,535,840	8,565,791	8,622,958	8,712,570
Industrial (Transport & Interruptible)	27,875,007	27,883,653	27,903,496	27,930,106	27,961,880
Power Generation	-	-	-	-	-
E. Washington & N. Idaho	**70,161,786**	**72,151,063**	**74,022,864**	**76,068,135**	**76,544,479**
Residential	18,270,487	18,012,981	18,434,286	19,148,628	19,038,325
Commercial (Sales)	13,879,169	13,650,524	13,914,251	14,523,188	14,305,497
Industrial (Transport & Interruptible)	24,872,314	26,995,099	27,755,670	27,954,384	27,998,985
Power Generation	13,139,817	13,492,459	13,918,657	14,441,934	15,201,671
E. Oregon & Medford	**78,701,481**	**81,668,996**	**84,562,252**	**87,696,407**	**90,091,572**
Residential	7,167,677	7,134,766	7,391,613	7,956,630	7,751,979
Commercial (Sales)	5,197,073	5,114,098	5,217,476	5,549,898	5,299,120
Industrial (Transport & Interruptible)	7,695,072	9,034,011	9,316,555	9,373,149	9,320,622
Power Generation	58,641,659	60,386,121	62,636,607	64,816,729	67,719,850
S. Idaho	**54,819,035**	**55,432,941**	**56,365,762**	**57,196,749**	**58,126,416**
Residential	20,726,273	20,920,486	21,417,911	21,903,604	22,459,484
Commercial (Sales)	10,363,450	10,432,643	10,737,157	11,012,999	11,322,953
Industrial (Transport & Interruptible)	21,987,524	22,323,663	22,466,351	22,535,803	22,599,636
Power Generation	1,741,789	1,756,149	1,744,343	1,744,343	1,744,343
PNW Annual Demand - Low	**773,897,218**	**792,075,082**	**794,797,057**	**807,334,435**	**813,368,368**
Residential	218,565,553	220,449,313	225,096,940	230,895,230	233,603,341
Commercial (Sales)	133,712,961	131,829,302	133,106,152	135,200,142	135,201,048
Industrial (Transport & Interruptible)	242,439,967	247,767,108	250,156,438	249,800,552	249,876,572
Power Generation	179,178,737	192,029,360	186,437,526	191,438,511	194,687,407

Northwest Gas Association
2007 Natural Gas Outlook
Peak Day Supply

SUPPLY	2007-08	2008-09	2009-10	2010-11	2011-12
Pipeline Interconnects	**3,903,728**	**3,903,728**	**3,903,728**	**3,903,728**	**3,903,728**
WCSB via TCPL/GTN	**1,420,625**	**1,420,625**	**1,420,625**	**1,420,625**	**1,420,625**
Stanfield (NWP from GTN)	*638,000*	*638,000*	*638,000*	*638,000*	*638,000*
Starr Rd (NWP from GTN)	*165,000*	*165,000*	*165,000*	*165,000*	*165,000*
Palouse (NWP from GTN)	*20,000*	*20,000*	*20,000*	*20,000*	*20,000*
GTN Direct Connects	*415,000*	*415,000*	*415,000*	*415,000*	*415,000*
Kingsgate/Yahk BC Interior from TCPL	*182,625*	*182,625*	*182,625*	*182,625*	*182,625*
Rockies via NWP	**493,000**	**493,000**	**493,000**	**493,000**	**493,000**
NWP north from NWP south	*653,000*	*653,000*	*653,000*	*653,000*	*653,000*
Max Demand on Reno Lateral	*(160,000)*	*(160,000)*	*(160,000)*	*(160,000)*	*(160,000)*
WCSB via DEGT	**1,990,103**	**1,990,103**	**1,990,103**	**1,990,103**	**1,990,103**
T-South to Huntingdon	*1,638,522*	*1,638,522*	*1,638,522*	*1,638,522*	*1,638,522*
T-South to BC Interior	*192,888*	*192,888*	*192,888*	*192,888*	*192,888*
T-South to Kingsvale	*51,300*	*51,300*	*51,300*	*51,300*	*51,300*
Southern Crossing to Huntingdon	*107,393*	*107,393*	*107,393*	*107,393*	*107,393*
Storage	**2,130,088**	**2,442,088**	**2,442,088**	**2,442,088**	**2,596,588**
Jackson Prairie (NWP from JP)	884,000	1,196,000	1,196,000	1,196,000	1,196,000
(includes deliverability expansion of 312,000 Dth/day in service 2008-09)					
Mist Storage (NWN)	530,450	530,450	530,450	530,450	530,450
(includes deliverability expansion of 51,310 Dth/day in service 2007-08)					
Plymouth (NWP from LNG)	305,300	305,300	305,300	305,300	305,300
Newport/Portland LNG (NWN)	180,000	180,000	180,000	180,000	180,000
Nampa LNG (IGC)	60,000	60,000	60,000	60,000	60,000
Gig Harbor Satellite LNG (PSE)	3,000	3,000	3,000	3,000	3,000
Swarr Stn Propane (PSE)	10,000	10,000	10,000	10,000	10,000
Tilbury LNG (TGI)	157,338	157,338	157,338	157,338	157,338
Vancouver Island LNG (permitted, provisional)	-	-	-	-	154,500
Total Available Supply	6,033,816	6,345,816	6,345,816	6,345,816	6,500,316

Table A5. Region Wide Demand Peak Day Supply/Demand Balance - Base (expected)

Northwest Gas Association
2007 Natural Gas Outlook
Peak Day Demand/Supply Balance (Dth/day) - Base Case

DEMAND (Region/Sector)	2007-08	2008-09	2009-10	2010-11	2011-12
BC Lower Main & Van. Island (I-5 Corridor)	**1,283,821**	**1,296,188**	**1,377,156**	**1,393,018**	**1,408,970**
Residential	621,291	628,698	636,491	645,609	654,759
Commercial (Firm Sales & Transport)	371,100	375,389	380,532	386,477	392,521
Industrial (Firm Sales & Transport)	97,127	97,798	98,535	99,335	100,092
Power Generation	194,302	194,302	261,597	261,597	261,597
W. Washington (I-5 Corridor)	**1,814,526**	**1,865,372**	**1,904,076**	**1,948,104**	**2,106,322**
Residential	813,956	836,690	861,500	886,472	912,578
Commercial (Firm Sales & Transport)	332,265	340,711	351,447	358,025	367,080
Industrial (Firm Sales & Transport)	198,267	203,933	203,762	203,649	203,687
Power Generation	470,038	484,038	487,367	499,958	622,977
W. Oregon (I-5 Corridor)	**935,762**	**960,017**	**985,211**	**1,011,247**	**1,038,154**
Residential	546,209	565,354	585,265	605,929	627,407
Commercial (Firm Sales & Transport)	253,370	258,477	263,759	269,129	274,557
Industrial (Firm Sales & Transport)	49,184	49,185	49,187	49,189	49,191
Power Generation	87,000	87,000	87,000	87,000	87,000
BC Interior	**441,473**	**443,339**	**448,305**	**453,485**	**458,878**
Residential	209,127	210,466	213,672	216,985	220,412
Commercial (Firm Sales & Transport)	114,025	114,607	116,379	118,260	120,246
Industrial (Firm Sales & Transport)	118,321	118,266	118,255	118,240	118,220
Power Generation	-	-	-	-	-
E. Washington & N. Idaho	**607,321**	**619,321**	**632,579**	**643,876**	**653,488**
Residential	195,492	201,560	207,898	214,201	220,215
Commercial (Firm Sales & Transport)	152,921	156,155	159,555	162,938	166,543
Industrial (Firm Sales & Transport)	80,558	87,130	87,169	87,218	87,209
Power Generation	178,350	174,476	177,958	179,520	179,520
E. Oregon & Medford (Non I-5 Supply)	**541,308**	**548,618**	**552,761**	**556,618**	**560,609**
Residential	86,281	89,309	92,536	95,704	98,997
Commercial (Firm Sales & Transport)	57,698	58,743	59,692	60,495	61,260
Industrial (Firm Sales & Transport)	66,876	70,114	70,081	69,967	69,900
Power Generation	330,452	330,452	330,452	330,452	330,452
S. Idaho	**553,627**	**561,164**	**572,947**	**585,012**	**597,465**
Residential	240,442	249,135	257,030	265,114	273,457
Commercial (Firm Sales & Transport)	123,864	122,708	126,597	130,578	134,688
Industrial (Firm Sales & Transport)	137,147	137,147	137,147	137,147	137,147
Power Generation	52,173	52,173	52,173	52,173	52,173
Total Design (Peak) Day Demand	**6,177,838**	**6,294,018**	**6,473,034**	**6,591,361**	**6,823,886**
Total Supply	**6,033,816**	**6,345,816**	**6,345,816**	**6,345,816**	**6,500,316**
Supply Surplus/**(Shortfall)**	(144,022)	**51,798**	(127,218)	**(245,545)**	**(323,570)**

Table A6. Region Wide Demand Peak Day Supply/Demand Balance - High Case

Northwest Gas Association
2007 Natural Gas Outlook
Peak Day Demand/Supply Balance (Dth/day) - High Case

DEMAND (Region/Sector)	2007-08	2008-09	2009-10	2010-11	2011-12
BC Lower Main & Van. Island (I-5 Corridor)	**1,286,161**	**1,305,539**	**1,398,786**	**1,431,478**	**1,455,377**
Residential	622,767	634,149	649,233	669,352	683,335
Commercial (Firm Sales & Transport)	371,964	379,289	389,420	401,193	410,352
Industrial (Firm Sales & Transport)	97,127	97,798	98,535	99,335	100,092
Power Generation	194,302	194,302	261,597	261,597	261,597
W. Washington (I-5 Corridor)	**1,835,984**	**1,895,721**	**1,941,933**	**1,993,444**	**2,160,121**
Residential	823,117	852,573	882,726	913,024	945,248
Commercial (Firm Sales & Transport)	337,142	346,884	359,151	367,109	377,726
Industrial (Firm Sales & Transport)	205,686	212,225	212,688	213,353	214,170
Power Generation	470,038	484,038	487,367	499,958	622,977
W. Oregon (I-5 Corridor)	**963,717**	**988,465**	**1,015,274**	**1,042,713**	**1,071,088**
Residential	562,153	581,765	602,839	624,564	647,179
Commercial (Firm Sales & Transport)	260,748	265,882	271,616	277,327	283,085
Industrial (Firm Sales & Transport)	53,816	53,817	53,820	53,822	53,824
Power Generation	87,000	87,000	87,000	87,000	87,000
BC Interior	**443,329**	**447,012**	**455,634**	**463,554**	**471,687**
Residential	210,328	212,844	218,416	223,502	228,700
Commercial (Firm Sales & Transport)	114,680	115,902	118,963	121,812	124,767
Industrial (Firm Sales & Transport)	118,321	118,266	118,255	118,240	118,220
Power Generation	-	-	-	-	-
E. Washington & N. Idaho	**621,000**	**636,094**	**654,449**	**670,674**	**684,381**
Residential	200,049	205,780	217,279	227,534	235,022
Commercial (Firm Sales & Transport)	157,803	160,641	167,333	173,181	179,356
Industrial (Firm Sales & Transport)	83,627	90,152	90,317	90,439	90,483
Power Generation	179,520	179,520	179,520	179,520	179,520
E. Oregon & Medford (Non I-5 Supply)	**543,111**	**549,812**	**582,753**	**561,921**	**567,715**
Residential	86,499	88,979	93,646	98,077	102,631
Commercial (Firm Sales & Transport)	58,498	59,503	61,271	62,684	64,005
Industrial (Firm Sales & Transport)	67,662	70,878	97,383	70,708	70,627
Power Generation	330,452	330,452	330,452	330,452	330,452
S. Idaho	**553,627**	**566,675**	**586,598**	**602,710**	**620,138**
Residential	240,442	250,148	260,816	271,611	283,288
Commercial (Firm Sales & Transport)	123,864	123,207	128,462	133,779	139,530
Industrial (Firm Sales & Transport)	137,147	141,147	145,147	145,147	145,147
Power Generation	52,173	52,173	52,173	52,173	52,173
Total Design (Peak) Day Demand	**6,246,928**	**6,389,318**	**6,635,427**	**6,766,494**	**7,030,506**
Total Supply	**6,033,816**	**6,345,816**	**6,345,816**	**6,345,816**	**6,500,316**
Supply Surplus/**(Shortfall)**	**(213,112)**	**(43,502)**	**(289,611)**	**(420,678)**	**(530,190)**

Northwest Gas Association
2007 Natural Gas Outlook
Peak Day Demand/Supply Balance (Dth/day) - Low Case

DEMAND (Region/Sector)	2007-08	2008-09	2009-10	2010-11	2011-12
BC Lower Main & Van. Island (I-5 Corridor)	**1,279,086**	**1,288,924**	**1,300,325**	**1,313,958**	**1,327,762**
Residential	620,620	626,639	633,244	641,241	649,350
Commercial (Firm Sales & Transport)	370,708	373,820	377,849	382,660	387,558
Industrial (Firm Sales & Transport)	93,455	94,162	94,929	95,755	96,552
Power Generation	194,302	194,302	194,302	194,302	194,302
W. Washington (I-5 Corridor)	**1,750,375**	**1,768,202**	**1,793,827**	**1,825,862**	**1,970,422**
Residential	799,617	806,421	821,306	837,219	852,877
Commercial (Firm Sales & Transport)	328,741	334,278	342,135	346,016	352,113
Industrial (Firm Sales & Transport)	197,790	203,276	202,831	202,480	202,267
Power Generation	424,227	424,227	427,556	440,147	563,166
W. Oregon (I-5 Corridor)	**898,404**	**915,790**	**939,559**	**989,601**	**990,259**
Residential	549,468	562,937	578,960	612,705	613,201
Commercial (Firm Sales & Transport)	258,557	262,251	269,620	285,117	285,274
Industrial (Firm Sales & Transport)	40,379	40,602	40,979	41,779	41,783
Power Generation	50,000	50,000	50,000	50,000	50,000
BC Interior	**441,473**	**442,421**	**447,389**	**452,570**	**457,049**
Residential	209,127	209,872	213,079	216,393	219,229
Commercial (Firm Sales & Transport)	114,025	114,283	116,056	117,937	119,600
Industrial (Firm Sales & Transport)	118,321	118,266	118,255	118,240	118,220
Power Generation	-	-	-	-	-
E. Washington & N. Idaho	**565,370**	**568,322**	**574,635**	**581,141**	**585,191**
Residential	192,928	191,181	195,314	199,516	201,814
Commercial (Firm Sales & Transport)	150,914	149,201	151,374	153,679	155,501
Industrial (Firm Sales & Transport)	80,407	86,820	86,827	86,826	86,756
Power Generation	141,120	141,120	141,120	141,120	141,120
E. Oregon & Medford (Non I-5 Supply)	**538,849**	**542,413**	**545,256**	**547,922**	**550,263**
Residential	84,865	85,400	87,663	89,886	91,907
Commercial (Firm Sales & Transport)	56,812	56,613	57,231	57,797	58,207
Industrial (Firm Sales & Transport)	66,720	69,949	69,910	69,788	69,697
Power Generation	330,452	330,452	330,452	330,452	330,452
S. Idaho	**538,061**	**544,569**	**552,416**	**559,398**	**567,862**
Residential	240,442	244,738	249,917	254,525	260,111
Commercial (Firm Sales & Transport)	123,864	126,077	128,745	131,119	133,997
Industrial (Firm Sales & Transport)	135,897	135,897	135,897	135,897	135,897
Power Generation	37,857	37,857	37,857	37,857	37,857
Total Design (Peak) Day Demand	**6,011,618**	**6,070,641**	**6,153,408**	**6,270,453**	**6,448,808**
Total Supply	**6,033,816**	**6,345,816**	**6,345,816**	**6,345,816**	**6,500,316**
Supply Surplus/**(Shortfall)**	22,198	275,175	192,408	75,363	51,508

Table A8. I-5 Corridor Peak Day Supply/Demand Balance - Base Case

Northwest Gas Association
2007 Natural Gas Outlook
I-5 Corridor Peak Day Demand/Supply Balance (Dth/day) - Base Case

DEMAND (Region/Sector)	2007-08	2008-09	2009-10	2010-11	2011-12
BC Lower Main & Van. Island (I-5 Corridor)	**1,283,821**	**1,296,188**	**1,377,156**	**1,393,018**	**1,408,970**
Residential	621,291	628,698	636,491	645,609	654,759
Commercial (Firm Sales & Transport)	371,100	375,389	380,532	386,477	392,521
Industrial (Firm Sales & Transport)	97,127	97,798	98,535	99,335	100,092
Power Generation	194,302	194,302	261,597	261,597	261,597
W. Washington (I-5 Corridor)	**1,814,526**	**1,865,372**	**1,904,076**	**1,948,104**	**2,106,322**
Residential	813,956	836,690	861,500	886,472	912,578
Commercial (Firm Sales & Transport)	332,265	340,711	351,447	358,025	367,080
Industrial (Firm Sales & Transport)	198,267	203,933	203,762	203,649	203,687
Power Generation	470,038	484,038	487,367	499,958	622,977
W. Oregon (I-5 Corridor)	**935,762**	**960,017**	**985,211**	**1,011,247**	**1,038,154**
Residential	546,209	565,354	585,265	605,929	627,407
Commercial (Firm Sales & Transport)	253,370	258,477	263,759	269,129	274,557
Industrial (Firm Sales & Transport)	49,184	49,185	49,187	49,189	49,191
Power Generation	87,000	87,000	87,000	87,000	87,000
Total Peak (Design) Day Demand	4,034,109	4,121,576	4,266,442	4,352,370	4,553,446

SUPPLY	2007-08	2008-09	2009-10	2010-11	2011-12
Pipeline Interconnects	**2,296,915**	**2,296,915**	**2,296,915**	**2,296,915**	**2,296,915**
Max north flow on NWP @ Gorge	**551,000**	**551,000**	**551,000**	**551,000**	**551,000**
Huntingdon/Sumas	**1,745,915**	**1,745,915**	**1,745,915**	**1,745,915**	**1,745,915**
T-South to Huntingdon	1,638,522	1,638,522	1,638,522	1,638,522	1,638,522
Kingsvale to Huntingdon (via Southern Crossing)	107,393	107,393	107,393	107,393	107,393
Underground Storage	**1,414,450**	**1,726,450**	**1,726,450**	**1,726,450**	**1,726,450**
Jackson Prairie (NWP from JP)	884,000	1,196,000	1,196,000	1,196,000	1,196,000
(includes deliverability expansion of 312,000 Dth/day in service 2008-09)					
Mist Storage (NWN)	530,450	530,450	530,450	530,450	530,450
(includes deliverability expansion of 51,310 Dth/day in service 2007-08)					
Peak LNG	**350,338**	**350,338**	**350,338**	**350,338**	**504,838**
Newport/Portland LNG (NWN)	180,000	180,000	180,000	180,000	180,000
Gig Harbor Satellite LNG (PSE)	3,000	3,000	3,000	3,000	3,000
Swarr Stn Propane (PSE)	10,000	10,000	10,000	10,000	10,000
Tilbury LNG (TGI)	157,338	157,338	157,338	157,338	157,338
Vancouver Island LNG (permitted, provisional)	-	-	-	-	154,500
Total Supply	**4,061,703**	**4,373,703**	**4,373,703**	**4,373,703**	**4,528,203**
Supply Surplus/**(Shortfall)**	**27,593**	**252,126**	**107,260**	**21,333**	**(25,243)**

Table A9. I-5 Corridor Peak Day Supply/Demand Balance - High Case

Northwest Gas Association
2007 Natural Gas Outlook
I-5 Corridor Peak Day Demand/Supply Balance (Dth/day) - High Case

DEMAND (Region/Sector)	2007-08	2008-09	2009-10	2010-11	2011-12
BC Lower Main & Van. Island (I-5 Corridor)	**1,286,161**	**1,305,539**	**1,398,786**	**1,431,478**	**1,455,377**
Residential	622,767	634,149	649,233	669,352	683,335
Commercial (Firm Sales & Transport)	371,964	379,289	389,420	401,193	410,352
Industrial (Firm Sales & Transport)	97,127	97,798	98,535	99,335	100,092
Power Generation	194,302	194,302	261,597	261,597	261,597
W. Washington (I-5 Corridor)	**1,835,984**	**1,895,721**	**1,941,933**	**1,993,444**	**2,160,121**
Residential	823,117	852,573	882,726	913,024	945,248
Commercial (Firm Sales & Transport)	337,142	346,884	359,151	367,109	377,726
Industrial (Firm Sales & Transport)	205,686	212,225	212,688	213,353	214,170
Power Generation	470,038	484,038	487,367	499,958	622,977
W. Oregon (I-5 Corridor)	**963,717**	**988,465**	**1,015,274**	**1,042,713**	**1,071,088**
Residential	562,153	581,765	602,839	624,564	647,179
Commercial (Firm Sales & Transport)	260,748	265,882	271,616	277,327	283,085
Industrial (Firm Sales & Transport)	53,816	53,817	53,820	53,822	53,824
Power Generation	87,000	87,000	87,000	87,000	87,000
Total Peak (Design) Day Demand	**4,085,862**	**4,189,724**	**4,355,993**	**4,467,635**	**4,686,586**

SUPPLY	2007-08	2008-09	2009-10	2010-11	2011-12
Pipeline Interconnects	**2,296,915**	**2,296,915**	**2,296,915**	**2,296,915**	**2,296,915**
Max north flow on NWP @ Gorge	**551,000**	**551,000**	**551,000**	**551,000**	**551,000**
Huntingdon/Sumas	**1,745,915**	**1,745,915**	**1,745,915**	**1,745,915**	**1,745,915**
T-South to Huntingdon	1,638,522	1,638,522	1,638,522	1,638,522	1,638,522
Kingsvale to Huntingdon (via Southern Crossing)	107,393	107,393	107,393	107,393	107,393
Underground Storage	**1,414,450**	**1,726,450**	**1,726,450**	**1,726,450**	**1,726,450**
Jackson Prairie (NWP from JP)	884,000	1,196,000	1,196,000	1,196,000	1,196,000
(includes deliverability expansion of 312,000 Dth/day in service 2008-09)					
Mist Storage (NWN)	530,450	530,450	530,450	530,450	530,450
(includes deliverability expansion of 51,310 Dth/day in service 2007-08)					
Peak LNG	**350,338**	**350,338**	**350,338**	**350,338**	**504,838**
Newport/Portland LNG (NWN)	180,000	180,000	180,000	180,000	180,000
Gig Harbor Satellite LNG (PSE)	3,000	3,000	3,000	3,000	3,000
Swarr Stn Propane (PSE)	10,000	10,000	10,000	10,000	10,000
Tilbury LNG (TGI)	157,338	157,338	157,338	157,338	157,338
Vancouver Island LNG (permitted, provisional)	-	-	-	-	154,500
Total Supply	4,061,703	4,373,703	4,373,703	4,373,703	4,528,203
Supply Surplus/**(Shortfall)**	**(24,159)**	**183,978**	**17,709**	**(93,933)**	**(158,384)**

Table A10. I-5 Corridor Peak Day Supply/Demand Balance - Low Case

Northwest Gas Association
2007 Natural Gas Outlook
I-5 Corridor Peak Day Demand/Supply Balance (Dth/day) - Low Case

DEMAND (Region/Sector)	2007-08	2008-09	2009-10	2010-11	2011-12
BC Lower Main & Van. Island (I-5 Corridor)	**1,279,086**	**1,288,924**	**1,300,325**	**1,313,958**	**1,327,762**
Residential	620,620	626,639	633,244	641,241	649,350
Commercial (Firm Sales & Transport)	370,708	373,820	377,849	382,660	387,558
Industrial (Firm Sales & Transport)	93,455	94,162	94,929	95,755	96,552
Power Generation	194,302	194,302	194,302	194,302	194,302
W. Washington (I-5 Corridor)	**1,750,375**	**1,768,202**	**1,793,827**	**1,825,862**	**1,970,422**
Residential	799,617	806,421	821,306	837,219	852,877
Commercial (Firm Sales & Transport)	328,741	334,278	342,135	346,016	352,113
Industrial (Firm Sales & Transport)	197,790	203,276	202,831	202,480	202,267
Power Generation	424,227	424,227	427,556	440,147	563,166
W. Oregon (I-5 Corridor)	**898,404**	**915,790**	**939,559**	**989,601**	**990,259**
Residential	549,468	562,937	578,960	612,705	613,201
Commercial (Firm Sales & Transport)	258,557	262,251	269,620	285,117	285,274
Industrial (Firm Sales & Transport)	40,379	40,602	40,979	41,779	41,783
Power Generation	50,000	50,000	50,000	50,000	50,000
Total Peak (Design) Day Demand	**3,927,865**	**3,972,915**	**4,033,711**	**4,129,421**	**4,288,443**
SUPPLY					
Pipeline Interconnects	**2,296,915**	**2,296,915**	**2,296,915**	**2,296,915**	**2,296,915**
Max north flow on NWP @ Gorge	**551,000**	**551,000**	**551,000**	**551,000**	**551,000**
Huntingdon/Sumas	**1,745,915**	**1,745,915**	**1,745,915**	**1,745,915**	**1,745,915**
T-South to Huntingdon	1,638,522	1,638,522	1,638,522	1,638,522	1,638,522
Kingsvale to Huntingdon (via Southern Crossing)	107,393	107,393	107,393	107,393	107,393
Underground Storage	**1,414,450**	**1,726,450**	**1,726,450**	**1,726,450**	**1,726,450**
Jackson Prairie (NWP from JP)	884,000	1,196,000	1,196,000	1,196,000	1,196,000
(includes deliverability expansion of 312,000 Dth/day in service 2008-09)					
Mist Storage (NWN)	530,450	530,450	530,450	530,450	530,450
(includes deliverability expansion of 51,310 Dth/day in service 2007-08)					
Peak LNG	**350,338**	**350,338**	**350,338**	**350,338**	**504,838**
Newport/Portland LNG (NWN)	180,000	180,000	180,000	180,000	180,000
Gig Harbor Satellite LNG (PSE)	3,000	3,000	3,000	3,000	3,000
Swarr Stn Propane (PSE)	10,000	10,000	10,000	10,000	10,000
Tilbury LNG (TGI)	157,338	157,338	157,338	157,338	157,338
Vancouver Island LNG (permitted, provisional)	-	-	-	-	154,500
Total Supply	**4,061,703**	**4,373,703**	**4,373,703**	**4,373,703**	**4,528,203**
Supply Surplus/**(Shortfall)**	133,838	400,787	339,992	244,281	239,759

APPENDIX D

Terasen Gas Discussion Paper
Natural Gas Competitiveness

TERASEN GAS DISCUSSION PAPER - NATURAL GAS COMPETITIVENESS

The competitiveness of natural gas in British Columbia relative to other forms of energy is being influenced by a large number of factors, some of which are changing quickly at the present time. Some of the factors are as follows:

- High oil prices
- Volatile energy market prices for electricity and fossil fuels
- Energy policy and legislation
- Climate change policies and legislation, including the B.C. Carbon Tax
- Innovation and alternative energy technologies
- Public perception of natural gas and other forms of energy in terms of cost and environmental attributes
- Perceptions of the development community (architects, builders, developers, etc.) with respect to natural gas as compared with other energy forms.

In the residential and commercial markets natural gas competes with other energy forms primarily in the end uses of space and water heating. Natural gas also captures a smaller share of the cooking and clothes drying end use markets. Natural Gas for Vehicles ("NGV") competes in the vehicle fuel market but in recent years success has been limited to the fleet vehicle segment of the market.

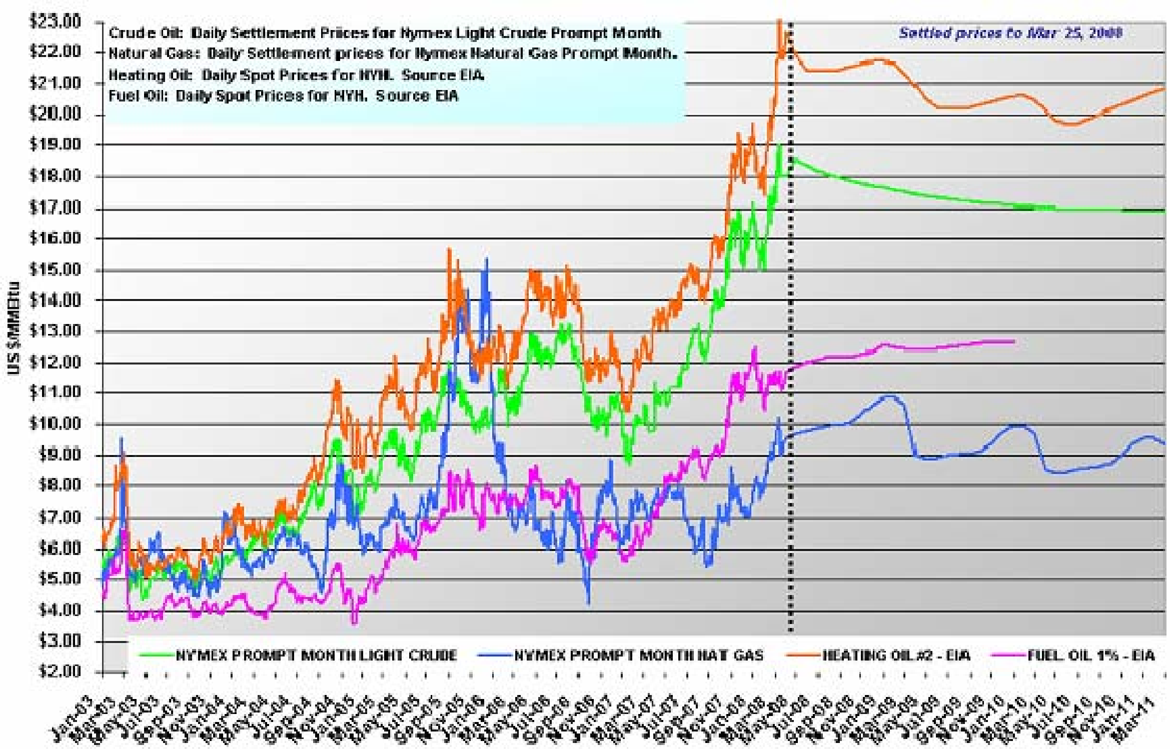
Natural gas competes with electricity, heating oil, propane, wood and alternative energy forms. The prominence of these energy sources as competitive alternatives to natural gas varies to some degree across the service territories of Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGW"). The issues of natural gas competitiveness versus electricity extend to all parts of the companies' service territories. The competitiveness of natural gas relative to heating oil is more of an issue on Vancouver Island where natural gas service became available much more recently than in the rest of the province. The price competitiveness of natural gas and propane is of interest in the two communities presently served by Terasen piped propane systems, Whistler and Revelstoke. Whistler will soon be converted to natural gas so future comparisons in the community will be between natural gas, electricity and alternative energy sources. Until another cost-effective alternative is identified and implemented, Revelstoke will continue to be served by the Terasen piped propane system so the competitiveness of propane relative to electricity and alternative energy forms will continue to be of interest there.

a) Commodity Price Trends

Prior to 2000 natural gas had enjoyed a long period of relatively low market commodity prices throughout North America as supplies outstripped demand during that period. In 2000-2001 the Western Energy Crisis pushed natural gas commodity prices in the western part of North America to levels not previously experienced and although the prices moderated for a period, natural gas has remained at much higher levels than historical prices prior to 2001. A second period of very high natural gas prices occurred in the fall and winter of 2005/06 after Hurricane Katrina impacted the natural gas delivery capability from the U.S. Gulf Coast. Natural gas prices moderated again for about a two-year period until the spring of 2008 when the impact of a cold winter depleted natural gas storage to very low levels.

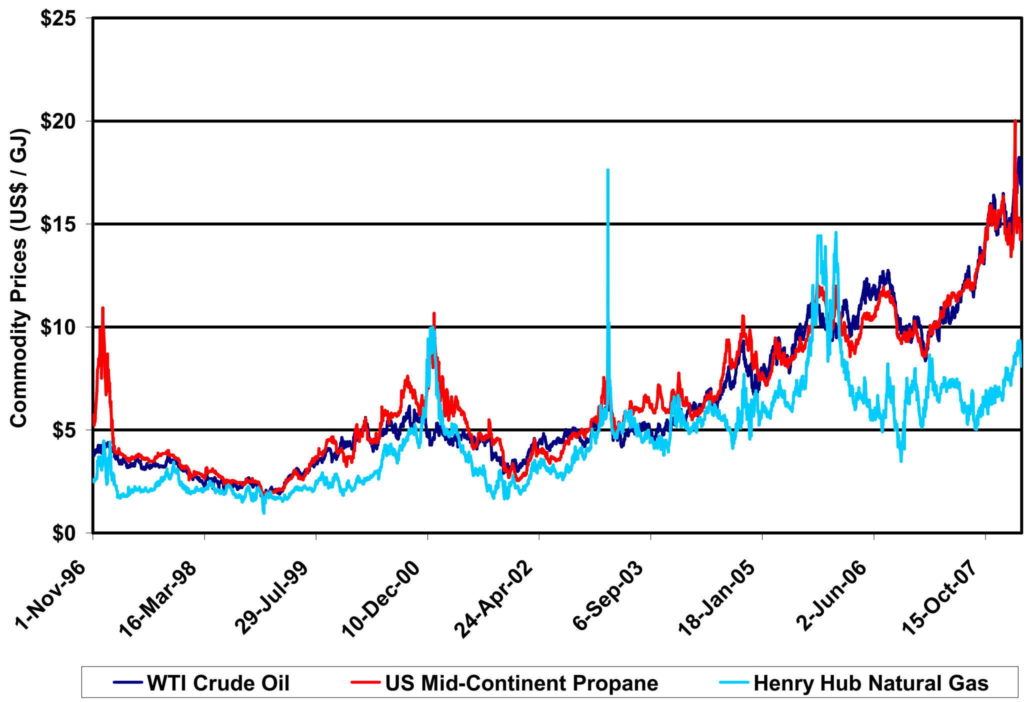
Historically, natural gas prices have ranged between those of residual fuel oil and heating oil. This trend results from the ability to substitute natural gas for residual fuel oil in industrial processes and power generation or for heating oil in space heating applications when oil prices are high. In recent years, however, natural gas future prices have become increasingly disconnected from these oil substitutes. The reason for this new trend is the recent rapid increases in crude oil prices, and possibly the fact that oil trades on a more global market, while the abundance of domestic supply is maintaining a largely North American market for natural gas. Since it is reasonable to assume that all cost-effective short-term oil to natural gas fuel switching capabilities have now been implemented, the forward price curve for natural gas currently is expected to remain below the traditional fuel oil “soft floor”. The commodity price chart in Figure A shows these trends.

Figure A - Competing Fuel Prices



Propane is a by-product of both oil refining and natural gas processing. Therefore the price of propane has historically tended to follow the higher of oil or natural gas prices, with natural gas price spikes above that of oil typically being short duration. The recent disconnection between oil and natural gas prices mean that propane prices have likewise followed rising oil commodity prices and become increasingly disconnected from natural gas prices. This trend can be seen in Figure B.

Figure B - Historic Natural Gas Prices versus Propane and Crude Oil



It is possible that the divergence between oil and gas prices could narrow again in the future but it is worth noting that market expectations as indicated by the forward prices on the chart are that the price divergence will continue. The lower market prices of natural gas suggest that the competitive position of natural gas is strong relative to heating oil (and propane) in these conditions.

b) Natural Gas and Electricity

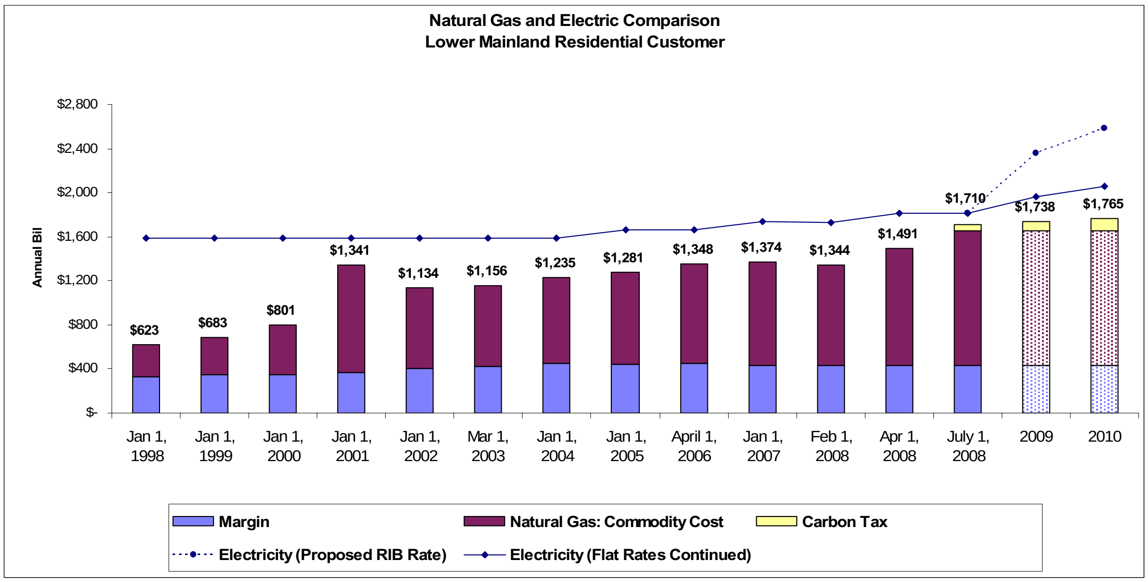
Electricity rates in British Columbia are among the lowest in North America. In spite of this, residential natural gas rates have remained competitive with electricity rates even in the more recent years of higher natural gas commodity prices (see Figure C below for a historical comparison of gas and electricity rates). Natural gas rates in B.C., however, are subject to changes in market commodity price fluctuations and have been more volatile than electricity rates. The gas rate increases and volatility have contributed to a perception that gas is no longer competitive with electricity.

With expected future trends in gas and electricity rates in B.C. there are reasonable prospects that natural gas may be able to maintain a similar level of competitiveness as it has in recent years. For BC Hydro several trends are expected to increase electricity rates over the next number of years. BC Hydro currently has its F2009 – F2010 Revenue Requirements Application under review by the Commission in which they have requested general rate increases of 6.56% and 8.21% for F2009 and F2010 respectively. A number of conditions are driving these increases, including higher capital spending to support growth and system reliability; incorporating new higher cost electricity supplies into the resource stack to meet demand growth, and the higher expected costs of alternative energy resources required to meet Provincial energy policies for clean and renewable electricity generation and electricity self sufficiency.

In addition BC Hydro has applied for an inclining block rate structure for its residential rates. The inclining block rate structure is being implemented to promote energy conservation in keeping with the 2007 BC Energy Plan and the provincial government's energy objectives as set out in the recently enacted Utilities Commission Amendment Act. Under the proposed inclining block rate structure BC Hydro's residential customers will pay a lower rate for the first block of electricity consumption in a given period and a higher rate for energy consumption that exceeds the first block threshold. As much of the electricity consumption for space heating falls into the higher-priced second block, the inclining block structure, when approved and implemented will improve the relative competitiveness of natural gas. This change is appropriate, in the Terasen Utilities' view, since BC Hydro's existing flat rate structure masks the true costs that new space heating load adds to BC Hydro's cost structure.

Figure C below provides a historical and projected comparison of natural gas bills with the comparable electricity bills. The natural gas bills are based on 110 gigajoules per year ("GJ/year") and an assumption of 90% efficiency, while the electricity bills assume 100% efficiency. Going forward the electricity bills include BC Hydro's applied-for F2009 and F2010 revenue requirements increases and the proposed inclining block rates. Natural gas rates and bills are assumed to be constant, a conservative assumption based on the forward commodity prices discussed above displaying a moderate downwards trend. However, the B.C. carbon tax on natural gas has been added in according to the phase-in schedule prescribed by the provincial government. Figure C demonstrates that while the historical natural gas cost advantage has experienced erosion, natural gas has maintained a competitive position relative to electricity. In the future to the extent that electric rate increases and rate structures such as the residential inclining block rate are approved natural gas will be afforded the opportunity to maintain its competitiveness with electricity. Terasen's efforts through DSM programs to assist customers to reduce their energy use will also contribute to natural gas being a competitive energy alternative in B.C.

Figure C - Natural Gas & Electric Comparison



c) Natural Gas and Alternative Energy Systems

In the current situation global climate change and high and volatile energy prices are the focus of much public discussion. In addition, the B.C. 2007 Energy Plan, several pieces of new provincial legislation and provincial programs have focused squarely on the objective of climate change mitigation and the promotion of energy conservation and alternative and renewable energy forms. The focus on alternative/renewable energy and greenhouse gas emission reductions extends through all stages of the energy supply chain – from the production of energy to the end use. In addition energy conservation is being targeted through building design, building codes and standards, better insulation and windows, and the promotion of energy efficient appliances. The development of district energy systems is another important means of capturing energy efficiencies that is gaining prominence in this context.

For the purposes of this discussion the comparison between natural gas and alternative energy systems focuses on the consumption of energy at the end use. For natural gas the primary end uses are for space and water heating. Alternative energy systems that target these end uses are based on technologies such as ground-source heat pumps ("GSHP"), air-source heat pumps ("ASHP"), solar thermal and photovoltaic. GSHPs and ASHPs are the alternative technologies that provide the most direct competition to natural gas and the following discussion will focus on those two alternatives. Solar thermal has the potential to capture a share of the domestic water heating market however not on a year-round basis in the cold winter climate of B.C. The potential for photovoltaic is more in the displacing of electrical load rather than natural gas load.

In comparing natural gas systems to ASHPs and GSHPs from a technical and economic perspective a few general comments are warranted. The first general comment is alternative energy systems tend to be characterized by higher upfront capital costs and lower ongoing operating costs (from lower energy consumption) relative to natural gas-based systems. Alternative energy systems also tend to have higher maintenance costs than natural gas-based systems which erodes some of the benefits of lower operating costs. Another general observation is there are more unique aspects with alternative energy systems from one installation to the next than with natural gas-based systems. The cost and configuration of GSHPs, for example, depends on local surface geology and soil conditions. The effectiveness of ASHPs depends on local climate – their efficiency falls off in colder conditions. A further general comment is that it is not generally cost effective to size ASHPs and GSHPs to meet the entire peak heating load of a dwelling. A backup system consisting typically of electric baseboard heaters or a natural gas furnace is needed to meet peak heating requirements in the winter.

Various other factors beyond technical and economic comparisons are considered in the selection of a dwelling's heating system. What the customer wants is an obvious consideration in this regard. The perceived value of other qualities of a heating system such as the use of greener and more sustainable technologies or avoiding future commodity price volatility and escalation are of greater importance to some consumers than comparisons from a purely economic standpoint.

Attachment 1 provides a sample analysis of natural gas space heating compared with ASHPs and GSHPs. It should be noted that this study is illustrative only and depends on various assumptions. The observations made should be considered directional only since as discussed above the costs and effectiveness of alternative energy systems vary from situation to situation. With these caveats in mind the following comments can be made on the competitive comparisons between natural gas and alternative energy systems:

- The initial capital cost differences between natural gas systems and ASHPs or GSHPs continue to be significant. Without incentives or other external sources of support the higher upfront capital costs will continue to be an obstacle to the penetration of ASHPs and GSHPs in the space heating market.
- The annual operating and maintenance ("O&M") costs of ASHPs and GSHPs are lower currently than those for natural gas systems however the annual cost advantage is not large enough to provide pay back of the upfront capital cost difference over a reasonable timeframe. With expected increases in electricity rates the annual O&M cost advantage currently enjoyed by ASHPs and GSHPs relative to natural gas installations may be diminished.
- ASHPs and GSHPs operate at higher efficiencies than natural gas systems and on this basis would be expected to provide benefits in achieving the energy efficiency and environmental objectives in the province. However, increased adoption of these technologies may increase the challenge of achieving electricity self-sufficiency in B.C., meaning there is an increased reliance on imported power (and its accompanying greater carbon footprint) until self sufficiency is achieved and a consequent delay in the achievement of the desired environmental benefits.
- Increased adoption of ASHPs and GSHPs will also further impact the cost pressures being faced by electric utilities by adding to the growth in both annual demand and peak capacity.

ATTACHMENT 1
SAMPLE Analysis of Heating Choices for a Typical New Detached Single Family Dwelling Located in the Lower Mainland

a) Systems compared

i. High efficiency (95%) gas forced air furnace heating
ii. Air Source Heat Pump (ASHP) forced air heating
iii. Ground Source Heat Pump (GSHP) closed loop system, forced air heating

b) Customer Choice

When heating systems are selected for homes there are a few common options available and promoted. These include electric base board, high efficiency gas, air source heat pumps and ground source heat pumps. Electric baseboards are inexpensive to install and maintain but do not address the fresh air circulation requirements of the home.

Fresh air supply is provided with the furnace and heat pump options. The configuration of these systems can be very similar with all of them utilizing the same furnace in the house for the air distribution component. The gas burner section of the furnace is the primary heating section as a furnace or the supplemental heating section for a heat pump. With gas heating the heat comes from the gas burner and the furnace fan distributes that hot air through the ducting system. With a heat pump the furnace is still the air handler but instead of the heat coming from the gas burner it is harnessed from either the outdoor air or ground and transferred to a coil inside of the furnace. It could be looked at as a heat pump as an add-on to a furnace. The incremental cost for an ASHP system would then be the compressor and coil section along with associated piping, controls, and extra labour.

Typical cooling load is quite often about one half of the heating load. A typical house may need 80,000 British thermal units per hour (“Btu/hour”) for heating and 40,000 Btu/hour for cooling. For this reason many heat pumps are sized for the cooling load and undersized for the heating load. Supplemental heating is then required which is provided by the gas section of the furnace or electric resistance heaters in the furnace/air handler.

Air source heat pumps (ASHP) will usually provide heating for most but not all of the heating season. As the outdoor temperature drops, the heating capacity of the ASHP decreases. There are about 25 days of the year in Vancouver when the ASHP, using typical sizing criteria, is not adequate to supply the heating load of the residence. Supplemental gas or electric heat will be required during these 25 days. This supplemental heating load will occur during peak load periods.

Ground source heat pumps provide steady performance with very little influence from outdoor ambient temperature. The drilling cost for a ground source heat pump is usually more than the cost of all equipment and labour. When heating only is required, high efficiency furnaces or air source heat pumps are the only economic options.

Homes in colder climates are usually smaller and better insulated so the heating load does not vary too much throughout the more populated areas of the province. Homes in the Interior have a cooling load not typical in the Coastal areas. As more heat pumps are installed in the Lower Mainland and Vancouver Island areas there will be an increase in summer electrical load in these regions of the province where the majority of BC Hydro's customers and demand are located.

c) <u>Design Assumptions</u>

2,500 Square Foot detached new house in the Vancouver area

Space heating load - 50 gigajoules per year ("GJ/year") or 13,890 kilowatt hours per year ("kWh/year")
Space cooling load - 6 GJ/year or 1,670 kilowatt hours ("kWh") (36,000 Btu/h unit x 12 hours/day x 14 days)
Supplemental heat - 12 GJ/year or 3,000 kWh (50,000 Btu/h or 15 kW x 8 hours/day x 25 days)

Assume air conditioning will be utilized when available. For Vancouver air conditioning ("AC") could be up to 2 weeks a year, for an Interior location like Kelowna AC could be up to 3 months a year, for Vancouver Island AC may not be required all year.

Assume supplemental heat required for air & ground source heat pumps due to common cooling load sizing of equipment (under sized for heating). Supplemental heat ("SH") could be required for 3 to 4 weeks a year in the Lower Mainland, for an Interior location like Kelowna SH could be required for up to 3 months a year, for Vancouver Island SH may not be needed.

Coefficient of Performance ("COP") and other referenced information taken from Natural Resources Canada, links below:
http://oee.nrcan.gc.ca/publications/infosource/pub/home/heating-heat-pump/booklet.pdf
http://oee.nrcan.gc.ca/publications/infosource/pub/home/Heating_and_Cooling_with_a_Heat_
http://oee.rncan.gc.ca/publications/infosource/pub/home/heating-heat-pump/asheatpumps.cfmPump_Section4.cfm

Air Source Heat Pump Coefficient of Performance (COP) = 3.3
Ground source (closed loop) Heat Pump COP = 4
COP used here for both heating and cooling calculations. See section titled - Efficiency Terminology from NRCan

Cost assumptions are based on cost to the customer. It is very difficult to estimate costs as contractors will not quote on fictitious houses. Different contractors will give different price quotes for the same house and two homes of the same square footage may have quite different requirements. Heating and cooling requirements will vary with size, type and location of the home as well as the number of occupants and preferences.

Costs are estimated on general industry knowledge.

d) Cost assumptions

Hi-efficiency furnace equipment - \$5,000 and installation - \$2,000 Total \$ 7,000
Air source Heat Pump equipment - \$10,000 and installation \$3,000 Total \$13,000
Ground source Heat Pump equipment - \$12,000 and installation - \$3,000 Total \$15,000
Ductwork material and installation costs - \$4 000 (common to all three systems)
Ground source drilling costs - \$30/foot x 200 feet/ton x 3 tons = \$18,000
(1 ton of cooling = 12,000 Btu/h)
Basic monthly charge for electricity and gas not included in calculations
Electricity costs – Current - \$0.0655/ kWh - BC Hydro April 1, 2008 residential rate
- 2010 Rate – 2nd Block Rate per BC Hydro RIB Application
Natural Gas costs - Current - \$14.33/GJ = TGI Jul 1, '08 Rate 1 + \$0.497 carbon tax
- 2010 Rate - \$14.83/GJ = Current + \$0.497/GJ additional carbon tax
- Basic charge – \$11.13/mo x 12 mo x 65% space heating share
Fan energy = 250 watts x 8hrs/day x 365 days/year = 730 kWh/year
Electrically Commutated Motors (ECM) will use considerably less energy if utilized
Annual maintenance costs*: Gas furnace \$150, Heat pumps \$300

*Typically heat pumps are serviced twice a year and furnaces are serviced once a year. For heat pump maintenance there are 2 different parts that have to be maintained; the condensing unit outside and the fan coil unit inside. Refrigeration mechanics service heat pumps and they are more expensive to hire than gas fitters who service furnaces.

e) Pros & Cons of Different Systems

High Efficiency Gas Furnace: Lowest installation costs of all forced air systems. Higher operating costs with some variability due to commodity pricing changes. Low maintenance costs. Easy to repair or replace. Heating air temperature is hot, fast response, comfortable

Air Source Heat Pump: Higher initial installation cost. Middle of range on operating costs due to new electrical load for cooling. Large electrical starting load and running load. Electrical service upgrade may be required. Complicated technology, higher maintenance and repair costs, long run time, noisy, heating air temperature is warm not hot, slow response. Life span less than ground source systems due to stress of defrost cycle. See Life Expectancy and Warranties section below.

Ground Source Heat Pump: Highest initial installation cost. Lowest operating costs. Large electrical starting load and running load. Electrical service upgrade may be required. Complicated technology, higher maintenance and repair costs, long run time, noisy, heating air temperature is warm, not hot, slow response.

Table 1 - Installation and Operating Costs

				Current Rates			2010 Rates[1]		
	kWh or GJ per Year		Efficiency / COP	Rate per kWh or GJ	Amount ($)		Rate per kWh or GJ	Amount ($)	
#1 Gas Furnace									
Equipment & installation					$7,000			$7,000	
Ductwork					$4,000			$4,000	
Total Installation					**$11,000**			**$11,000**	
Natural Gas - Energy Charge	50	GJ	0.95	$14.33	$754		$14.83	$781	
- Basic Charge[2]					$87			$87	
Fan electricity	730	kWh	1.00	$0.0655	$48		$0.0935	$68	
Maintenance					$150			$150	
Total Operating & Maintenance					**$1,039**	**/ year**		**$1,086**	**/ year**
#2 Air Source Heat Pump									
Equipment & installation					$13,000			$13,000	
Ductwork					$4,000			$4,000	
Total Installation					**$17,000**			**$17,000**	
Electric heat	11,390	KWh	3.30	$0.0655	$226		$0.0935	$323	
Electric cool	1,670	KWh	3.30	$0.0655	$33		$0.0935	$47	
Supplementary electric heat	3,000	KWh	1.00	$0.0655	$197		$0.0935	$281	
Fan electricity	730	KWh	1.00	$0.0655	$48		$0.0935	$68	
Maintenance					$300			$300	
Total Operating & Maintenance					**$804**	**/ year**		**$1,019**	**/ year**
#3 Ground Source Heat Pump									
Equipment & installation					$15,000			$15,000	
Drilling					$18,000			$18,000	
Ductwork					$4,000			$4,000	
Total Installation					**$37,000**			**$37,000**	
Electric heat	11,390	KWh	4.00	$0.0655	$187		$0.0935	$266	
Electric cool	1,670	KWh	4.00	$0.0655	$27		$0.0935	$39	
Supplementary electric heat	3,000	KWh	1.00	$0.0655	$197		$0.0935	$281	
Fan electricity	730	KWh	1.00	$0.0655	$48		$0.0935	$68	
Maintenance					$300			$300	
Total Operating & Maintenance					**$759**	**/ year**		**$954**	**/ year**

Notes: 1. 2010 rates for natural gas include $1.00/GJ for carbon tax. 2010 rates for electricity assume the proposed BC Hydro RIB Tier 2 rate.
2. A portion of the Basic Charge is included for natural gas on the basis that gas service is optional while all dwellings would have electricity.

Table 2 - Summary of Costs for Gas and Heat Pump Heating Systems

	Current Rates			2010 Rates		
Equipment	**Gas Furnace**	**Air Source Heat Pump**	**Ground Source Heat Pump**	**Gas Furnace**	**Air Source Heat Pump**	**Ground Source Heat Pump**
Installation Cost	$11,000	$17,000	$37,000	$11,000	$17,000	$37,000
Annual Operating & Maintenance	$1,039	$804	$759	$1,086	$1,019	$954

f) Observations

The summary information presented in Table 2 suggests that based on the sample scenario and assumptions the annual ASHP and GSHP systems will continue to have lower annual operating and maintenance costs than a comparable high efficiency natural gas system will. The savings in annual operating and maintenance costs may not, in the absence of incentives, be large enough to provide payback of the upfront capital cost differences in a reasonable time frame. These comparisons should be considered to be directional only since they are based on various assumptions about system efficiencies and future gas and electric rates. Also, as indicated above, the particular circumstances affecting ASHP and GSHP installations are likely to vary considerably from one site to the next.

2 EXCERPTS FROM NATURAL RESOURCES CANADA (NRCAN) LINKS CITED ON PAGE 1

a) Life Expectancy and Warranties

Earth Energy Systems ("EES") have a life expectancy of about 20 to 25 years. This is higher than for air-source heat pumps because the compressor has less thermal and mechanical stress, and is protected from the environment. Air-source heat pumps have a service life of between 15 and 20 years. The compressor is the critical component of the system. Most heat pumps are covered by a one-year warranty on parts and labour, and an additional five- to ten-year warranty on the compressor (for parts only). However, warranties vary between manufacturers, so check the fine print.

b) Upgrading the Electrical Service

Generally speaking, it is not necessary to upgrade the electrical service when installing an air-source add-on heat pump. However, the age of the service and the total electrical load of the house may make it necessary to upgrade. A 200 ampere electrical service is normally required for the installation of either an all-electric air-source heat pump or a ground-source heat pump.

c) Summer Cooling May Add to Energy Bills

Heat pumps supply heat to the house in the winter and cool the house in the summer. They require electricity to operate. If you add a heat pump to your heating system or convert from another fuel to a heat pump, and your old system was not equipped with central air conditioning, you may find that your electricity bills will be higher than before.

d) Sizing Considerations

Unlike the outside air, the temperature of the ground remains fairly constant. As a result, the potential output of an EES varies little throughout the winter. Since the EES's output is relatively constant, it can provide almost all the space heating requirement.

As with air-source heat pump systems, it is not generally a good idea to size an EES to provide all of the heat required by a house. For maximum cost-effectiveness, an EES should be sized to meet 60 to 70 percent of the total maximum "demand load" (the total space heating and water heating requirement). The occasional peak heating load during severe weather conditions can be met by a supplementary heating system.

e) Efficiency Terminology

The efficiency ratings for different types of heat pumps use different terminology. For example, air-source heat pumps have seasonal heating and cooling ratings. The heating rating is the heating seasonal performance factor ("HSPF"); the cooling rating is the seasonal energy efficiency ratio ("SEER") Both are defined above. However, in the manufacturers' catalogues you may still see COP or energy efficiency ratio ("EER") ratings. These are steady state ratings obtained at one set of temperature conditions and are not the same as the HSPF or SEER ratings. Earth-energy systems use only coefficient of performance ("COP") and EER ratings.
Again, these ratings only hold for one temperature condition and cannot be directly used to predict annual performance in an application. In the section of this booklet titled "Major Benefits of Earth-Energy Systems" (see page 37), the COP ratings were used in a calculation to estimate HSPFs in different regions across Canada. HSPFs are not normally used to express the efficiency of earth-energy systems, but are used here to enable a comparison with air-source heat pumps.

The **coefficient of performance (COP)** is a measure of a heat pump's efficiency. It is determined by dividing the energy output of the heat pump by the electrical energy needed to run the heat pump, at a specific temperature. The higher the COP, the more efficient the heat pump. This number is comparable to the steady-state efficiency of oil- and gas-fired furnaces.

The **heating seasonal performance factor (HSPF)** is a measure of the total heat output in Btu of a heat pump over the entire heating season divided by the total energy in watt hours it uses during that time. This number is similar to the seasonal efficiency of a fuel-fired heating system and includes energy for supplementary heating. Weather data characteristic of long-term climatic conditions are used to represent the heating season in calculating the HSPF.

The **energy efficiency ratio (EER)** measures the steady state cooling efficiency of a heat pump. It is determined by dividing the cooling capacity of the heat pump in Btu/h by the electrical energy input in watts at a specific temperature. The higher the EER, the more efficient is the unit.

The **seasonal energy efficiency ratio (SEER)** measures the cooling efficiency of the heat pump over the entire cooling season. It is determined by dividing the total cooling provided over the cooling season in Btu by the total energy used by the heat pump during that time in watt hours. The SEER is based on a climate with an average summer temperature of 28°C.

APPENDIX E

Terasen Gas
Annual Demand Forecast Methodology

ANNUAL DEMAND FORECAST METHODOLOGY BY COMPANY

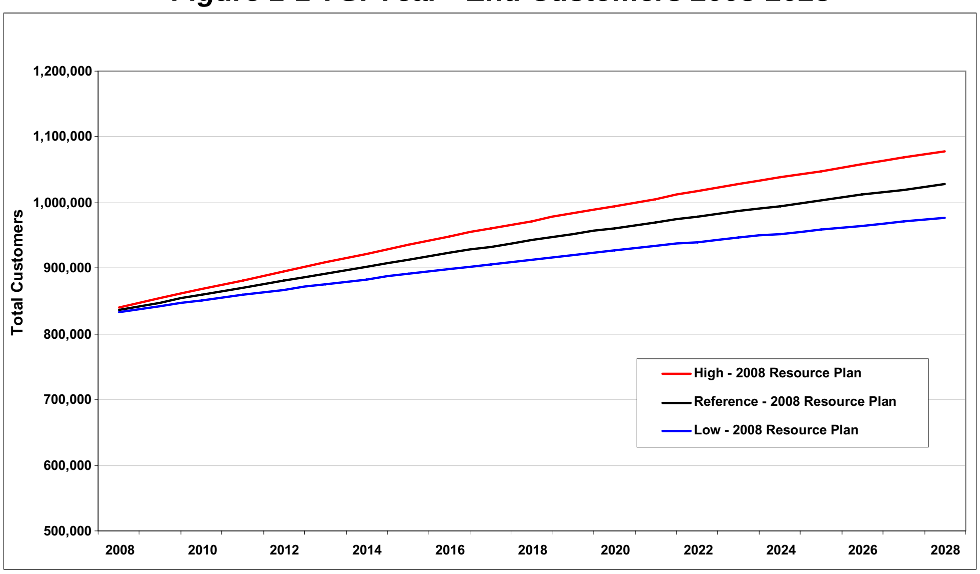
1 TGI

a) Total Customers & Customer Additions

The total number of Terasen Gas Inc. ("TGI") customers is forecast to continue increasing in the range of 0.8% to 1.3% over the planning period with the Reference case at 1.0%. New residential customer additions, which have been strong over the recent years due to an economic and housing boom, are expected to decrease to more moderate levels driven by slowing growth in the population brought on by the aging of baby boomers and lower birth rates.

Commercial customer additions reflect the same long-term growth patterns as residential customers based on the assumption that businesses tend to be created to serve demand stemming from growth in the population.

Figure 1-1 TGI Year - End Customers 2008-2028



b) Use per Customer

As discussed earlier in the Trends section, there are several factors including renewal of existing furnace stock and the shift in housing type which is driving the longer term 1% year-over-year decline in residential use rates being observed by natural gas utilities across North America. The decrease in residential use per customer rates for B.C. is expected to flatten-out in approximately 10 years when the last of the low-efficiency furnaces have been replaced. Though customers do adjust their consumption when major price spikes occur, as witnessed in 2001, there is no ability to predict price shocks over the 20 year planning period. As such, the forecast of residential use rates reflects recent results and then decreases by 1% annually for the first 10 years. Subsequent years are held constant afterwards.

Since the sharp increase in natural gas commodity costs in 2000/1, commercial use rates have been relatively stable on an aggregate basis. The strong performance of the economy since that time coupled with competitive pressures likely suggests that businesses were quicker to upgrade less efficient equipment. With no clear trends visible across the various commercial rate classes, the observed growth rate over the past three years is applied to each rate class to arrive at the forecast for the first 5 years and then held constant for the remainder of the planning period. Without an identified and quantifiable driver, as exists with furnace renewals for residential customers, there is insufficient information to project changes in commercial use rates beyond the five year window.

The table below summarizes the residential and commercial use per customer rates for TGI. The steeper decline in residential rates experienced at the beginning of the decade has moderated in the past few years with the decrease from 2006 to 2007 being 0.6%. Using a 1% annual decline is considered appropriate for longer term planning based on analysis of furnace data. Rates 2 & 3 have seen increasing use per customer rates since 2001 likely driven by economic growth experienced in the province. Rate 23 does show some decline from earlier in the decade, but that is a reflection of the fact that this rate class only originated in 1997 and that the early entrants into this rate class were higher consuming customers. The number of customers in Rate 23 has more than tripled since 1999 and the rate class is now showing stable consumption over the past three years.

Table 1-1 TGI Use per Customer (GJ)

	1999	2000	2001	2002	2003	2004	2005	2006	2007
Rate 1	116.7	111.7	100.5	105.6	103.1	102.6	97.4	96.8	96.2
Rate 2	339.4	324.6	305.4	301.8	303.6	313.8	305.8	314.3	316.5
Rate 3	3,982	3,660	3,332	3,378	3,292	3,501	3,388	3,314	3,426
Rate 23	6,945	6,447	5,802	5,281	4,883	5,113	4,714	4,686	4,778

c) Industrial Demand

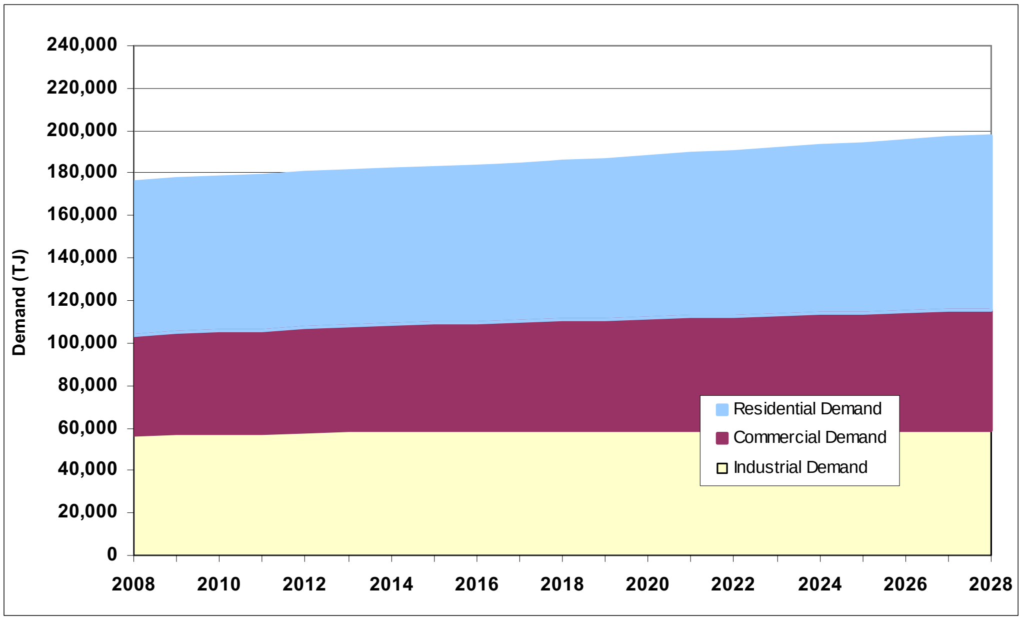
As in past years, a survey of TGI's industrial customers was completed to determine anticipated consumption over the next five years. The industrial survey solicits input from Rate Classes 7, 22, 25 and 27 while demand for Rate Classes 4, 5 & 6 is modelled from market information and historical trends. The results from the survey conducted in the summer of 2007 account for 50% of the industrial customers but over 80% of the annual demand.

d) Annual Demand – Reference Case

Combining the elements of total customer, use rates per customer and the industrial forecast produces the Reference Case for TGI's Annual Demand forecast.

As can be seen in the graph below, overall demand is expected to grow moderately at less than 1% annually over the planning period. Residential demand - and to a lesser degree commercial demand - is expected to account for a larger portion of that demand over time.

Figure 1-2 Reference Case: TGI Annual Demand 2008 – 2028



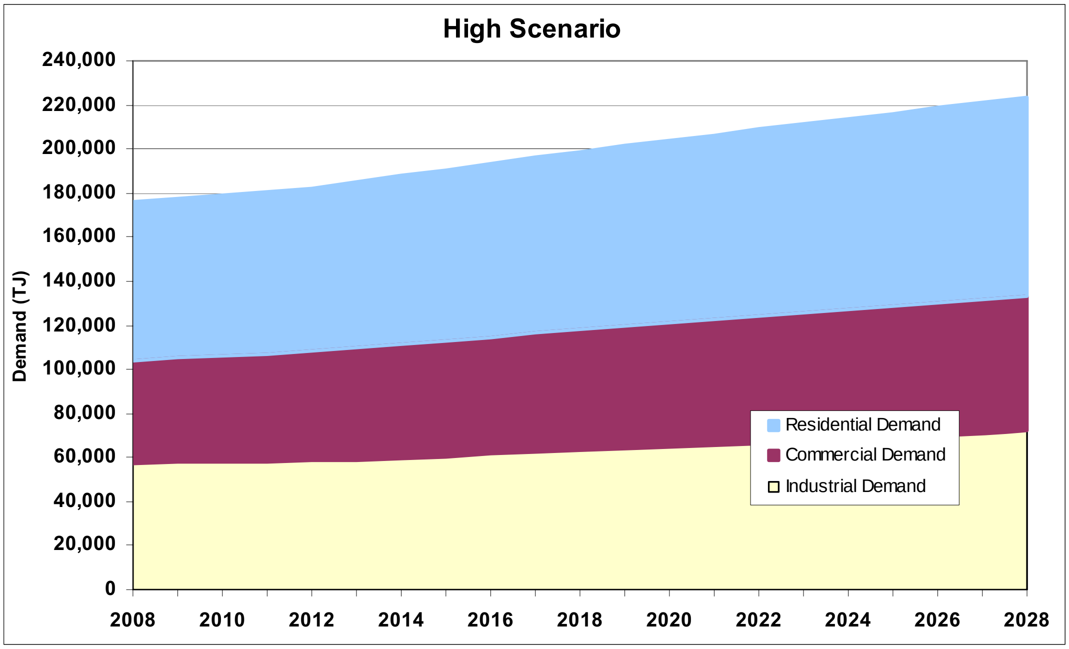
e) High Scenario

Strong growth in the provincial economy translates into more new residents coming to live in the province. Also, TGI manages to capture a larger share of new residential units. These two factors are captured in customer additions that are 25% above the Reference Case.

Residential use rates cease their decline after the fifth year, in spite of the renewal of lower efficiency furnaces, as both existing and new customers increasingly adopt natural gas for other appliances in the home such as domestic hot water heating and clothes drying. This shift in customer behaviour is driven through incentives or possible by a change in building codes or other legislation. Currently, 35% of existing homes heat their water with electricity, though only 20% of these homes use electricity for space heating.

Demand from natural gas vehicles (NGVs) experiences strong growth – especially for fleet vehicles – in reaction to high oil costs and the goal of lowering local pollution levels. The electrification of the province's ports moves ahead and is supplied through natural gas fuelled generation. Finally, industrial demand, which reflects customer input for the first five years, grows at 1 ¼% (roughly half of GDP growth).

Figure 1-3 TGI Annual Demand 2008 - 2028



f) Low Scenario

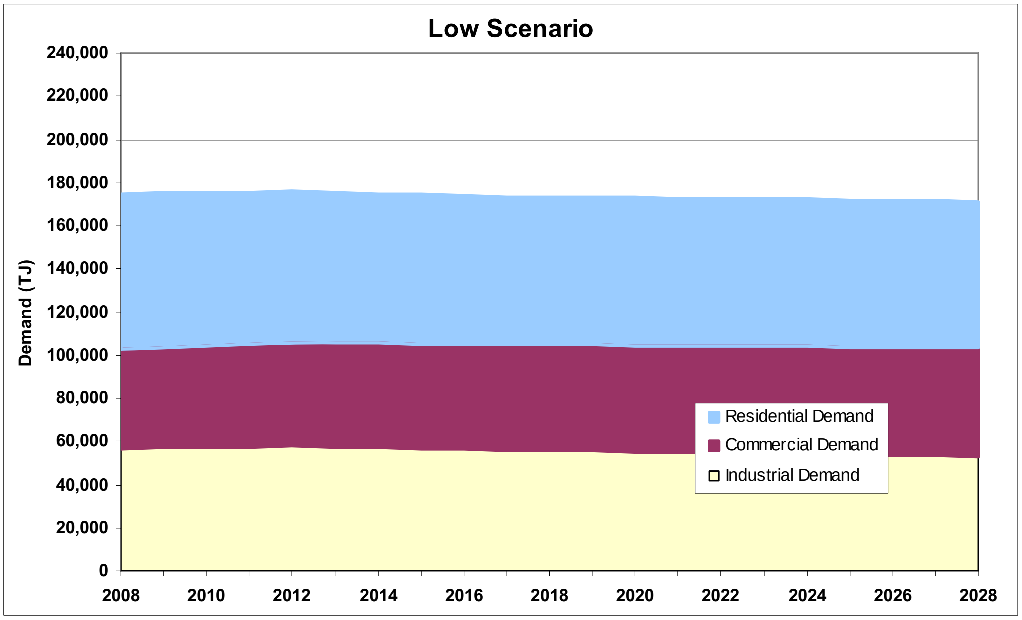
Under this scenario, the provincial economy underperforms over the long-term due to factors such as a protracted slowdown in the U.S. and world economies. This results in a lower level of new arrivals to the province. Also, this scenario assumes that TGI is less successful in attaching multi-family dwellings who opt for electricity or alternative energy systems to heat their homes. These factors are captured in customer additions that are 25% below the Reference Case.

Residential use per customer rates decline at a steeper annual rate of 1.5% for the first ten years suggesting that customers are finding ways to curtail their demand beyond the effects of furnace renewal. This scenario also sees annual use per customer rates continue to decline over the latter portion of the planning period as home owners either find ways to reduce their consumption or shift to non-fossil fuel alternatives.

Commercial customers use per customer rates are decreased by 1% (as compared to the Reference case) for the first five years, then decline at a slower annual rate of 0.5% over the remainder of the planning period.

Like commercial use rates, industrial volumes are also adjusted downwards by 1% in each of the first five years and then by 0.5% annual for subsequent years to reflect a slower economy as well as a continued shift of industry and manufacturing to other geographies.

Figure 1-4 TGI Annual Demand 2008 - 2028



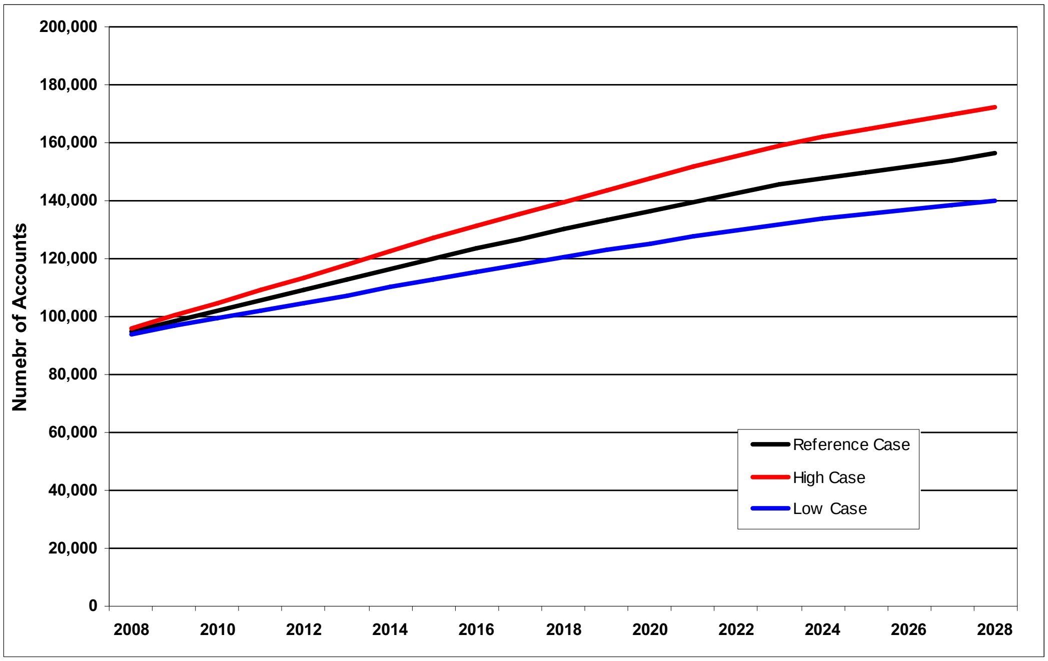
2 TGVI

a) Total Customers & Customer Additions

The total number of Terasen Gas Vancouver Island ("TGVI") customers is forecast to continue increasing in the range of 2.0% to 3.0% over the planning period with the Reference case at 2.5%. New residential customer additions, which have been strong over the recent years due to strong growth in new home construction is expected to decrease to more moderate levels driven by slowing growth in the population brought on by the aging of baby boomers. TGVI continues to also add 'on main' conversion customers at a rate of approximately 700 to 900 customers per year in the last two years. This rate of conversions is down from 2004-5 levels of 1,200 customers per year. It is expected that the proportion of conversion customers will continue to decline over the long-term and eventually more closely resemble TGI which averages approximately 200 conversions per year for a much larger customer base.

As with TGI, TGVI commercial customer additions reflect the same long-term growth patterns as residential customers based on the assumption that businesses tend to be created to serve demand stemming from growth in the population.

Figure 2-1 TGVI Account Forecast from 2008 – 2028



b) Use per Customer

As mentioned earlier in the Trends section, TGVI is not exhibiting the same decline in residential use rates as seen with TGI. This is to be expected as the source of decline for TGI is primarily attributed to the replacement of low-efficiency furnaces that were installed prior to 1990. In the case of TGVI, natural gas only arrived on Vancouver Island in 1991, so any furnace installations would have occurred using mid-efficiency technology or better. Replacement of those furnaces will not likely begin until 2016 and the effect will not be as pronounced given that it will be mid-efficiencies furnaces being taken out of service rather than low-efficiency units.

Also, given the recent arrival of natural gas to TGVI, many of the natural gas services installed were to existing homes which had existing oil furnaces. As these furnaces come due for replacement, the likelihood is that they will choose to convert to natural gas due to high heating oil costs and the higher home insurance costs associated with storing heating oil on-site. Fuel switching from heating oil to natural gas for space heating may cause residential use per customer rates to actually increase over time.

As detailed in the table below, residential use per customer rates continue to show year to year variability, but the values continue move in a consistent range of 57 to 60 gigajoules per year ("GJ/yr"). Commercial use per customer rates, though also exhibiting variability, has either demonstrated increasing or stable rates over the past 5 years.

Table 2-1 TGVI Use per Customer (GJ)

	2003	2004	2005	2006	2007
RGS	60.6	57.6	58.7	60.2	57.0
SCS1	66.6	63.5	75.0	75.1	90.7
SCS2	297	285	314	314	310
LCS1	901	885	943	903	943
LCS2	2,325	2,326	2,384	2,295	2,406
AGS	1,248	1,407	1,339	1,387	1,367
LCS3	15,460	16,740	16,521	17,379	17,694

Based on historical data, the Reference Case for TGVI Annual Demand assumes constant use rates for all rate classes over the course of the entire planning period.

c) Transportation Customers

TGVI provides transportation services to Vancouver Island Gas Joint Venture ("VIGJV"), BC Hydro's Island Cogeneration Project ("ICP") and to the municipality of Squamish – formerly Terasen Gas Squamish ("TGS"). In addition, TGVI will begin providing transportation services to Terasen Gas Whistler ("TGW") upon the completion of the natural gas pipeline to that community sometime in 2009.

Vancouver Island Gas Joint Venture ("VIGJV")
August 16th, 2007, VIGJV gave notice to reduce its contract demand to 8.0 terajoules per day ("TJ/d") effective August 16th, 2008, from the current level of 9.1 TJ per Day, as a result of Pope& Talbot's decision to curtail production at its Harmac facility.

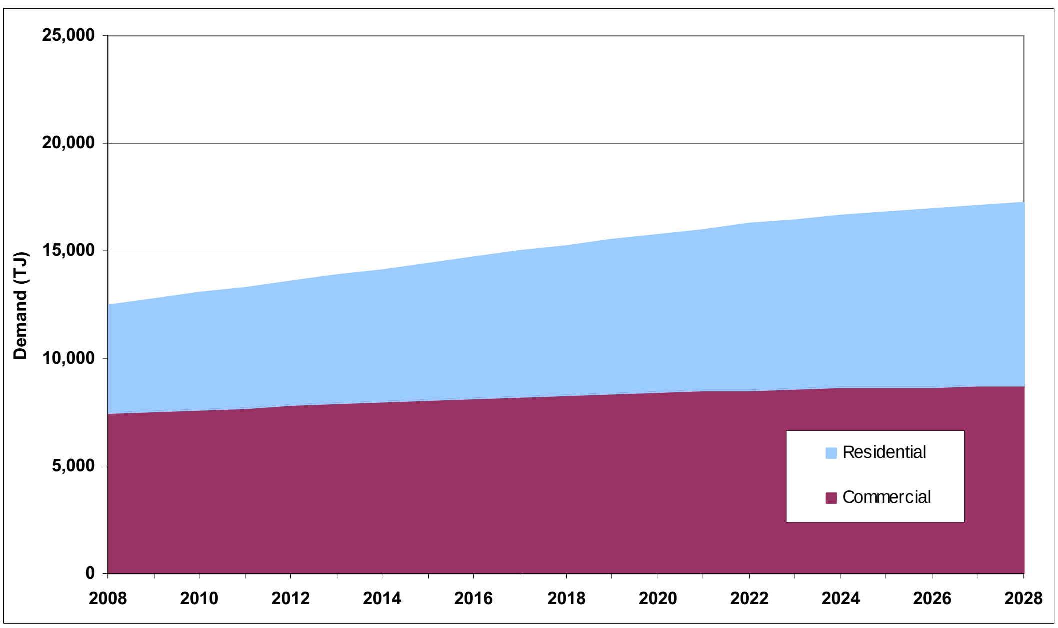
ICP

TGVI has incorporated the terms of the long term TSA between TGVI and BC Hydro for the purposes of this filing with a Contract Demand for 2008 of 45 TJ per Day, which implies annual firm demand of 16,470 TJ (45 TJ * 366 days).

d) Annual Demand – Reference Case

Combining the forecasts of total customers with use rates per customer results in the Reference Case for TGVI's Annual Demand forecast. As can be seen in the graph below, overall demand is expected to grow moderately over the planning period with residential demand expected to account for the largest growth in demand over time.

Figure 2-2 TGVI Total Annual Demand 2008 -2028

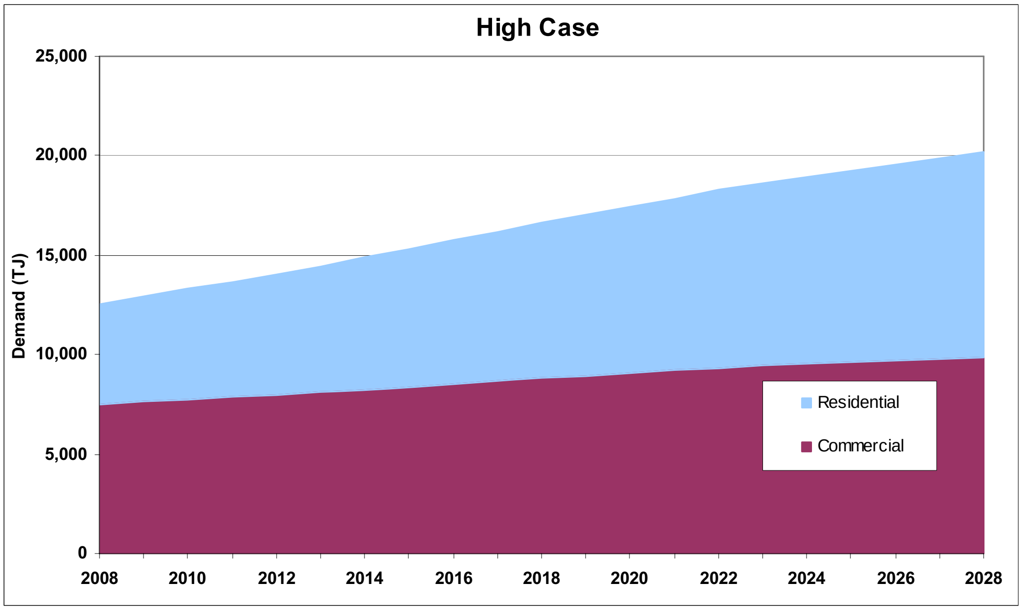


e) High Scenario

Strong growth in the provincial economy translates into more new residents coming to live in the province. As with TGVI, this scenario also assumes a higher capture rate of new construction which, combined with higher immigration levels, produces customer additions that are 25% above the Reference Case. Commercial customer additions also grow at the same rate as residential.

Residential use per customer rates, which are flat in the Reference case, increase in this scenario by 1% annually based on existing customers increasing the number of natural gas appliances in their homes and on the majority of new customers attaching to the system with natural gas as their primary source of space and water heating. Over time, the expectation is that TGVI residential use per customer rates would tend towards convergence with TGI residential rates. Commercial use per customer rates are also increased by 0.5% annually over the planning period to reflect long-term growth on Vancouver Island and commercial customers finding more ways to incorporate the use of natural gas in their business to enhance their competitiveness.

Figure 2-3 TGVI Total Annual Demand 2008 – 2028

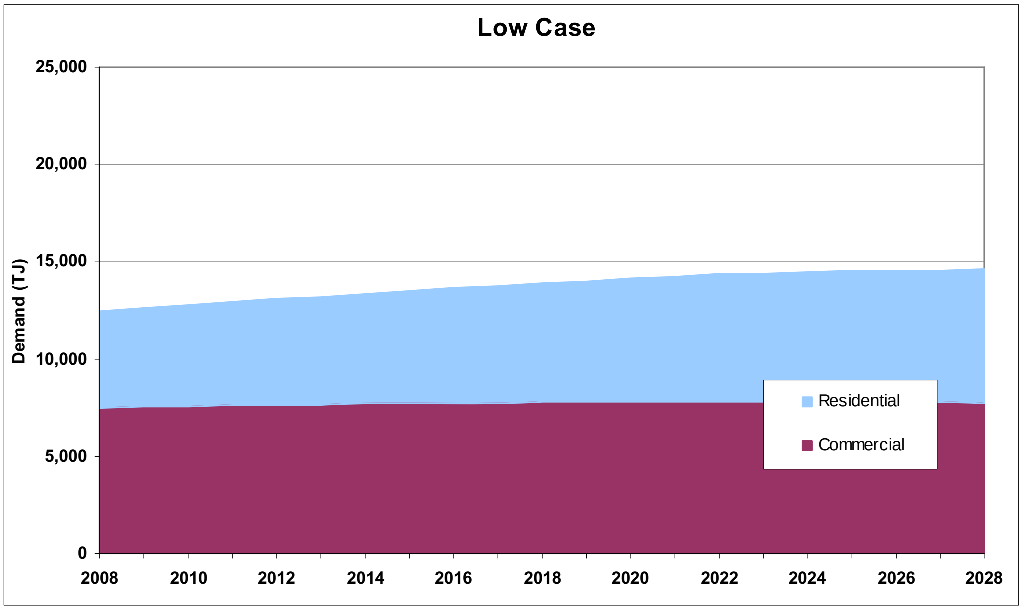


f) Low Scenario

As with the TGI Low Scenario, the economy on Vancouver Island underperforms over the long-term due to factors such as a protracted slowdown in the U.S. and world economies. This results in a lower level of new arrivals to TGVI's service territory. Under this scenario, multi-family dwellings continue to gain in market share while TGVI is less successful in them. These factors are reflected in customer additions that are 25% below the Reference Case.

Residential use per customer rates which were forecast to remain stable in the Reference case are assumed to decline by 0.5% over the planning period as the penetration of natural gas appliances fails to increase while building efficiencies improve slowly and alternative forms of energy grow as well. The same developments occur with commercial use rates resulting in the same 0.5% annual decline in use per customer rates occurring over the planning period.

Figure 2-4 TGVI Total Annual Demand 2008 - 2028



3 TGW

a) Total Customers & Customer Additions

Due to geographical constraints and the community's goal of managing growth in a sustainable manner, customer additions have been relatively modest over the past few years. Looking forward, the total number of Terasen Gas Whistler ("TGW") customers is forecast to grow in the range of 0.8% to 1.2% per year over the planning period, with the Reference case at 1.0%. The level of growth that has been seen recently is forecast to continue, but it will take place under municipal guidelines/regulations that stress minimizing the environmental impact of new developments. Specifically, the municipality encourages the reduction of all energy consumption and strives to lower the production of greenhouse gases. The arrival of the natural gas pipeline in Whistler will help to achieve the community's objectives as natural gas is less greenhouse gas intensive than propane for a given amount of energy.

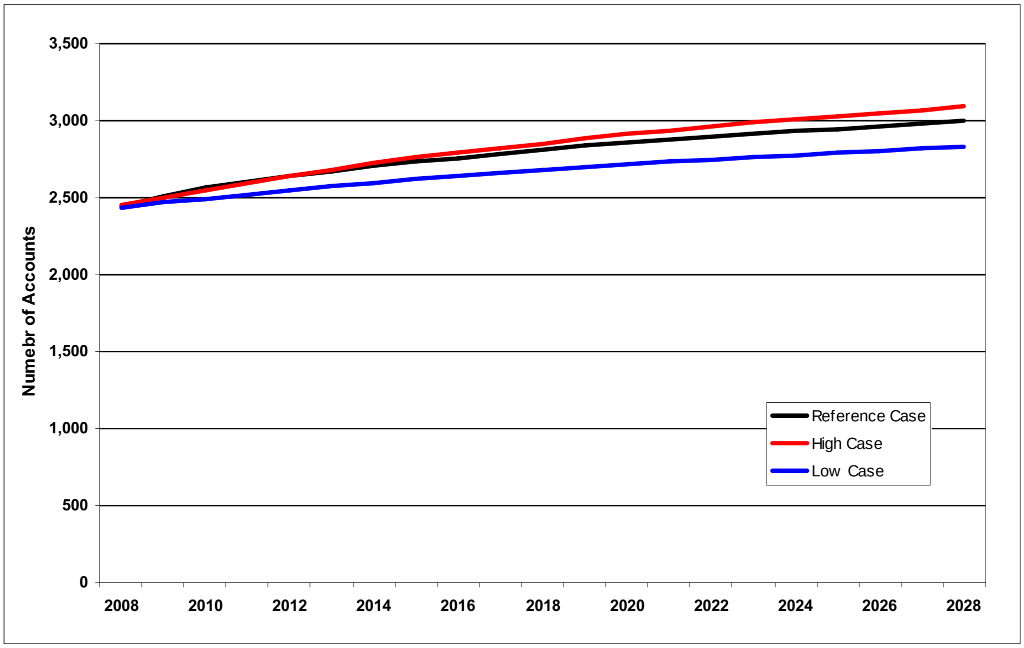
The arrival of natural gas vehicle (NGV) fleets serving both local transit and other fleets will result in the addition of a natural gas refuelling station which will add a significant amount of demand on the system.

Conversion of existing buildings (and therefore customers) to Ground Source Heat Pump (GSHP) technology is expected to occur over time. Based on a "Geo-exchange Retrofit Feasibility Evaluation" study conducted by Hemmera Energy Consultants in 2005[1], TGW has assumed that for any customer that adopts GSHP technology, the GSHP will replace approximately 70% of the customers design day load and approximately 90% of the customer's annual load. Further, TGW has assumed that natural gas or propane will continue to be the preferred peaking or supplementary energy resource for these customers, supplying them with the remaining 30% of peak load and 10% of annual load. Large commercial customers (LGS 3) would retain 43% of peaking load and 27% of annual load, as cooking and fireplace loads would not be replaced by GSHP technology. An audit performed in 2005 of 16 large commercial customers allowed for the distinction, but as TGW does not have end-use information available for other customer segments, the above estimations are applied.

As with the other Terasen utilities, commercial customer additions for TGW reflect the same long-term growth patterns as residential customers based on the assumption that businesses tend to be created to serve demand stemming from growth in the population.

[1] Hemmera Energy and DEC Design. Terasen Inc. and Resort Municipality of Whistler Geoexchange Retrofit Feasibility Study, Whistler Village BC. 59p. November 2005.

Figure 3-1 TGW Account Forecast from 2008 - 2028



b) Use per Customer

As discussed above in customer additions, Whistler is actively working towards reducing its total emissions of greenhouse gases. However, recent historical data shows that residential and most commercial use per customer rates have moved within a stable range over the past years. Variability is higher within TGW as the local economy is subject to fluctuations driven by tourism.

Table 3-1 TGW Use per Customer (GJ)

	1999	2000	2001	2002	2003	2004	2005	2006	2007
SGS-1/2 RES	94.8	91.8	87.9	89.4	90.6	85.7	93.4	85.6	95.7
SGS-1/2 COM	182	205	223	171	170	189	211	219	265
LGS-1	1,236	1,167	1,143	1,133	1,078	1,110	1,159	1,150	1,285
LGS-2	3,363	3,363	3,132	3,142	3,148	3,126	3,430	3,204	3,214
LGS-3	10,903	14,705	14,439	13,422	13,007	13,456	12,889	13,093	11,853

As the 2010 Winter Olympics approaches, the expectation is that Whistler will continue to see robust economic activity that should at a minimum maintain use per customer rates.

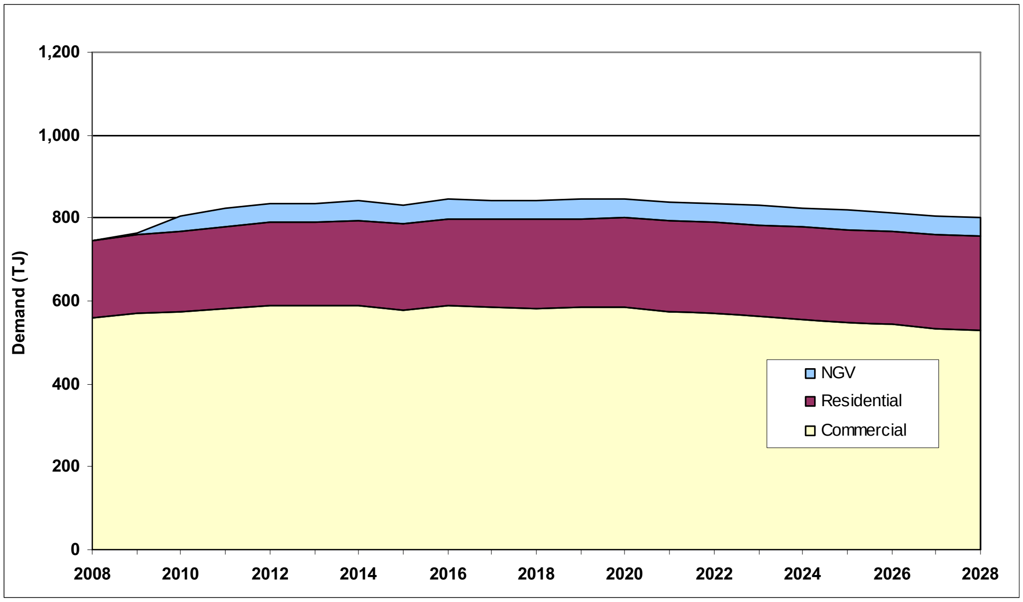
Based on these historical trends, the Reference Case for TGW Annual Demand assumes constant use rates for all rate classes over the course of the entire planning period. The impact of either existing customers converting to or new customers adopting GSHP technology will act to lower effective use per customer rates over time.

c) Annual Demand – Reference Case

Combining the elements of total customer and use per customer rates produces the Reference Case for TGW's Annual Demand forecast.

As can be seen in the graph below, overall demand is expected to grow over the short term as NGV is introduced, but then decline slightly for the remainder of the planning period as the effect of commercial customers converting space heating and hot water energy systems to GSHP technology more than offsets customer growth.

Figure 3-2 TGW Total Annual Demand 2008 - 2028

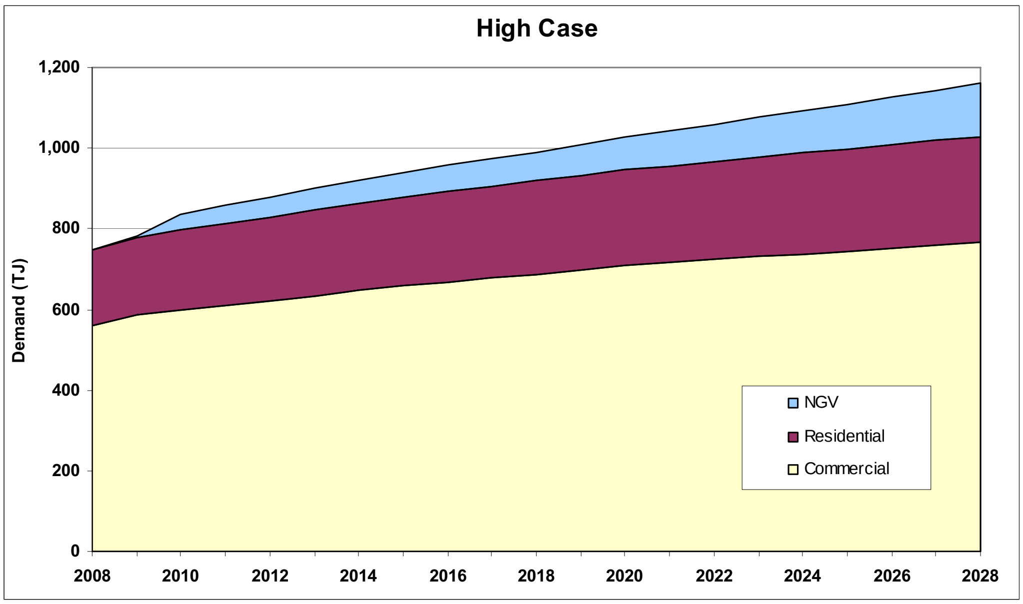


d) High Scenario

In spite of the recent slowdown in new home construction in Whistler, the area remains a desirable location which will be featured around the world as a result of the 2010 Winter Olympics. Over the course of the twenty year planning period, it is not unreasonable that the area could experience growth beyond that projected household formations growth. Other skiing centres in locations such as Europe have experienced declines in snow levels which could bring more people to Whistler if trends continue. To evaluate the impact on annual demand, the High scenario includes customer additions for both residential and commercial with are 25% above the Reference case.

Under the High scenario, uses per customer rates are also projected to rise modestly at an annual rate of 0.5% for both residential and commercial. This increase is meant to portray the case where Whistler continues to expand its appeal as a year-round destination by increasing tourism during the summer months while maintaining or improving results during the summer months. Under this scenario customers are assumed to continue using natural gas to serve their energy needs, rather than incorporate GSHP technology.

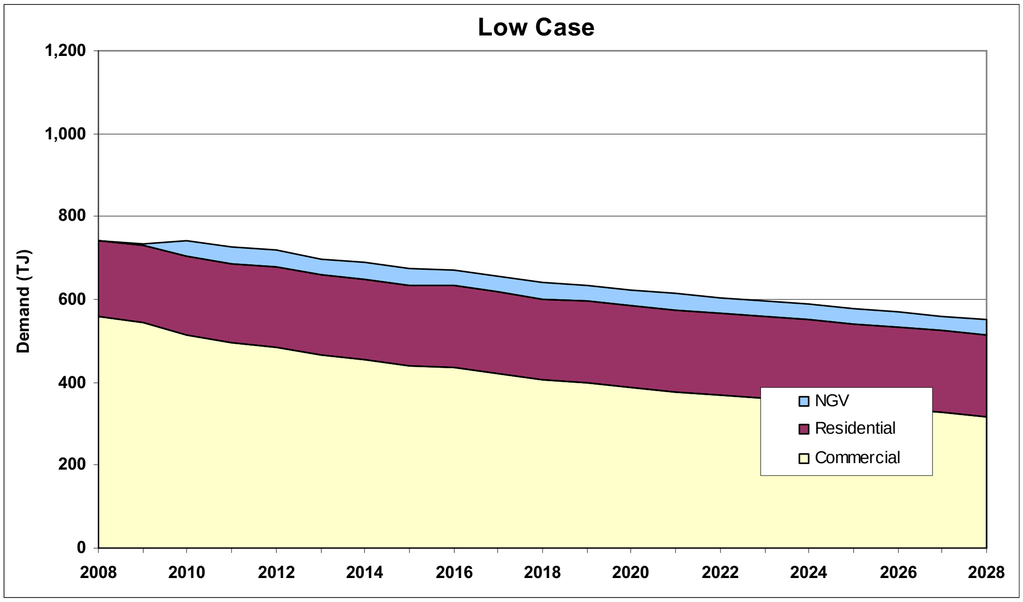
Figure 3-3 TGW Total Annual Demand 2008 -2028



e) Low Scenario

This scenario represents an outlook where growth in all account types decreases by 25% due to a series of factors that would include slower than expected growth in the area and municipal regulations that favour alternative energy and electricity-based heating systems over the use of natural gas. Existing customers convert space heating and hot water energy systems to incorporate GSHP technology at an accelerated rate, and also integrate other alternative energy solutions in serving their energy requirements. The result of these actions is forecasted to result in annual declines in use per customer rates of 0.5% over the entire planning period.

Figure 3-4 TGW Total Annual Demand 2008 - 2028 (Low Case)



APPENDIX F

Terasen Gas
Design Day Demand Forecast Methodology

DESIGN DAY DEMAND FORECAST METHODOLOGY

Terasen Gas uses a similar methodology to forecast design day demand for each of Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGW"), with some differences as a result of variations in the way data collection, rate structures and other information has evolved for each company over time. This methodology description is specific to TGI, but provides an example of the general methodology for design day forecasting for all of the companies.

Design day demand or design hour demand represents the maximum expected amount of gas in any one day or hour required by customers. Since Core customers' demand is primarily weather dependent, design-day or design-hour demand is forecasted based upon a statistical approach called Extreme Value Analysis, which provides an estimate of the coldest day weather event expected with a 1 in 20 year return period. This results in a design day temperature of 30.8 heating degree days (HDD)[1] (-12.8 °C) for the Lower Mainland region; 44.1 HDD (-26.1°C) for the Inland region; and 49.4 HDD (-31.4°C) for the Columbia region. To estimate the design day requirements, actual daily send-outs[2] for the past three contract years (November 1 – October 31) are regressed against temperature.

System planning and gas supply options are driven primarily by the design day demand or design hour demand[3]. For the CTS, design hour demand is used since the CTS

1 A heating degree day is a measure of the coldness of the weather experienced. The number of heating degree days for a given day is calculated based on the extent to which the daily mean temperature falls below a reference temperature - typically 18 degrees Celsius.

2 Daily firm send-out refers to the daily sales made to customers on a bundled rate (rates 1-6), UAF losses, heater and compressor fuel.

3 Design Day / Design Hour Demand - the maximum demand for natural gas a utility expects it must provide over a single day or hour as the case may be.

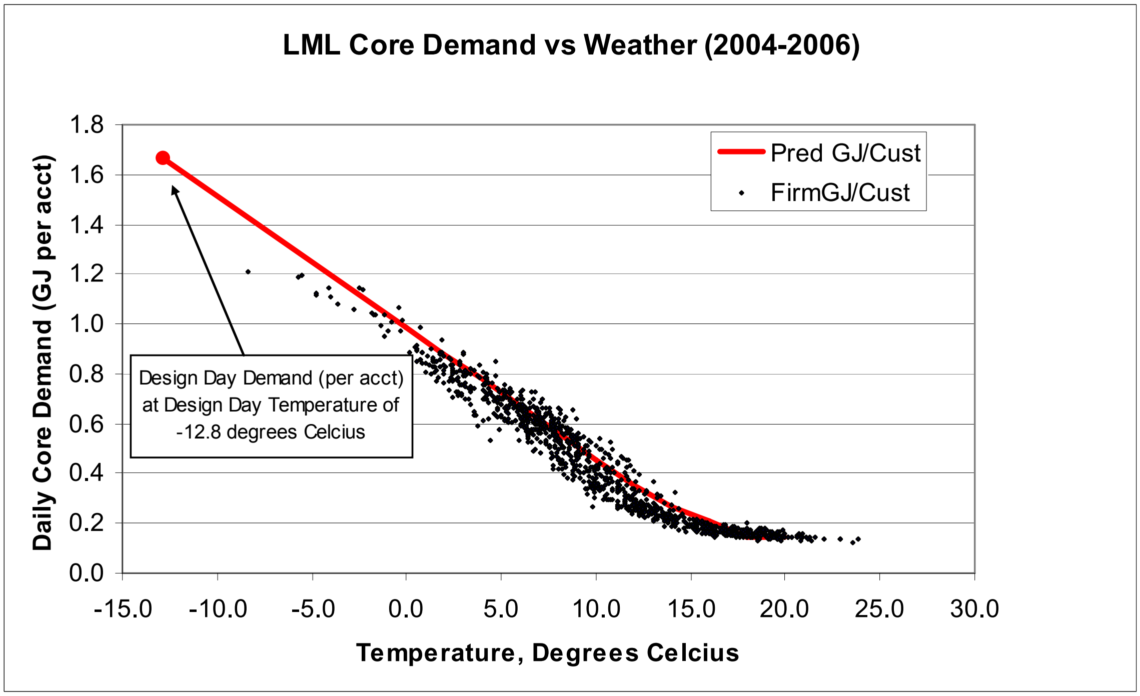
covers a much smaller geographic area with less climatic diversity and has a higher portion of heat sensitive load. The CTS also has a lower maximum operating pressure. These factors combine to limit the capacity of the system, as linepack is not sufficient to moderate intra-day demand designs. As it covers a larger geographic area with lower population density than the Lower Mainland, the ITS uses design day demand as a design requirement rather than design hour demand.

a) Weather Influences on Customer Demand

To estimate design day demand, a relationship between weather and demand must be established and then applied to the design day temperature described above. The relationship between weather and demand is established by analyzing daily historical demand as a function of weather (on an HDD basis). This is accomplished through regression analysis by estimating the model: Daily Demand = $\beta0 + \beta1 \times HDD13 + \beta2 \times HDD18$, where HDD13 = Heating Degree Day based upon a 13 degree Celsius control point, HDD18 = Heating Degree Day based upon a 18 degree Celsius control point and Daily Demand = daily natural gas consumption for all core customers. Each of the past three most recently completed contract years (i.e. 2004, 2005 and 2006 contract years as of January 2008) are modelled separately, providing three sets of regression equations. Those equations are converted to a “per customer” basis, averaged over the three contract years and then grown over the forecast period to reflect the number of future customer accounts.

By applying the design day temperature to the averaged regression equation, TGI is able to estimate the design day demand. The following graph illustrates the historical consumption and weather experienced over the 2004 to 2006 contract years.

Relationship between Customer Demand and Weather



b) Example of Design Day Demand Estimation - Lower Mainland Region

To forecast the design day demand for the Lower Mainland region, actual daily sendout for the most recently completed three contract years (2004 - 2006) are regressed against actual temperatures in the form of heating degree days based on both 13 degree Celsius and 18 degree Celsius control points (e.g. A temperature of 11 degrees Celsius would have an HDD13 = 2 and an HDD18 = 7). The regression coefficients derived from the regression for each contract year are converted into "per account" values, averaged, and then applied to the forecast number of accounts over the 2007/08 contract year (the 2007 year-end customer account forecast). The forecast firm growth for 2008 is then applied to determine the 2008/09 total design day demand for each region. This analysis results in the following:

- The three-year average Intercept/HDD13/HDD18 statistics over 2004-2006 are: Intercept = 0.1447, HDD13 = 0.0306, and HDD18 = 0.0224. With a design temperature of -12.8 degrees Celsius (HDD13 = 25.8, HDD18 = 30.8), this implies:
- Lower Mainland Design Use Per Customer = 0.1447 + (0.0306 X 25.8) + (0.0224 X 30.8) = 1.6232.
- Applying the 2007 year-end firm customer account value of 573,300 accounts to the design use per customer results in an estimated Design Day Demand of 1.6232 X 573,300 = 930.6 TJ's for the Lower Mainland sales region over the 2007/08 contract year.
- Applying the 2008 growth rate of 3.67% for firm demand to the 2007/08 estimate results in an estimated Design Day Demand of 930.8 X (1 + 3.67%) = 940.2 TJ's for the Lower Mainland sales region over the 2008/09 contract year.

To determine how well the regression parameters estimate design day demand, the sendout for the coldest day in each of the 2002 through 2006 contract years was compared against the sendout estimated by those years' regression parameters. Table 1 and 2 below illustrate both the estimated and actual sendout for those days.

Table 1 Coldest Day in each of 2002-2006 Contract Years for the Lower Mainland Region

Region	Contract Year	Coldest Day	Temperature	HDD13	HDD18	Firm Accounts
LML	2002	February 24, 2003	1.6	11.4	16.4	537,678
LML	2003	January 4, 2004	-7.6	20.6	25.6	541,710
LML	2004	January 14, 2005	-5.5	18.5	23.5	549,707
LML	2005	December 15, 2005	0.2	12.8	17.8	558,033
LML	2006	November 28, 2006	-8.4	21.4	26.4	564,462

Table 2 Estimated and Actual Send out for the Coldest Days (TJ's)

Region	Contract Year	Estimated Sendout	Actual Sendout	Variance
LML	2002	479.7	453.6	5.8%
LML	2003	763.8	729.7	4.7%
LML	2004	678.8	656.2	3.4%
LML	2005	521.6	495.5	5.3%
LML	2006	784.7	681.1	15.2%

The above variances are reasonable given the warmer years recently experienced and need to extrapolate these to the design day use per customer value. The large variance seen for the 2006 contract year can be explained primarily by the extensive power outages that occurred prior to and during the peak day (November 28, 2006). The exact number of customers affected by the power outages is unknown, and therefore the impact to peak day demand cannot be determined. However, the reasonable variances seen from 2002 through 2005 indicate the models employed are accurate, and therefore the 2006 variance should be viewed as an anomaly.

APPENDIX G

Terasen Gas
20 – Year Demand Forecast Tables by Utility

TGVI

TGVI
Year end accounts
by Rate Class

Rate Class	2008	2009	2010	2011	2012	2013	2014	2015
RGS	85,689	89,128	92,567	95,916	99,165	102,646	106,085	109,524
SCS1	4,451	4,561	4,671	4,771	4,871	4,991	5,101	5,211
SCS2	1,761	1,779	1,797	1,813	1,829	1,850	1,868	1,886
LCS1	1,464	1,474	1,484	1,494	1,504	1,516	1,528	1,540
LCS2	535	540	545	550	555	559	563	567
AGS	836	853	870	889	908	926	944	962
LCS3	143	144	145	146	147	148	149	150
HLF	6	6	6	6	6	6	6	6
ILF	9	9	9	9	9	9	9	9
Total	**94,894**	**98,494**	**102,094**	**105,594**	**108,994**	**112,651**	**116,253**	**119,855**

Percent change in
Year end Accounts
by Rate Class

Rate Class	2008	2009	2010	2011	2012	2013	2014	2015
RGS		4.01%	3.86%	3.62%	3.39%	3.51%	3.35%	3.24%
SCS1		2.47%	2.41%	2.14%	2.10%	2.46%	2.20%	2.16%
SCS2		1.02%	1.01%	0.89%	0.88%	1.15%	0.97%	0.96%
LCS1		0.68%	0.68%	0.67%	0.67%	0.80%	0.79%	0.79%
LCS2		0.93%	0.93%	0.92%	0.91%	0.72%	0.72%	0.71%
AGS		2.03%	1.99%	2.18%	2.14%	1.98%	1.94%	1.91%
LCS3		0.70%	0.69%	0.69%	0.68%	0.68%	0.68%	0.67%
HLF		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
ILF		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Annual use rate
per Customer
by Rate Class(GJ)

Rate Class	2008	2009	2010	2011	2012	2013	2014	2015
RGS	59.3	59.3	59.3	59.3	59.3	59.3	59.3	59.3
SCS1	72.7	72.7	72.7	72.7	72.7	72.7	72.7	72.7
SCS2	307.2	307.2	307.2	307.2	307.2	307.2	307.2	307.2
LCS1	915.8	915.8	915.8	915.8	915.8	915.8	915.8	915.8
LCS2	2,341.3	2,341.3	2,341.3	2,341.3	2,341.3	2,341.3	2,341.3	2,341.3
AGS	1,389.1	1,389.1	1,389.1	1,389.1	1,389.1	1,389.1	1,389.1	1,389.1
LCS3	18,188.0	18,188.0	18,188.0	18,188.0	18,188.0	18,188.0	18,188.0	18,188.0
HLF	25,000.0	25,000.0	25,000.0	25,000.0	25,000.0	25,000.0	25,000.0	25,000.0
ILF	18,433.0	18,433.0	18,433.0	18,433.0	18,433.0	18,433.0	18,433.0	18,433.0

Annual Demand
by Rate Class(TJ)

Rate Class	2008	2009	2010	2011	2012	2013	2014	2015
RGS	4,973	5,178	5,382	5,584	5,780	5,979	6,184	6,388
SCS1	319	327	335	343	350	358	366	374
SCS2	538	544	549	554	559	565	571	576
LCS1	1,336	1,345	1,355	1,364	1,373	1,382	1,393	1,404
LCS2	1,245	1,257	1,269	1,280	1,292	1,304	1,313	1,322
AGS	1,151	1,173	1,196	1,222	1,248	1,273	1,298	1,323
LCS3	2,588	2,606	2,625	2,643	2,661	2,679	2,697	2,716
HLF	150	150	150	150	150	150	150	150
ILF	166	166	166	166	166	166	166	166
Total	**12,467**	**12,746**	**13,027**	**13,306**	**13,579**	**13,855**	**14,138**	**14,419**

Design Day Demand
(TJ/Day)

	2008	2009	2010	2011	2012	2013	2014	2015
Core Customers	**110.4**	**113.0**	**115.6**	**118.2**	**120.7**	**123.2**	**125.7**	**128.1**

TGVI
Year end accounts
by Rate Class

Rate Class	2016	2017	2018	2019	2020	2021	2022	2023
RGS	112,873	116,121	119,283	122,408	125,497	128,458	131,309	133,973
SCS1	5,310	5,409	5,505	5,596	5,684	5,772	5,854	5,929
SCS2	1,903	1,920	1,934	1,948	1,962	1,974	1,986	1,998
LCS1	1,552	1,564	1,572	1,580	1,588	1,596	1,604	1,612
LCS2	571	575	579	583	587	591	595	599
AGS	983	1,004	1,022	1,040	1,058	1,076	1,089	1,101
LCS3	151	152	153	154	155	156	156	156
HLF	6	6	6	6	6	6	6	6
ILF	9	9	9	9	9	9	9	9
Total	**123,358**	**126,760**	**130,063**	**133,324**	**136,546**	**139,638**	**142,608**	**145,383**

Percent change in
Year end Accounts
by Rate Class

Rate Class	2016	2017	2018	2019	2020	2021	2022	2023
RGS	3.06%	2.88%	2.72%	2.62%	2.52%	2.36%	2.22%	2.03%
SCS1	1.90%	1.86%	1.77%	1.65%	1.57%	1.55%	1.42%	1.28%
SCS2	0.90%	0.89%	0.73%	0.72%	0.72%	0.61%	0.61%	0.60%
LCS1	0.78%	0.77%	0.51%	0.51%	0.51%	0.50%	0.50%	0.50%
LCS2	0.71%	0.70%	0.70%	0.69%	0.69%	0.68%	0.68%	0.67%
AGS	2.18%	2.14%	1.79%	1.76%	1.73%	1.70%	1.21%	1.10%
LCS3	0.67%	0.66%	0.66%	0.65%	0.65%	0.65%	0.00%	0.00%
HLF	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
ILF	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Annual use rate
per Customer
by Rate Class(GJ)

Rate Class	2016	2017	2018	2019	2020	2021	2022	2023
RGS	59.3	59.3	59.3	59.3	59.3	59.3	59.3	59.3
SCS1	72.7	72.7	72.7	72.7	72.7	72.7	72.7	72.7
SCS2	307.2	307.2	307.2	307.2	307.2	307.2	307.2	307.2
LCS1	915.8	915.8	915.8	915.8	915.8	915.8	915.8	915.8
LCS2	2,341.3	2,341.3	2,341.3	2,341.3	2,341.3	2,341.3	2,341.3	2,341.3
AGS	1,389.1	1,389.1	1,389.1	1,389.1	1,389.1	1,389.1	1,389.1	1,389.1
LCS3	18,188.0	18,188.0	18,188.0	18,188.0	18,188.0	18,188.0	18,188.0	18,188.0
HLF	25,000.0	25,000.0	25,000.0	25,000.0	25,000.0	25,000.0	25,000.0	25,000.0
ILF	18,433.0	18,433.0	18,433.0	18,433.0	18,433.0	18,433.0	18,433.0	18,433.0

Annual Demand
by Rate Class(TJ)

Rate Class	2016	2017	2018	2019	2020	2021	2022	2023
RGS	6,589	6,785	6,975	7,162	7,346	7,526	7,698	7,862
SCS1	382	389	396	403	410	416	422	428
SCS2	582	587	592	596	601	605	608	612
LCS1	1,415	1,426	1,436	1,443	1,450	1,458	1,465	1,472
LCS2	1,332	1,341	1,350	1,360	1,369	1,378	1,388	1,397
AGS	1,350	1,379	1,406	1,431	1,456	1,481	1,504	1,522
LCS3	2,734	2,752	2,770	2,788	2,806	2,825	2,837	2,837
HLF	150	150	150	150	150	150	150	150
ILF	166	166	166	166	166	166	166	166
Total	**14,700**	**14,976**	**15,242**	**15,499**	**15,754**	**16,004**	**16,238**	**16,446**

Design Day Demand
(TJ/Day)

	2016	2017	2018	2019	2020	2021	2022	2023
Core Customers	**130.5**	**132.8**	**134.9**	**136.6**	**138.3**	**139.8**	**141.4**	**143.2**

TGVI
Year end accounts
by Rate Class

Rate Class	2024	2025	2026	2027	2028
RGS	136,246	138,316	140,208	142,216	144,469
SCS1	5,989	6,046	6,096	6,149	6,210
SCS2	2,007	2,016	2,025	2,034	2,043
LCS1	1,616	1,624	1,628	1,632	1,636
LCS2	603	607	611	615	619
AGS	1,110	1,116	1,122	1,128	1,134
LCS3	156	156	156	156	156
HLF	6	6	6	6	6
ILF	9	9	9	9	9
Total	**147,742**	**149,896**	**151,861**	**153,945**	**156,282**

Percent change in
Year end Accounts
by Rate Class

Rate Class	2024	2025	2026	2027	2028
RGS	1.70%	1.52%	1.37%	1.43%	1.58%
SCS1	1.01%	0.95%	0.83%	0.87%	0.99%
SCS2	0.45%	0.45%	0.45%	0.44%	0.44%
LCS1	0.25%	0.50%	0.25%	0.25%	0.25%
LCS2	0.67%	0.66%	0.66%	0.65%	0.65%
AGS	0.82%	0.54%	0.54%	0.53%	0.53%
LCS3	0.00%	0.00%	0.00%	0.00%	0.00%
HLF	0.00%	0.00%	0.00%	0.00%	0.00%
ILF	0.00%	0.00%	0.00%	0.00%	0.00%

Annual use rate
per Customer
by Rate Class(GJ)

Rate Class	2024	2025	2026	2027	2028
RGS	59.3	59.3	59.3	59.3	59.3
SCS1	72.7	72.7	72.7	72.7	72.7
SCS2	307.2	307.2	307.2	307.2	307.2
LCS1	915.8	915.8	915.8	915.8	915.8
LCS2	2,341.3	2,341.3	2,341.3	2,341.3	2,341.3
AGS	1,389.1	1,389.1	1,389.1	1,389.1	1,389.1
LCS3	18,188.0	18,188.0	18,188.0	18,188.0	18,188.0
HLF	25,000.0	25,000.0	25,000.0	25,000.0	25,000.0
ILF	18,433.0	18,433.0	18,433.0	18,433.0	18,433.0

Annual Demand
by Rate Class(TJ)

Rate Class	2024	2025	2026	2027	2028
RGS	8,009	8,138	8,256	8,371	8,497
SCS1	433	437	441	445	449
SCS2	615	618	620	623	626
LCS1	1,478	1,483	1,489	1,493	1,496
LCS2	1,407	1,416	1,425	1,435	1,444
AGS	1,535	1,545	1,553	1,561	1,570
LCS3	2,837	2,837	2,837	2,837	2,837
HLF	150	150	150	150	150
ILF	166	166	166	166	166
Total	**16,629**	**16,790**	**16,937**	**17,081**	**17,235**

Design Day Demand
(TJ/Day)

	2024	2025	2026	2027	2028
Core Customers	**145.1**	**146.9**	**148.9**	**151.0**	**153.0**

TGW

TGW
Year end accounts
by Rate Class

Rate Class	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
SGS-1/2 RES	2,128	2,178	2,228	2,258	2,288	2,316	2,342	2,367	2,387	2,409	2,428	2,450
SGS-1/2 COM	162	166	169	172	175	178	181	184	186	188	190	192
LGS-1 COM	85	91	93	95	97	99	101	103	104	106	107	109
LGS-2 COM	51	53	53	54	54	55	55	56	56	57	57	58
LGS-3 COM	20	21	21	22	22	23	23	24	24	25	25	26
NGV	0	1	1	1	1	1	1	1	1	1	1	1
Total	2,446	2,510	2,565	2,602	2,637	2,672	2,703	2,735	2,758	2,786	2,808	2,836

Percent change in
Year end Accounts
By Rate Class

Rate Class	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
SGS-1/2 RES		2.3%	2.3%	1.3%	1.3%	1.2%	1.1%	1.1%	0.8%	0.9%	0.8%	0.9%
SGS-1/2 COM		2.5%	1.8%	1.8%	1.7%	1.7%	1.7%	1.7%	1.1%	1.1%	1.1%	1.1%
LGS-1 COM		7.1%	2.2%	2.2%	2.1%	2.1%	2.0%	2.0%	1.0%	1.9%	0.9%	1.9%
LGS-2 COM		3.9%	0.0%	1.9%	0.0%	1.9%	0.0%	1.8%	0.0%	1.8%	0.0%	1.8%
LGS-3 COM		5.0%	0.0%	4.8%	0.0%	4.5%	0.0%	4.3%	0.0%	4.2%	0.0%	4.0%
NGV		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Annual use rate per Customer
by Rate Class(GJ)

Rate Class	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
SGS-1/2 RES	88.2	88.2	88.2	88.2	88.2	88.2	88.2	88.2	88.2	88.2	88.2	88.2
SGS-1/2 COM	206.3	206.3	206.3	206.3	206.3	206.3	206.3	206.3	206.3	206.3	206.3	206.3
LGS-1 COM	1,139.7	1,139.7	1,139.7	1,139.7	1,139.7	1,139.7	1,139.7	1,139.7	1,139.7	1,139.7	1,139.7	1,139.7
LGS-2 COM	3,253.3	3,253.3	3,253.3	3,253.3	3,253.3	3,253.3	3,253.3	3,253.3	3,253.3	3,253.3	3,253.3	3,253.3
LGS-3 COM	13,145.9	13,145.9	13,145.9	13,145.9	13,145.9	13,145.9	13,145.9	13,145.9	13,145.9	13,145.9	13,145.9	13,145.9
NGV	0.0	3,525.0	39,750.0	46,000.0	46,000.0	46,000.0	46,000.0	46,000.0	46,000.0	46,000.0	46,000.0	46,000.0

Annual Demand
by Rate Class(TJ)

Rate Class	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
SGS-1/2 RES	186	190	194	198	200	203	205	208	210	211	213	215
SGS-1/2 COM	33	34	35	35	35	36	36	36	36	35	35	35
LGS-1 COM	95	98	102	105	106	106	107	107	107	106	106	106
LGS-2 COM	166	167	169	171	171	171	171	168	170	170	171	172
LGS-3 COM	263	272	266	271	276	274	277	268	277	275	271	271
NGV	0	4	40	46	46	46	46	46	46	46	46	46
Total	744	764	807	825	835	836	841	833	845	844	842	844

Design Day Demand(TJ/Day)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
TGW	6.7	7.0	7.1	7.3	7.2	7.4	7.3	7.4	7.4	7.5	7.5	7.7

TGW
Year end accounts
by Rate Class

Rate Class	2020	2021	2022	2023	2024	2025	2026	2027	2028
SGS-1/2 RES	2,466	2,483	2,500	2,515	2,529	2,544	2,556	2,570	2,584
SGS-1/2 COM	194	196	198	200	202	204	205	207	209
LGS-1 COM	110	111	112	113	114	115	116	117	118
LGS-2 COM	58	58	58	58	58	58	58	58	58
LGS-3 COM	26	26	26	26	26	26	26	26	26
NGV	1	1	1	1	1	1	1	1	1
Total	2,855	2,875	2,895	2,913	2,930	2,948	2,962	2,979	2,996

Percent change in
Year end Accounts
By Rate Class

Rate Class	2020	2021	2022	2023	2024	2025	2026	2027	2028
SGS-1/2 RES	0.7%	0.7%	0.7%	0.6%	0.6%	0.6%	0.5%	0.5%	0.5%
SGS-1/2 COM	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	0.5%	1.0%	1.0%
LGS-1 COM	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%
LGS-2 COM	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
LGS-3 COM	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
NGV	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Annual use rate per Customer
by Rate Class(GJ)

Rate Class	2020	2021	2022	2023	2024	2025	2026	2027	2028
SGS-1/2 RES	88.2	88.2	88.2	88.2	88.2	88.2	88.2	88.2	88.2
SGS-1/2 COM	206.3	206.3	206.3	206.3	206.3	206.3	206.3	206.3	206.3
LGS-1 COM	1,139.7	1,139.7	1,139.7	1,139.7	1,139.7	1,139.7	1,139.7	1,139.7	1,139.7
LGS-2 COM	3,253.3	3,253.3	3,253.3	3,253.3	3,253.3	3,253.3	3,253.3	3,253.3	3,253.3
LGS-3 COM	13,145.9	13,145.9	13,145.9	13,145.9	13,145.9	13,145.9	13,145.9	13,145.9	13,145.9
NGV	46,000.0	46,000.0	46,000.0	46,000.0	46,000.0	46,000.0	46,000.0	46,000.0	46,000.0

Annual Demand
by Rate Class(TJ)

Rate Class	2020	2021	2022	2023	2024	2025	2026	2027	2028
SGS-1/2 RES	217	218	220	221	222	224	225	226	227
SGS-1/2 COM	35	35	35	35	34	34	34	34	34
LGS-1 COM	105	104	103	103	102	101	100	99	98
LGS-2 COM	173	171	171	170	168	168	167	165	165
LGS-3 COM	270	265	261	255	251	246	242	236	232
NGV	46	46	46	46	46	46	46	46	46
Total	846	840	836	829	824	819	813	806	802

Design Day Demand(TJ/Day)

	2020	2021	2022	2023	2024	2025	2026	2027	2028
TGW	7.6	7.6	7.6	7.6	7.6	7.6	7.5	7.5	7.5

TGI COASTAL

Coastal Region
YE Accounts by rate class

Core	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate 1	524,258	531,426	538,468	545,446	552,424	559,361	566,249	573,173	580,051
Rate 2	52,617	52,931	53,240	53,546	53,852	54,159	54,459	54,763	55,059
Rate 3	3,924	3,929	3,934	3,939	3,944	3,950	3,955	3,960	3,965
Rate 4	33	33	33	33	33	33	33	33	33
Rate 5	256	256	256	256	256	256	256	256	256
Rate 6	30	30	30	30	30	30	30	30	30
Total Coastal Region-Core	581,118	588,605	595,961	603,250	610,539	617,789	624,982	632,215	639,394
Transportation & IT Customers									
Rate 7	1	1	1	1	1	1	1	1	1
Rate 22	25	25	25	25	25	25	25	25	25
Rate 23	1,131	1,179	1,226	1,273	1,320	1,370	1,420	1,471	1,522
Rate 25	488	488	488	488	488	488	488	488	488
Rate 27	84	84	84	84	84	84	84	84	84
Total -Transportation & IT	1,729	1,777	1,824	1,871	1,918	1,968	2,018	2,069	2,120
Total Coastal Region	**582,847**	**590,382**	**597,785**	**605,121**	**612,457**	**619,757**	**627,000**	**634,284**	**641,514**

Percent change
in YE Accounts

Core	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate 1		1.37%	1.33%	1.30%	1.28%	1.26%	1.23%	1.22%	1.20%
Rate 2		0.60%	0.58%	0.57%	0.57%	0.57%	0.55%	0.56%	0.54%
Rate 3		0.13%	0.13%	0.13%	0.13%	0.15%	0.13%	0.13%	0.13%
Rate 4		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 5		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 6		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Transportation & IT Customers									
Rate 7		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 22		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 23		4.24%	3.99%	3.83%	3.69%	3.79%	3.65%	3.59%	3.47%
Rate 25		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 27		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Annual use rate per Customer
by Rate Class(GJ)

Core	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate 1	102.6	101.9	100.6	99.7	98.8	97.8	96.8	95.9	94.9
Rate 2	333.3	335.9	338.5	341.4	344.1	344.1	344.1	344.1	344.1
Rate 3	3,429.2	3,415.3	3,401.9	3,388.1	3,374.6	3,374.6	3,374.6	3,374.6	3,374.6
Rate 4	4,128.9	4,128.9	4,128.9	4,128.9	4,128.9	4,128.9	4,128.9	4,128.9	4,128.9
Rate 5	10,573.0	10,573.0	10,573.0	10,573.0	10,573.0	10,573.0	10,573.0	10,573.0	10,573.0
Rate 6	2,977.2	2,977.2	2,977.2	2,977.2	2,977.2	2,977.2	2,977.2	2,977.2	2,977.2
Transportation & IT Customers									
Rate 7	10,931.1	10,930.3	10,930.3	10,930.3	10,931.1	10,931.1	10,931.1	10,931.1	10,931.1
Rate 22	493,201.3	486,749.9	509,251.9	512,825.9	516,048.4	516,049.4	516,049.4	516,049.4	516,049.4
Rate 23	4,746.5	4,681.5	4,617.3	4,553.4	4,490.9	4,490.9	4,490.9	4,490.9	4,490.9
Rate 25	19,321.4	20,012.0	19,556.8	19,381.8	19,588.0	19,588.0	19,588.0	19,588.0	19,588.0
Rate 27	55,777.8	58,341.9	58,709.5	58,398.4	58,636.0	58,636.0	58,636.0	58,636.0	58,636.0

Annual Demand
by Rate Class (TJ)

Core	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate 1	53,377	53,759	53,788	54,006	54,208	54,347	54,473	54,590	54,699
Rate 2	17,439	17,685	17,928	18,187	18,436	18,541	18,647	18,750	18,854
Rate 3	13,439	13,402	13,366	13,329	13,293	13,310	13,330	13,347	13,364
Rate 4	80	80	80	80	80	80	80	80	80
Rate 5	2,707	2,707	2,707	2,707	2,707	2,707	2,707	2,707	2,707
Rate 6	86	86	86	86	86	89	89	89	89
Total Coastal Region-Core	87,129	87,719	87,956	88,395	88,810	89,074	89,325	89,563	89,793
Transportation & IT Customers									
Rate 7	11	11	11	11	11	11	11	11	11
Rate 22	12,330	12,169	12,731	12,821	12,901	12,901	12,901	12,901	12,901
Rate 23	5,142	5,305	5,454	5,592	5,726	5,939	6,164	6,387	6,616
Rate 25	9,429	9,766	9,544	9,458	9,559	9,559	9,559	9,559	9,559
Rate 27	4,685	4,901	4,932	4,905	4,925	4,925	4,925	4,925	4,925
Total Coastal Region-Transportation & IT	31,597	32,151	32,671	32,787	33,123	33,336	33,560	33,784	34,013
Total Coastal Region	**118,725**	**119,870**	**120,627**	**121,183**	**121,933**	**122,410**	**122,886**	**123,346**	**123,806**

Design Day Demand(TJ/Day)

	2008	2009	2010	2011	2012	2013	2014	2015	2016
Core Customers	**940.2**	**949.5**	**958.6**	**967.6**	**976.6**	**985.7**	**994.6**	**1,003.5**	**1,012.4**

Coastal Region
YE Accounts by rate class

Core	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Rate 1	586,916	593,756	600,557	607,098	613,615	619,895	626,188	632,122	638,028
Rate 2	55,358	55,654	55,947	56,224	56,503	56,770	57,037	57,284	57,533
Rate 3	3,970	3,974	3,978	3,982	3,986	3,990	3,994	3,998	4,002
Rate 4	33	33	33	33	33	33	33	33	33
Rate 5	256	256	256	256	256	256	256	256	256
Rate 6	30	30	30	30	30	30	30	30	30
Total Coastal Region-Core	646,563	653,703	660,801	667,623	674,423	680,974	687,538	693,723	699,882
Transportation & IT Customers									
Rate 7	1	1	1	1	1	1	1	1	1
Rate 22	25	25	25	25	25	25	25	25	25
Rate 23	1,577	1,633	1,692	1,749	1,808	1,865	1,927	1,984	2,043
Rate 25	488	488	488	488	488	488	488	488	488
Rate 27	84	84	84	84	84	84	84	84	84
Total -Transportation & IT	2,175	2,231	2,290	2,347	2,406	2,463	2,525	2,582	2,641
Total Coastal Region	**648,738**	**655,934**	**663,091**	**669,970**	**676,829**	**683,437**	**690,063**	**696,305**	**702,523**

Percent change
in YE Accounts

Core	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Rate 1	1.18%	1.17%	1.15%	1.09%	1.07%	1.02%	1.02%	0.95%	0.93%
Rate 2	0.54%	0.53%	0.53%	0.50%	0.50%	0.47%	0.47%	0.43%	0.43%
Rate 3	0.13%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
Rate 4	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 5	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 6	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Transportation & IT Customers									
Rate 7	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 22	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 23	3.61%	3.55%	3.61%	3.37%	3.37%	3.15%	3.32%	2.96%	2.97%
Rate 25	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 27	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Annual use rate per Customer
by Rate Class(GJ)

Core	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Rate 1	94.0	94.0	94.0	94.0	94.0	94.0	94.0	94.0	94.0
Rate 2	344.1	344.1	344.1	344.1	344.1	344.1	344.1	344.1	344.1
Rate 3	3,374.6	3,374.6	3,374.6	3,374.6	3,374.6	3,374.6	3,374.6	3,374.6	3,374.6
Rate 4	4,128.9	4,128.9	4,128.9	4,128.9	4,128.9	4,128.9	4,128.9	4,128.9	4,128.9
Rate 5	10,573.0	10,573.0	10,573.0	10,573.0	10,573.0	10,573.0	10,573.0	10,573.0	10,573.0
Rate 6	2,977.2	2,977.2	2,977.2	2,977.2	2,977.2	2,977.2	2,977.2	2,977.2	2,977.2
Transportation & IT Customers									
Rate 7	10,931.1	10,931.1	10,931.1	10,931.1	10,931.1	10,931.1	10,931.1	10,931.1	10,931.1
Rate 22	516,049.4	516,049.4	516,049.4	516,049.4	516,049.4	516,049.4	516,049.4	516,049.4	516,049.4
Rate 23	4,490.9	4,490.9	4,490.9	4,490.9	4,490.9	4,490.9	4,490.9	4,490.9	4,490.9
Rate 25	19,588.0	19,588.0	19,588.0	19,588.0	19,588.0	19,588.0	19,588.0	19,588.0	19,588.0
Rate 27	58,636.0	58,636.0	58,636.0	58,636.0	58,636.0	58,636.0	58,636.0	58,636.0	58,636.0

Annual Demand
by Rate Class (TJ)

Core	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Rate 1	54,798	55,442	56,083	56,711	57,324	57,926	58,517	59,093	59,649
Rate 2	18,956	19,059	19,161	19,261	19,357	19,452	19,544	19,635	19,720
Rate 3	13,380	13,396	13,409	13,423	13,436	13,450	13,466	13,480	13,493
Rate 4	80	80	80	80	80	80	80	80	80
Rate 5	2,707	2,707	2,707	2,707	2,707	2,707	2,707	2,707	2,707
Rate 6	89	89	89	89	89	89	89	89	89
Total Coastal Region-Core	90,011	90,773	91,529	92,270	92,993	93,704	94,403	95,083	95,739
Transportation & IT Customers									
Rate 7	11	11	11	11	11	11	11	11	11
Rate 22	12,901	12,901	12,901	12,901	12,901	12,901	12,901	12,901	12,901
Rate 23	6,849	7,095	7,345	7,609	7,864	8,130	8,388	8,665	8,919
Rate 25	9,559	9,559	9,559	9,559	9,559	9,559	9,559	9,559	9,559
Rate 27	4,925	4,925	4,925	4,925	4,925	4,925	4,925	4,925	4,925
Total Coastal Region-Transportation & IT	34,246	34,491	34,742	35,006	35,260	35,527	35,785	36,061	36,315
Total Coastal Region	**124,256**	**125,264**	**126,271**	**127,276**	**128,253**	**129,231**	**130,188**	**131,145**	**132,054**

Design Day Demand(TJ/Day)

	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Core Customers	**1,021.3**	**1,030.1**	**1,038.9**	**1,047.3**	**1,055.7**	**1,063.8**	**1,071.8**	**1,079.4**	**1,086.9**

Coastal Region
YE Accounts by rate class

Core	2026	2027	2028
Rate 1	643,690	649,467	655,182
Rate 2	57,766	58,007	58,243
Rate 3	4,006	4,010	4,014
Rate 4	33	33	33
Rate 5	256	256	256
Rate 6	30	30	30
Total Coastal Region-Core	705,781	711,803	717,758
Transportation & IT Customers			
Rate 7	1	1	1
Rate 22	25	25	25
Rate 23	2,102	2,161	2,223
Rate 25	488	488	488
Rate 27	84	84	84
Total -Transportation & IT	2,700	2,759	2,821
Total Coastal Region	**708,481**	**714,562**	**720,579**

Percent change
in YE Accounts

Core	2026	2027	2028
Rate 1	0.89%	0.90%	0.88%
Rate 2	0.40%	0.42%	0.41%
Rate 3	0.10%	0.10%	0.10%
Rate 4	0.00%	0.00%	0.00%
Rate 5	0.00%	0.00%	0.00%
Rate 6	0.00%	0.00%	0.00%
Transportation & IT Customers			
Rate 7	0.00%	0.00%	0.00%
Rate 22	0.00%	0.00%	0.00%
Rate 23	2.89%	2.81%	2.87%
Rate 25	0.00%	0.00%	0.00%
Rate 27	0.00%	0.00%	0.00%

Annual use rate per Customer
by Rate Class(GJ)

Core	2026	2027	2028
Rate 1	94.0	94.0	94.0
Rate 2	344.1	344.1	344.1
Rate 3	3,374.6	3,374.6	3,374.6
Rate 4	4,128.9	4,128.9	4,128.9
Rate 5	10,573.0	10,573.0	10,573.0
Rate 6	2,977.2	2,977.2	2,977.2
Transportation & IT Customers			
Rate 7	10,931.1	10,931.1	10,931.1
Rate 22	516,049.4	516,049.4	516,049.4
Rate 23	4,490.9	4,490.9	4,490.9
Rate 25	19,588.0	19,588.0	19,588.0
Rate 27	58,636.0	58,636.0	58,636.0

Annual Demand
by Rate Class (TJ)

Core	2026	2027	2028
Rate 1	60,193	60,730	61,270
Rate 2	19,805	19,886	19,968
Rate 3	13,507	13,520	13,534
Rate 4	80	80	80
Rate 5	2,707	2,707	2,707
Rate 6	89	89	89
Total Coastal Region-Core	96,381	97,012	97,649
Transportation & IT Customers			
Rate 7	11	11	11
Rate 22	12,901	12,901	12,901
Rate 23	9,187	9,449	9,717
Rate 25	9,559	9,559	9,559
Rate 27	4,925	4,925	4,925
Total Coastal Region-Transportation & IT	36,583	36,845	37,114
Total Coastal Region	**132,964**	**133,858**	**134,762**

Design Day Demand(TJ/Day)

	2026	2027	2028
Core Customers	**1,094.2**	**1,101.5**	**1,108.8**

TGI INTERIOR

Interior Region
YE Accounts by rate class

Rate Class - Core	2008	2009	2010	2011	2012	2013	2014	2015
Rate 1	229,734	233,248	236,701	240,123	243,545	246,749	249,751	252,903
Rate 2	23,001	23,293	23,580	23,865	24,150	24,417	24,662	24,925
Rate 3	814	817	820	823	826	833	837	841
Rate 4	13	13	13	13	13	13	13	13
Rate 5	37	37	37	37	37	37	37	37
Rate 6	1	1	1	1	1	1	1	1
Total Interior Region-Core	253,600	257,409	261,152	264,862	268,572	272,050	275,301	278,720
Transportation & IT Customers								
Rate 7	1	1	1	1	1	1	1	1
Rate 22	27	27	27	27	27	27	27	27
Rate 23	245	264	283	302	321	342	363	382
Rate 25	100	99	99	99	99	99	99	99
Rate 27	13	13	13	13	13	13	13	13
Total Interior Region-Transportation & IT	386	404	423	442	461	482	503	522
Total Interior Region	**253,986**	**257,813**	**261,575**	**265,304**	**269,033**	**272,532**	**275,804**	**279,242**

Percent change
in Year End Accounts

Core	2008	2009	2010	2011	2012	2013	2014	2015
Rate 1		1.5%	1.5%	1.4%	1.4%	1.3%	1.2%	1.3%
Rate 2		1.3%	1.2%	1.2%	1.2%	1.1%	1.0%	1.1%
Rate 3		0.4%	0.4%	0.4%	0.4%	0.8%	0.5%	0.5%
Rate 4		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 5		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 6		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Transportation & IT Customers								
Rate 7		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 22		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 23		7.8%	7.2%	6.7%	6.3%	6.5%	6.1%	5.2%
Rate 25		-1.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 27		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Annual use rate per Customer
by Rate Class (GJ)

Core	2008	2009	2010	2011	2012	2013	2014	2015
Rate 1	81.3	80.5	79.7	78.8	78.0	77.2	76.5	75.7
Rate 2	299.1	299.9	300.7	301.5	302.4	302.4	302.4	302.3
Rate 3	3,422.5	3,394.9	3,367.5	3,340.7	3,314.2	3,314.7	3,315.4	3,315.2
Rate 4	8,143.1	8,143.1	8,143.1	8,143.1	8,143.1	8,143.1	8,143.1	8,143.1
Rate 5	13,734.4	13,734.4	13,734.4	13,734.4	13,734.4	13,734.4	13,734.4	13,734.4
Rate 6	13,200.0	13,200.0	13,200.0	13,200.0	13,200.0	13,611.6	13,611.6	13,611.6
Transportation & IT Customers								
Rate 7	8,400.0	6,000.0	6,000.0	6,000.0	6,000.0	5,943.0	5,943.0	5,943.0
Rate 22	769,681.1	769,633.8	767,076.0	768,799.6	769,291.8	787,087.6	787,087.6	787,087.6
Rate 23	5,345.9	5,275.1	5,205.4	5,137.5	5,070.6	5,073.8	5,077.1	5,075.8
Rate 25	52,234.3	52,735.9	52,782.2	52,521.1	54,463.8	54,464.5	54,464.5	54,464.5
Rate 27	57,829.3	57,287.7	59,326.1	60,088.1	60,334.9	60,334.9	60,334.9	60,334.9

Annual Demand
by Rate Class (TJ)

Core	2008	2009	2010	2011	2012	2013	2014	2015
Rate 1	18,471	18,579	18,686	18,750	18,824	18,893	18,943	18,982
Rate 2	6,829	6,937	7,043	7,149	7,256	7,339	7,417	7,492
Rate 3	2,779	2,767	2,755	2,743	2,731	2,747	2,767	2,780
Rate 4	81	81	81	81	81	81	81	81
Rate 5	508	508	508	508	508	508	508	508
Rate 6	13	13	13	13	13	14	14	14
Total Interior Region-Core	28,682	28,885	29,087	29,244	29,414	29,582	29,730	29,858
Transportation & IT Customers								
Rate 7	8	6	6	6	6	6	6	6
Rate 22	20,781	20,780	20,711	20,758	20,771	21,251	21,251	21,251
Rate 23	1,246	1,334	1,415	1,495	1,571	1,672	1,780	1,880
Rate 25	5,223	5,221	5,225	5,200	5,392	5,392	5,392	5,392
Rate 27	752	745	771	781	784	784	784	784
Total Interior Region-Transportation & IT	28,011	28,086	28,129	28,239	28,525	29,105	29,213	29,313
Total Interior Region	**56,693**	**56,971**	**57,216**	**57,483**	**57,939**	**58,687**	**58,943**	**59,171**

Design Day Demand(TJ/Day)

	2008	2009	2010	2011	2012	2013	2014	2015
Core Customers	**338.4**	**342.8**	**347.1**	**351.5**	**355.8**	**359.8**	**363.6**	**367.6**

Interior Region
YE Accounts by rate class

Rate Class - Core	2016	2017	2018	2019	2020	2021	2022	2023
Rate 1	255,547	257,728	259,670	261,584	263,484	265,386	267,245	269,128
Rate 2	25,136	25,317	25,472	25,627	25,779	25,933	26,084	26,236
Rate 3	845	845	845	845	845	845	845	845
Rate 4	13	13	13	13	13	13	13	13
Rate 5	37	37	37	37	37	37	37	37
Rate 6	1	1	1	1	1	1	1	1
Total Interior Region-Core	281,579	283,941	286,038	288,107	290,159	292,215	294,225	296,260
Transportation & IT Customers								
Rate 7	1	1	1	1	1	1	1	1
Rate 22	27	27	27	27	27	27	27	27
Rate 23	400	417	430	447	464	481	500	520
Rate 25	99	99	99	99	99	99	99	99
Rate 27	13	13	13	13	13	13	13	13
Total Interior Region-Transportation & IT	540	557	570	587	604	621	640	660
Total Interior Region	**282,119**	**284,498**	**286,608**	**288,694**	**290,763**	**292,836**	**294,865**	**296,920**

Percent change
in Year End Accounts

Core	2016	2017	2018	2019	2020	2021	2022	2023
Rate 1	1.0%	0.9%	0.8%	0.7%	0.7%	0.7%	0.7%	0.7%
Rate 2	0.8%	0.7%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%
Rate 3	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 4	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 5	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 6	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Transportation & IT Customers								
Rate 7	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 22	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 23	4.7%	4.3%	3.1%	4.0%	3.8%	3.7%	4.0%	4.0%
Rate 25	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 27	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Annual use rate per Customer
by Rate Class (GJ)

Core	2016	2017	2018	2019	2020	2021	2022	2023
Rate 1	74.9	74.2	74.2	74.2	74.2	74.2	74.2	74.2
Rate 2	302.3	302.3	302.3	302.3	302.3	302.3	302.3	302.3
Rate 3	3,315.1	3,314.9	3,314.9	3,314.9	3,314.9	3,314.9	3,314.9	3,314.9
Rate 4	8,143.1	8,143.1	8,143.1	8,143.1	8,143.1	8,143.1	8,143.1	8,143.1
Rate 5	13,734.4	13,734.4	13,734.4	13,734.4	13,734.4	13,734.4	13,734.4	13,734.4
Rate 6	13,611.6	13,611.6	13,611.6	13,611.6	13,611.6	13,611.6	13,611.6	13,611.6
Transportation & IT Customers								
Rate 7	5,943.0	5,943.0	5,943.0	5,943.0	5,943.0	5,943.0	5,943.0	5,943.0
Rate 22	787,087.6	787,087.6	787,087.6	787,087.6	787,087.6	787,087.6	787,087.6	787,087.6
Rate 23	5,075.5	5,075.4	5,075.5	5,079.1	5,081.8	5,084.2	5,086.4	5,088.2
Rate 25	54,464.5	54,464.5	54,464.5	54,464.5	54,464.5	54,464.5	54,464.5	54,464.5
Rate 27	60,334.9	60,334.9	60,334.9	60,334.9	60,334.9	60,334.9	60,334.9	60,334.9

Annual Demand
by Rate Class (TJ)

Core	2016	2017	2018	2019	2020	2021	2022	2023
Rate 1	19,015	19,007	19,162	19,305	19,446	19,588	19,727	19,865
Rate 2	7,564	7,623	7,674	7,721	7,768	7,815	7,861	7,906
Rate 3	2,794	2,801	2,801	2,801	2,801	2,801	2,801	2,801
Rate 4	81	81	81	81	81	81	81	81
Rate 5	508	508	508	508	508	508	508	508
Rate 6	14	14	14	14	14	14	14	14
Total Interior Region-Core	29,976	30,034	30,240	30,431	30,618	30,806	30,992	31,175
Transportation & IT Customers								
Rate 7	6	6	6	6	6	6	6	6
Rate 22	21,251	21,251	21,251	21,251	21,251	21,251	21,251	21,251
Rate 23	1,976	2,063	2,142	2,219	2,306	2,394	2,486	2,588
Rate 25	5,392	5,392	5,392	5,392	5,392	5,392	5,392	5,392
Rate 27	784	784	784	784	784	784	784	784
Total Interior Region-Transportation & IT	29,410	29,497	29,575	29,652	29,740	29,827	29,919	30,021
Total Interior Region	**59,386**	**59,531**	**59,815**	**60,083**	**60,358**	**60,634**	**60,911**	**61,196**

Design Day Demand(TJ/Day)

	2016	2017	2018	2019	2020	2021	2022	2023
Core Customers	**370.9**	**373.7**	**376.2**	**378.7**	**381.1**	**383.5**	**385.9**	**388.3**

Interior Region
YE Accounts by rate class

Rate Class - Core	2024	2025	2026	2027	2028
Rate 1	271,025	272,895	274,790	276,585	278,370
Rate 2	26,389	26,535	26,686	26,829	26,969
Rate 3	845	845	845	845	845
Rate 4	13	13	13	13	13
Rate 5	37	37	37	37	37
Rate 6	1	1	1	1	1
Total Interior Region-Core	298,310	300,326	302,372	304,310	306,235
Transportation & IT Customers					
Rate 7	1	1	1	1	1
Rate 22	27	27	27	27	27
Rate 23	539	556	576	593	610
Rate 25	99	99	99	99	99
Rate 27	13	13	13	13	13
Total Interior Region-Transportation & IT	679	696	716	733	750
Total Interior Region	**298,989**	**301,022**	**303,088**	**305,043**	**306,985**

Percent change
in Year End Accounts

Core	2024	2025	2026	2027	2028
Rate 1	0.7%	0.7%	0.7%	0.7%	0.6%
Rate 2	0.6%	0.6%	0.6%	0.5%	0.5%
Rate 3	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 4	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 5	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 6	0.0%	0.0%	0.0%	0.0%	0.0%
Transportation & IT Customers					
Rate 7	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 22	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 23	3.7%	3.2%	3.6%	3.0%	2.9%
Rate 25	0.0%	0.0%	0.0%	0.0%	0.0%
Rate 27	0.0%	0.0%	0.0%	0.0%	0.0%

Annual use rate per Customer
by Rate Class (GJ)

Core	2024	2025	2026	2027	2028
Rate 1	74.1	74.1	74.1	74.1	74.1
Rate 2	302.3	302.3	302.3	302.3	302.3
Rate 3	3,314.9	3,314.9	3,314.9	3,314.9	3,314.9
Rate 4	8,143.1	8,143.1	8,143.1	8,143.1	8,143.1
Rate 5	13,734.4	13,734.4	13,734.4	13,734.4	13,734.4
Rate 6	13,611.6	13,611.6	13,611.6	13,611.6	13,611.6
Transportation & IT Customers					
Rate 7	5,943.0	5,943.0	5,943.0	5,943.0	5,943.0
Rate 22	787,087.6	787,087.6	787,087.6	787,087.6	787,087.6
Rate 23	5,090.0	5,089.2	5,089.9	5,089.1	5,087.6
Rate 25	54,464.5	54,464.5	54,464.5	54,464.5	54,464.5
Rate 27	60,334.9	60,334.9	60,334.9	60,334.9	60,334.9

Annual Demand
by Rate Class (TJ)

Core	2024	2025	2026	2027	2028
Rate 1	20,004	20,143	20,281	20,419	20,551
Rate 2	7,952	7,998	8,043	8,087	8,130
Rate 3	2,801	2,801	2,801	2,801	2,801
Rate 4	81	81	81	81	81
Rate 5	508	508	508	508	508
Rate 6	14	14	14	14	14
Total Interior Region-Core	31,360	31,545	31,728	31,911	32,085
Transportation & IT Customers					
Rate 7	6	6	6	6	6
Rate 22	21,251	21,251	21,251	21,251	21,251
Rate 23	2,686	2,782	2,873	2,969	3,055
Rate 25	5,392	5,392	5,392	5,392	5,392
Rate 27	784	784	784	784	784
Total Interior Region-Transportation & IT	30,120	30,216	30,307	30,403	30,489
Total Interior Region	**61,480**	**61,761**	**62,035**	**62,314**	**62,573**

Design Day Demand(TJ/Day)

	2024	2025	2026	2027	2028
Core Customers	**390.7**	**393.1**	**395.5**	**397.8**	**400.1**

APPENDIX H

Terasen Gas
Executive Summary – Energy Efficiency and Conservation Programs Application

TERASEN GAS INC.

and

TERASEN GAS (VANCOUVER ISLAND) INC.

ENERGY EFFICIENCY AND CONSERVATION PROGRAMS APPLICATION

May 28, 2008

Executive Summary

Terasen Gas Inc. ("TGI") and Terasen Gas (Vancouver Island) Inc. ("TGVI"), (collectively referred to as the "Companies" or the "Terasen Utilities"), herein apply, pursuant to section 44.2 of the *Utilities Commission Act* (the "Act"), for approval of increased expenditures in support of an expanded Energy Efficiency and Conservation ("EEC") strategy, and approval to capitalize incremental EEC expenditures by charging the expenditures to a regulatory asset deferral account and amortizing the balance over 20 years. The specific relief sought is set out in Sections 2 and 6 of the Application, and is summarized in greater detail below. The Companies believe that the strategy outlined in this Application, and the related relief sought, is consistent with government's energy objectives as defined by the Act, is cost effective, and is in the interest of persons in British Columbia who receive or may receive service from the Companies. The Terasen Utilities respectfully submit that the relief sought should be granted. Approval is respectfully requested by August 15, 2008 in order to permit implementation of the EEC strategy as early as possible.

Funding for Terasen Gas (Whistler) Inc. ("TGW") has not been included in this Application, primarily due to the timing of the conversion from propane to natural gas, and the need for additional analysis once that work is completed. An EEC plan, including funding, appropriate to TGW will be developed following receipt of an appliance conversion audit currently being conducted by TGW as part of the pipeline extension project from Squamish to Whistler.

The Companies' EEC activity, referred to in previous filings with the Commission as Demand Side Management ("DSM") activity, has remained essentially unchanged since the late 1990's. For TGI, funding levels were established by Order No. G-85-97, at approximately $1.50 million for incentives, which funds were to be placed in a deferral account and amortized over three years. Additionally, non-incentive expenses of approximately $1.624 million annually are treated as Operations and Maintenance ("O&M") expense and are expensed in the year in which they are incurred. EEC initiatives for TGI have been focused on conservation.

For TGVI, Order No. C-02-05 directed TGVI to develop an EEC strategy and budgets, and to seek approval through the Resource Plan process for DSM strategy and budgets. TGVI has historically had EEC expenditures of approximately $650,000 annually for incentives, plus $500,000 annually for non-incentive costs. Incentive expenditures are placed in a deferral account and fully amortized the year following that in which they were incurred. Non-incentive costs are treated as O&M and are expensed in the year in which they are incurred. EEC initiatives for TGVI have been focused on capturing additional economic customers within the TGVI service area (load-building) and encouraging customers using other fuels to connect to the natural gas distribution system (fuel-switching).

The Terasen Utilities have enjoyed success with the limited funding that they have had available for EEC activity. TGI's EEC activity in 2007 produced a yield of $2.58 spent/GJ conserved, well below customer gas cost rates including midstream cost that averaged $8.33 Cdn/GJ for residential lower mainland customer in 2007.

This Application fulfills the commitment the Terasen Utilities made in their respective negotiated settlement agreements to bring forth such an Application addressing EEC. Commission Order No. G-33-07 approved the extension for 2008-2009 of the 2004-2007 TGI PBR Settlement Agreement[1] ("TGI PBR Extended Settlement"); and Order No. G-34-07 approved the extension for 2008-2009 of the 2006-2007 TGVI Revenue Requirements Negotiated Settlement Agreement[2] (TGVI RR Extended Settlement") (collectively the "Extended Settlements").

Although the Companies have enjoyed success with the current EEC programs, existing budget constraints have not allowed the Companies and customers to take full advantage of the potential energy savings activity available. A great deal has changed since the Companies' approved levels of EEC expenditures were established, and there is an opportunity to expand EEC strategies in a manner consistent with government's energy objectives, with favorable results for customers. Rising energy costs - in BC, natural gas rates have more than doubled since 1998 - present greater potential for cost effective EEC initiatives and have made the public more receptive to these initiatives. An expanded EEC strategy for the Companies dovetails with government's energy objectives of, for instance, conservation, reduction of greenhouse gas (GHG) emissions, and electricity self-sufficiency. The Province set out

[1] Order No. G-51-03 approved the Terasen Gas Inc. 2004-2007 Multi-Year Performance-Based Rate Plan Settlement Agreement

[2] Order No. G-126-05 approved the Terasen Gas (Vancouver Island) Inc. 2006-2007 Negotiated Settlement Agreement

ambitious objectives regarding these items in its 2007 Energy Plan and has further demonstrated its commitment to these policies by enacting legislation to amend the *Utilities Commission Act* to require the Commission to address government's energy objectives in considering applications under section 44.2, among other things.[3] Despite the Province's leadership in developing conservation and GHG policies, the Terasen Utilities – which together are British Columbia's largest public utilities in terms of delivered energy - currently invest less on conservation in BC (in absolute dollars and on a per customer basis) than other utilities, both in BC and elsewhere in North America.

In 2005, the Terasen Utilities retained Marbek Resource Consultants Ltd. ("Marbek") to undertake a Conservation Potential Review ("CPR"), a review which had been contemplated in the 2004 Resource Plans for TGI and TGVI. The CPR was received by the Companies in 2006. The findings of the CPR were further refined through consultation with Habart and Associates Consultants ("Habart"). The Companies also developed "portfolio level" initiatives in addition to traditional energy efficiency and fuel switching programs. The strategies outlined in this Application, and the expenditures for which approval is being sought, are based to a significant degree on the findings of the CPR and the subsequent work undertaken with Habart. These cost-effective initiatives will lead to significant energy savings for customers and will result in a reduction in GHG emissions.

In summary, there are four components to the relief sought in this Application:

1. The Companies are seeking to expand overall EEC expenditures to a total of $56.6 million over three years, representing $46.944 million for TGI and $9.667 million for TGVI.
2. The Companies are proposing to capitalize incremental EEC expenditures, include them in a regulatory asset deferral account and amortize the balance of the account over a period of 20 years.
3. The Companies are proposing to increase the amortization period to 20 years for incentive amounts that are added to deferral accounts in 2008 and 2009 as part of the TG PBR Extended Settlement and TGVI RR Extended Settlement, which will align with the amortization period for incremental EEC expenditures.

[3] Bill 15, *Utilities Commission Amendment Act, 2008*

4. The Companies are proposing a methodology for evaluating the costs and benefits of the overall EEC portfolio.

The specific relief sought is detailed in Section 2 “Application”, but is summarized below.

Expanded EEC Funding

The TGI PBR Extended Settlement already includes DSM funding totaling $3.124 million ($1.50 million for incentives and $1.624 million for expense), in each of 2008 and 2009. Similarly, TGVI RR Extended Settlement includes DSM funding totaling $1.150 million ($0.650 million for incentives and $0.500 million for expense), in each of 2008 and 2009. The respective Extended Settlements specify how these DSM related expenditures are to be included in revenue requirements and rate determinations for 2008 and 2009. The two year total (2008 plus 2009) of DSM related expenditures for both Companies that are included in the Extended Settlements is $8.548 million ($3.124 million *2 plus $1.15 million *2). The Companies’ current approved EEC expenditures are outlined in Table 1 below.

The Companies are proposing incremental EEC/DSM expenditures over three years of $40.696 million for TGI and $7.366 million for TGVI. On a combined basis, the total additional funding for the three years ending 2010 over and above the approved levels stipulated in Extended Settlements for the two years ending 2009 is $48.062 million, bringing the three year total for both Companies to $56.61 million. This information is summarized in Table 1, below. While this funding increase will allow for a comprehensive set of expanded programs the Companies will continue to explore where the programs may be enhanced as experience is gained. Should beneficial opportunities be identified the Companies may bring additional applications forward as appropriate.

Table 1 – Current, Proposed, and Incremental EEC expenditures, by Utility

Current Level of Spend for 2008 and 2009 ($million)

Utility	O&M	Incentive	Total
TGI	$1.624	$1.500	$3.124
TGVI	$0.500	$0.650	$1.150
Total	$2.124	$2.150	$4.274

Proposed ($million)

Utility	2008	2009	2010	Total by Utility
TGI	$13.996	$15.752	$17.196	$46.944
TGVI	$2.830	$3.043	$3.793	$9.666
Total	$16.826	$18.795	$20.989	$56.610

Incremental ($million)

Utility	2008	2009	2010	Total by Utility
TGI	$10.872	$12.628	$17.196	$40.696
TGVI	$1.680	$1.893	$3.793	$7.366
Total	$12.552	$14.521	$20.989	$48.062

Much of the expenditure being requested, and the activity described in the Application, is based upon the CPR, conducted by Marbek, and received by the Companies in May 2006, as discussed in the 2006 Resource Plans for TGI and TGVI. The findings of the CPR were further refined through consultation with Habart, and the high-level program planning work was begun. The Companies also developed "portfolio level" initiatives in addition to traditional energy efficiency and fuel switching programs.

The Companies are seeking Commission approval for the overall incremental expenditures in Table 1 based on the contemplated program areas and funding described outlined in Table 2 below and described in detail in Section 6. This approach preserves the Companies' ability to subsequently redirect funds from one program area to another program area that the Companies conclude is generating more favorable results based on the assessment criteria outlined in this Application. One of the program areas is $500,000 for a new CPR study to be completed in 2009 for the purposes of developing new EEC programs and funding proposals, including a future application to the Commission. The expenditures set out in Tables 1 and 2 do not include contributions from partners for joint programs where there are electrical savings, which total about $5.5 million over the three year time period. The Terasen Utilities have proposed mechanisms in Section 6.14 to permit the Commission and stakeholders to review how the money has been spent and ensure accountability.

Table 2 - Proposed EEC Expenditure by Program Area

Spend by Program Area 2008 - 2010 ($000's)	TGI	TGVI	Totals
Residential Energy Efficiency	$8,552	$734	$9,286
Commercial Energy Efficiency	$19,592	$2,199	$21,791
Residential Fuel Switching	$1,332	$2,367	$3,699
Conservation Education and Outreach	$11,068	$2,767	$13,835
Joint Initiatives	$2,400	$600	$3,000
Trade Relations	$1,200	$300	$1,500
2009 Conservation Potential Review	$400	$100	$500
Innovative Technologies, NGV and Measurement	$2,400	$600	$3,000
Total	$46,944	$9,667	$56,611

The funding budgets for each program area were derived based on the Companies' expectation that they will be undertaking the initiatives identified in Section 6.

The Terasen Utilities believe that by targeting the above areas, the energy savings from the proposed increase in expenditure and activity are significant. The present value of the savings from energy efficiency is estimated to be almost 10 million GJs over the lives of the various measures proposed, while it is estimated that the proposed activities designed to switch people who currently use a less efficient energy source as compared to natural gas (i.e. fuel switching activities) would result in additional load with a present value of approximately 2.3 million GJs. The net energy savings from the contemplated energy efficiency and fuel-switching activity is anticipated to be approximately 7.7 million GJs. This does not include potential savings resulting from Conservation Education and Outreach, Joint Initiatives, or Innovative Technologies, NGV and Measurement. The Companies anticipate that the proposed EEC activity will continue to provide good value for customers in a manner that is consistent with government's energy objectives. For example, the Energy Efficiency activity that the Companies are contemplating for customers of TGI produces a simple yield of $3.15 spent/GJ saved. The EEC portfolio contemplated in this Application, when assessed in accordance with the proposed evaluation methodology, has a Total Resource Cost ("TRC") ratio of 3.1 and a net financial benefit to customers of $165.1 million.

The Companies will continue to assess over the course of the Program Period whether customers would benefit from additional EEC spending over and above the funding sought in this Application, and will bring forward any further applications as appropriate.

Financial Treatment

As discussed in more detail in Section 6, this EEC Application proposes to treat the incremental EEC expenditures above amounts already approved as part of TG PBR Extended Settlement and TGVI RR Extended Settlement as capital. An amortization period of 20 years has been selected to match the benefit received by customers from the EEC expenditures resulting in appliance and energy system installations with a weighted average measurable life of 22.5 years. In addition to closely matching the cost recovery to the period over which benefits will accrue to customers, the proposed amortization period will smooth impacts to rates from the proposed increase in expenditure. The Terasen Utilities propose that the incremental EEC expenditures and existing incentive amounts in TG PBR Extended Settlement and TGVI RR Extended Settlement (TG - $1.5 million and TGVI - $.650 million) be charged to a regulatory asset deferral account on a tax-adjusted basis, the balance of which is amortized over twenty years, with amortization commencing the year following the year the expenditure is made. As indicated above, the longer amortization period than the periods contemplated in the Extended Settlements will smooth the impact to rates from the proposed increase in expenditure, and is more representative of the longevity of the energy savings resulting from the expenditure and from the new appliances to be installed by customers as a result of expenditures. This financial treatment is consistent with an approach used by other utilities in British Columbia, and the approach identified in the Commission's 1995 Guidelines in respect of the financial treatment of DSM.[4]

Evaluation Methodology

The Application also outlines specific approaches for evaluating the performance of the programs undertaken. The Companies are proposing a portfolio approach to cost-benefit analysis, so that rather than evaluating cost-effectiveness on a program-by-program basis, the overall EEC portfolio must maintain a TRC ratio of 1.0 or higher. This approach will allow the Companies to undertake the important portfolio-level activities needed to support the EEC activity, as well as to encourage market penetration of technologies that have a TRC of less than one because they have not yet reached economies of scale but have longer term potential for a higher TRC ratio. Further, the portfolio approach will allow the Companies to offer programs to customers in service areas where the TRC may have a result of less than 1.0 due

[4] British Columbia Utilities Commission Order No. G-55-95, Amendments to the Uniform System of Accounts for Gas and Electric Utilities

to lower usage patterns, to support the Companies' goal of making the same programs available to customers across the service territory. The Companies propose that the "benefits" input to the cost-benefit analysis be based on gross energy savings rather than net savings (thus eliminating consideration of the perceived effects of free riders), due in part to uncertainties around free ridership rates. Free riders are customers who participate in an EEC program, who notionally would have undertaken the same conservation actions even if the program were not offered. The Companies are of the view that the inclusion of the notional free rider effects in the cost-benefit tests for EEC programs will distort test results and consequently may lead to results that run counter to the objectives of energy policies. The Companies further propose that the "benefits" input to the cost-benefit analysis include energy savings resulting from future regulations that may be introduced partly as a result of the Companies' EEC activity. The TRC ratios referenced in the Application have been derived using this approach.

Mechanics of Implementation

As discussed above, the TGI PBR Extended Settlement includes DSM funding totaling $3.124 million ($1.50 million for incentives and $1.624 million for expense), in each of 2008 and 2009. Similarly, TGVI RR Extended Settlement includes DSM funding totaling $1.150 million ($0.650 million for incentives and $0.500 million for expense), in each of 2008 and 2009. The respective Extended Settlements specify how these DSM related expenditures are to be included in revenue requirements and rate determinations for 2008 and 2009. The two year total (2008 plus 2009) of DSM related expenditures for both Companies that are included in the Extended Settlements is $8.548 million ($3.124 million *2 plus $1.15 million *2).

The Terasen Utilities propose that the incremental expenditures for the 2008 and 2009 years be added to the DSM expenditures that have previously been approved by the Commission for inclusion in the Companies respective revenue requirements and rate determinations as set out in the Extended Settlements for 2008 and 2009.

The result of the mechanics described above based on the EEC expenditures proposed with this Application, the Companies expect that total EEC expenditures of $14.702 million ($16.826 less $1.624 less $0.500) will be added to the deferral accounts of the Terasen Utilities in 2008 on a before tax basis. The 2008 amortizations will remain unchanged from the amounts approved under the previous TGI Annual Review and the TGVI Settlement Update. Amortization for 2009 will equal one-twentieth (1/20th) of the forecasted year ending balance in the deferral account as at December 31, 2008. For 2009, in aggregate, the Companies expect that $16.671 million ($18,795 million less $1.624 less $0.500) will be added to the deferral accounts of the Terasen Utilities on a before tax basis. The deferral accounts will be included in rate base, on an after tax basis.

Stakeholders

The Terasen Utilities have undertaken to consult with stakeholders in its preparation of the Application. Feedback has been generally supportive. In consideration of this feedback, the Companies are of the view that a written regulatory review process culminating in a Negotiated Settlement Process is appropriate for this Application.

Conclusion

The Companies are of the view that proposals set out in this Application are consistent with government's energy objectives and will provide significant value to customers. Additionally, the Companies are of the view that the capitalization of incremental EEC expenditures is reasonable in light of the significant benefits that customers will realize with the successful introduction of the EEC programs proposed with this Application. The proposed portfolio approach to evaluation will allow the companies to undertake a broad range of programs throughout the Companies' service area. Accordingly, the Terasen Utilities are of the opinion that the proposals set out in this Application are fair, reasonable and in the best interests of customers.

APPENDIX I

Terasen Gas
Description of Current & Past DSM / EEC Programs

APPENDIX I
DESCRIPTION OF TERASEN GAS CURRENT AND PAST DSM / EEC PROGRAMS

A. Terasen Gas Inc.

Current Programs

Residential – Energy Star Heating System Upgrade

The Energy Star Heating System Upgrade Initiative has existed in different forms since the current level of DSM funding available to Terasen Gas Inc. ("TGI") was established in 1997. In its current form (running September 1, 2007 to March 31, 2008), the program offers existing residential customers in the Lower Mainland and Interior a bill credit of $250 for the installation of an Energy Star furnace or boiler. TGI has partnered with B.C. Hydro and Fortis Inc. (depending on the customer's location) who fund an additional rebate of $50, if the furnace installed by the customer has a variable speed motor. Further, TGI worked with heating appliance manufacturers and distributors, and a number of them also offered coupons ranging in value from $150 to $1,000 during the program period from September 1, 2007 to January 31, 2008.

In the 1997 DSM Semi-Annual Status Report, submitted by B.C. Gas Utility Ltd. on November 19, 1997, the number of participants in the heating upgrade program was 68 at the time of reporting, projected to grow to 205 by year-end. This year, close to 3,200 residential customers participated in the program which is a notable gain in program participation. Terasen Gas plans to re-launch this program in September 2008. The Energy Star furnace upgrade program gives TGI an excellent opportunity to communicate with customers, not only about the details of the program, but also to provide additional, complementary messages. For example, the bill insert for the program included information about Natural Resources Canada's eco-Energy home retrofit program, and a copy of Terasen Gas' "Hot Tips" energy savings brochure was sent to all participants, thus providing additional information to those customers to help them to reduce their energy consumption and manage their energy bills.

Commercial – Efficient Boiler Program

The Companies' key Commercial incentive program, the Efficient Boiler Program ("EBP"), garnered a significant level of interest from the Commercial building sector, to the extent that the retrofit portion of the program was oversubscribed and then closed due to budget constraints. The EBP is currently only available to new construction projects, and is not available to customers of Terasen Gas (“Vancouver Island”), given the past focus on load-building, as opposed to efficiency incentives, in that region.

Commercial – Commercial Energy Assessment Program

This program provides energy assessments to commercial and small industrial customers upon request. The energy assessment offering first appeared in 2001. The current version of the program was launched in mid-2005; the program offers a thorough energy audit conducted by third-party energy consultants at no charge to qualified program participants. Over 100 assessments are typically conducted each year for various customers across the province. In order to assess the effectiveness of this initiative, Terasen Gas has hired a third-party consultant to perform an evaluation of this program to measure its effectiveness. The study will evaluate assessments that were completed between Q1 of 2003 to Q2, 2007 and the results will be available in the fourth quarter of 2008.

Education and Outreach Initiatives – Destination Conservation

Destination Conservation (“DC”) is a K-12 school program involving students, teachers and school facilities management staff. The program is organized by the Pacific Resource Conservation Society, a B.C. based not-for-profit group, and offered to school districts. It features energy conservation curricula and support materials for participating teachers, and technical assistance to school facilities management staff. The DC program includes an energy monitoring component which allows school districts to monitor, analyze and report energy usage information. Utilizing software programs such as ‘Utility Manager 4.0 Pro’ coupled with operator training; schools are able to report weather-normalized energy savings resulting from implementation of energy efficiency measures. TGI considers this approach to be a cost-effective means of monitoring program impacts.

TGI contributes a portion of the first year operating costs for the program to a number of school districts in prior years. In the FortisBC service territory, Fortis contributes the second year operating costs, providing another example of how Terasen Gas works with partners to deliver programs.

Past Programs

Other programs offered by TGI since 2005 are described below, with results summarized in Table 1.

Residential Programs

- Residential New Construction Heating Program (RNCHP)

This program targeted the installation of ENERGY STAR qualified natural gas furnaces and boilers in new construction with an incentive payable to residential builders. The intent of the program was to alter the existing market where only 20% of new homes had high-efficiency equipment installed. The total incentive available was $500, with TGI contributing $250 to the incentive, and the remainder coming from Ministry of Energy, Mines and Petroleum Resource (MEMPR). The program was launched in early 2005 and ran until March 31, 2007.

- New Home Program

The New Home Program, launched in July 2006 and was in effect until March 31, 2007, provided up to $3000 for a new home with an EnerGuide 80 rating, natural gas heating, natural gas hot water, ENERGY STAR appliances and windows, natural gas range and dryer, 40% CFL[1] lighting, and an ENERGY STAR ventilation fan. On average, these homes consume one third less energy than a standard home and the program encouraged the use of high efficient natural gas equipment. Program partners included BC Hydro, MEMPR, NRCan and possibly FortisBC and CHBA-BC. TGI contribution to this program was $1,000 of the total incentive amount available. There was also an option for the builder to participate only in the natural gas and Energy Star appliance bundle, in which case the builder was eligible for an incentive of $600, to which TGI contributed $100.

Table 1 – TGI Historical Program Summary 2005-2007

[1] CFL=Compact Florescent Light bulbs

Year	Program Name	Number of Participants	Savings per Participant per Year (GJ)	Annual Savings (GJ)
2005	Energy Star Heating System Upgrade Program	3,000	14	41,400
	Residential New Construction Heating Program (RNCHP)	750	9	6,825
	Commercial Energy Assessment Program	90	600	31,500
	Efficient Boiler Program (EBP)	15	1,570	23,535
	Destination Conservation	20	n/a [1]	4,000
	Total 2005	**3,875**	**n/a**	**107,260**
2006	Energy Star Heating System Upgrade Program (VSM)	2,343	14	32,333
	Energy Star Heating System Upgrade Program (VSM)	1,220	14	16,836
	Residential New Construction Heating Program (RNCHP)	1,180	9	10,738
	Efficient Boiler Program (EBP)	30	n/a [2]	30,849
	Commercial Energy Assessment Program	18	600	10,800
	Destination Conservation	4	113	452
	Total 2006	**4,795**	**n/a**	**102,008**
2007	Energy Star Heating System Upgrade Program	4,316	13.8	59,561
	Residential New Construction Heating Program (RNCHP)	2,981	9.1	27,127
	Efficient Boiler Program (EBP)	20	n/a [3]	14,650
	Destination Conservation	44	113	4,972
	Commercial Energy Assessment Program	100	600	60,000
	Total 2007	**7,461**	**n/a**	**166,310**

Note that the numbers above are based on combination of actual and estimates as presented in the 2005, 2006 and 2006 Annual Reviews

[1] The savings for DC Program were presented as an aggregate of savings in 2005

[2, 3] The savings for the Efficient Boiler Program are not presented per participant per year, but are instead an aggregate of savings for all participants for the year

B. Terasen Gas (Vancouver Island) Inc.

DSM programming for Terasen Gas (Vancouver Island) Inc. has historically been different from TGI due to the focus on efficient load building activities for this younger utility. The majority of the TGVI programs targeted the residential sector. The most recent program offerings for TGVI concluded in the March 2007 or earlier. Programs offered by TGVI since 2005 are described below, with the results summarized in Table 2.

"Think Grand" Residential New Construction Heating Program

Think Grand provided $1,000 to builders to install ENERGY STAR natural heating equipment and domestic hot water. The program was introduced June 1, 2005, and was in effect until March 31, 2007. TGVI contributed $250 to the total amount of the grant. Partners included BC Hydro, MEMPR and Natural Resources Canada (NRCan) who also contributed $250 per participant. The primary purpose of the program was to reverse the trend of builders in installing electric baseboard heating and electric hot water tanks. The incentive was also offered as part of the New Home incentive bundle program mentioned below.

"Yank the Tank" Electric Water Heater Conversion Offer

Yank the Tank provided $400 to homeowners for conversions of electric water heaters to natural gas with BC Hydro contributing half of the incentive. The program was intended to increase the natural gas penetration on existing mains and reduce electric load on Vancouver Island. The water heater conversion program was originally introduced September 1, 2005 as part of the Switch and Save campaign, and was re-introduced as Yank the Tank in March 1, 2006 and ran to December 31, 2006. Terasen contributed $200 to the total amount of the grant.

Build Smart Program

Build Smart provided $75 to builders for each pre-piped appliance (specifically: ranges, cook-tops, wall ovens and/or clothes dryers) within a new home. The program was intended to maximize gas use in new construction.

The Energy Bandit Reward

The Energy Bandit Reward program provided $300 to homeowners for conversions of electric, oil or propane furnaces/boilers to natural gas and an additional $150 if the new natural gas furnace/boiler installed was high efficiency and ENERGY STAR qualified.

The primary objectives of this program were to increase natural gas penetration on existing mains and reduce Vancouver Island reliance on heating oil. MEMPR paid the $150 high efficiency incentive while TGVI covered the $300 conversion incentive. The program was introduced March 1, 2006, and ran until March 31, 2007. Promotional efforts for this program were combined with the promotional efforts for the Yank the Tank program.

The PowerSmart New Home Program

Launched in July 2006 this program ran until March 31, 2007. The New Home Program provided up to $3,000 for a new home with an EnerGuide 80 rating, natural gas heating, natural gas hot water, ENERGY STAR appliances and windows, natural gas range and dryer, 40% CFL[2] lighting, and an ENERGY STAR ventilation fan. On average, these homes consume one third less energy than a standard home and the program encouraged the use of high efficient natural gas equipment. Program partners included BC Hydro, MEMPR, and NRCan. TGVI contribution to this program was equivalent to the Think Grand incentive, plus an additional $100 for a natural gas appliance package. TGVI contribution to program costs for the New Home Program was minimal; most of the program costs were covered by BC Hydro.

[2] CFL=Compact Florescent Lightbulbs

Table 2 - TGVI Historical Program Summary 2005-2007

	Program Name	Number of Participants	Savings per Participant per Year (GJ)	Annual Savings (Gj)
2005	Fireplace Program (2004 carry over)	10	10	100
	Build Smart	805	5	4,025
	Home Builders' Grant	452	80	36,160
	Water Heating Rebate	402	25	10,050
	H/E Furnace Installation (2004 carry over)	54	55	2,970
	Fireplace/Water Heater Combination	16	30	480
	Existing Customer Water Heater Conversion	60	25	1500
	Clean Choice	132	55	7260
	Think Grand	59	80	4,720
	Switch & Save	182	55	10,010
	Switch & Save (water heater only)	81	25	2,025
	Total 2005	**2,253**	**445**	**79,300**
2006	Think Grand	344	80	40,000
	Build Smart	408	5	2,500
	Yank the Tank	94	25	2,500
	Energy Bandit	161	55	33,000
	PowerSmart New Home	431	85	8,500
	Total 2006	**1,438**	**250**	**86,500**
2007	Think Grand	276	80	40000
	Build Smart	18	5	2500
	Yank the Tank	67	25	2500
	Energy Bandit	278	55	33000
	PowerSmart New Home	0	85	8500
	Total 2007	**639**	**250**	**86,500**

APPENDIX J

Terasen Gas 5-Year Capital Plans

J-1 TGI
J-2 TGVI
J-3 TGW

APPENDIX J-1
TGI 5–Year Capital Plan

TGI 5 YEAR CAPITAL PLAN AND STATEMENT OF FACILITY EXTENSIONS

1 PREAMBLE

TGI has segmented its 5 Year Capital Plans as follows:

Regular Capital Plan
- Customer Driven Capital
- Non-Customer Driven Capital

Major Capital Plan
- Capital Projects that do not require a CPCN
- Capital Projects that require a CPCN

Regular Capital is defined as forecast Capital Expenditures that are under $1 million (excluding AFUDC). These expenditures have been categorized into either customer driven capital or non-customer driven capital. This category excludes Capitalized Overheads, Contributions in aid of Construction (“CIAC”) and Allowance for funds used during construction (“AFUDC”).

Major Capital projects are defined as those discrete projects that are in excess of $1 million (excluding AFUDC). These forecast expenditures have been categorized into projects which do not require a CPCN and those which do require a CPCN to proceed. Typically, major capital projects for TGI in excess of $5 million have required a CPCN.

TGI’s 5 Year Capital Plans for the period 2008 to 2012 are presented to provide additional background and context for the Resource Plan. TGI is of the view that these Capital Plans are not included for the purposes of approval by the British Columbia Utilities Commission (“BCUC”) as part of its review of the TGI Resource Plan. TGI believes that the regulatory review process for Resource Plans is not the appropriate forum for review of its Capital Plans. TGI submits that its 2007 Annual Review Application included detailed capital expenditures that were reviewed and approved by Commission on December 10, 2007 by Order G-153-07. Consistent with past practice, TGI continues to believe that the appropriate forum for review of its Capital Expenditures is its Performance Based Regulation (“PBR”) and Annual Review proceedings.

As TGI’s 5 Year Regular Capital Plan and Major Capital Plans include all planned capital expenditures, TGI believes that this information satisfies the requirements of the statement of facilities extensions as set out in Section 45(6) of the Utilities Commission Act.

TGI has endeavoured to provide a comprehensive 5 Year Capital Plan as part of its submission. However, the projects and figures contained herein are subject to change and may be revised to reflect additional information as part of the Company’s Annual Review filing, which is anticipated in October, 2008.

2 5 YEAR REGULAR CAPITAL PLAN

The following table identifies the cost projections for regular capital expenditure in 2008-2012. For the purposes of the 5 Year Capital Forecast, Regular Capital includes the following types of capital expenditures:

Capital Additions "Customer Driven" Capital

- Mains
- Services
- Meters for New Customer Additions

Other Regular Capital

- Meter Replacements
- Transmission Plant
- Distribution Plant
- IT Capital
- Non-IT Capital

Regular Capital excludes Capital Projects which are subject to CPCN applications. Table 2-1 identifies the cost projections for regular capital expenditure in 2008-2012.

Table 2-1- Forecast of Regular Capital Expenditures ('000's)

	2008 Projection	2009 Forecast	2010 Forecast	2011 Forecast	2012 Forecast
Customer Driven Capital					
Mains	9,527	9,437	9,551	9,749	10,043
Services	19,443	19,260	19,492	19,896	20,496
Meters (Customer Additions)	3,834	3,798	3,844	3,924	4,042
	32,804	**32,496**	**32,888**	**33,569**	**34,581**
Other Regular Capital					
Replacement Customer Meters (Allocation)	13,392	17,231	21,082	25,414	27,310
Transmission Plant	11,652	4,841	5,063	5,164	5,267
Distribution Plant	9,174	7,793	7,814	8,058	8,270
IT	10,736	11,038	11,246	11,471	11,471
Non-IT	12,301	12,450	12,699	12,953	13,212
	57,255	**53,352**	**57,904**	**63,060**	**65,530**
Total Regular Capital	**90,059**	**85,848**	**90,791**	**96,629**	**100,111**

Figures exclude AFUDC and Capitalized Overheads.

Over the next eight months, TGI will be revising its 5 Year Capital Forecast in advance of the TGI 2008 Annual Review proceeding. This exercise is consistent with its internal planning cycle and is anticipated to result in further refinements to the 5 Year Capital Plan.

3 5 YEAR MAJOR CAPITAL PLAN

3.1 Major Capital Projects that do not require a CPCN

Table 3-1 identifies the cost projections for major capital projects not subject to CPCN applications for the period 2008-2012.

Table 3-1 Forecast of Major Capital Projects not requiring a CPCN ('000's)

Project Description	Project Category	2008 Projection	2009 Forecast	2010 Forecast	2011 Forecast	2012 Forecast
Transmission Plant						
SCP Code Compliance Upgrades	Upgrade/Enhancement	2,000	1,500			
LNG Coldbox Upgrade	Upgrade/Enhancement	2,785				
Scada Upgrade	Upgrade/Enhancement	100	1,500			
Kootenay River Crossing	Upgrade/Enhancement	368	2,950	25		
Columbia River Crossing	Upgrade/Enhancement	2,379	339	25		
Distribution Plant						
Riverside IP, Abbotsford	Capacity Shortfall		1,192			
72nd Street IP, Delta	Capacity Shortfall					1,800
36th Avenue IP, Delta	Capacity Shortfall					1,211
Mission IP Seismic Upgrade	Upgrade/Enhancement		1,600			
IT						
SAP Upgrade	Upgrade/Enhancement	2,700				
Asset Data Integration	Upgrade/Enhancement	1,350				
Non-IT						
No Projects Identified						
Total Major Projects		**11,682**	**9,081**	**50**	**-**	**3,011**

3.1.1 Transmission Plant - SCP Code Compliance Upgrades

The Southern Crossing Pipeline ("SCP") is a key transmission pipeline supplying natural gas to the Interior and through to the Lower Mainland regions of British Columbia. The pipeline was constructed and put in service in December 2000. Since construction of the pipeline, the population density and class location near Oliver has increased from the original design value. The resulting difference has resulted in the lowering of the allowable operating pressure. This upgrade to the pipeline will restore the original operating pressure. This project cost is estimated to be $3.5 million (excluding AFUDC) and will commence in 2008 and anticipated to be completed in 2009.

3.1.2 Transmission Plant - LNG Coldbox Upgrade

The Liquefied Natural Gas ("LNG") Coldbox is part of the plant component at the Terasen Gas Tilbury LNG Facility. The LNG Coldbox is the plant component that reduces gas temperature to -162° Celsius, thereby converting natural gas into LNG. The existing plant was built in 1970-1971. The LNG Coldbox consists of a number of very complex shell and tube, spiral-wound heat exchanges. A number of the tubes in one heat exchanger failed in early 2005. Repairs were successful but very challenging. A materials engineering investigation was completed as to cause and likelihood of additional failures in future. This report stated that further tube failures will occur. As tube failure in the Coldbox will result in Terasen Gas not being able to produce LNG, Terasen Gas plans to spend approximately $4.2 million (excluding AFUDC) for replacement of this plant. Preliminary work commenced in 2006 and the project is expected to be completed in 2008.

3.1.3 Transmission Plant - SCADA System Upgrade

The SCADA system operates, controls, and monitors Terasen Gas' transmission and compression facilities in British Columbia. Timely vendor support of the current version (6.0) of the SCADA application may be at risk as knowledge support diminishes with vendor support staff attrition. Preliminary studies are expected to commence in 2008 with an upgrade to the next supported version to be in service in 2009. The total estimated cost of this project is $1.6 million (excluding AFUDC).

3.1.4 Transmission Plant - Kootenay River (near Shoreacres) Crossings

The aerial crossing of the Kootenay River on the Savona – Nelson Mainline between Castlegar and Nelson has been identified as requiring extensive rehabilitation. This structure was constructed in 1957 and has extensive cable and support corrosion. Repair or replacement is required to ensure continued gas service to Nelson. A horizontal directional drill ("HDD") has been identified as the prime alternative to an aerial crossing. In addition to being a lower cost alternative, the HDD would eliminate all future structural maintenance issues as well as inspection costs. Construction is anticipated to commence in 2008 with completion expected in 2009. The total project cost is estimated at approximately $3.3 million (excluding AFUDC).

3.1.5 Transmission Plant - Columbia River Crossing near Brilliant

Due to extensive cable and pipe corrosion, rehabilitation is required at the Columbia River on the Savona – Nelson Mainline aerial crossing between Castlegar and Nelson near Brilliant. This structure was constructed in 1957 and must be repaired or replaced to avoid any gas service disruptions to Nelson. As an alternative to an aerial crossing, a HDD has been selected as preferred option at this location. Preliminary investigations have been performed and preliminary project designs have been completed. The estimated cost of this project is $2.7 million (excluding AFUDC) and completion anticipated in 2009.

3.1.6 Distribution Plant – Riverside IP, Abbotsford

This project consists of a 1.6 km loop of NPS 12 (323mm OD) pipeline operating at 275 pounds per square inch gauge ("psig") (1,900 kPa). The estimated cost of this project is $1.2 million (excluding AFUDC). This project is currently planned to be constructed and in service in 2009. This system improvement is required to restore capacity in the King Intermediate Pressure ("IP") system feeding Abbotsford and Mission to ensure that tail end pressures remain above minimum acceptable levels. The capacity of the King IP system has been eroded over time by load growth in Abbotsford and to a lesser extent in Mission.

3.1.7 Distribution Plant - 72nd Street IP, Delta

This project is currently planned to be constructed in 2012. It consists of a 2.6 km loop of 323mm O.D. pipeline operating at 1,200 kilopascals (“kPa”). The estimated cost of this project is $1.8 million (excluding AFUDC) and is expected to be in service in 2012.

This system improvement is required to accommodate load growth to greenhouses in the Delta area. This system improvement will only be installed if the affected greenhouses convert some, or all, of their interruptible load to firm load. With this loop installed greenhouses would not need to be curtailed until colder ambient temperatures are reached.

3.1.8 Distribution Plant - 36th Avenue IP, Delta

This project is currently planned to be constructed in 2012. It consists of a 1.75 km loop of 323mm O.D. pipeline operating at 1,200 kPa. The estimated cost of this project is $1.2 million (excluding AFUDC) and is expected to be in service in 2012. This system improvement is required to increase capacity to offset aggressive long term load growth projections that have been provided by the greenhouses in the Delta area. This system improvement will only be installed if the affected greenhouses convert some, or all, of their interruptible load to firm load.

3.1.9 Distribution Plant – Mission IP Seismic Upgrade – North of Fraser River

This project consists of the installation of 1.2 km of NPS 8 (219mm OD) pipeline operating at 275 psig (1,900 kPa) northward from the north end of the Mission Highway Bridge to a tie in point at the Lougheed Highway. The estimated cost of this project is $1.6 million (excluding AFUDC). This project is currently planned to be constructed and in service in 2009. This system improvement is required to replace a section of NPS 6 (168mm OD) pipeline that is susceptible to damage from movement of the adjacent road structure due to a 1:100 seismic event and to restore capacity to the 7th & Cedar District Regulator Station by ensuring the tail end pressure of the pipeline remains above minimum acceptable levels.

3.1.10 Transmission & Distribution Plant - Gateway Project

The Gateway Program was established by the Province of British Columbia in response to the impact of growing regional congestion, and to improve the movement of people, goods and transit throughout Greater Vancouver. The Gateway Program is sponsored by the Ministry of Transportation (“MoT”) and includes three components:

- Port Mann / Highway 1 Project – This includes twinning the Port Mann Bridge, upgrading interchanges and improving access and safety on Highway 1 from Vancouver to Langley.

- The South Fraser Perimeter Road Project is a proposed new four-lane, 80 km/h route along the south side of the Fraser River extending from Deltaport

- Way in southwest Delta to the planned Golden Ears Bridge connector road in Surrey/Langley.

- The North Fraser Perimeter Road Project is a proposed set of improvements on existing roads to provide an efficient, continuous route from New Westminster to Maple Ridge.

The highway projects and segments are in various stages of planning, design and construction. The planned highway construction and upgrades will impact the Terasen Gas Transmission and Distribution systems along the highway corridors. Since 2006, the MoT and Terasen Gas have been involved in ongoing discussions regarding this project and as a result Terasen Gas has conducted conceptual and preliminary investigations into system modifications that will be required. Based upon the current plans and available information, Terasen Gas projects that total system modifications will cost approximately $26 million (excluding AFUDC). Terasen Gas has been in discussions with MoT with respect to the cost recovery principles and is hopeful that an agreement will be reached that will allow for maximum recovery of costs.

3.1.11 IT Capital – SAP Core Application Upgrade

SAP is the enterprise application that supports business processes including: Operations and Maintenance; Order Fulfilment; Meter Management and Supply Chain. It also supports back-office functions such as: Payroll; Finance and Performance Reporting.
Vendor support of the current version of the SAP application (R3 v4.6C) expired in the fourth quarter of 2006. An upgrade to the next supported version is therefore required.
Terasen Gas has negotiated an extension to the support agreement for 2007 and will renegotiate a further extension to mid-year 2009 or the completion of the upgrade project - whichever comes first. The start of the upgrade project is expected in late 2008 with an anticipated go-live date in mid 2009. The cost is anticipated to be in the range of $2.5 (pure technical upgrade) to $4.8 million (excluding AFUDC), dependent on the number of enhancements that would be included in the project. The driver for the enhancements will be business priorities to be determined prior to the start of the upgrade project.

3.1.12 IT Capital – Asset Integrity Integration Project

The System Integrity department's mission of providing risk based management services depends heavily on having access to the most current and complete pipeline condition data on which to base its analysis. This pipeline asset and condition data is currently maintained in multiple exclusive databases, digital files, or paper reports, with no current means of automated integration, causing numerous challenges in providing integrity management services. Manual alignment of data from these sources for analysis is difficult and time consuming.

This project will increase integration and continuity within the existing data environment that would allow compliance with the requirements of Z662 Code Annex N (Guidelines for Pipeline Integrity Management Programs) which has recently been adopted by the Oil and Gas Commission of B.C. ("OGC"), the technical regulator for the Terasen Gas pipeline assets operating at pressures greater than 700kPa, as the standard to which operating companies shall develop their Integrity Management Plans ("IMP"). In addition to helping the Company meet compliance objectives, this project will:

- Create an automated method to integrate and spatially align pipeline asset integrity data.
- Introduce new tools to determine and analyze risks to the pipeline and surroundings, as caused by current and forecasted conditions.
- Introduce new tools to evaluate various options to reduce the risk to levels considered to be not significant.
- Ensure future capability to integrate distribution data is not compromised.

This estimated cost of this project is $1.6 million (excluding AFUDC) and expected to be completed in 2008.

3.2 Major Capital Projects that require a CPCN

Table 3-2 identifies the cost projections for major capital projects subject to CPCN applications for 2008-2012.

Table 3-2 Forecast of Major Capital Projects subject to CPCN Applications ('000's)

Project Description	2008 Projection	2009 Forecast	2010 Forecast	2011 Forecast	2012 Forecast
Approved CPCN's & Deferral Accounts					
Vancouver LP Replacement	8,900				
Residential Unbundling	3,000				
Distribution Mobile Solution Project	2,891				
	14,791	**-**	**-**	**-**	**-**
Anticipated CPCN's & Deferral Accounts					
Fraser River SBSA Rehabilitation	1,500	7,500			
	1,500	**7,500**	**-**	**-**	**-**
Total CPCN's & Deferral Accounts	**16,291**	**7,500**	**-**	**-**	**-**

3.2.1 Low Pressure System – Vancouver Low Pressure ("LP") System Replacement

Approximately 95km of Low Pressure ("LP") mains are still in service in densely populated and established areas of Vancouver. The LP system serves approximately 7,100 customers including: commercial establishments; residences; schools and hospitals. It is planned to replace the steel/iron LP system with a polyethylene system, operating at Distribution Pressure of 420 kPa (60 psig), over a 3 year period commencing in 2006 with completion in late 2008.

In May 2006, Terasen Gas submitted a CPCN Application to complete this work. In its application, Terasen Gas projected that it would cost approximately $23.1 million (excluding AFUDC) to complete the 3 year replacement program. Current forecasts indicate that this project will be on target for costs and completion date. This CPCN application was approved by the Commission on June 26, 2006 by Order No. C-2-06.

3.2.2 Residential Unbundling

Since the release of the B.C. Energy Policy in 2002, Policy Action #19 stating that "Natural gas marketers will be allowed to sell directly to small volume customers", Terasen Gas has been facilitating providing commodity choice for small volume customers. The Commercial Commodity Unbundling program was launched in November 2004 with Residential Commodity Unbundling commencing in November, 2007.

With direction from the Commission, Terasen Gas completed a detailed design review and cost estimate using external consultants as part of its Pre-Scoping and Scoping Phases for Residential Unbundling between July 2005 and March 2006. To complete this work, the Commission approved $1.4 million in funding in 2005 to be recorded in a deferral account. On April, 2006, Terasen Gas submitted an application to enhance its business processes and systems required to support the provision of commodity choice to residential customers in the Terasen Gas service area. In its application it specifically requested the following:

- Implement Commodity Unbundling for all residential customers in its service territory, excluding Fort Nelson and Revelstoke, effective November 1, 2007.

- Capital Expenditures of $11.1 million (in addition to the $1.4 million approved for the pre-scoping and scoping phases), for the two year 2006 and 2007 to implement the Residential Unbundling program.

On August 14, 2006 the Commission issued Order No. C-6-06 approving $12.5 million towards the implementation phase costs in 2006 and 2007 and $3.6 million towards the ongoing program costs after 2007. $3.0 million of the ongoing program costs is required for continued customer education and $.6 million is required for annual operating costs.

3.2.3 Approved CPCN – Distribution Mobile Solution Project

The current MobileUP application is used for the Mobile Data Dispatch of customer service activities and the transfer of customer meter and billing information to the Energy Customer Information System. The existing system has reached the end of its useful life and there is significant risk that the current system will fail due to aging technology components. The implementation of the Distribution Mobile Solution provides a new platform for coordinating scheduling and dispatching. The conversion will align customer service activities with construction activities. The Commission issued Order C-5-07 approving the CPCN on July 2, 2007. The estimated cost of this project is $5.98 million (excluding AFUDC) and it is expected to be complete by October 2008.

3.2.4 Anticipated CPCN – Fraser River South Bank South Arm (“SBSA”) Crossing

In 2006, an engineering assessment of the current 20” and 24” underwater Transmission pipeline crossings of the South Arm of the Fraser River serving Vancouver and Richmond was completed. The engineering assessment provided an opinion indicating that both the underwater crossings and the adjacent south bank require extensive rehabilitation to ensure they do not pose a risk in the event of a seismic occurrence. Terasen Gas has recently received a second opinion on the matter, which confirms that rehabilitation work is necessary. Terasen Gas anticipates that it will file a CPCN application for this project towards late 2008 targeting an expected completion date of the project in 2009. Project costs are currently estimated to be $9.75 million (excluding AFUDC).

APPENDIX J-2
TGVI 5–Year Capital Plan

TGVI 5 YEAR CAPITAL PLAN AND STATEMENT OF FACILITIES EXTENSIONS

TGVI is attaching its 5 Year Regular Capital Plan and 5 Year Major Capital Plan to the 2008 TGVI Resource Plan. In aggregate these two plans constitute the Company's 5 Year Capital Plans.

TGVI has segmented its 5 Year Capital Plans as follows:

Regular Capital Plan
- Customer Driven Capital
- Non-Customer Driven Capital

Major Capital Plan
- Capital Projects that do not require a CPCN
- Capital Projects that require a CPCN

Regular Capital include forecast Capital Expenditures that are under $1 million. These expenditures have been categorized into either customer driven capital or non-customer driven capital. This category excludes Capitalized Overheads, Contributions in aid of Construction ("CIAC") and Allowance for funds used during construction ("AFUDC").

Major Capital projects are defined as those discrete projects that are in excess of $1 million (excluding AFUDC). These forecast expenditures have been categorized into projects which do not require a CPCN and those which do require a CPCN to proceed. Typically, major capital projects for TGVI in excess of $4 million have required a CPCN.

TGVI's 5 Year Capital Plans for the period 2008 to 2012 are presented to provide additional background and context for the Resource Plan. TGVI is of the view that these Capital Plans are not included for the purposes of approval by the BCUC as part of its review of the TGVI Resource Plan. TGVI believes that the regulatory review process for Resource Plans is not the appropriate forum for review of its Capital Plans. The TGVI 2007 Settlement Update included detailed capital expenditures that were reviewed and approved by Commission on December 11, 2007 by Order No. G-154-07. Consistent with past practice, TGVI continues to believe that the appropriate forum for review of its Capital Expenditures is its Revenue Requirements and Annual Review/Settlement Update proceedings.

As TGVI's 5 Year Regular Capital Plan and Major Capital Plans include all planned capital expenditures, TGVI believes that this information satisfies the requirements of the statement of facilities extensions as set out in Section 45(6) of the Utilities Commission Act.

TGVI has endeavoured to provide a comprehensive 5 Year Capital Plan as part of its submission. However, the projects and figures contained herein are subject to change and may be revised to reflect additional information as part of the Company's Settlement Update filing, which is anticipated in October, 2008.

1 5 Year Regular Capital Plan

The following table identifies the cost projections for regular capital expenditure in 2008-2012. For the purposes of the 5 Year Capital Forecast, Regular Capital includes the following types of capital expenditures:

Capital Additions "Customer Driven" Capital

- Mains
- Services
- Meters for New Customer Additions

Other Regular Capital

- Meter Replacements
- Transmission Plant
- Distribution Plant
- IT Capital
- Non-IT Capital

Regular Capital excludes Capital Projects which are subject to CPCN applications. Table 1 identifies the cost projections for regular capital expenditure in 2008-2012.

Table 1 - Forecast of Regular Capital Expenditures ('000's)

	2008 Projection	2009 Forecast	2010 Forecast	2011 Forecast	2012 Forecast
Customer Driven Capital					
Mains	4,500	4,384	4,516	4,522	4,525
Services	8,030	6,875	7,081	7,091	7,095
Meters (Customer Additions)	894	908	935	936	937
	13,424	**12,167**	**12,532**	**12,549**	**12,557**
Other Regular Capital					
Replacement Customer Meters (Allocation)	673	896	1,257	1,225	2,134
Transmission Plant	5,799	5,326	3,627	6,500	3,683
Distribution Plant	1,230	587	696	556	885
IT	1,724	1,656	1,687	1,721	1,721
Distribution	1,533	1,443	1,470	1,498	1,527
Transmission	211	67	68	70	71
Equipment	16	16	16	17	17
Facilities	425	479	682	686	688
Unallocated	-	-	-	-	-
Non-IT	2,185	2,004	2,237	2,270	2,302
	11,610	**10,470**	**9,504**	**12,273**	**10,725**
Total Regular Capital	**25,034**	**22,637**	**22,036**	**24,822**	**23,282**

Figures exclude AFUDC and Capitalized Overheads.

Over the next five months, TGVI will be revising its 5 Year Capital Forecast in advance of the TGVI Settlement Update meeting. This exercise is consistent with the Company's internal planning cycle and is anticipated to result in further refinements to the 5 Year Capital Plan.

2 5 Year Major Capital Plan

2.1 Major Capital Projects that do not require a CPCN

Table 2 identifies the cost projections for major capital projects not subject to CPCN applications for the period 2008-2012.

Table 2 – Forecast of Major Capital Projects not requiring a CPCN ('000's)

Project Description	2008 Projection	2009 Forecast	2010 Forecast	2011 Forecast	2012 Forecast
Transmission Plant					
Washout contingency	1,140	1,040	1,040	1,040	1,040
Relocate Coquitlam Dam Crossing	300	500	700		
V1 Coquitlam Compressor Unit 3 Purchase	2,126				
V3 Port Mellon Compressor Purchase		1,713			
Distribution Plant					
No Projects Identified					
IT					
No Projects Identified					
Non-IT					
No Projects Identified					
Total Major Projects	**3,566**	**3,253**	**1,740**	**1,040**	**1,040**

2.1.1 Relocate Coquitlam Dam Pipeline Crossing

The TGVI Transmission mainline crosses the BC Hydro Coquitlam Dam. BC Hydro has undertaken a project to construct a new dam structure immediately downstream of the existing dam designed for adequate seismic performance in the event of an earthquake. TGVI has been in ongoing discussions with BC Hydro regarding this project, with the intention to relocate its pipeline onto the new dam structure. This work has been delayed since 2003 pending BC Hydro's decision to commence the project. The estimated cost of this project is now approximately $1.5 million (excluding AFUDC). After a number of discussions over the past 5 years, BC Hydro has now agreed in concept to the relocation of the pipeline to the upstream slope of the new the dam. This acceptance of the routing is subject to a number of conditions, including an independent hazard assessment, provision of design details, a right of way agreement, and TGVI activities not interfering with the schedule of the dam construction which include the subsequent commissioning of the dam over 2 to 3 years. It is now expected pipeline work will be completed in 2010.

2.1.2 Miscellaneous Creek Crossings

The hydro-technical survey by Northwest Hydraulic Consultants identified a number of locations where stream migration and erosion of TGVI's transmission pipelines may occur and pose a risk to the pipeline. In order to ensure adequate system and integrity capital is available to complete necessary works, this category has been included in the Transmission Capital System Integrity Plan. Forecasted cost for 2008 is $1.14 million (excluding AFUDC) and reflects the reduced likelihood of a significant washout occurring in 2008 at the Englishman River.

Channel migration and erosion of cover over the transmission pipeline at the Englishman River crossing between Parksville and Nanaimo poses a risk to the pipeline. It is proposed to replace the existing Transmission pipeline river crossing using horizontal directional drilling. TGVI continues to monitor the crossing and does not believe that the directional drill is required at the moment.

2.1.3 V1 Coquitlam Compressor Unit 3 Purchase

On January 1, 1999, TGVI (formerly Centra Gas) entered into a ten year agreement with Westcoast Capital Corporation to lease a Taurus 70S compressor unit. This lease agreement expires on December 31, 2008. Under the terms of the lease agreement, the purchase price option is available at the estimated fair market value of $2.1 million. At this time, TGVI believes that the purchase option is economically and operationally preferable to a lease renewal and will continue to re-evaluate options prior to the lease expiry date.

2.1.4 V3 Port Mellon Compressor Purchase

On January 1, 2000, TGVI (formerly Centra Gas) entered into an additional ten year agreement with Westcoast Capital Corporation to lease a Taurus 60S compressor unit. The lease agreement expires on December 31, 2009 and contains a purchase option at an estimated fair market value of $1.7 million. TGVI will evaluate available options prior to the lease expiry date to ensure prudent spend.

2.2 Major Capital Projects that require a CPCN

Table 3 identifies the cost projections for major capital projects subject to CPCN applications for 2008-2012.

Table 3 Forecast of Major Capital Projects subject to CPCN Applications ('000's)

Project Description	2008 Projection	2009 Forecast	2010 Forecast	2011 Forecast	2012 Forecast
Approved CPCN's & Deferral Accounts					
Squamish to Whistler NG Pipeline	14,000	1,000			
Mt. Hayes LNG Storage Facility	55,981	56,524	50,162	28,333	
Distribution Mobile Solution Project	321				
	70,302	**57,524**	**50,162**	**28,333**	**-**
Anticipated CPCN's & Deferral Accounts					
V1 Compressor Replacement	50	3,000	3,000		
	50	**3,000**	**3,000**	**-**	**-**
Total CPCN's & Deferral Accounts	**70,352**	**60,524**	**53,162**	**28,333**	**-**

2.2.1 Squamish to Whistler Natural Gas Pipeline

TGVI filed an application with the Commission for a CPCN in December 2005 to construct a 50 kilometer natural gas pipeline from Squamish to Whistler. Concurrently, TGW filed an application with the Commission for a CPCN to convert its propane system to natural gas and enter into a transportation service agreement with TGVI. In June 2006, the Commission approved both applications in Order No. C-3-06.

Total pipeline construction costs were approved for $30.2 million (excluding AFUDC) in 2005 dollars with an annual inflation adjustment allowance. The allowed rate base inclusion is +/- 10 percent of the approved total excluding the named stream crossings. The project completion date was originally anticipated to be July 2008 but is now currently expected to be March 2009. A delay in pipeline construction has been identified as this project cannot be completed until the highway improvements (a completely independent project by the Ministry of Transportation) are substantially completed. The project team has commenced with planning various scenarios if the pipeline is not ready by the March 2009 target and determine an optimal approach for TGVI to mitigate this risk, if it occurs. As more information becomes available over the upcoming months, TGVI will be in a better position to determine the most prudent approach. TGW will make a capital contribution to TGVI to mitigate the cost impact to TGVI customers. The capital contribution amount will be determined at that time. However it is currently forecast to be $19.9 million.

2.2.2 Mount Hayes LNG Project

TGVI filed an application with the Commission in June 2007 seeking approval to construct and own an LNG Storage Facility, at a location referred to as Mt. Hayes near Ladysmith, and associated facilities to connect the LNG Storage Facility to TGVI's natural gas transmission system. The Application also sought approval of a storage and delivery agreement between TGVI and TGI. In November 2007, the Commission granted conditional approval for the project in order No. C-9-07. Final cost estimates and cost risk analysis were completed and final approval for the project was granted on April 1st, 2008. The total Project capital cost is estimated at $192 million and is expected to be in-service for the winter 2011/12.

The LNG Storage Facility consists of a 1.5 Bcf storage tank with liquefaction, vaporization and other ancillary facilities, an electrical substation and connecting power line. The associated facilities are the pipeline laterals that connect the facility to the existing TGVI transmission pipeline and upgrades to the existing transmission system. The project will allow TGVI to provide both additional system capacity and a gas peaking resource for the benefit of TGVI's customers and provide storage and delivery services to TGI.

2.2.3 Distribution Mobile Solution

The current MobileUP application is used for the Mobile Data Dispatch of customer service activities and the transfer of customer meter and billing information to the Energy Customer Information System. The existing system has reached the end of its useful life and there is significant risk that the current system will fail due to aging technology components. The implementation of the Distribution Mobile Solution provides a new platform for coordinating scheduling and dispatching. The conversion will align customer service activities with construction activities. The Commission issued Order C-5-07 approving the CPCN on July 2, 2007. The estimated TGVI cost of this project in 2008 is $0.3 million (excluding AFUDC) and it is expected to be complete by October 2008.

2.2.4 V1 Compressor Replacement

In 2008, TGVI is undertaking a study to evaluate a business case that, if successful, would see a CPCN submission raised for replacement of the natural gas compressors on units #1 and #2 at Compressor Station V1, located in Coquitlam. Core drivers to this business case are the age of the existing compressors (approaching 18 years) and the technology advancements that industry has made in the area of gas emission reductions (through the use of dry gas seals) and efficiency improvements through new design. If the business case is viewed as viable and the CPCN application is approved, the proposed schedule would see one compressor replaced in the summer of 2010 and the other in the summer of 2011.

APPENDIX J-3
TGW 5–Year Capital Plan

TGW 5 YEAR CAPITAL PLAN AND STATEMENT OF FACILITY EXTENSIONS

1.1 TGW 5 Year Regular Capital Plan

The following table identifies the cost projections for regular capital expenditure in 2008-2012. For the purposes of the 5 Year Capital Forecast, Regular Capital includes the following types of capital expenditures:

Capital Additions "Customer Driven" Capital

- Mains
- Services
- Meters for New Customer Additions

Other Regular Capital

- Meter Replacements
- Transmission Plant
- Distribution Plant
- IT Capital
- Non-IT Capital

Regular Capital excludes Capital Projects which are subject to CPCN applications. Table 1 identifies the cost projections for regular capital expenditure in 2008-2012.

Table 1 - Forecast of Regular Capital Expenditures ('000's)

	2008 Projection	2009 Forecast	2010 Forecast	2011 Forecast	2012 Forecast
Mains, Services & Meters Capital					
New Customer Mains	48	90	79	52	52
New Customer Services	77	140	125	86	86
New Customer Meters (Allocation)	23	50	51	52	53
Replacement Customer Meters (Allocation)	22	20	15	11	6
	169	**299**	**269**	**201**	**197**
System Integrity & Reliability Capital					
Transmission	-	-	-	-	-
Distribution	5	5	5	5	5
	5	**5**	**5**	**5**	**5**
Non IT Capital					
Distribution	62	352	62	64	67
Transmission	-	-	-	-	-
Equipment	50	50	30	11	11
Facilities	-	10	53	10	15
Unallocated	-	-	-	-	-
	112	**412**	**145**	**84**	**93**
IT Capital					
IT	**5**	**164**	**20**	**-**	**-**
Total Regular Capital	**291**	**881**	**440**	**290**	**295**

TGW will be revising its 5 Year Capital Forecast in advance of the TGW Rate Design and Revenue Requirements Application.

1.2 TGW 5 Year Major Capital Plan

2.1 Major Capital Projects that require a CPCN

2.1.1 Whistler Distribution System Conversion

TGW filed an application with the Commission for a CPCN in December 2005 to convert its propane system to natural gas and enter into a transportation service agreement with TGVI. Concurrently, TGVI filed an application with the Commission for a CPCN to construct a 50 kilometer natural gas pipeline from Squamish to Whistler. In June 2006, the Commission approved both applications in Order No. C-3-06.

Total project costs associated with CPCN development and conversion of the existing propane system to natural gas was approved for $0.75 million and $5.19 million respectively (excluding AFUDC) in 2005 dollars with an annual inflation adjustment allowance. The allowed rate base inclusion is +/- 10 percent of the approved total.

APPENDIX K

Terasen Gas Annual Contracting Plan Executive Summaries

K-1 TGI
K-1 TGVI

APPENDIX K-1
TGI Annual Contracting Plan Executive Summary

EXECUTIVE SUMMARY

1. INTRODUCTION

The contents of this report summarize the proposed 2008/09 Midstream Annual Contracting Plan (the "2008/09 ACP") for Terasen Gas Inc. ("Terasen Gas" or “TGI”) for the year commencing November 1, 2008.

The Essential Services Model (“ESM”) was developed by Terasen Gas and approved by the British Columbia Utilities Commission (the “Commission”) to support commodity unbundling for residential and commercial customers. The ESM model allows for the provision of commodity (baseload supply gas) by Terasen Gas and other commodity marketers (“Commodity Unbundling Marketers”) to meet normal annual demand. In addition Terasen Gas provides midstream services which include the commodity (seasonal and peaking supply), storage and pipeline capacity necessary to meet the peak day demand and to manage the variability in demand. For the purposes of this submission, Terasen Gas, in its role as manager of midstream resources, will be referred to as "Terasen Midstream". Also Terasen Gas, in its role as a provider of commodity, will be referred to as “Terasen Commodity”.

2. KEY MESSAGES: 2008/09 ACP

- **Peak Day Demand 2008/09:** Slight increase of 0.3% (1279 TJ/d from1275 TJ/d) compared to 2007/08.

- **Normal Day Demand 2008/09:** Very slight drop in the annual normal to just under 117 PJ resulting in an average daily normal load of approximately 319 TJ/d.

- **Commodity Portfolio:** Baseload Supply has dropped only slightly from last year but the receipt point allocation remains the same which is 70% at Station 2, 15% at Huntingdon and 15% at AECO.

- **Midstream Portfolio:**
    - Loss of downstream storage and firm redelivery at end of 07/08 has prompted Terasen Gas to search for new downstream contracts or evaluate other options such as Huntingdon or Station 2 supply.
    - Renewal of capacity at Aitken Creek storage.

- **Operating Issues/Concerns:**
    - Prolonged two month Operational Flow Order on Northwest Pipeline raise concerns of increased pricing and security of supply issues due to unavailability of downstream storage via displacement at Huntingdon.
    - Winter operational problems on the Westcoast Energy Inc. (‘Westcoast”) system, particularly in the context of Terasen Gas’ heavy reliance on it, continue to raise concerns for Terasen Gas with respect to the long-term reliability of the Westcoast system.
    - Lack of contracting on T-North continues to increase supply concerns at Station 2 as producers are flowing gas on interruptible contracts to avoid firm annual tolls. This further provides producers with the option to transport gas to the higher of the Station 2 or AECO priced marketplaces after recovery of interruptible tolls. This raises costs for Terasen Gas’ customers and reduces reliability of supply.

- **Long-Term Contracting:**
  - Terasen Gas will continue to monitor infrastructure developments in the Pacific North West ("PNW"). It appears that with growth in the market pipeline capacity is becoming constrained. Development of new capacity from the south has the potential to turn Huntingdon into a swing supply market and affect the cost of delivery of market area storage through loss of displacement opportunities.
  - Terasen Gas would need to evaluate its downstream storage capacity due to the proposed expansion pipelines.
  - Terasen Gas will need to evaluate supply options within its own infrastructure that would provide access to broader markets, such as AECO, in order to be price competitive while maintaining security of supply on behalf of its customers.
  - Evaluate Terasen Gas' pipeline portfolio mix as a result of added costs due to asset replacements, maintenance and carbon tax expenses which would lead to further toll increases for customers. This would prompt Terasen Gas to evaluate its transportation options given new regional infrastructure resulting from the proposed pipeline expansion in the Rockies and options that access gas from Alberta.

3. OBJECTIVES OF THE 2008/09 ACP

The primary objectives of the 2008/09 ACP are consistent with previous years' filings and are comprised of the following two mandates:

1. To contract for cost-effective supply resources which ensure safe and reliable natural gas deliveries to meet core customer design peak day while mitigating against potential upstream and downstream supply disruptions.

2. To develop a portfolio resource mix which incorporates price diversity and provides contracting flexibility for both short-term and longer-term planning.

Terasen Midstream must not only meet peak design day demand but also manage elevated loads over extended periods of colder weather, and mitigate any interruptions in delivery capacity related to both transportation and storage. While customers and regulators expect Terasen Gas to procure and deliver natural gas in the most cost-effective manner possible, Terasen Midstream holds the responsibility to identify, monitor and mitigate potential operational and market-related risks. These objectives of cost effectiveness while meeting reliability, diversity and flexibility can at times not result in the least cost alternative.

The optimal portfolio is selected based on a balance of resources that combines the objectives of cost effectiveness and supply security which includes resources such as storage and transportation contracts whose duration of time is longer than the term of this 2008/09 ACP. The portfolio selected each year is based on market data available to Terasen Gas at that time. However, many factors influencing natural gas supply and demand and the market for natural gas are always changing. Not only are there absolute price changes but also changes in premiums for securing physical supply and the relationships between pricing points. So even though a portfolio initially may be the most cost effective, viewed in hindsight there may have been other options that were lower cost. For example in a warm winter, the price of natural gas may not be much different than the price in the summer storage injection season and so in hindsight it may not have been as cost effective to hold storage versus purchasing supply each day. Alternatively, in a cold winter or a winter where there are supply problems, it may have been better to seek a portfolio with more storage and less direct purchase on the day.

4. CONTRACTING STRATEGY

The contracting strategy of Terasen Gas is based on the peak day demand forecast for the service region. A portion of that peak day demand is met by Terasen Commodity and gas marketers who are involved in the Commodity Unbundling Program. This baseload supply is based on the normalized annual demand with the remaining portion of peak day demand being met through Terasen Midstream services, which include seasonal and peaking commodity supply and storage and pipeline capacity to deliver baseload, seasonal and storage gas supply to Terasen Gas' service region. Due to the peaky nature (increased demand for only few days during the winter season) of load duration, Terasen Gas' Commodity and Midstream portfolios play a vital role in meeting the primary objectives of the 2008/09 ACP as discussed above.

The contracting strategy for the Terasen Commodity and Midstream portfolios include a combination of monthly and daily priced supply for price diversification. Daily priced supply can be resold in the market at the same price as it is bought and therefore remove any price exposure compared to monthly priced supply. This strategy helps Terasen Gas in remaining cost neutral and effective when reselling gas on the day.

4.1. Demand Forecast (Design Peak Day And Normal Load)

The recommended design day demand for the 2008/09 contract year is 1,279 TJ/d. The design day demand forecast methodology is consistent with the 2007/08 ACP and the 2007 Resource Plan filings. The design day demand forecast is derived by first establishing the relationship between weather and consumption, based on an average of the past three most recently completed contract years. Once that relationship is established, a design day temperature is derived through an Extreme Value Analysis, which estimates the coldest temperature expected to occur with a return period of one in twenty years. By applying the design day temperature to the relationship that has been established between weather and consumption, and then grossing up to reflect current customer accounts, the design day demand forecast is established.

Table 1 illustrates the historical and forecast proposed peak day and normal loads during winter and summer season for each service region.

Table 1: Filed and Forecast Design Peak Day by Service Region and Normal Loads during winter and summer season

Contract Year	2003-04*	2004-05*	2005-06*	2006-07*	2007-08*	2008-09	2009-10	2010-11	2011-12	2012-2013
Columbia	28	27	24	26	27	28	29	29	29	29
Coastal	924	902	907	939	934	940	950	959	968	977
Squamish	4	4	4	4	4					
Ft. Nelson	5	5	5	5	5	5	5	5	6	6
Inland	299	322	319	308	304	305	309	313	317	321
Total Peak Day Load	1260	1260	1259	1282	1275	1279	1292	1306	1319	1332
Change	15	0	-1	23	-7	4	13	14	13	13
Normal Load (Winter)	511	504	497	523	517	495	497	500	502	506
Normal Load (Summer)	187	185	179	180	188	196	197	197	198	200

Notes:

1. Peak Day filed values are indicated with an asterisk. Peak day values do not include company use compressor fuel.

2. Normal Load values are actualized till 2006-07 and the numbers beyond that reflect forecast values.

It is important to note that the design peak day based on the design demand forecast methodology is an estimate and actual use will vary somewhat from the forecast due to actual consumption and temperature variations. As can be observed in the table, while the trend has been slow upward growth, whenever the base year is reforecast, small adjustments up or down from the previous base can be expected.

For the 2008/09 contract year, the annual normal load has dropped very slightly to just under 117 PJs for the year resulting in an average daily normal load of approximately 319 TJ/d – a slight drop from last year's 321 TJ/d. This will be the daily baseload supply that will be received by Terasen Midstream on behalf of Terasen Commodity and the Commodity Unbundling Marketers. Since the actual daily winter load is higher than the baseload amount provided by Terasen Commodity and the Commodity Unbundling Marketers, Terasen Midstream will supplement this 319 TJ/d in the winter months with seasonal winter supply, peaking contracts and storage assets to manage the demand. In the summer months, since the average daily load is less than the 319 TJ/d, Terasen Midstream will utilize the excess supply to re-fill its storage capacity. Please note that Squamish volumes are included with Coastal volumes starting in 2008/09 as that company was amalgamated with Terasen Gas effective 2007.

4.2. Commodity Portfolio Overview: 2008-09

Based on the normal forecasted volumes at March 1, 2008, Terasen Commodity and Commodity Unbundling Marketers must provide the normalized annual load requirement of 319 TJ/d, plus fuel, to Terasen Midstream from November 1, 2008 for the 2008/09 contract year based on the following delivery allocations: 70% at Station 2, 15% at AECO, and 15% at Huntingdon. Customer migration to Marketers under Commodity Unbundling is forecasted to be approximately 57 TJ/d for November 1, 2008. This estimate is subject to change over the summer months due to updated information related to customer migration from Terasen Gas to Commodity Unbundling Marketers. Consequently, Terasen Commodity will be required to provide the following amounts at the specified delivery points starting November 1, 2008 based on the current estimate:

Station 2:	(319 TJ/d – 57 TJ/d) x 70% plus 2.2% fuel	= 188 TJ/d
Huntingdon:	(319 TJ/d – 57 TJ/d) x 15%	= 39 TJ/d
Alberta:	(319 TJ/d – 57 TJ/d) x 15% plus 1% fuel	= 39 TJ/d

The total amount of gas (319 TJ/d) is the daily baseload supply that is delivered to Terasen Midstream on behalf Terasen Commodity and Commodity Unbundling Marketers.

The methodology used to calculate the fuel percentages (used above) for 2008/09 is consistent with that used in previous years.

4.3. Midstream Portfolio Overview: 2008-09

Terasen Midstream's annual evaluation of its portfolio considers critical factors such as security of supply, reliability, delivered cost of supply, and availability of alternative incremental resources as the fundamental drivers in determining the most viable options. To replace expiring resources and/or meet future growth requirements, Terasen Midstream has several alternatives to assess for 2008/09:

1. Huntingdon Supply
2. Station #2 Supply
3. Seasonal Storage (Typically for 151 days of Winter season)
4. Downstream Storage (Typically for 15-40 days during winter)
5. Stanfield Seasonal, Spot and Peaking Supply
6. Kingsgate and/or Alberta Supply

Terasen Gas performed a review of the supply options available for the upcoming winter period, taking into account key market developments which have affected regional pricing and supply sourcing dynamics in the PNW. Upon evaluation of the peak and normal day load forecasts, current portfolio mix and market developments, Terasen Midstream recommends the following resource portfolio for 2008/09:

Table 2: Recommended Peak day portfolio for 2008-09 vs. 2007-08

Terasen Gas - Peak Day Portfolio

For the 2008-09 Contract Year

PEAK DAY PORTFOLIO (TJ/d)	2007-08 ACP Filed	2008-09 ACP Forecast Portfolio
Fort Nelson Division	**5**	**5**
Huntingdon Baseload Supply (CCRA gas & Mktrs)	48	48
Alberta Baseload Supply (CCRA gas & Mktrs)	48	48
Station 2 Baseload Supply (CCRA gas & Mktrs)	225	223
Total Baseload Supply	**321**	**319**
Seasonal Supply	183	183
Seasonal Storage	157	157
Downstream Storage	262	227
Peaking Supply (Hunt, Kingsgate, Stanfield)	128	129
Spot Supply	26	26
LNG (4 days)	166	166
Industrial Curtailment	26	26
Other Seasonal (Storage, Stn. 2 or Huntingdon)	0	40
Total Midstream Supply	**948**	**954**
Total Resources (TJ/day)	**1274**	**1279**
Peak Day Demand (TJ/day)	**1275**	**1279**

In addition, Terasen Midstream will continue its practice from previous years with respect to backstopping, industrial curtailment available on a peak day and downstream balancing requirements.

Terasen Midstream will maintain the ability to purchase daily spot gas as required to back-stop disruptions in supply, meet colder than design weather or replace declines in deliverability associated with storage, Liquefied Natural Gas (“LNG”) or peaking supply.

Terasen Midstream requests approval from the Commission for the following proposed recommendations and changes to the Midstream portfolio for the 2008/09 contract year:

1. Terasen Midstream recommends a peak day value for 2008/09 of 1,279 TJ/d, a slight increase of 0.3% from the 2007/08 value of 1,275 TJ/d.

2. For 2008/09, supply from Commodity Providers will be based on a normalized annual demand of 319 TJ/d, plus fuel.

3. The Receipt Point Allocation Percentages remain consistent with the current year’s delivery requirements: 70% at Station 2, 15% at Alberta and 15% at Huntingdon.

4. Commencing November 1, 2008, Commodity Providers (Commercial and Residential Unbundling Marketers and Terasen Gas) will be required to deliver - excluding fuel - 223 TJ/d at Station 2, 48 TJ/d at Huntingdon and 48 TJ/d at AECO (Alberta).

5. Commodity Providers’ fuel requirements for the period November 1, 2008 to October 31, 2009 are projected to be the same as for the previous year: 2.2% at Station 2 and 1.0% at Alberta. This information is subject to updates over the course of the summer months and will be communicated to the Commodity Providers before Oct 1/2008 if required.

6. Incremental storage contracts and third party storage redelivery service agreements will be negotiated as outlined in greater detail within the confidential sections of the 2008/09 ACP. Terasen Midstream recommends the renewal of storage contracts and third party redelivery service which expire or require notice to extend prior to the submission of the 2009/10 Midstream Annual Contracting Plan, as outlined in greater detail within the confidential sections of the 2008/09 ACP.

7. Terasen Gas may opt to purchase winter seasonal supply at Station 2 or Huntingdon if it's unable to renew or acquire any new downstream storage contracts with firm redelivery to replace those contracts that have expired after the 2007/08 winter season.

8. Station 2, Alberta, Huntingdon, Stanfield and Kingsgate supply will be negotiated as outlined in greater detail within the confidential sections of the 2008/09 ACP.

5. MARKET OVERVIEW

The energy market in North America is driven by a combination of supply and demand factors which have created high volatility in both natural gas and crude oil prices. This was evident when crude oil futures exceeded $110 US/bbl for the first time ever in the month of March 2008 and settled at just under $120 US/bbl for May 2008. Natural gas futures rose to more than a two-year high (above $10 US/MMBtu), finding support from crude oil prices and on concerns that cold weather could deplete storage inventories faster than expected.

Total US natural gas consumption is expected to increase by 0.9 percent in 2008 and by 1.0 percent in 2009[1]. Natural gas demand in Canada is expected to be about 2% higher in 2008 as compared to 2007, owing largely to the return of normal winter weather[2]. Weather is a significant driver of natural gas prices and over the previous two years North America experienced warmer than normal winters resulting in larger than expected builds in natural gas inventories. However, this past winter, the return of cold weather during February and March 2008 resulted in larger than expected withdrawals of gas from storage. Residential and commercial sectors are counted as the main contributors towards the consumption growth in 2008[3]. Gas-fired electric generation continues to be one of the most influential factors towards the growth in demand for natural gas in North America.

Even though on average most of the North American supply basins (excluding the Rockies supply basin) are mature, meaning that the typical gas well produces less gas each year due to declining field pressure, total US marketed natural gas production is expected to increase by 2.2 percent in 2008 and by 0.8 percent in 2009[1.] Projected growth in 2008 is primarily due to the start up of new deepwater supply infrastructure in the Gulf of Mexico and continued production growth from unconventional reserve basins. Overall, gas directed rig activity in Canada in early February 2008 levelled out at around 348 rigs, a decrease of about 19% from last year. Total Western Canadian natural gas production in 2008 is estimated to average about 15.4 BCF/d, a decrease of about 0.9 BCF/d from last year's levels[4].

5.1. Supply and Demand

5.1.1. Regional Supply-Demand Balance

The most recent Northwest Gas Association ("NWGA") Outlook Study (2007) concluded that the PNW region continues to require additional long-term supply and storage resources to meet demand requirements. Natural gas demand in the region is expected to grow over the NWGA's five year planning period, paced by demand for gas-fired electrical generation and continued growth in the number of

[1] *EIA (Energy Information Administration) Short term energy outlook 2008, Feb 12, 2008*

[2] *Ross Smith energy outlook Feb 2008*

[3] *NWGA (Northwest Gas Association) outlook 2007*

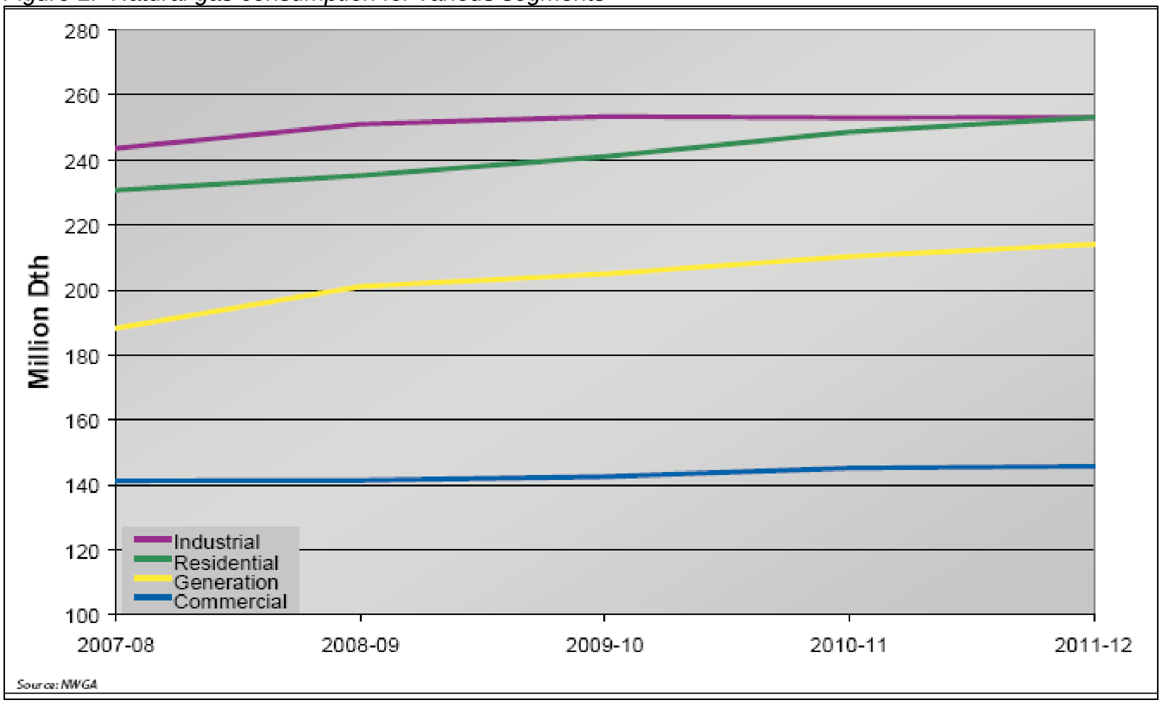
[4] *National Energy Board – "A Market Assessment" October 2007*

residential customers. To secure adequate supply and the right type of resources over the short and long-term, it is important to understand the recent changes in the demand pattern and gas supply/flows in the region. This section provides a brief overview of these recent trends and some of the infrastructure proposed for the region.

5.1.2. Demand Growth with Recent Trends

According to the NWGA, natural gas consumption in the region is expected to grow at an average of about 2% a year, with a cumulative projected growth rate of 7.2% to 2012[5].

Figure 1: Natural gas consumption for various segments



As is clear from Figure 1, most of the increase in natural gas consumption is due to growth in residential demand and demand due to gas-fired electric generation.

Gas-fired electric generation plays a key role in meeting the strong growth in electric demand both through higher utilization of existing facilities and through the development of new facilities. In British Columbia, according to British Columbia Hydro and Power Authority's ("BC Hydro") long term electricity forecast, demand growth continues to be very strong with an estimated increase of 30% over the next 21 years[6]. Elsewhere in the region, electricity demand continues to grow as well. Gas-fired generation is viewed in most jurisdictions as an efficient and acceptable way of producing electricity due to its lower environmental impact when compared to other fossil fuels. In the absence of any new significant sources of electricity generation in the PNW, meeting electric demand growth will pose a significant challenge to gas infrastructure as well.

[5] *Northwest Gas Association - Outlook 2007*

[6] *BC Hydro website – Demand Growth – Forecasting Growth*

- In the I-5 Corridor, a significant amount of gas-fired electric generation capacity is currently under-utilized[7]. As is the case in the rest of North America, the only short-term response to increases in electricity demand will have to be served through gas-fired sources which could have a significant impact on supply-demand balance for natural gas within the region. The NWGA Outlook Update forecasts a combined peak day in the I-5 corridor of approximately 4.10 BCF/d for 2008-09 and shows that planned and existing pipeline and storage infrastructure is only just adequate assuming 100% availability to meet that peak day in the next several years. Currently under-utilized gas-fired generation facilities could upset that delicate balance representing a potential peak day demand of up to 1.1 BCF/d (excluding Burrard Thermal), almost double that currently forecast in the study.

5.1.3. Supply Expansions

The PNW is beginning to look at various supply expansions to meet demand growth and diversify supply. Over the past few years the focus was on bringing imported LNG via ship to the region and several projects continue to be pursued. However these projects continue to have issues with sourcing supply as LNG production has lagged predictions somewhat and LNG producers have looked to larger markets first[8]. From 1999 to 2005, Rockies dry gas productive capacity rose from 4.3 to about 7.4 BCF/d and this capacity is expected to grow to 10 BCF/d by 2010[9]. Due to this growth, several projects have now focused in on bringing this supply to the Western US. The Rockies projects are driven by supply growth primarily and expansions have been focused on moving gas east until recently. As supply has continued to grow, producers have looked to additional markets for pipeline expansions. Several projects to move gas west have been proposed primarily to serve the California market which is expected to grow strongly and is looking to diversify its supply sources. California regulators have been very supportive of energy supply projects since the energy crisis they experienced in 2000/2001. In the PNW several projects have been proposed that would link additional Rockies or Alberta supply into the region. The various proposals for expansion will be reviewed over the near term by the various regulatory bodies in the US for approval for construction.

6. LONG-TERM CONTRACTING STRATEGY

Terasen Midstream's longer-term contracting strategy is mainly driven by the same objectives as the short-term supply and price risk plans of ensuring safe, reliable and cost-effective natural gas deliveries while maintaining contracting flexibility. In addition, long-term contracting strategy intends to address longer term resource requirements, assess the impact of changing supply, demand, and pricing dynamics on gas procurement strategies and to recognize the need to develop a supply portfolio which promotes diversified access to supply and selection of resources which most effectively meets customer demand characteristics over a longer time.

Some of the key messages that have been derived from long-term planning include:

- Development of cost-effective transportation infrastructure to Huntingdon which will improve access to a competitive market.
- Considering the effects of the following issues on Station 2 premiums: increasing migration of BC sourced supply into Alberta, and the impact of Westcoast's policies on availability of supply and value of capacity. Evaluate the impacts of continued de-contracting of T-North capacity to Station 2 by producers and marketers, and increasing movement of gas east.

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[7] *Northwest Gas Association - Outlook 2007*

[8] *Bloomberg website – May 9, 2008 article*

[9] *PIRA Energy Group – "The Changing Face of North American Gas Supply"*

- Continue to use downstream storage and encourage the development of incremental facilities to replace expiring contracts, if economical. Local facilities, such as LNG storage on Vancouver Island provide increased deliverability and supply security within the region. Downstream storage is increasingly more difficult to obtain and further constrained by a shortage of firm redelivery service back to Sumas.

- Continue to diversify the portfolio by purchasing a mix of supply at various price indices (AECO, Huntingdon, Kingsgate, Stanfield and Station 2)and term (monthly and daily price indices), with the flexibility to shift pricing from these points to optimize portfolio assets and overall economics depending on market conditions.

APPENDIX K-2
TGVI Annual Contracting Plan Executive Summary

EXECUTIVE SUMMARY

1 INTRODUCTION

The contents of this report outline the proposed Annual Contracting Plan ("ACP" or the "Plan") for Terasen Gas (Vancouver Island) Inc. ("TGVI") for the year commencing November 1, 2008. Over time, the structure and content of the ACP have evolved to reflect both the results of on-going discussions with staff of the British Columbia Utilities Commission (the "Commission") with respect to special topics of interest, and the changing gas contracting environment.

2 KEY MESSAGES: 2008/09 ACP

- **Peak Day Demand 2008/09:** Increase of 1.7 TJ/d (1.6%) to 110.4 TJ/d from 2007/08.
- **Commodity Portfolio:** Commodity portfolio slightly changed from 2007/08 including receipt points and supply mix.
- **Midstream Portfolio:** Storage and transportation portfolio unchanged from 2007/08.
- **Operating Issues/Concerns:** Issues on third party pipelines raise concerns about the long-term reliability of these systems given TGVI's reliance upon them.
- **Long-Term Contracting:** In addition to the Mt. Hayes LNG facility, TGVI will need to evaluate other options, such as access to AECO supply, in light of the contracting situation at Station 2 coupled with higher costs on Westcoast due to asset replacements, increased maintenance and carbon tax expenses which would lead to further toll increases for customers.

3 OBJECTIVES OF THE 2008/09 ACP

The primary objectives of TGVI's ACP are consistent with previous years' filings and are comprised of the following two objectives:

1. To contract for cost-effective supply resources that ensure safe and reliable natural gas deliveries to meet core customer design peak day while mitigating upstream and downstream supply disruptions.
2. To develop a portfolio resource mix with price diversity that incorporates contracting flexibility for both short-term and longer-term planning.

TGVI must not only meet peak design day demand but also manage higher than normal winter loads over extended periods, and mitigate any interruptions in delivery capacity related to both transportation and storage. While customers and the Commission expect TGVI to procure and deliver natural gas in the most cost-effective manner possible, TGVI holds the responsibility to identify, monitor and mitigate potential operational and market-related risks. These objectives of cost effectiveness while meeting reliability, diversity and flexibility can at times be competing with one another. The optimal portfolio that is selected is based on a balance of resources that combines the objectives of the Plan.

TGVI currently diversifies its supply portfolio by sourcing gas from a combination of two market hubs: Huntingdon and Station 2. TGVI's gas supply requirements are reviewed both on a peak day and annual demand basis for firm sales customers, including system usage.

4 CONTRACTING STRATEGY

4.1 Demand Forecast (Design Peak Day And Normal Load)

Forecast annual demand is based on normalized use per firm sales customer grossed up to reflect forecast customer attachments and system usage. Normalized customer usage is established as ten-year averages for each of the three major centers on Vancouver Island - Victoria, Nanaimo and Courtenay. TGVI's annual core demand for the period November 1, 2008 to October 31, 2009 is estimated at 12.6 PJ, which is a slight increase from 12.2 PJ in 2007/08.

TGVI's forecast 2008/09 peak day supply requirement is estimated at 110,398 GJ/d (excluding system gas and fuel) which equates to approximately 114,000 GJs when system gas and fuel are included at Huntingdon. The peak day demand was derived by estimating the relationship between weather and firm sendout, and then applying the design day temperature of -10.7 degrees Celsius along with the projected firm customer attachments. The load duration curve shown below was developed to project gas purchase requirements using the daily estimated demand on a design year basis.

TGVI's forecasted peak day increased by 1.7 TJ/d or 1.6% in 2008/09 over 2007/08. Growth on Vancouver Island continues to be relatively strong as shown in Table 1 with the peak day forecast to grow at a rate of over 2% per year over the next five years. Ongoing strong growth means that TGVI transmission system capacity limitations will continue to be an issue until such time the proposed Mt Hayes Storage Facility comes into service. Construction of this facility commenced in April 2008 and it is expected to be in-service in 2011.

Table 1: TGVI's five year forecasted peak day in TJs

Contract Year	2008-09	2009-10	2010-11	2011-12	2012-13
Peak Day (TJ)	110.4	113.0	115.6	118.2	120.7
Change over previous year	-	2.6	2.6	2.6	2.5
% Change over previous year	-	2%	2%	2%	2%

TGVI proposes the following recommendations and changes for the 2008/09 contract year, as compared to the 2007/08 contract year in the following table:

Table 2: TGVI Recommended Peak Day Portfolio for 2008/09 Forecasted vs. 2007/08 Actuals (TJ/d)

Terasen Gas (Vancouver Island) Inc.
Peak Day Supply Portfolio for 2008/09

SUPPLY PORTFOLIO (TJ/day)	**2007/08 Actuals**	**2008/09 Forecast Porfolio**
Station 2		
Baseload	0.0	0.0
Seasonal	27.3	27.3
Total Station 2 Supply	27.3	27.3
Huntingdon		
Seasonal	15.1	19.6
Peaking	24.7	25.2
Total Huntingdon Supply	39.9	44.8
Aitken Creek	13.1	13.1
Mist	25.2	25.2
Total Storage	38.3	38.3
On-System Peaking Resources		
On-System Peaking	0.0	0.0
Total Resources (TJ/day)	**105.5**	**110.4**
Peak Day Demand (TJ/day)	**108.7**	**110.4**
Total TGVI Capacity to Island	96.9	98.0
Peaking Capacity from BC Hydro	19.0	27.0
Total Capacity to Island Available to TGVI	115.9	125.0

TGVI will continue to evaluate resource options as better market information unfolds related to availability and pricing of alternatives, basis differentials, and other relevant developments. Any significant deviation from the proposed portfolio outlined in this Plan will be promptly filed with the Commission for re-approval at a future date.

5 MARKET OVERVIEW

The energy market in North America is driven by a combination of supply and demand factors which have created high volatility in both natural gas and crude oil prices. This was evident when crude oil futures exceeded $110 US/bbl for the first time ever in the month of March 2008 and settled at just under $120 US/bbl for May 2008. Natural gas futures rose to more than a two-year high (above $10 US/MMBtu), finding support from crude oil prices and on concerns that cold weather could deplete storage inventories faster than expected.

Total US natural gas consumption is expected to increase by 0.9 percent in 2008 and by 1.0 percent in 2009[1]. Natural gas demand in Canada is expected to be about 2% higher in 2008 as compared to 2007, owing largely to the return of normal winter weather[2]. Weather is a significant

[1] *EIA (Energy Information Administration) Short term energy outlook 2008, Feb 12, 2008*

[2] *Ross Smith energy outlook Feb 2008*

driver of natural gas prices and over the previous two years North America experienced warmer than normal winters resulting in larger than expected builds in natural gas inventories. However, this past winter, the return of cold weather during February and March 2008 resulted in larger than expected withdrawals of gas from storage. Residential and commercial sectors are counted as the main contributors towards the consumption growth in 2008[3]. Gas-fired electric generation continues to be one of the most influential factors towards the growth in demand for natural gas in North America.

Even though on average most of the North American supply basins (excluding the Rockies supply basin) are mature, meaning that the typical gas well produces less gas each year due to declining field pressure, total US marketed natural gas production is expected to increase by 2.2 percent in 2008 and by 0.8 percent in 2009[1.] Projected growth in 2008 is primarily due to the start up of new deepwater supply infrastructure in the Gulf of Mexico and continued production growth from unconventional reserve basins. Overall, gas directed rig activity in Canada in early February 2008 levelled out at around 348 rigs, a decrease of about 19% from last year[2]. Total Western Canadian natural gas production in 2008 is estimated to average about 15.4 BCF/d, a decrease of about 0.9 BCF/d from last year's levels[4].

5.1 Supply and Demand

5.1.1 Regional Supply-Demand Balance

The most recent Northwest Gas Association ("NWGA") Outlook Study (2007) concluded that the PNW ("Pacific Northwest") region continues to require additional long-term supply and storage resources to meet demand requirements. Natural gas demand in the region is expected to grow over the NWGA's five year planning period, paced by demand for gas-fired electrical generation and continued growth in the number of residential customers. To secure adequate supply and the right type of resources over the short and long-term, it is important to understand the recent changes in the demand pattern and gas supply/flows in the region. This section provides a brief overview of these recent trends and some of the infrastructure proposed for the region.

5.1.2 Demand Growth with Recent Trends

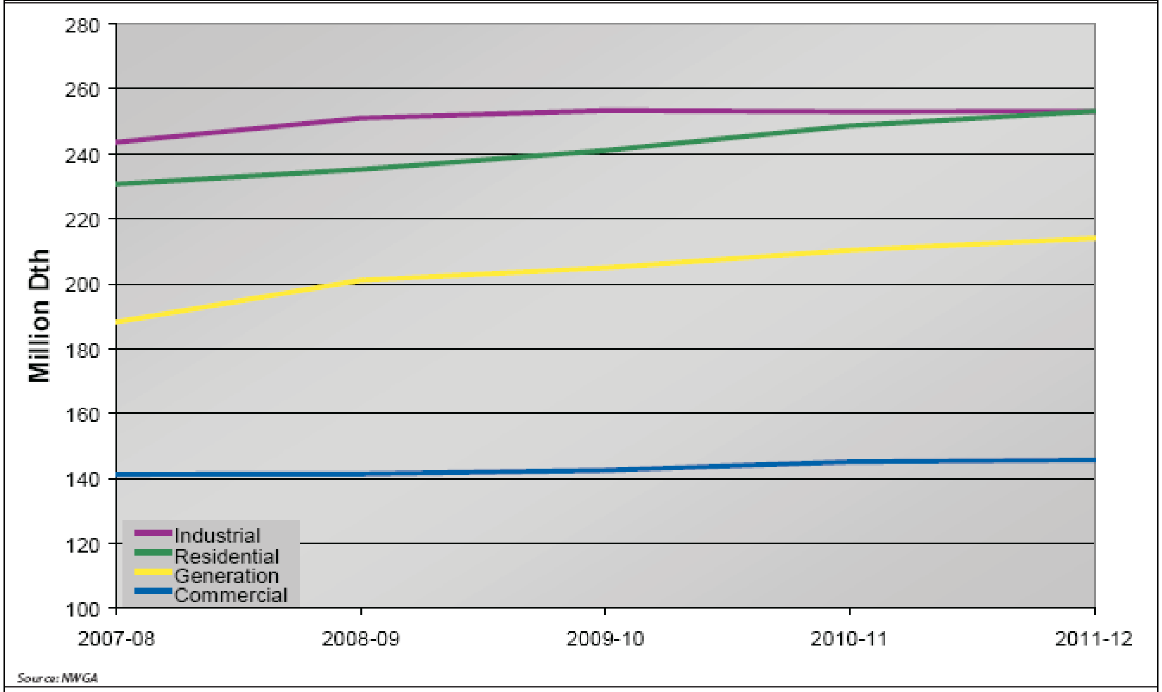
According to the NWGA, natural gas consumption in the region is expected to grow at an average of about 2% a year, with a cumulative projected growth rate of 7.2% to 2012[5].

[3] *NWGA (Northwest Gas Association) outlook 2007*

[4] *National Energy Board – "A Market Assessment" October 2007*

[5] *IBID [3]*

Figure 1: Natural gas consumption for various segments



As is clear from Figure 1, most of the increase in natural gas consumption is due to growth in residential demand and demand due to gas-fired electric generation.

Gas-fired electric generation plays a key role in meeting the strong growth in electric demand both through higher utilization of existing facilities and through the development of new facilities. In British Columbia, according to British Columbia Hydro and Power Authority's ("BC Hydro") long term electricity forecast, demand growth continues to be very strong with an estimated increase of 30% over the next 21 years[6]. Elsewhere in the region, electricity demand continues to grow as well. Gas-fired generation is viewed in most jurisdictions as an efficient and acceptable way of producing electricity due to its lower environmental impact when compared to other fossil fuels. In the absence of any new significant sources of electricity generation in the PNW, meeting electric demand growth will pose a significant challenge to gas infrastructure as well.

- In the I-5 Corridor, a significant amount of gas-fired electric generation capacity is currently under-utilized[7]. As is the case in the rest of North America, the only short-term response to increases in electricity demand will have to be served through gas-fired sources which could have a significant impact on supply-demand balance for natural gas within the region. The NWGA Outlook Update forecasts a combined peak day in the I-5 corridor of approximately 4.10 BCF/d for 2008-09 and shows that planned and existing pipeline and storage infrastructure is only just adequate assuming 100% availability to meet that peak day in the next several years. Currently under-utilized gas-fired generation facilities could upset that delicate balance representing a potential peak day demand of up to 1.1 BCF/d (excluding Burrard Thermal), almost double that currently forecast in the study.

[6] *BC Hydro website – Demand Growth – Forecasting Growth*

[7] *Northwest Gas Association - Outlook 2007*

5.1.3 Supply Expansions

The PNW is beginning to look at various supply expansions to meet demand growth and diversify supply. Over the past few years the focus was on bringing imported LNG via ship to the region and several projects continue to be pursued. However these projects continue to have issues with sourcing supply as LNG production has lagged predictions somewhat and LNG producers have looked to larger markets first[8]. From 1999 to 2005, Rockies dry gas productive capacity rose from 4.3 to about 7.4 BCF/d and this capacity is expected to grow to 10 BCF/d by 2010[9]. Due to this growth, several projects have now focused in on bringing this supply to the Western US. The Rockies projects are driven by supply growth primarily and expansions have been focused on moving gas east until recently. As supply has continued to grow, producers have looked to additional markets for pipeline expansions. Several projects to move gas west have been proposed primarily to serve the California market which is expected to grow strongly and is looking to diversify its supply sources. California regulators have been very supportive of energy supply projects since the energy crisis they experienced in 2000/2001. In the PNW several projects have been proposed that would link additional Rockies or Alberta supply into the region. The various proposals for expansion will be reviewed over the near term by the various regulatory bodies in the US for approval for construction.

6 LONG-TERM CONTRACTING STRATEGY

When contracting for resources to meet the requirements of its service area, TGVI must consider not only local market factors affecting the Utility on Vancouver Island and the Sunshine Coast, but also the regional dynamics of the industry in British Columbia, the US Pacific Northwest and in North America.

In formulating a longer-term strategy, TGVI must consider a number of key issues which will affect its contracting practice:

- Decontracting of capacity in the region, especially on Westcoast, and its impact on tolls and availability of firm supply at Huntingdon and its impact upon the operations of Northwest Pipeline.
- Impact on Station 2 supply and prices as increasing volume of gas heads east to Alberta bypassing Station 2.
- Continued concern over potential capacity shortfalls at Huntingdon and in the PNW on peak days.
- Increases in gas-fired generation in the PNW placing demands on regional supply.

TGVI will continue, on an annual basis, to determine the appropriate balance of baseload, seasonal and spot supply necessary to meet its core load, storage injections requirements, as well as to optimize and mitigate the utility's resources. TGVI's longer-term contracting strategy continues to be driven by the same objectives as the short-term supply and price risk plans of ensuring safe, reliable and cost-effective natural gas deliveries while maintaining contracting flexibility.

[8] *Bloomberg website – May 9, 2008 article*

[9] *PIRA Energy Group – "The Changing Face of North American Gas Supply"*

APPENDIX L

Terasen Gas
Regional Natural Gas Resource Planning
Trends & Issues

DISCUSSION PAPER
REGIONAL NATURAL GAS RESOURCE PLANNING TRENDS & ISSUES

1 OVERVIEW OF REGIONAL NATURAL GAS RESOURCES

The assessment of regional supply, demand, and infrastructure is fundamental to creating a resource mix that can reliably meet short-term and long-term energy requirements. Understanding the regional energy market ensures the gas supply planning process is cognizant of challenges and opportunities that can potentially impact access to cost-competitive resources, and to foster greater integration in energy planning.

The supply side resource alternatives in the region include pipeline transportation, underground and liquefied natural gas (“LNG”) storage, and third-party commodity purchase. The sustained growth in natural gas demand, and increased regional production, continue to change procurement strategies of utilities and the competitive environment of pipelines in the Pacific North West (“PNW”). Additionally, the constraints on regional pipeline and storage infrastructure make the PNW more susceptible to changes in supply-demand balances relative to the Alberta market where excess gas supplies is exported to alternative markets.

Figure 1-1 shows the existing pipeline and storage infrastructure and market trading points available to utilities in the Pacific Northwest (PNW). The region’s pipeline infrastructure provides access to base load supply from two major production basins; the Western Canadian Sedimentary Basin (“WSCB”) and the Rocky Mountain area (Rockies). The opportunity to shape gas supply to the winter peaking nature of regional demand is provided by underground and Liquefied Natural Gas (LNG) storage options which are mostly located south of Huntingdon. A summary of the existing regional storage and pipeline options is provided below.

1.1 Spectra Westcoast Pipeline

The Westcoast T-South pipeline connects northern British Columbian (B.C.) gas production at Station 2 to the PNW market at Huntingdon. With a firm T-South

Huntingdon capacity of 1702 million cubic feet per day (“MMcf/d”)[1] and a winter average flow of approximately 1330MMcf/d, this pipeline is currently the primary path for PNW utilities to access northern B.C. production for delivery to Huntingdon.

Since 2003[2], the Westcoast pipeline has experienced major restructuring of contracted capacity with producers and marketers reducing their levels of firm T-North and T-South transportation service to access alternative markets. Although there was significant re-contracting in 2007, the changing shipper profile and increased competition for northern B.C. supply from Alliance and NGTL pipelines poses challenges for moderating Westcoast pipeline tolls and creates long term uncertainty in supply access at Station 2.

1.2 Terasen Gas Inc. Southern Crossing Pipeline

The Southern Crossing Pipeline (“SCP”) with associated upstream transportation on TransCanada Pipeline (“TCPL”) provides an alternative supply path for gas deliveries to Huntington and access to the more liquid AECO trading hub. SCP is fully contracted and continues to be a potential alternative supply resource for PNW shippers.

1.3 Williams Northwest Pipeline

The Northwest pipeline system (“NWP”) is a bi-directional pipe capable of south and north gas flows from Huntington and U.S. Rockies respectively, enabling PNW utilities to source gas from either Canadian or Rocky Mountain supply basins. The bi-directional capability means NWP utilizes a combination of actual gas flows and displacement capacity whereby gas flows in opposite directions negate each other.

The redelivery of gas supply from U.S. storage facilities to the Huntingdon market area depends on firm transportation capacity or displacement contracts on NWP. The firm transportation options include annual capacity at a TF-1 rate, or shorter duration storage redelivery service at a discounted TF-2 rate. An alternative option for storage redelivery to Huntingdon is displacement contracts. Typically offered by third party shippers that hold firm market area storage and NWP transportation, storage gas redelivery is

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[1] Spectra Energy Inc. Western Energy Conference Presentation

[2] ibid

achieved by diverting gas destined for markets south of Huntington and replaced further south by gas from Mist or Jackson Prairie storage.

NWP remains heavily contracted with no availability of incremental TF-2 storage redelivery transportation service. The combined effect of limited access to storage redelivery capacity and operating constraints (which inhibit storage redelivery by displacement), create a challenge for Terasen Gas Inc. (“TGI”) to access incremental supply at Huntingdon from storage facilities on the NWP system.

1.4 Upstream Storage

The Aitken Creek storage facility in northern B.C. is a supply alternative to winter commodity production delivered at Station 2. The facility offers price diversification opportunity and operational flexibility to manage daily and intra-day variation in demand. Although Aitken Creek reduces the reliance winter commodity purchases at Station 2, the facility’s location depends on Westcoast T-North and T-South transportation for delivery to Huntingdon.

1.5 Market Area Storage

Natural gas storage located near market centres is a strategic asset in the resource portfolios of PNW utilities. Storage is cost effective in meeting the seasonal and peaking nature of regional demand and allows the opportunity to take advantage of summer/winter commodity price differentials. Other benefits of storage include diversification of supply, operating flexibility to manage swings in demand, and facilitate the management of imbalances with interconnecting pipelines.

Market area storage is limited in the PNW to Jackson Prairie and Mist. As both underground storage facilities are located in the U.S., access to storage service at Huntingdon is further challenged by the need for firm NWP redelivery transportation or reliable displacement.

The increasing importance of storage in the regional resource mix is highlighted by the full contracting of incremental Jackson Prairie storage expansion capacity offered in the 2006 NWP Open Season, and recent storage capacity recall by Avista Corporation, Northwest Natural, and Puget Sound Energy. The rising value of market area storage resulting from higher growth in peak demand and its increased use to provide firm supply to gas-fired generation, mean long term access to cost competitive market area storage will be a significant challenge for PNW utilities relying on third party storage services.

1.6 Jackson Prairie Storage[3]

Jointly owned by Puget Sound Energy, Northwest Pipeline, and Avista Corporation, Jackson Prairie Storage ("JPS") currently has 23.2 million Dth of working gas capacity and 884 MDth/d of maximum withdrawal capability. This underground storage facility has been undergoing phased expansions and is expected to have 1196 MDth/d maximum withdrawal rate and a total capacity of 25.6 million Dth by 2008 and 2010 respectively.
The economics of JPS comprise of reservation costs associated with storage capacity and firm redelivery service at the discounted TF-2 NWP rate. The unavailability of incremental TF-2 storage redelivery service or reliable displacement contract are the primary constraints of using JPS as a peaking resource at the Huntingdon market area.

1.7 Mist Storage Facility

Northwest Natural's ("NWN") Mist underground storage facility provides 15.9 million Dth of working gas capacity and 520 MDth/d of maximum withdrawal capability. The facility is fully contracted with NWN reviewing the potential for future expansion. Similar to JPS, the redelivery of gas in Mist storage to Huntington is restricted due to the unavailability of incremental NWP transportation capacity from Mist to SIPI.

1.8 LNG Storage

The PNW has over 5 million Dth of peaking LNG storage capacity and 712 MDth/d of maximum withdrawal capability. Access to these facilities is limited as they are either fully contracted or reserved to meet supply requirements for core customers.

TGI owns and operates Tilbury LNG storage which provides 600 MMcf of capacity and 150 MMcf/d of deliverability. Construction of the 1.5 billion cubic feet ("Bcf") gas storage

[3] Storage details are referenced from NWGA 2007 Outlook Study

facility at Mt.Hayes, Vancouver Island commenced in April 2008 and is expected to provide 150 MMcf/d of incremental peaking supply beginning 2011.

Figure 1-1Pipeline and Storage Infrastructure in the PNW

2 TRENDS INFLUENCING REGIONAL RESOURCE DEVELOPMENT

The requirement for appropriate natural gas infrastructure to meet the growing and changing nature of demand, and which supports long term supply diversity are key challenges identified in the resource plans of PNW utilities. The proactive development of pipeline and storage infrastructure is encouraged by the Northwest Gas Association ("NWGA"). New infrastructure development will be a major determinant in ensuring the region continues to provide reliable and cost competitive energy supply. The following discussion relates to emerging trends in the energy market which have potential implications on the direction of infrastructure development in the PNW.

2.1 Infrastructure Constrained Market

The NWGA completes a regional study "Outlook Study" on an annual basis that reviews regional supply and demand. In its most recent study the NWGA identifies existing regional storage and pipeline infrastructure to be currently adequate to meet normal demand; however the system would be near capacity limits under extreme peak conditions. The projected growth in customer base and higher reliance on gas-fired generation will require the development of appropriate infrastructure to ensure the region maintains access to cost competitive resources.

Figure 2-1 shows the region's natural gas infrastructure is expected to be constrained to meet peak demand and sustained high winter demand by the end of this decade. Similarly, the Northwest Power and Conservation Council ("NWPCC") projects that the region will require 2500 mega watts ("MW") of incremental supply by 2015 under an average annual growth rate of 1.5% per year[4]. The need for peaking resources is reflective of the higher growth in weather dependent demand, and market recognition that natural gas plants are currently the primary source of incremental generation, and strategic to balancing energy reliability and environmental requirements.

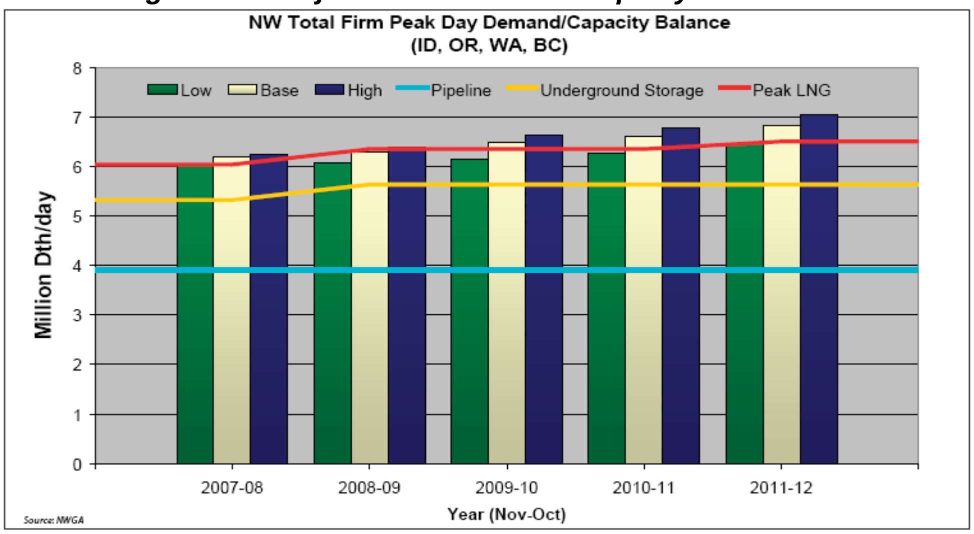
The escalating capacity pressure on regional infrastructure reveals the scarcity in resource alternatives and the focus of PNW utilities to procure firm delivery services. The need to enhance supply diversity and improve access to liquid supply points is

[4] The Fifth Northwest Electric Power and Conservation Plan. May 2005

recognized by market participants as the principal strategy to maintain long term reliability and cost competitiveness.

The development of regional storage and pipeline infrastructure is fundamental to ensuring long term resource adequacy and moderating future gas prices. Achieving reliable cost effective supply will require greater coordination between market participants to foster the wise use of natural gas and to ensure the region develops the right resources for a sustainable energy future.

Figure 2-1 Projected Resource Adequacy in the PNW

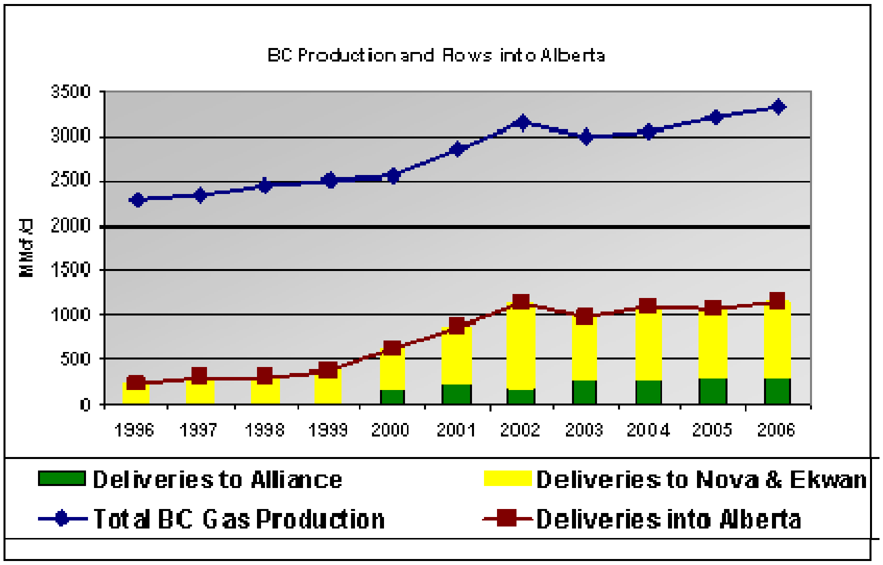


2.2 Diversion of Northern B.C. Supply

The development of pipeline infrastructure provides both the benefit of access to new production and simultaneously increases market competition for supply. The connection of regional production to multiple markets has increased the competitive environment of regional pipelines, and provides greater opportunities to divert supply from traditional market areas.

The Alliance and Ekwan pipelines are recent examples of regional infrastructure developments which have opened access of northern B.C. production to eastern North American and California markets. Figure 2-2 shows increases in northern B.C. production have been offset by higher flows onto NGTL and Alliance pipelines. With ongoing investment in developments such as the 170 MMc/d Alliance 2008 expansion, future growth in northern B.C. production will continue to move eastward while raising uncertainty in long term supply at Station 2 if Westcoast pipeline is unable to attract incremental supply.

Figure 2-2 B.C. Production and Flows into Alberta

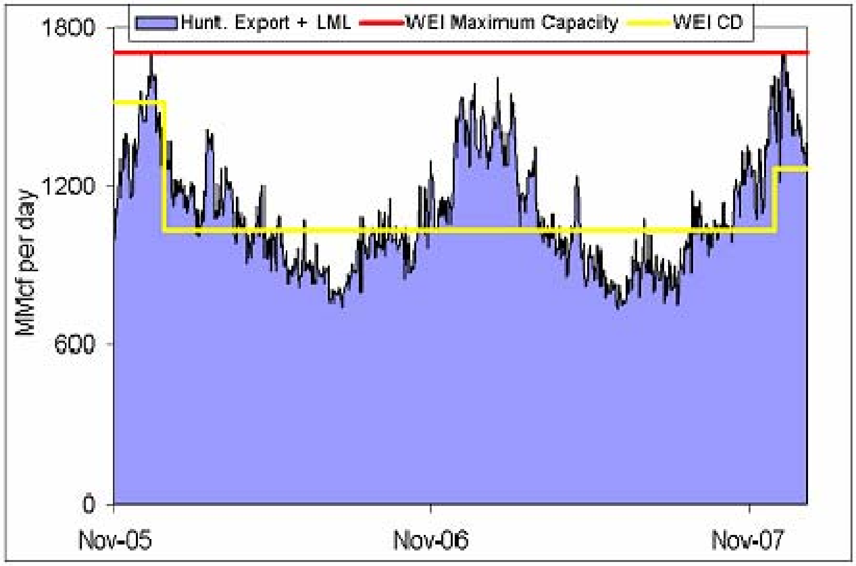


The greater geographic integration between northern B.C. production and the Alberta market has increased market opportunities for producers and subsequently changed the shipper profile on the Westcoast T-South pipeline. The current contracted capacity on Westcoast T-South is equivalent to just under 75% of maximum capability, the decline primarily attributable to the significant reduction in producer held firm service. The higher take away capacity at Station 2 relative to contracted capacity, and greater use of interruptible transport service are indicators of the enhanced flexibility to divert northern B.C. production from the traditional PNW to markets offering higher prices.

Similarly, the focused development of moving gas out of northern B.C. has reduced the contracted capacity on Westcoast T-North capacity to Station 2. Currently the contracted capacity on Westcoast T-North accounts for less than 50% of maximum capability. The 370 MMcf/d decline in contractible capacity on Ft. Nelson and Ft. St. John Mainline reduces the ability of the Westcoast pipeline system to provide supply alternatives in the event of major outages at McMahan, Fort Nelson or Pine River plants. These capacity reductions to Station 2 impede opportunities to diversify supply for purposes of maintaining reliability and contribute to greater uncertainty in daily supply availability and market prices.

Although the changing contracting patterns have reduced the level of contracted capacity, the PNW depends on 100% of the Westcoast pipeline system under peak demand conditions. Figure 2-3 depicts the contracted levels and pipeline utilization of Westcoast T-South. Of significance is the maximum pipeline utilization at times of high demand, and a current market need that exceeds contracted capacity. The greater reliance on interruptible service has adverse implications on long term supply reliability, market liquidity, and gas price volatility. Furthermore, the investment in future infrastructure developments becomes more challenging when greater proportions of cost recovery depend on interruptible rates.

Figure 2-3 Westcoast Pipeline Utilization at Peak Demand



2.3 Converging Electric and Natural Gas Markets

Energy demand in the PNW continues to exhibit strong growth. Regional electricity and natural gas needs are projected to grow on average 1.5% and 1.9%[5] per year respectively. With the common challenge of a widening resource deficit, sourcing strategies of PNW utilities will influence long term resource adequacy in the region, and the ability of market participants to secure reliable cost effective energy supply.

The similarities between electric and gas utilities in the PNW include a highly weather dependent demand, limited availability of commercial cost-effective utility scale resources, long lead times for infrastructure development, and the influence of climate change and environmental regulation on resource preference. These key challenges are expected to drive natural gas demand and how natural gas resources are used.

The use of natural gas for power generation continues to grow in the PNW. Since the 2001 energy crisis, gas consumption by the generation sector has risen by 50%[6],

[5] Northwest Power and Conservation Council

[6] Source NWGA: 2002 = 113753MDth; 2006 = 170233MDth

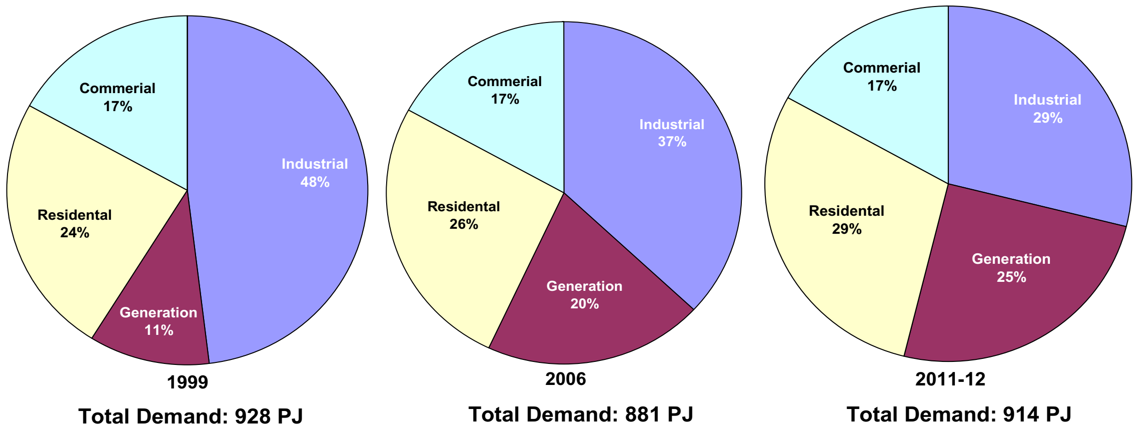
indicative of the greater convergence of natural gas and electric markets. Figure 2-4 highlights the changing customer mix in PNW natural gas demand with generation fuel requirements projected to rise to 26%[7] of total annual demand by 2011/12. The growing reliance on gas-fired generation is expected to continue as regional electric utilities focus on supply strategies which minimize risks associated with baseload coal resources and integrate more intermittent wind resources to meet targets under the renewable portfolio standards.

The growth in generation load implies the region's natural gas infrastructure will increasingly support electric demand and intensify the competition for cost effective resources. The inclusion of Mist and Jackson Prairie storage in the electric supply portfolios of Portland General Electric (PGE) and Puget Sound Energy (PSE) respectively highlight the accelerated reduction in access to storage resources to meet end use natural gas demand.

As the use of natural gas to meet electric demand in the PNW continues to increase, the convergence of electric and natural gas market prices is more likely, and the need for integrated energy infrastructure planning becomes fundamental to ensuring the region has adequate resources to deliver natural gas to meet requirements of both energy markets.

[7] NWGA

Figure 2-4 the Changing Make-up of Natural Gas Demand in the Pacific Northwest



Source: EIA, StatsCan, NWGA

2.4 Increased Sourcing from Rocky Mountain Area

The growth in U.S. Rockies production combined with lagging development in take-away pipeline infrastructure continues to depress Rockies prices compared to other markets in North America. The resulting increase in commodity price differential between Sumas and Rockies trading hubs makes it economic for U.S. PNW utilities to maximize supply from the Rockies. Although the Rockies Express Pipeline increases market access for Rockies production, the take away capacity is unlikely to significantly change the relative prices between Sumas and Rockies. The higher Sumas-Rockies commodity price differential is expected to continue at least until the next major Rockies expansion scheduled in 2011.

The increased procurement of Rockies gas has resulted in the full contracting of pipeline capacity connecting Rockies supply to the Interstate 5 (I-5) corridor and rising north bound gas flow on NWP through the Columbia gorge. This change in gas flows and limited availability of firm NWP transportation capacity to Huntington contributes to higher uncertainty in flows on Westcost T-South. Additionally, greater north bound gas flows during prolonged periods of cooler weather increases the likelihood of operational constraints on NWP, and the requirement of shippers to flow gas in a specified direction. The consequent reduction in the displacement capability of NWP restricts redelivery of gas from Mist and Jackson Prairie storage facilities to the Huntingdon market area via displacement.

The uncertainty in access to resources at Huntingdon has implications for long term contracting strategies of regional utilities. With limited resource alternatives, the ability to shape and diversify the supply portfolio is minimized, and accordingly puts pressure on maintaining competitive and stable natural gas rates. For example, the consequence of securing additional Westcoast T-South capacity to meet incremental storage requirements would result in ineffective resource utilization, higher portfolio costs, and increased exposure to Station 2 supply.

The interconnection of regional resources means changes in physical gas flows on NWP can potentially impact utilization and contracting of other assets. It is anticipated that the demand for Westcoast T-South transportation service is likely to become highly variable. If Westcoast becomes the regional swing supply, it will lower producer confidence to commit to long term supply at Station 2, and during periods of higher demand will require higher prices at Station 2 to divert gas from Aliiance and NGTL. To mitigate supply uncertainty at Station 2, PNW utilities appear to be choosing to diversify sourcing to new supplies in Alberta or Rockies which fundamentally depends on major investments in regional pipeline infrastructure.

3 DEVELOPMENT IN REGIONAL SUPPLY & INFRASTRUCTURE

The timing and development of appropriate natural gas infrastructure in the PNW is essential to addressing the region's tight supply / demand balance. The following discussion provides an update of infrastructure developments in the region, and concludes that most of the current proposals are focused on securing supply for alternative markets and offer limited solutions to address the need for enhanced access to diverse cost effective supply in the PNW.

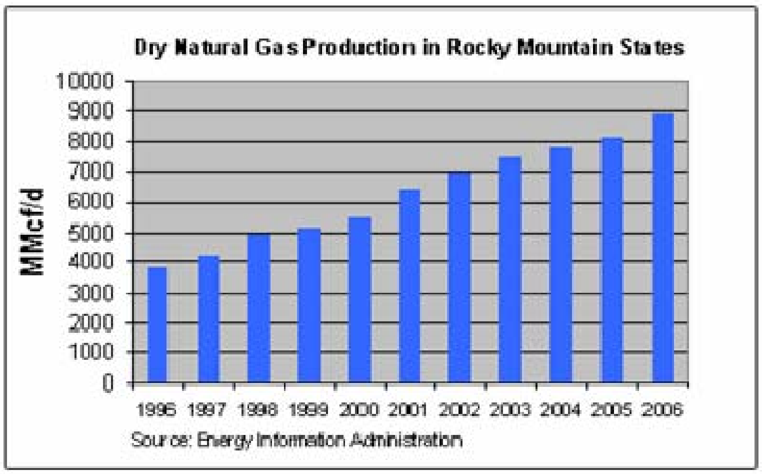
3.1 Supply Update

3.1.1 Growing Regional Production

The PNW sources natural gas supply from two major producing regions; the Western Canadian Sedimentary Basin, and the Rocky Mountain area. Combined, the two production areas contain approximately 99 trillion cubic feet ("Tcf") of proven reserves and an ultimate resource potential of 500Tcf[8].

Together with Figure 2-2, Figure 3-1 illustrates the strong growth in natural gas production levels in northern B.C. and the Rockies. It shows in the past decade, the doubling of production in the U.S. Rockies and an approximately 50% increase in northern B.C. production. Although the continued growth in western production means supply is sufficient to meet long term needs in the PNW, the rapid addition of new pipeline capacity connecting these production areas to alternate North American markets is expected to intensify the competition for supply until new regional supply resources are added.

Figure 3-1 Historical Production in the Rockies Supply Basin



3.1.2 New Supply Potential

The expansion of production in traditional North American supply areas is projected to be insufficient in meeting long term continental demand. Access to alternate supply including northern frontier gas (Mackenzie, Alaska), unconventional resources, and import LNG is considered critical to meet future North American demand.

8 NWGA 2007 Outlook Study

The NWGA Outlook Study states public policies and industry actions encouraging access to new supply sources is essential for long term supply adequacy. Figure 3-2 represents the projected mix of resources to meet future demand in North America. It identifies import LNG and frontier gas will be fundamental to counteract the decline in production from maturing gas supply sources.

The expectation of import LNG to be the marginal supply resource in North America has resulted in several proposals for the development of import LNG facilities in the PNW. These include two located in British Columbia (Kitimat and Texada Island), and four located in Oregon (Oregon LNG, Northern Star, Port Westward, and Jordon Cove)[9]. Designed to provide large base load supply, an import LNG facility located in the region would be a significant source of supply, provide diversification opportunity, and depending on location can potentially displace traditional supply sources.

The role of import LNG in the PNW continues to be uncertain due to significant commercial and regulatory challenges. It is expected that the bulk of LNG import will be sited to serve eastern North America and the Gulf coast. The greater reliance on LNG import to meet continental demand will however have regional impacts due to the integrated nature of the North American market.

In addition to import LNG, Figure 3-2 identifies the reliance on frontier gas from the Mackenzie River Delta (Canada) and the Alaska North Slope to meet long term demand. The major pipelines proposals, the Artic Natural Gas Transmission System, Mackenzie Valley pipeline, and the Alaskan Gas Pipeline, have a combined capacity of 9.3Bcf/d[10] and are expected to interconnect in northern B.C. or Alberta. The cost challenges and expected delays in the pipeline proposals mean frontier gas supplies are projected to enter the market in 10 years or longer.

Apart from Artic gas, the potential for domestic supply is vast when Canadian unconventional gas resources are considered. These resources include natural gas from coal or coalbed methane, tight gas sands and carbonates, shale gas, and gas hydrates. Table 3-1 illustrates the estimated supply potential in British Columbia. It shows the province has significant and diverse supply resources including coal bed

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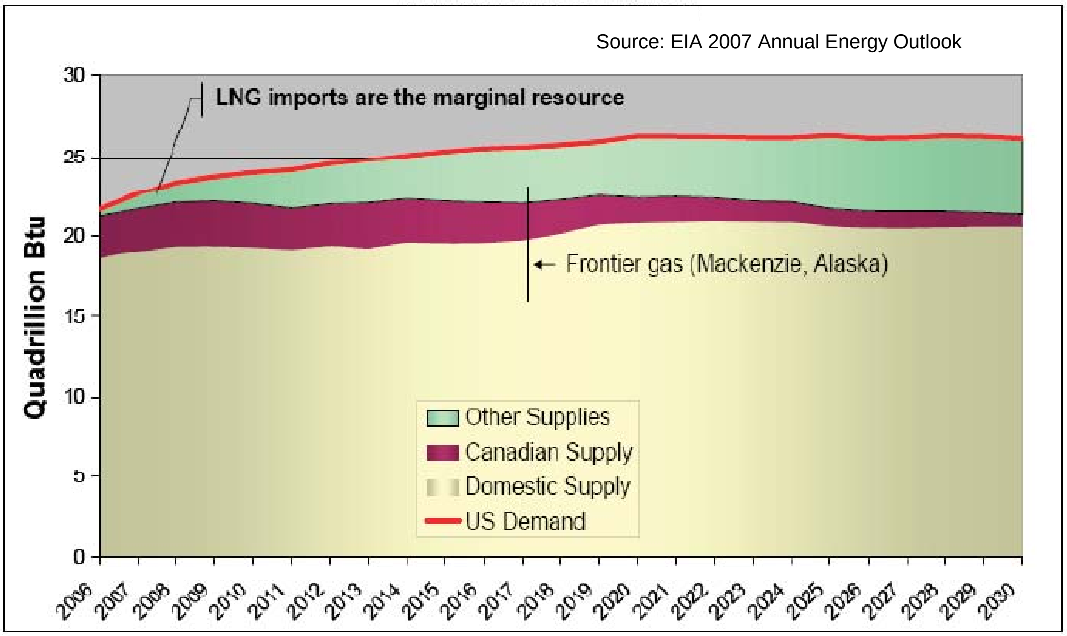
[9] California Energy Commission March 2008

[10] Puget Sound Energy 2007 IRP

methane and tight/shale gas reserves of approximately 84Tcf and 550Tcf[11] respectively. Recent exploration findings in the Horne River Basin in northeast B.C. indicate massive reserves and the potential for shale gas to become a significant supply source.

Currently unconventional production accounts for approximately 25% of Canada's gas production[12]. Unconventional gas is anticipated to become a major supply source in meeting future requirements with the decline in conventional gas production.

Figure 3-2 U.S. Perspective of Long Term Supply-Demand Balance



LNG (green area) will play a vital role in serving future U.S. demand as cumulative U.S. and Canadian supplies grow only slightly or hold steady. Alaskan gas will provide much-needed domestic supply boost after 2017.

11 NWGA

12 Western Energy Institute, June 2007 Presentation

Table 3-1 Supply Potential in British Columbia

Conventional Gas	
Gas	98.0 Tcf
Oil	17.6 B bbl
Unconventional Gas	
Coalbed gas	84.0 Tcf
Tight gas	300 Tcf
Shale gas	250 Tcf
Offshore Gas	41.8 Tcf
Offshore Oil	9.8 B bbl
Gas Hydrates	113-847 Tcf
Tcf	**Trillion cubic feet**
B bbl	**Billion barrels**

3.1.3 Proposed New Transmission Pipelines

3.1.3.1 Access to Rocky Mountain Production

With rising national demand, recent developments in natural gas pipeline have been primarily focused on connecting the growth in western production areas to alternative North American markets. The significant investments to increase access to Rockies supply and proposed new pipeline additions demonstrate the continental need for incremental resources and the importance of bringing supply diversity to markets.

Table 3-2 identifies current proposals for new natural gas pipelines which may affect the region's supply-demand balance and sourcing strategies of PNW utilities. Over half of the projects relate to the connection of Rockies production to either the California or eastern markets.

There are currently three pipeline proposals that bring incremental supply out of the Rockies to points that would impact supply to the PNW. The Ruby pipeline project, a joint venture between El Paso, PG&E, and Bear Energy, would transport between 1.2 –

2 Bcf/d gas from Opal to Malin. Similarly, the Spectra Energy 1 Bcf/d Bronco proposal, and Williams (NWP) and TransCanada (GTN) 1.2 Bcf/d Sunstone project, would connect Rockies gas at Opal to Californian markets at Malin. Additionally, several pipeline projects have been announced that would connect Rockies production to the U.S. Midwest and north east markets.

The development of natural gas pipeline infrastructure to access Rockies production is highly competitive and intends to move large volumes of natural gas. It is expected that the completion of two major projects would change Rockies pricing. While majority of the proposed pipeline projects targeting Rockies production alleviate resource needs in alternative markets, the impact for the PNW is increased competition for supply and consequent increases in depressed Rockies commodity prices.

3.1.3.2 Access to LNG Import

The second major driver of natural gas pipeline proposals in the PNW relates to connecting LNG import terminals to the region's infrastructure. Identified in Table 3-2, three of the new pipeline proposals are contingent on the development of LNG import terminals. While the Pacific Connector and Palomar pipeline projects support separate LNG import terminals proposed in Oregon, both connect to the gas transmission northwest ("GTN") system to allow gas deliveries to the northern California border. The Oregon pipeline proposal connects a LNG import terminal in Warrenton Oregon to the NWP system at Molalla Oregon. The Pacific Trails Pipeline supports the Kitimat import LNG proposal primarily targeting supply requirements for the Canadian Oil Sands in Alberta.

3.1.3.3 New Supply for the Pacific Northwest

Currently, three pipeline proposals provide access to alternative supply sources for the PNW market. All three projects aim to help alleviate the reliance on a single source of natural gas transmission service and offer the opportunity for diverse cost-competitive supply. Each proposal has the potential to access incremental Alberta or Rockies production either directly or via displacement.

The Blue Bridge Pipeline project is a joint venture between Williams NWP and Puget Sound Energy. The proposal is a looping of the existing NWP system and is looking to directly connect to Rockies supply. The project is designed to transport up to 500,000

Dth/d gas from Stanfield Oregon to delivery points north along the Williams NWP natural gas transmission system.

The Palomar pipeline project is a joint venture between TransCanada and Northwest Natural. The proposed 1.4 Bcf/d new transportation route would connect to the GTN system at Northwest Oregon, and primarily enables Northwest Natural to reduce it's reliance on NWP. Additionally, the pipeline's bi-directional flow capability would connect gas from the proposed Bradwood Landing LNG import terminal to the region.

The Terasen Gas Inc. Inland Pacific Connector ("IPC") project is an extension of the existing B.C. Interior transmission system. Originating from Oliver British Columbia, the proposal aims to increase the region's access to the more liquid markets at Huntingdon. IPC provides one of the shortest routes for the PNW to access alternate supply, and additionally preserves the traditional north to south gas flows on NWP to increase displacement capability.

Table 3-2 Proposed Natural Gas Pipeline Infrastructure Projects

Access to Rocky Mountain Production				
Pipeline Projects	Market	Supply Source	Project Specifics	In-Service
Bison Pipeline - Northern Border Pipeline Company	U.S. Midwest Chicago	Rockies	400 – 660 MMcf/d from Powder River Basin to Morton County North Dakota	2010
Bronco Pipeline - Spectra Energy	California	Rockies	1 Bcf/d from Rockies to Malin Oregon	2011
Pathfinder Pipeline - TransCanada	U.S. Midwest	Rockies	1.2 Bcf/d from Wamsutter Wyoming to Ventura and Chicago	2010
Rockies Alliance Pipeline - Alliance Pipeline & Questar	U.S. Midwest, Central Canada	Rockies	1.2 – 1.8 Bcf/d from Rockies to Ventura and Chicago trading hubs	2011
Rockies Express Pipeline - Kinder Morgan, Sempra Energy, ConocoPhillips	U.S. Midwest, Eastern	Rockies	1.8 Bcf/d from Rio Blanco County Colorado to Monroe County Ohio	2009
Ruby Pipeline - El Paso, Bear Energy, PG&E	California, Nevada, PNW	Rockies	1.2 Bcf/d (potentially 2 Bcf/d) from Opal Wyoming to Malin Oregon	2011
Sunstone Pipeline - Williams & TransCanada	California, Nevada, PNW	Rockies	1.2 Bcf/d from Opal Wyoming to Stanfield Oregon	2011
Access to LNG Import				
Pipeline Projects	Market	Supply Source	Project Specifics	In-Service
Pacific Connector Gas Pipeline - Williams, Fort Chicago (Canada), PG&E	California, Nevada, PNW	Import LNG	1Bcf/day from proposed Jordon Cove import LNG terminal Coos bay Oregon to Malin Oregon	2011
Pacific Trails Pipeline - Galveston LNG & Pacific Northern Gas	Alberta	Import LNG	1 Bcf/d bi-directional pipe from proposed Kitimat LNG BC to Summit Lake B.C. connecting to existing	2010
Oregon Pipeline - Oregon Pipeline	PNW	Import LNG	XXX Bcf/d from proposed Oregon LNG import terminal Warrenton Oregon to Molalla Oregon connecting to existing NWP system	XXXX
New Supply for the Pacific Northwest				
Pipeline Projects	Market	Supply Source	Project Specifics	In-Service
Blue Bridge Pipeline - Williams & Puget Sound Energy	PNW	Rockies Alberta	500,000Dth/d from Stanfield Oregon to points north along NWP existing pipeline corridor to PNW market	2011
Palomar Pipeline - TransCanada & Northwest Natural	PNW Western US	WSCB Rockies Import LNG	1.4Bcf/d bi-directional connecting NWN distribution system at Molalla Portland to GTN system in central Oregon, and to proposed Bradwood Landing LNG pipeline	2011

3.1.4 Proposed Regional Storage

The NWGA analysis of resource requirements for peak day and extended winter demand indicate the long term need for shaped resources to meet the region's higher projected growth in weather sensitive demand. The recent investments to increase the region's storage capacity include expansions at Jackson Prairie and Mist storage facilities, and the approval to develop the Mt. Hayes LNG storage facility on Vancouver Island.

The Jackson Prairie expansion project will increase the storage deliverability from 884 MDth/d to 1196 MDth/d and is expected to be in service by November 2008[13]. The expansion of storage capacity from 19.0 million Dth to 25.6 million Dth is projected to be completed by 2010. Stated in their Draft 2007 Integrated Resource Plan, the expansion of Mist Storage will continue to be the primary focus in meeting incremental supply requirements for Northwest Natural. The construction of the Mt. Hayes LNG storage facility is expected to be completed in 2011 and will provide incremental peaking supply of 150 MMcf/d for a maximum of 10 days.

Future storage expansion in the PNW is contingent on the availability of cost-effective incremental redelivery transportation service. Regional infrastructure developments that maintain traditional north-south gas flow on NWP would enhance the ability to use storage redelivery displacement contracts consequently maximize synergies of existing regional storage and pipeline infrastructure.

3.1.5 Conclusions

The tightening supply / demand balance in the PNW is a result of increasing weather sensitive demand and new infrastructure moving supply to alternate markets. This trend creates the need for alternate sources of supply, new infrastructure to bring the supply to the PNW and additional regional storage. Unconventional supply sources such as northern frontier gas, shale gas, coal bed methane and LNG imports are considered critical to meeting future demand.

[13] Puget Sound Energy, 2008

Pipeline proposals such as Blue Bridge, Palomar and IPC provide access to alternative supply sources for the PNW market and would help alleviate the reliance on a single source of natural gas transmission service and offer the opportunity for diverse cost-competitive supply. The development of new market area storage assets will also serve an important role in shaping resources to meet the expected growth in weather sensitive demand.

APPENDIX M

Terasen Gas
Description – Proposed Inland Pacific Connector Project

DESCRIPTION – PROPOSED INLAND PACIFIC CONNECTOR PROJECT

1 Background

The proposed Inland Pacific Connector ("IPC") will extend existing gas transportation service provided by Terasen Gas' existing Southern Crossing Pipeline ("SCP"). SCP transports gas from the Alberta trading hub through its interconnection point with TransCanada's BC System pipeline at Yahk, BC to an interconnect Oliver, BC. From Oliver, two Terasen Gas transmission pipelines move gas to the core market and transport customers in South and Central Okanagan regions. A third existing Terasen Gas pipeline transports gas from SCP at Oliver to an interconnection with Spectra's Westcoast Pipeline at Kingsvale for delivery to the Huntingdon-Sumas trading hub where it can be accessed by core market and transport customers in the Lower Mainland as well as other shippers in the Pacific Northwest ("PNW"). SCP currently has capacity to transport 105 MMscfd and 134 MMscfd of Alberta gas to Kingsvale and into the Okanagan regions, respectively.

Because of limited pipeline capacity between Oliver and Kingsvale, however, Terasen Gas in 2000 proposed the new IPC pipeline project along with compression additions on SCP. IPC in conjunction with SCP would deliver additional gas from the Alberta trading hub to the Huntingdon-Sumas trading point, providing an alternative supply resource to TGI's coastal service area, TGVI, and other customers in the U.S. PNW. Other options could see IPC connected to the Westcoast Pipeline at Kingsvale or Hope. Figure 1-1 shows the three route alternatives for the project.

Figure 1-1 IPC Route Alternatives

IPC project development activities were suspended in response to market decline resulting from the 2000/01 western energy crisis, and subsequent political and economic events. With the recovery of natural gas demand and continued growth in demand forecasted throughout the PNW, IPC is again identified as an important future regional transmission resource alternative for both British Columbia and the rest of Pacific Northwest to meet future demand growth. IPC could also serve the regions desire to increase supply alternatives, particularly into the I-5 corridor.

2 IPC Project Description

The IPC project proposal consists of a new pipeline extension from Oliver and compression additions and related interconnection facility additions as described below. The project could potentially delivery in the range of 300 - 350 MMscfd of Alberta gas to the PNW through the Huntingdon-Sumas trading point. Ultimate capacity potential could be increased to 450 MMscfd with further compression additions.

1. Pipeline Extension

The extension would be a 24 inch diameter natural gas pipeline with a MOP of 9928 kPa (1440 psig). The pipeline would extend from Southern Crossing at Oliver-Y control station to either an interconnection with Westcoast at Kingsvale or at Hope, or directly to the Huntingdon-Sumas hub in the Lower Mainland. The pipeline lengths of the three alternatives are:

- Oliver-Y to Kingsvale - 158 km
- Oliver-Y to Hope - 158 km
- Oliver-Y to Huntingdon - 246 km

2. Initial Compressor Additions

Compression additions for the initial Huntingdon-Sumas hub delivery capacity of 350 MMscfd would consist of 4 new Compressor Stations on Southern Crossing, as well as upgrading the existing Kitchener-B Compressor Station, also on the Southern Crossing. Table 1 summarizes the additions, totalling approximately 62,000 hp of compression capability.

Table 1 IPC Compression Additions

Addition Type	Station Name	Compressor Units	km Post on Southern Crossing [East to West]
New	Yahk	3 x 7200 hp	- 0
Upgrade	Kitchener-B	2 x 7200 hp	+16
New	Salmo River	2 x 7200 hp	+104
New	Cascade	1 x 7200 hp	+185
New	Boundary	2 x 7200 hp	+243

3. Station Modifications

The upgrades to station facilities at interconnection points of the IPC project to accommodate the new pipeline extension are briefly described as follows:

- TransCanada Pipeline custody transfer station modifications to accommodate the increased receipt of Alberta supply associated with the IPC project.

- Odorization station modifications and additions. Gas receipt from TCPL is currently odorized at Yahk. With the extension of the IPC project from the SCP which enables direct interconnections between TCPL and Westcoast pipeline systems, odorization is not required for gas transmission but would be required for distribution. Therefore, the scope for odorization would be:

- remove existing odorization on SCP at Yahk,
- add odorization at Oliver-Y for gas delivery to the Okanagan, and
- add odorization if the IPC endpoint is at Huntingdon.

- Oliver-Y control station modifications to accommodate the additional connection to the new NPS 24 IPC project

- Interconnection addition to either the Westcoast Pipeline or at Huntingdon. This addition will facilitate interconnection either with Westcoast at Kingsvale or Hope, or at Huntingdon with Terasen Gas' Coastal Transmission System and interconnection to Williams Northwest Pipeline via the Huntingdon International Pipeline Co. Station.

4. IPC Benefits

The IPC project, depending on the amount of compression added, would be able to transport an additional 200 to 450 MMscfd of Alberta market supply into the Huntingdon-Sumas hub. To the benefit of the PNW region, including TGI, TGVI and TGW customers, this increase in access to Alberta market supply via the IPC to Sumas would reduce the growing supply-demand imbalance, expand supply diversity to the I-5 corridor, improve supply reliability and correspondingly reduce gas price volatility at Huntingdon-Sumas.

APPENDIX N

Terasen Gas
Description - Proposed Electricity from Waste Heat Project

DESCRIPTION – PROPOSED ELECTRICITY FROM WASTE HEAT PROJECT

1 WASTE HEAT RECOVERY ELECTRICITY GENERATION

TGVI is evaluating a potential project that would capture waste heat energy from the exhaust gas of compressor units at its Coquitlam Compressor Station to generate clean electricity.

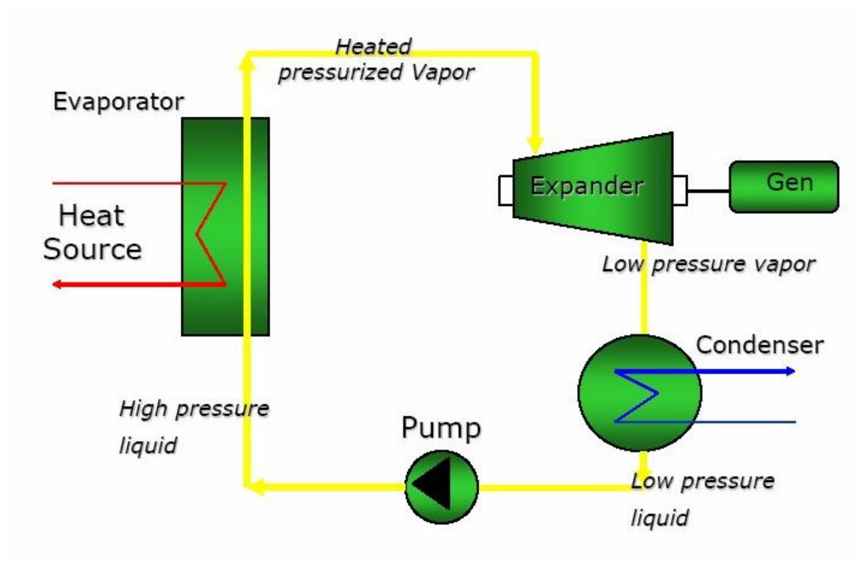
1.1 Project Description

The existing Coquitlam Compressor Station operates to increase pipeline pressure and transport natural gas from the Lower Mainland to the Sunshine Coast and Vancouver Island. The compressor units are driven by natural gas fired turbines. The exhaust from the turbines is vented to the atmosphere at a relatively high temperature (about 950 ^{o}F). This waste heat could be captured and transformed into usable energy with existing technology.

The waste heat recovery technology employs a conventional shell and tube heat exchanger where the exhaust gas is re-directed into a shell to heat a tube containing an intermediate heat transfer fluid. The exhaust gas is then vented after the heat exchange. The heat transfer fluid carries the heat into a separate heat exchanger where the heat is further exchanged with a motive fluid.

The power generation technology uses the motive fluid in a thermodynamic cycle to power a turbine or expander. The Rankine Cycle shown in Figure 7-6 is an example. In simple terms, the Rankine Cycle follows the thermodynamic path of a motive fluid starting from a low pressure liquid state, brought to a high pressure state with a pump, and then heated to a high temperature vapour state, in this case, by the waste heat recovered from the pipeline compressor exhaust. The motive fluid, now at a high pressure and temperature vapour state, would expand into a turbine which is coupled to a generator to produce electricity. After producing work in the turbine, the motive fluid would be at a low pressure but high temperature vapour state. A condenser would then cool the motive fluid back to the low pressure liquid state to repeat the next thermodynamic cycle. See Figure 1-1 for the schematic of the Rankine Cycle.

Figure 1-1 Rankine Thermodynamic Cycle



The electricity generated is a clean energy since it is captured from waste heat with no additional use of fuel. To avoid the need for additional transmission wire, the clean electricity would be delivered to BC Hydro's distribution grid through the electrical wire already in place to service the compressor site.

1.2 Project Benefits

The potential project is to capture the energy from the waste heat and to convert it into electrical energy without additional environmental impact in terms of noise, sight, water quality and air emission. The project is expected to provide an overall balance of energy efficiency, environment & economy.

The potential project is expected to generate about 3.2 MW of electrical power and in the range of 15,000 MWh to 18,700 MWh per year of clean energy. This energy production would be able to satisfy the electrical demand for 1500 to 1870 homes in the Lower Mainland. The clean electricity would qualify for sales to BC Hydro under the Standing Offer Program. The Income from electricity sales would be used to offset the project costs to benefit TGVI ratepayers. This clean electricity can contribute to meeting the objectives of the BC Energy Plan including the electricity self-sufficiency and net zero GHG emissions goals by 2016. In addition, compared to imported power generated from coal fired generation, this clean energy would displace over 13,510 tonnes[1] CO2e of GHG emissions per annum.

This project would increase the utilizing of energy from the natural gas fuel to produce additional usable energy. The compressor units presently capture 26% of the total fuel energy for the compression of pipeline gas. With waste heat recovery generation, an additional 10% of the total fuel energy is captured to generate clean electricity. This represents a 38% improvement in efficiency associated with the compressor operations at the Coquitlam Station.

By producing electricity locally in a primary load centre of the electrical transmission system in B.C., the Project displaces or reduces the need to transmit the same energy from Interior B.C. where most of the electricity generating capacity is located. British Columbia Transmission Corporation (BCTC) has reported that the average bulk transmission losses are in the order of 6%, with peak losses in the order of 7%[2]. Since the Project will produce more electricity in the peak winter months it also provides an excellent matching of supply with BC Hydro's periods of high demand. Generation at the load centre and during high electricity demand in peak winter months from this Project will effectively reduce transmission losses and improve the operating efficiency of the electrical transmission system.

The application of known engineering principles and proven technologies for the customized, relative small scale and non-steady state conditions that would occur in the Project is not expected to create new patentable intellectual properties. However, the success and experience gained from the Project would be applicable to other similar small scale applications in Terasen's gas utilities, other gas utilities and gas gathering systems in Canada and abroad where small compressor units, either the reciprocating or the turbine types, are used, and where the compressor sites are close to electrical grids for interconnection. As the project develops, Terasen Gas will continue to explore other similar new opportunities.

[1] Based on GHG emission factor of 855 tonne CO2e/GWh for a 560 MW greenfield thermal coal plant at the Hat Creek site, as stated in BC Hydro 2006 IEP, Appendix F, 2005 Resource Options Report

[2] From Information Release by BCTC Transmission System Planning dated 27/11/2007