2012 Integrated System Plan

Volume 2

2012 Long Term Resource Plan
(2012 Resource Plan)

June 30, 2011

FortisBC Inc.

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1 EXECUTIVE SUMMARY

FortisBC Inc. (FortisBC or the Company) is an integrated electric utility that generates, transmits and distributes electricity to customers in the southern interior of British Columbia (BC). The Company serves approximately 161,000 customers directly and indirectly, focusing on the delivery of safe, reliable and cost effective electricity. FortisBC's customer base represents approximately 8 percent of British Columbia's electric utility customer total[1] and accounts for about 6 percent[2] of total provincial domestic electricity sales.

This 2012 Long Term Resource Plan (2012 Resource Plan) analyzes the regulatory, policy, commercial and operational context within which FortisBC operates, its load and peak demand forecasts, its current resource capabilities and the potential generation resource options available to meet its forecast needs over a 30-year planning period. As a result, the 2012 Resource Plan will enable the Company to achieve its goals of:

1. continuing to ensure the availability of cost effective long-term, reliable power for FortisBC's customers;
2. understanding the uncertainty and risks inherent in the Company's historic, current and proposed market purchase strategy; and obtaining firm power resources over time to achieve 100 percent self sufficiency, and
3. balancing cost effectiveness with the applicable of British Columbia's energy objectives as defined in the *Clean Energy Act*[3].

FortisBC has prepared and is filing this 2012 Resource Plan with the British Columbia Utilities Commission (the Commission) as part of its 2012 Integrated System Plan, in accordance with section 44.1 of the *Utilities Commission Act* (the Act) and with the Commission's *Resource Planning Guidelines*. This 2012 Resource Plan, together with the 2012 Integrated System Plan, is in the public interest.

1.1 The Clean Energy Act

FortisBC has prepared this 2012 Resource Plan mindful of the recently enacted *Clean Energy Act*[4]. Table 1.1-A below lists those objectives set out in *Clean Energy Act* which FortisBC

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[1] FortisBC / (BC Hydro + FortisBC) customers. Customer counts from FortisBC and BC Hydro 2010 Annual Reports

[2] FortisBC / (BC Hydro + FortisBC) domestic sales. Sales information from FortisBC and BC Hydro 2010 Annual Reports

[3] Government of British Columbia, June 3, 2010

believes are directly relevant to the Company's resource planning process. Further details are provided in Section 2.4.2.1 and Appendix F.

Table 1.1-A - Relevant *Clean Energy Act* Objectives

***Clean Energy Act* Objectives**	**2012 Resource Plan Satisfies Objective**	
To achieve electricity self-sufficiency;	✓	Key input in evaluating capacity and energy alternatives (see Section 6)
To generate at least 93 percent of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;	✓	Key input in evaluating capacity and energy alternatives (see Section 6)
To ensure that BC Hydro's ratepayers receive the benefits of the heritage assets and to ensure the benefits of the heritage contract under the BC Hydro Public Power Legacy and Heritage Contract Act continue to accrue to ratepayers;	✓	See Section 5.1.2.1.1
To reduce BC greenhouse gas emissions	✓	Key input in evaluating capacity and energy alternatives (see Section 6)
To reduce waste by encouraging the use of waste heat, biogas and biomass;	✓	Key input in developing the New Clean Energy Resources recommendation (see Section 6)
To maximize the value, including the incremental value of the resources being clean or renewable resources, of British Columbia's generation and transmission assets for the benefit of British Columbia;	✓	Key input behind future capacity options recommendation (see Section 6)
To take demand side measures and to conserve energy…	✓	Key input in developing FortisBC's DSM target (see Section 6)

1.2 Energy and Capacity Supply / Demand Gaps

1.2.1 EXISTING SUPPLY

FortisBC owns four hydroelectric generating plants on the Kootenay River (the FortisBC Plants) which represent approximately 30 percent of its current capacity requirements and 45 percent of its current energy requirements. FortisBC is also party to long-term power purchase agreements with the British Columbia Hydro and Power Authority (BC Hydro) and the Brilliant Power Corporation. The Company also has a five year capacity agreement with Powerex. The FortisBC Plants, the Power Purchase Agreement with BC Hydro (BC Hydro PPA), the Capacity Purchase Block with Powerex, and the Power Purchase Agreement with Brilliant Power Corporation (the BPPA) together constitute the bulk of the Company's existing power supply

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[4] *Clean Energy Act*, [SBC 2010] Chapter 22. http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/00_10022_01

resources, providing a total winter peak capacity of approximately 710 MW, a total summer peak capacity of approximately 524 MW.

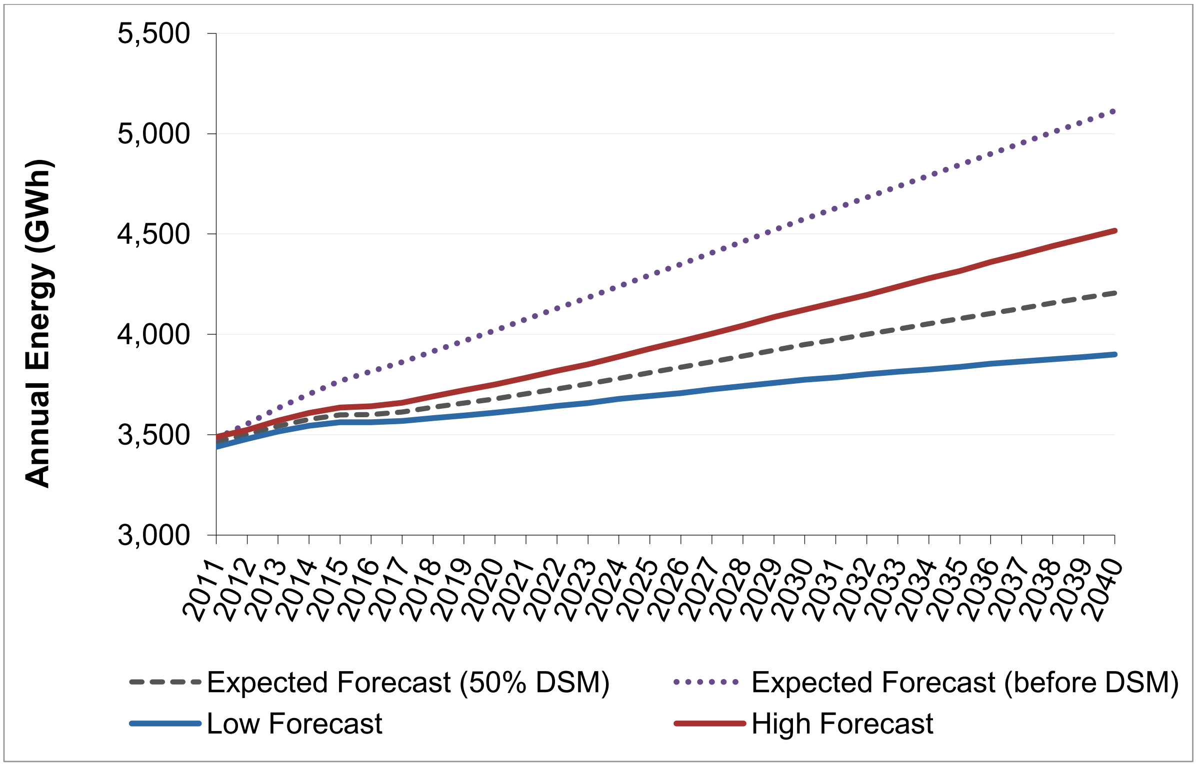
In addition to the existing resources, FortisBC recently entered in a long term agreement to purchase capacity related to the Waneta Expansion (WAX) project being developed by the Waneta Expansion Limited Partnership. The WAX Capacity Purchase Agreement (WAX CAPA) will provide FortisBC with a capacity resource of sufficient size to replace the Powerex Capacity Purchase Block and to meet its expected forecast capacity requirements throughout much of the planning period of this 2012 Resource Plan. The capacity entitlements under WAX CAPA become available upon commissioning of the WAX generating units in January 2015 and April 2015. The WAX CAPA is suitably shaped to solve FortisBC's winter and summer peak demand requirements when capacity is needed most and provides less capacity during the three freshet months when it is needed least. This capacity profile is an ideal match for FortisBC's seasonal load shape, and is an important addition to the Company's resource portfolio.

1.2.2 LOAD FORECAST

FortisBC's load forecast is prepared annually and is composed of individual forecasts for each of the residential, wholesale, industrial, commercial and irrigation and lighting classes and well as system losses and DSM savings. The forecast energy sales for each customer class is reduced by a forecast of annual DSM savings and other non-DSM savings including Customer Portal Information and Residential Inclining Block and Advanced Metering Infrastructure (AMI).

The Company is targeting to meet 50 percent of its annual energy load growth through DSM savings. The forecast of the expected energy before and after DSM is shown in Figure 1.2.2. In addition, the High and Low Forecasts create a high/low range around the Expected Forecast, which is the result of a probabilistic analysis and includes the potential variability associated with DSM achievement. For more details on the Load Forecast calculations, see Tab 3 of the Company's 2012 - 2013 Revenue Requirements, which was filed concurrently on June 30, 2011.

Figure 1.2.2 - Annual Energy Forecast before and after DSM (GWh)



1.2.3 DETERMINING THE FORECAST GAP

In order to plan for increasingly less certain forecasts over time, FortisBC has identified a range of potential capacity and energy gaps over the extended 30-year planning horizon driven by the following key variables:

- **Load Forecast:** FortisBC's load is expected to grow over time. The primary factor influencing the pace of residential load growth is customer count. However, other factors such as widespread adoption of new electric technologies (e.g. electric vehicles) and societal changes (e.g. a move to smaller residences) may have significant impacts. FortisBC recognizes that there are considerable uncertainties regarding forecasts and particularly those which extend far out into the future. As described in greater detail in Section 4, FortisBC prepares a Monte Carlo forecast to determine a high forecast and low forecast.

- **DSM Contribution:** As described in the DSM Strategic Plan, also found in the 2012 Integrated System Plan (Volume 2), FortisBC is targeting to meet 50 percent of its forecast annual load growth via DSM measures. Given that DSM is a non-firm resource with results subject to voluntary participation, is therefore prudent to consider the possible DSM contribution to resourcing as a range of outcomes rather than as a single pre-determined percentage of load growth avoidance.

- **Long Term Power Purchase Contracts:** FortisBC has a number of long-term supply contracts in its portfolio that are critical to its ability to meet its long term requirements. The Brilliant Power and WAX CAPA agreements extend throughout the planning period and FortisBC and BC Hydro are currently in discussions regarding the renewal of the BC Hydro PPA which otherwise expires in 2013. The BC Hydro PPA is an important supply resource for FortisBC and its customers, currently providing approximately 25 percent of FortisBC's capacity and energy needs. FortisBC expects the BC Hydro PPA to be renewed on comparable terms to the existing PPA, and continues to rely on the BC Hydro PPA energy to meet load growth projected over the term of this 2012 Resource Plan. If there are differences in the renewal terms, FortisBC may be required to find replacement energy either in the market or by accelerating the development of new resources to meet any resulting supply/demand gap.

1.2.4 PLANNING RESERVE MARGIN (PRM)

The Western Electricity Coordinating Council (WECC) recommends that utilities plan for positive capacity margins on a long-term basis (also known as PRM). For the purposes of ascertaining prudent long-term firm PRM requirements, the Company engaged Midgard Consulting Incorporated (Midgard) to conduct a Planning Reserve Margin Report (attached as Appendix D). The conclusion of Midgard's report is that it is prudent for FortisBC to adopt a WECC-recommended methodology for calculation of PRM, with such adjustments that consider the unique distinguishing aspects of the FortisBC system including the nature of the contracted resources and the operation of the Canal Plant Agreement. As a result the following criterion was developed as the basis for PRM design:

PRM = 5% of Load Responsibility + the Single Largest Utilized Contingency

The assessment of the capacity resource/ demand gap includes the need to provide for PRM based on this criterion.

1.2.5 CAPACITY RESOURCE / DEMAND GAP

Figures 1.2.5-A, 1.2.5-B and 1.2.5-C illustrate how the Company's owned and contracted resources are able to meet the forecast range of demand on its system, including the requirement for PRM, at different points in the planning period. Due to the nature of the resources available to it, as defined by the Canal Plant Agreement and related agreements, the

Company's capacity resource stack varies by month. As illustrated by the figures, when the WAX CAPA comes into effect in 2015, it will address most of the Company's short to medium term capacity gaps. Over the longer-term, peak load requirements begin to exceed the Company's firm resource requirements and new resources will be required to meet the capacity gaps as they continue to grow. As shown in the figures, the timing for new resources will depend on a number of factors including actual demand growth, success of DSM programs, and cost and availability of long term contract purchases.

Figure 1.2.5-A - 2020 Monthly Capacity Load / Resource Balance (MW)

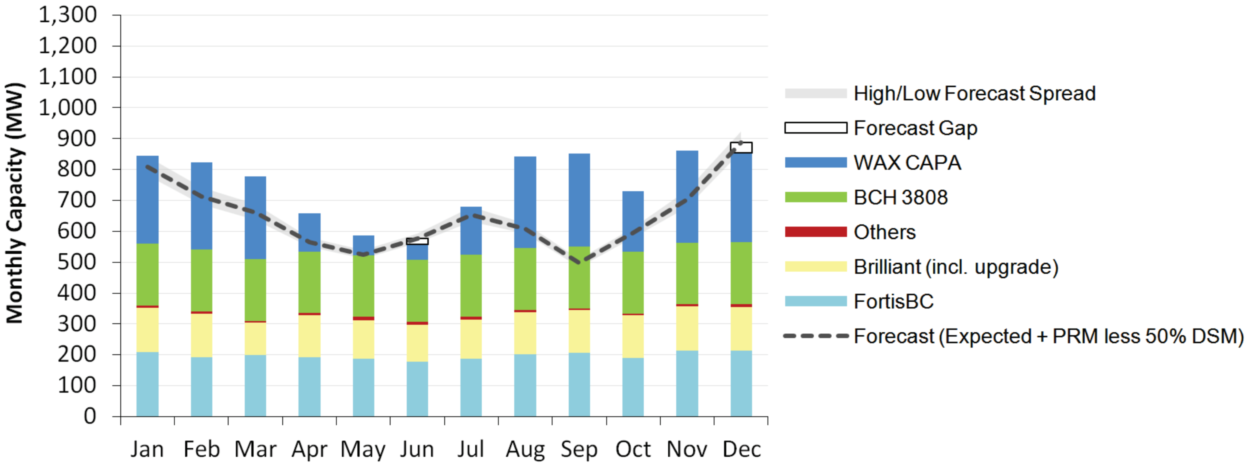


Figure 1.2.5-B - 2030 Monthly Capacity Load / Resource Balance (MW)

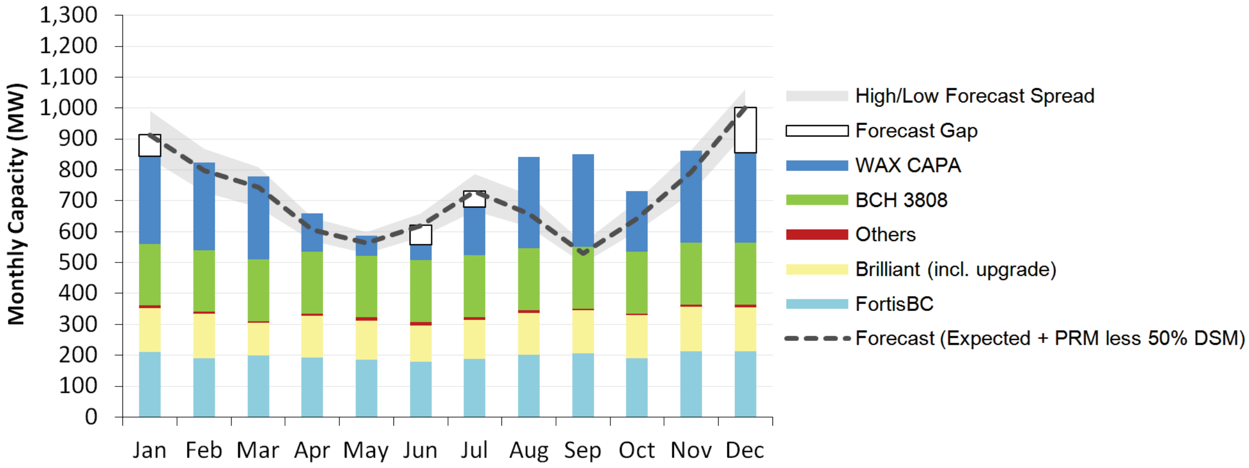
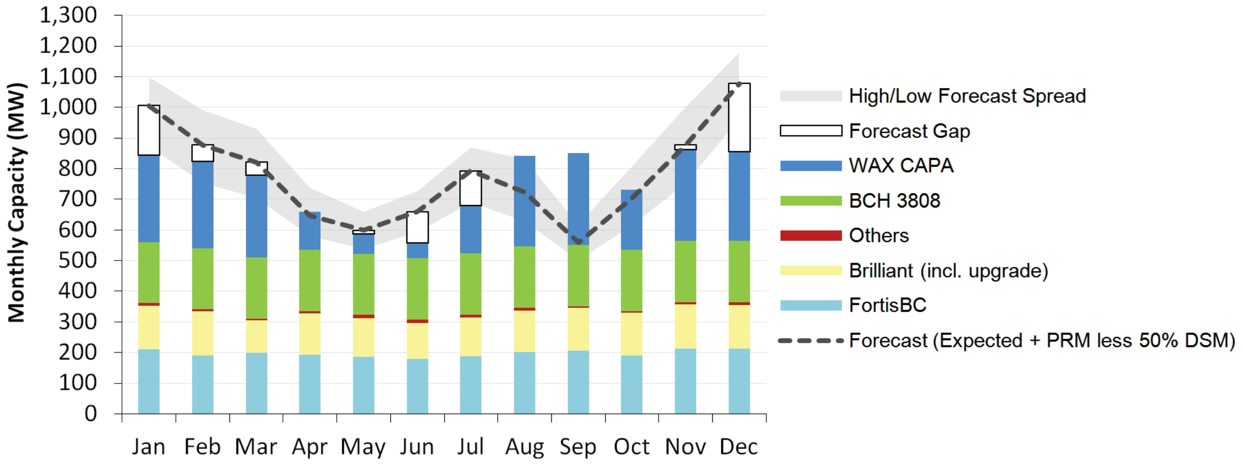


Figure 1.2.5-C - 2040 Monthly Capacity Load / Resource Balance (MW)



1.2.6 ENERGY RESOURCE / DEMAND GAP

Figure 1.2.6-A illustrates the high/expected/low annual energy gap over the 30-year planning horizon. As illustrated, the supply resources available to meet future demand growth assumes that the BC Hydro PPA will be renewed in 2013 and the Company will continue to have the right to the capacity and all associated energy that it has under the current agreement. The PPA provides significant benefits to FortisBC's customers, since it supplies them (through FortisBC) with power at BC Hydro's embedded cost and ensures they share with all British Columbians in the benefits of the heritage contract under the *BC Hydro Public Power Legacy and Heritage Contract Act*[5]. As a result, FortisBC expects to be able to meet part of its incremental energy requirements under the BC Hydro PPA, capped only by its 200 MW capacity right.

Nevertheless, although energy requirements are largely expected to be met with existing and contracted resources on an annual basis for the short to medium term, the nature of the resources and the shape of FortisBC's load will still result in winter energy gaps in the near term.

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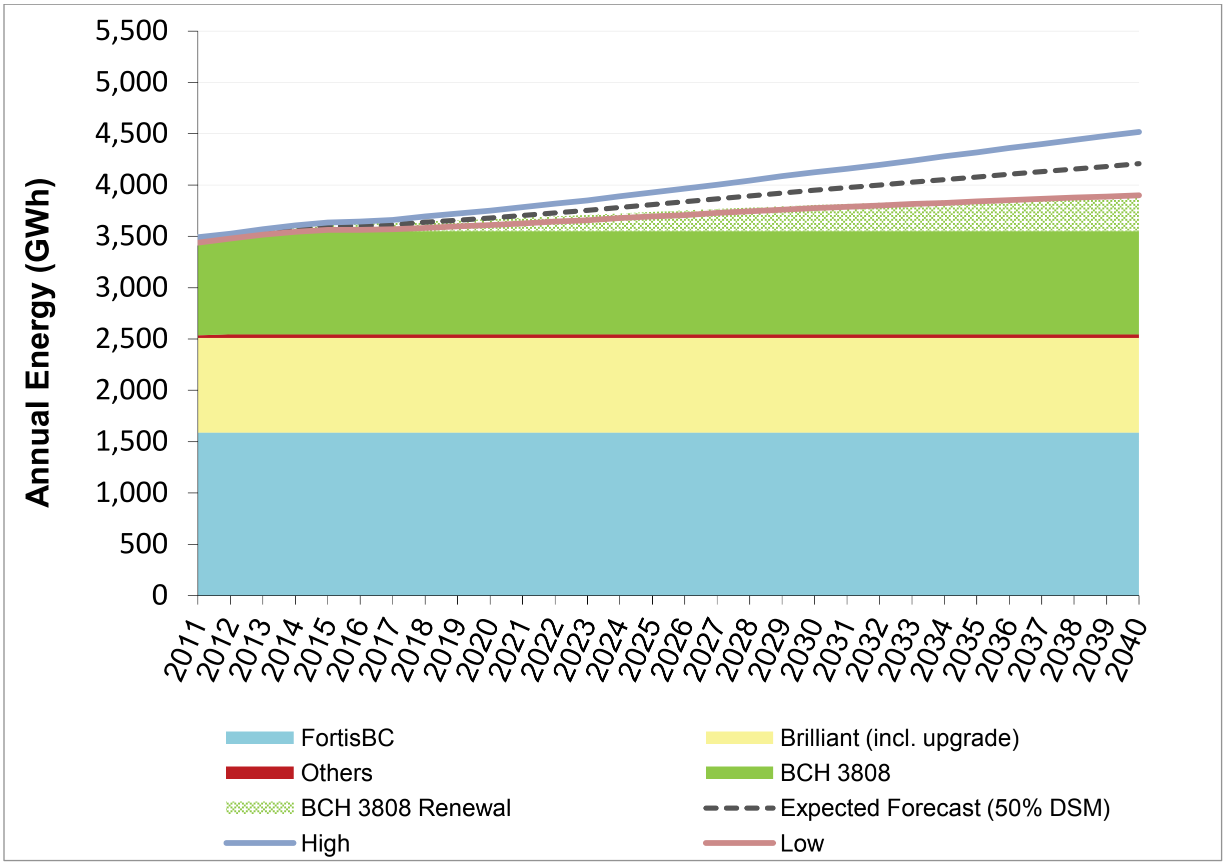
[5] BC Hydro Public Power Legacy and Heritage Contract Act, [SBC 2003] Chapter 86 http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/00_03086_01

Figure 1.2.6-A - Annual Energy Resource / Load Gap (GWh)



1.3 Resource Options and Strategies

The addition of the capacity available under the WAX CAPA in 2015 will serve to largely meet FortisBC's capacity requirements for the short to medium term. However, even with the existing and contracted energy resources, the Company is beginning to experience winter energy shortages which are forecast to increase. As part of developing a practical strategy to address its longer term capacity and energy requirements, FortisBC has considered a wide variety of potential resource options in order to identify the most economical resources applicable to its needs. FortisBC's resource options can be categorized into the following high level strategies:

1. New Resources (Build Strategy): includes resource options that cover a variety of generation technologies, but are always linked to a newly constructed facility;
2. Wholesale market (Buy Strategy): a contractual source of capacity or energy that may or may not be linked to a specific existing generation facility; and
3. Combined Strategy: A strategy that balances the attributes and risks of both the Buy and Build strategies over time.

The Company has evaluated the various resource options over three distinct time periods, short term (one to five years), medium term (six to ten years) and long term (beyond ten years), to account for uncertainty in longer range forecasts. The Resource Options and Strategies evaluation is fully discussed in Section 6 of this 2012 Resource Plan

1.3.1 BUILD STRATEGY

FortisBC engaged Midgard to update the Company's new resource option analysis resulting in the 2010 Resource Options Report (ROR) (attached as Appendix C), which evaluated the resource options available to FortisBC and ranked the resources based upon the economic metrics of unit capacity cost (UCC) and unit energy cost (UEC).

The Company then refined its resource option rankings by running the resource options that passed initial UCC and UEC econometric screening through a set of filters that represent key FortisBC priorities and requirement. The most attractive new resources that were identified are shown in Table 1.3.1.

Table 1.3.1 - FortisBC - Most Attractive New Resources

Rank	Capacity Requirements	Energy Requirements
1	Simple Cycle Gas Turbine (SCGT)	Similkameen Hydroelectric Project
2	Similkameen Hydroelectric Project	New Clean Energy Resources
3	Pumped Storage Hydro (PSH)	Combined Cycle Gas Turbine (CCGT)

1.3.2 BUY STRATEGY

FortisBC currently relies on the wholesale electricity market to meet an increasing proportion of its power supply requirements. The Company can purchase these products directly from the US electricity market or from BC Hydro's trading subsidiary Powerex. Although the Company's exposure to the wholesale market for capacity resources will be limited following commissioning of the WAX project in 2015, the Company's total energy gap is growing.

Wholesale market prices are presently attractive but ongoing reliance on market purchases of energy and capacity exposes FortisBC to future market price increases and volatility. Although the economic difficulties that began in 2008 have dampened electricity demand in the US and Canada, longer term economic growth will erode the region's resource surplus and could quickly drive up prices for energy and capacity in the wholesale market as product availability decreases and/or transmission constraints increase.

1.3.3 COMPARATIVE COSTS: BUILD VERSUS BUY

In order to forecast the price of future resources, the Company engaged Midgard to establish forecast cost curves for Wholesale Market Resources[6] and for New Resources[7]. These cost curves were combined with the Company's energy and capacity gap information to produce Wholesale Market (Buy Strategy) vs. New Resource (Build Strategy) cost comparisons, as shown in Figures 1.3.3-A and 1.3.3-B.

Figure 1.3.3-A - Buy Strategy vs. Build Strategy – Energy Costs

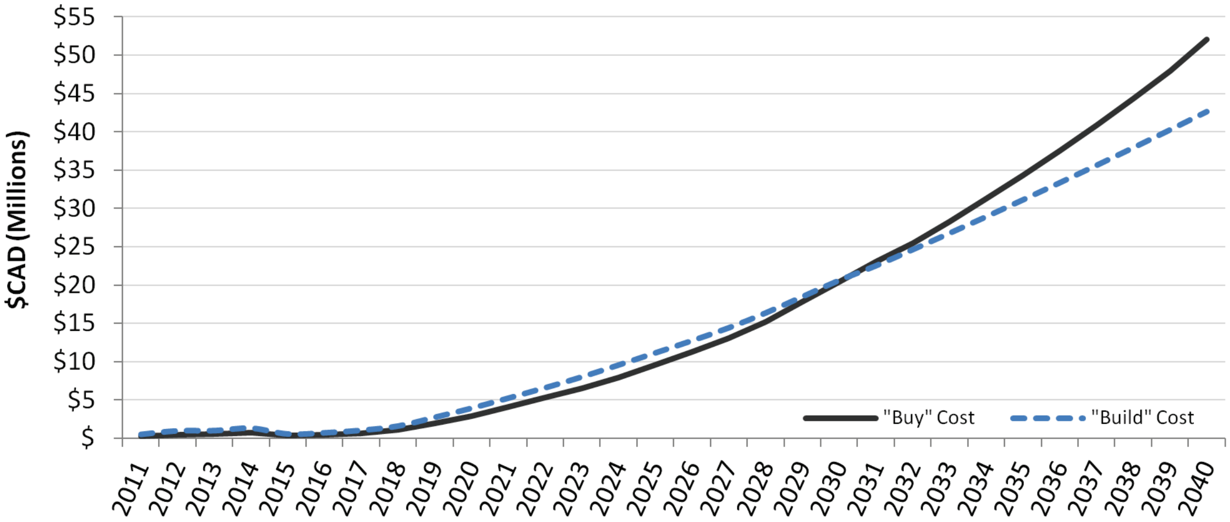
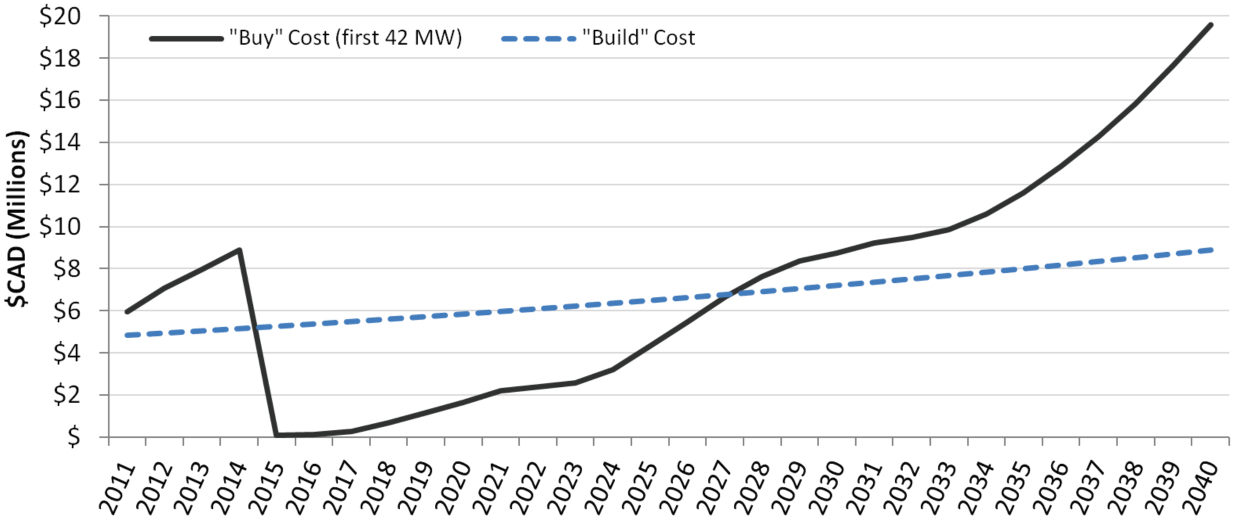


Figure 1.3.3-B - Buy Strategy vs. Build Strategy – Capacity Costs (First 42 MW Block)



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[6] 2011 Resource Plan Appendix B: 2011 Energy Market Assessment

[7] 2011 Resource Plan Appendix B: 2011 Energy Market Assessment

These comparisons show that over the short term (2011-2015) and medium term (2016-2020) it may be cost effective for FortisBC to continue relying upon the wholesale electricity market to meet its incremental energy and capacity needs. However, the Company will face growing cost and reliability risks if it relies upon the wholesale market to meet its energy and capacity needs over the long term (beyond 2020), and as a result Build Strategy alternatives should be assessed.

For more information regarding FortisBC's resource options analysis, see Section 6 of the 2012 Resource Plan.

1.4 Preferred Resource Acquisition Strategy

Table 1.4 outlines FortisBC's preferred resource acquisition strategy (Preferred Strategy). This Preferred Strategy represents a balanced and flexible approach to addressing FortisBC's forecast capacity and energy requirements by combining the Buy and the Build strategies. Presuming ongoing development work to maintain select new supply resources, the Preferred Strategy preserves a flexible approach to ensuring the correct supply solutions are delivered as and when needed, and in a manner that minimizes impacts to the Company's ratepayers. The Preferred Strategy is based on current price and load forecasts, which will be reviewed regularly. The renewal of the BC Hydro PPA may also impact the timing and nature of the Preferred Strategy if the final terms are different than what has been assumed in the 2012 Resource Plan. The Company will monitor these conditions and if they change, it may impact the timing and the nature of the Company's strategy. Any changes will be reflected in FortisBC's next Resource Plan.

Table 1.4 - FortisBC Preferred Resource Acquisition Strategy

Time Period	Capacity Solution	Energy Solutions
Short term (2011 – 2015)	• Wholesale market purchases of Capacity (Buy Strategy) as required • Early stage assessment of capacity resource options: i. SCGT ii. PSH iii. 60 MW Similkameen Hydroelectric Project	• Wholesale market purchases of Energy (Buy Strategy) • Early stage assessment of energy resource options: i. 234 GWh/year Similkameen Hydroelectric Project

Time Period	Capacity Solution	Energy Solutions
Medium term (2016 – 2020)	• Wholesale market purchases of Capacity (Buy Strategy) as required • Be prepared to accelerate the commissioning of one or more capacity resources (Build Strategy): i. SCGT ii. PSH iii. 60 MW Similkameen Hydroelectric Project	• Wholesale market purchases of Energy (Buy Strategy) • Early stage development of energy resource options: i. 234 GWh/year Similkameen Hydroelectric Project ii. 200 – 500 GWh New Clean Energy Resources
Long term (2021 – 2040)	• New Resources (Build Strategy) capacity resources by mid 2020s. One or more of: i. 1-2 x 42 MW SCGT ii. 100 - 200 MW PSH iii. 60 MW Similkameen Hydroelectric Project • Additional New Resources (Build Strategy) capacity resource in the 2030s. • Wholesale market purchases (Buy Strategy) remain an option to fill small residual gaps after capacity resource are commissioned.	• New Resources (Build Strategy) energy resources. One or both of: i. 234 GWh/year Similkameen Hydroelectric Project ii. New Clean Energy Resources • Wholesale market purchases (Buy Strategy) remain an option to fill small residual gaps after energy resources are commissioned.

For more information regarding FortisBC's Preferred Strategy, see Section 6.

1.5 Action Plan

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

1. Continuing to review and optimize the energy and capacity portfolio resources, which includes completing the renewal of the BC Hydro PPA, integrating the WAX CAPA into the FortisBC resource stack, and assessing the potential requirements and timing for new resource options.

2. Continuing to monitor and evaluate FortisBC's customer load growth, and assessing the PRM requirements

3. Liaising with provincial, regional and national energy and climate related policy makers, providing the FortisBC Utilities' expertise in energy issues and planning to the development of policy that will impact British Columbia's energy customers.

2 INTRODUCTION, PURPOSE AND CONTEXT

2.1 Introduction to FortisBC Inc.

FortisBC Inc. (FortisBC or the Company) is an integrated electric utility that generates, transmits and distributes electricity to customers in the southern interior of British Columbia. The Company serves approximately 161,000 customers directly and indirectly, focusing on the delivery of safe, reliable and cost effective electricity. FortisBC's customer base represents approximately 8 percent of British Columbia's electric utility customer total[8] and accounts for about 6 percent[9] of total provincial domestic sales.

In 2010 FortisBC had revenues of $257 million from sales of 3,046 GWh. FortisBC's peak capacity requirement was recorded in 2008 at 746 MW in December 2008 and summer peak was recorded at 569 MW in July 2007.

The Company owns four hydroelectric generating plants located on the Kootenay River between Nelson and Castlegar, British Columbia, with a combined installed capacity of 223 MW, and approximately 7,000 kilometres of transmission and distribution power lines.

2.2 Purpose of 2012 Resource Plan

The 2012 Resource Plan is a practical template to guide FortisBC, over the period from 2012 to 2040, in its acquisition and management of new power resources, in order to ensure that the actions the Company takes now are prudent over the 30-year planning horizon.

This 2012 Resource Plan analyzes the regulatory, policy, commercial and operational context within which FortisBC operates, its load and peak demand forecasts, its current resource capabilities and the potential generation resource options available to it to meet forecast needs over a 30-year planning period. As a result, the 2012 Resource Plan will enable the Company to achieve its goals of:

a) continuing to ensure the availability of cost effective long-term, reliable power for FortisBC's customers;

b) understanding the uncertainty and risks inherent in the Company's historic, current and proposed market purchase strategy; and obtaining firm power resources over time to achieve 100 percent self sufficiency, and

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[8] FortisBC / (BC Hydro + FortisBC) customers. Customer counts from FortisBC and BC Hydro 2010 Annual Reports.

[9] FortisBC / (BC Hydro + FortisBC) domestic sales. Sales information from FortisBC and BC Hydro 2010 Annual Reports.

c) balancing cost effectiveness with the directions and Policy Actions of the *Clean Energy Act*[10].

FortisBC has prepared and is filing this 2012 Resource Plan with the British Columbia Utilities Commission (the Commission or BCUC) in accordance with the applicable requirements of the *Utilities Commission Act*, R.S.B.C. 1996 c.473, (the Act), and in accordance with the Commission's "Resource Planning Guidelines".

2.3 Relevant Provisions of Utilities Commission Act (British Columbia)

Table 2.3-A presents the requisite contents for a public utility's long-term resource plan, as defined by Section 44.1(2) of the Act, and indicates the corresponding sections (found in this 2012 Resource Plan) in which these requirements have been addressed.

Table 2.3-A - Requisite Contents for a Resource Plan (Section 44.1(2) of the Act)

Section of the Act	Requirement Defined in the Act	Section(s) Addressing Requirement
44.1(2)(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[11] during the period addressed by the plan	5.1.4
44.1(2)(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	2012 Long Term DSM Plan filed June 30, 2011.
44.1(2)(c)	An estimate of the demand for energy that the public utility expects to serve after it has taken cost-effective demand side measures	5.2
44.1(2)(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)	6.4
44.1(2)(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)	6.4
44.1(2)(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	6, 6.4

Table 2.3-B presents the additional terms, as defined by Section 44.1(8) of the Act, which the Commission must consider prior to the acceptance of a long-term resource plan.

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[10] Clean Energy Act, S.B.C. 2010, chapter 22.

[11] Referred to as Demand Side Management (DSM) in this 2012 Resource Plan.

Table 2.3-B - Additional Terms Reviewed by the Commission (Section 44.1(8) of the Act)

Section of the Act	Terms the Commission Must Consider Prior to Acceptance	Section(s) Addressing Requirement
44.1(8)(a)	Applicable British Columbia energy objectives	2.4.2
44.1(8)(b)	The extent to which the plan is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*	6
44.1(8)(c)	Whether the plan shows that the public utility intends to pursue adequate, cost-effective demand side measures[12]	2012 Long-Term DSM Plan filed June 30, 2011
44.1(8)(d)	The interests of persons in British Columbia who receive or may receive service from the public utility	2.6

FortisBC has prepared this 2012 Resource Plan to satisfy the requirements defined in the Act (summarized above in Table 2.3-A and Table 2.3-B) relating to long-term resource planning.

2.4 Governmental Policy and Legislation Regarding the Environment

Environmental legislation, regulation and policies of both the Federal and Provincial governments directly impact FortisBC's resource planning process.

Certain regional collaborative policy initiatives of Provincial and State governments on each side of the Canada-United States border are also directly relevant to FortisBC's planning process.

Various other legislative and policy initiatives of the Federal and specific State governments in the United States may affect the wholesale electricity market in the western United States. This market operates adjacent to FortisBC's service territory and is a potential source of energy and capacity products for FortisBC. FortisBC believes it must remain aware of, and where appropriate, responsive to, the changing United States regulatory regime governing that market in order to adequately fulfill FortisBC's planning mandate.

Relevant governmental initiatives are discussed in Sections 2.4.1 to 2.4.3.

2.4.1 CANADIAN FEDERAL LEGISLATIVE/ REGULATORY FRAMEWORK

2.4.1.1 Framework for Regulating Air Emissions

The Government of Canada is committed to reducing Canada's total greenhouse gas emissions by 17 percent from 2005 levels by 2020[13]. The Government of Canada's plan to combat climate

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[12] The Clean Energy Act defines "demand side measure" as meaning "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".

change is embodied in a document entitled “A Regulatory Framework for Air Emissions” (the Framework).[14] The Government of Canada issued the Framework on April 27, 2007 as part of its overall “Turning the Corner: an Action Plan to Reduce Greenhouse Gases and Air Pollution” regulatory framework. The Framework contemplates that greenhouse gas emission reduction regulations will cover facilities in various industrial segments, including plants producing electricity by combustion. By 2015, a reduction in emissions intensity of 26 percent from 2006 levels must be met. The “Turning the Corner” regulatory framework envisions greenhouse gas emission reductions of 60 to 70 percent by 2050.

On March 10, 2008**,** the Government of Canada published further details of the “Turning the Corner” regulatory framework. This updated plan includes mandatory reductions for industry, along with additional new measures to address two of Canada's key emitting sectors: oil sands and electricity. The details of the plan include:

- establishing a market price for carbon;
- setting up a carbon emissions trading market, including a carbon offset system, to provide incentives for Canadians to reduce their greenhouse gas emissions;
- setting a target that will effectively require oil sands projects starting operations in 2012 to implement carbon capture and storage; and
- effectively banning the construction of new “dirty” coal plants starting in 2012.

The details of the plan specify how emissions targets will apply to each industry sector, how the offsets and trading systems will work, and how credits will be provided to companies taking early action to reduce their emissions.

2.4.2 BRITISH COLUMBIA LEGISLATIVE/ REGULATORY FRAMEWORK

2.4.2.1 Clean Energy Act

In 2010 the Government of British Columbia enacted the *Clean Energy Act*, S.B.C. 2010, c.22. The *Clean Energy Act* contains a set of 16 specific energy objectives for the Province of BC. The objectives relevant to FortisBC’s resource planning are listed in Table 2.4.2.1-A (see Appendix F for the complete list of *Clean Energy Act* objectives). The *Clean Energy Act* provides a guide to help the Province meet its self-sufficiency goals, to support job creation and retention, and to reduce greenhouse gas (GHG) emissions.

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[13] http://climatechange.gc.ca/default.asp?lang=En&n=72F16A84-0

[14] http://www.ec.gc.ca/default.asp?lang=En&n=4891B242-1#s3

The *Clean Energy Act* also adds several new social goals for the Province, including a greater focus on encouraging economic development, creating and retaining jobs, and encouraging economic development for First Nations and rural communities through the development of clean or renewable power.

Table 2.4.2.1-A - *Clean Energy Act* Objectives Impacting FortisBC's 2012 Resource Plan[15]

Section of the Act	***Clean Energy Act* Objectives**	**2012 Resource Plan Satisfies Objective**	
2(a)	To achieve electricity self-sufficiency;	✓	Key input in evaluating capacity and energy alternatives (see Section 6)
2(b)	to take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%;	✓	Key input in developing FortisBC's DSM target (see Section 5.1.4)
2(c)	To generate at least 93 percent of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;	✓	Key input in evaluating capacity and energy alternatives (see Section 6)
2(e)	To ensure that BC Hydro's ratepayers receive the benefits of the heritage assets and to ensure the benefits of the heritage contract under the BC Hydro Public Power Legacy and Heritage Contract Act continue to accrue to [BC Hydro's] ratepayers;	✓	See Section 5.1.2.1.1
2(g)	To reduce BC greenhouse gas emissions (i) by 2012 and for each subsequent calendar year to at least 6 percent less than the level of those emissions in 2007, (ii) by 2016 and for each subsequent calendar year to at least 18 percent less than the level of those emissions in 2007, (iii) by 2020 and for each subsequent calendar year to at least 33 percent less than the level of those emissions in 2007, (iv) by 2050 and for each subsequent calendar year to at least 80 percent less than the level of those emissions in 2007, and (v) by such other amounts as determined under the *Greenhouse Gas Reduction Targets Act*;	✓	Key input in evaluating capacity and energy alternatives (see Section 6)

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[15] http://www.leg.bc.ca/39th2nd/1st_read/gov17-1.htm; Bill 17 – 2010 Clean Energy Act, Part 1, Section 2

Section of the Act	***Clean Energy Act* Objectives**	**2012 Resource Plan Satisfies Objective**	
2(j)	To reduce waste by encouraging the use of waste heat, biogas and biomass;	✓	Key input in developing the New Clean Energy Resources recommendation (see Section 6)
2(m)	To maximize the value, including the incremental value of the resources being clean or renewable resources, of British Columbia's generation and transmission assets for the benefit of British Columbia;	✓	Key input behind future capacity options recommendation (see Section 6)

FortisBC recognizes that the *Clean Energy Act*'s treatment of BC Hydro's heritage resources has an impact upon FortisBC's resource planning process. The Government of British Columbia's 2002 Energy Plan legislated a "Heritage Contract" for an initial term of 10 years to ensure that BC Hydro's customers benefit from existing low cost heritage resources[16]. With the 2007 BC Energy Plan, the Government confirmed the Heritage Contract in perpetuity to ensure all of BC Hydro's customers will continue to receive the benefits of this low-cost electricity for generations to come. FortisBC is a customer of BC Hydro and BC Hydro's treatment of FortisBC affects FortisBC's customers. As discussed in further detail in Section 5.1.2.1.1, FortisBC is addressing the implications of this heritage resource issue in its discussions with BC Hydro for the renewal of the Power Purchase Agreement between FortisBC and BC Hydro (currently expiring in 2013).

The *Clean Energy Act* objectives have played an important role in shaping FortisBC's analysis and decision-making within the 2012 Resource Plan.

2.4.2.2 Western Climate Initiative

In 2007 the Government of British Columbia joined the Western Climate Initiative (WCI), which is a collaboration of certain Canadian provinces and US states[17] in a market-based climate program to reduce greenhouse gas emissions, promote a thriving economy and protect public health. WCI is committed to the development of a broad multi-sector "cap and trade scheme" as part of a comprehensive regional effort to reduce greenhouse gas emissions.

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[16] *BC Hydro Public Power Legacy and Heritage Contract Act*, [SBC 2003] Chapter 86. http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/00_03086_01

[17] Including British Columbia, Manitoba, Ontario, Quebec, Arizona, California, Montana, Oregon, New Mexico, Utah and Washington (with Saskatchewan, Yukon, New Brunswick, Nova Scotia, Idaho, Nevada, Colorado, Kansas, Alaska as well as additional Mexican states participating as "observer" jurisdictions)

In August 2007, WCI set an aggregate regional greenhouse gas emission reduction goal of 15 percent below 2005 levels by 2020. This regional goal is to be achieved by WCI partners through a cap and trade scheme, and complementary measures to reduce greenhouse gas emissions.

Five WCI Partner jurisdictions are working together to implement the regional emissions trading program. California, British Columbia and Quebec are working towards a 2012 start date. Ontario and Manitoba will join after the program starts.[18]

2.4.2.3 Greenhouse Gas Reduction Target Act

In 2007 the Government of British Columbia enacted the Greenhouse Gas Reduction Targets Act[19], S.B.C. 2007, c.42 (*GHG Targets Act*). The GHG Targets Act sets targets that are among the most aggressive in North America for reducing greenhouse gases. Under the *GHG Targets Act*, British Columbia's greenhouse gas emissions are to be reduced by at least 33 percent below 2007 levels by 2020. A further emissions-reduction target of 80 percent below 2007 levels is set for 2050.

2.4.2.4 Carbon Tax Act

On May 29, 2008, the Government of British Columbia enacted the *Carbon Tax Act*[20], S.B.C. 2008, c.40, which imposes a broadly based carbon tax on the purchase and use in British Columbia of fossil fuels such as gasoline, diesel, natural gas, heating fuel, propane and coal. The tax rates, effective July 1, 2008, were initially based on $10 per tonne per carbon dioxide equivalent (CO_2e) emissions from the combustion of each fuel. The tax rate then increased by $5 per tonne each year, reaching $30 per tonne by 2012. Specific tax rates vary for each type of fuel, depending on the amount of CO_2e emissions released as a result of its combustion.

2.4.3 US REGULATORY FRAMEWORK

2.4.3.1 Increasing Reliance on Renewable Portfolio Standards

Thirty US states currently have some type of Renewable Portfolio Standards (RPS)[21] with a Federal RPS initiative also being considered. The targets[22] established in these various RPS initiatives are expected to promote a large boost in the renewable composition of each region's

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[18] http://www.westernclimateinitiative.org/news-and-updates/129-wci-status-update

[19] http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/00_07042_01

[20] http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/00_08040_01

[21] States with Renewable Portfolio Standards. http://apps1.eere.energy.gov/states/maps/renewable_portfolio_states.cfm .

[22] The RPS targets vary, depending upon jurisdiction.

generation base and to change the mix of generation technologies that are anticipated to be built over the next decade. Across all North American Electric Reliability Corporation (NERC) regions between 2009 and 2018, approximately 409 GW of new generation capacity is expected to be built, of which 260 GW (or 64 percent) are expected to be renewable generation resources[23].

Wind generation resources are expected to comprise almost 90 percent of the incremental renewable generation resources in North America - increasing from 28 GW in 2009 to 256 GW in 2018. Despite this large increase in wind generation as a percentage of the overall installed capacity, wind resources are only anticipated to contribute 38 GW to peak capacity needs.24 In other words, although wind generation resources will make a material contribution to the total installed generation capacity between now and 2018, its contribution to the electricity system's ability to meet its peak demand is modest.

As a result, additional power firming resources will be needed to facilitate the operational integration of these wind resources (and other intermittent generation resources) into the electricity system.

Within the Northwest Power Pool (NWPP)[25] area (a sub-region of the Western Electricity Coordination Council, or WECC) the situation is similar to that of North America as a whole. Between 2009 and 2018, 17 GW of new generation resources are expected to be built, of which 7 GW will be wind resources and 3 GW other renewable resources.[26]

The current quantity of installed wind generation resources has caused Bonneville Power Administration (BPA) and other balancing authorities to "increase their Reserve Margins to compensate for the variability of these [wind] resources"[27]. However, BPA claims that "the federal dams do not have the flexibility to provide such high levels of reserves without violating

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[23] North American Electric Reliability Corporation, 2009 Long-Term Reliability Assessment, October 2009, page 22, table 5. http://www.nerc.com/files/2009_LTRA.pdf

[24] North American Electric Reliability Corporation, 2009 Long-Term Reliability Assessment, October 2009, page 22, table 5. http://www.nerc.com/files/2009_LTRA.pdf

[25] The Northwest Power Pool Area consists all or the majority of Idaho, Montana, Nevada, Oregon, Utah, Washington and Wyoming, as well as British Columbia and Alberta.

[26] North American Electric Reliability Corporation , 2009 Long-Term Reliability Assessment, October 2009, page 156. http://www.nerc.com/files/2009_LTRA.pdf

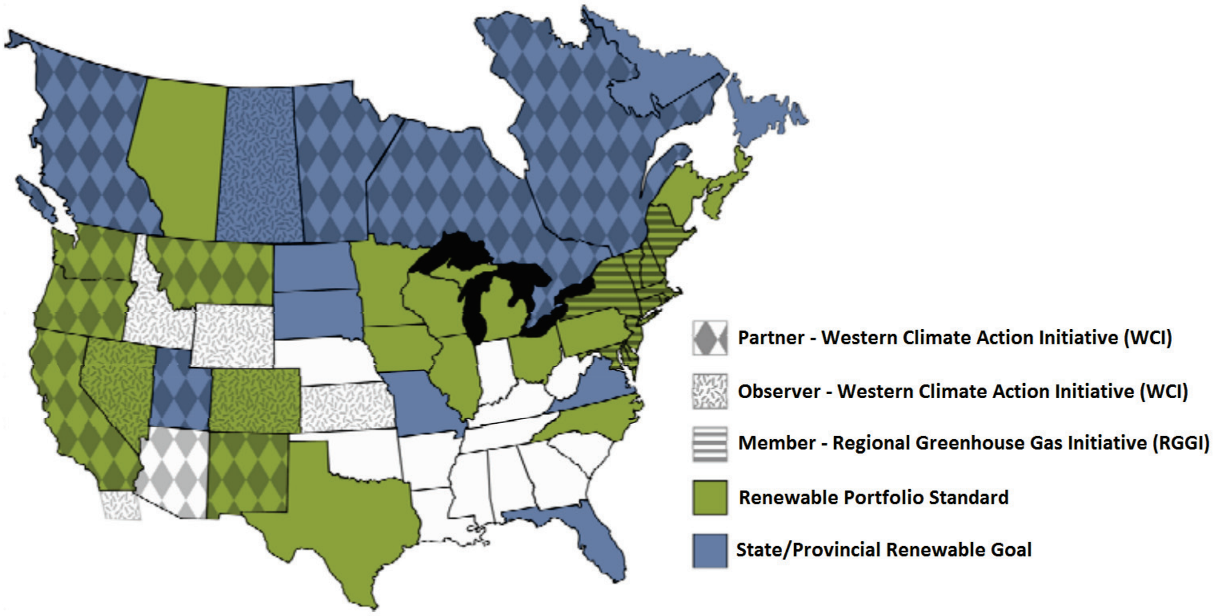
[27] North American Electric Reliability Corporation, 2009 Long Term Reliability Assessment, October 2009, page 153. http://www.nerc.com/files/2009_LTRA.pdf

stream flow or fish protection requirements"[28]. It is believed that between 3 and 3.5 GW of wind resources could be supported under current reserve margin protocols – a figure well below the 7 GW of wind generation capacity expected to be installed over the next decade.

2.4.3.2 State and Local Initiatives to Limit CO_2 Emissions

Two regional initiatives – the Regional Greenhouse Gas Initiative (RGGI) in the New England area and the Western Climate Initiative (WCI) in the west - remain at the forefront of US efforts to reduce greenhouse gas emissions on a regional basis (see Figure 2.4.3.2-A for a geographical layout). Additionally, legislation on climate change continues to be debated at the US Federal level.

Figure 2.4.3.2-A - Snapshot of North American Climate Change Initiatives[29]



Washington, Oregon, and California have each proposed a number of emissions reduction projects under the "West Coast Governors Global Warming Initiative". Currently, both Oregon and Washington require new power plants to offset a certain portion of their anticipated CO_2 emissions. Similarly, the California Public Utilities Commission requires that a "carbon adder" (an estimate of the cost of complying with future carbon emission limits) be used by the State's utilities when comparing the costs of alternative generation during resource planning processes.

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[28] North American Electric Reliability Corporation, 2009 Long Term Reliability Assessment, October 2009, page 153. http://www.nerc.com/files/2009_LTRA.pdf

[29] North American Electric Reliability Corporation, 2009 Long-Term Reliability Assessment, October 2009, page 8. http://www.nerc.com/files/2009_LTRA.pdf

In May 2007, Washington State adopted a new law regulating greenhouse gas emissions (Senate Bill 6001). The law has two key components that affect electric utilities. The first component is a set of guidelines pertaining to emission rates for CO_2 from new electric resources (whether owned or contracted). The second component sets goals to reduce total greenhouse gas emissions in the state to 1990 levels by 2020, 75 percent of 1990 levels by 2035, and 50 percent of 1990 levels by 2050.

Although the various initiatives are not expected to have a material impact upon the reliability of the bulk electricity system in the near future, the uncertainty surrounding the timing of the initiatives and the potential legislation may postpone or delay investment decisions with regards to the addition and mix of future generation resources. In the meantime, these climate change initiatives reinforce the trends discussed earlier in this section – namely the planned addition of renewable (i.e. non-emitting) generation resources.

2.4.3.3 Demand Side Management as a Source of Capacity

In addition to RPS, another common policy initiative is to encourage Demand Side Management (DSM) programs.

Capacity-focused DSM programs consist of automatic, contractual, or voluntary reductions in electricity consumption. Energy efficiency targets consist mainly of programs that lower consumers' energy requirements or decrease their energy intensity (produce the same quantity of output with a lower energy input).

DSM and energy efficiency targets play an important role in reliability and resource adequacy planning, and that role will continue to grow in importance as DSM becomes an ever larger component shaping the overall resource portfolio.

Widespread adoption of RPS as well as climate change legislation and directives continue to encourage a high proportion of new renewable generation resource additions. As renewable generation resources comprise an increasing percentage of the total installed generation capacity the demand for capacity resources is anticipated to rise in order to 'firm up' the intermittent generation.

Additionally, the widespread adoption of DSM programs and energy efficiency targets as substitutes for firm generation resources has injected a large amount of uncertainty into future load forecasts. Should load growth exceed forecasts, reliance on DSM and energy efficiency programs may lead to both energy and capacity deficits. Overall failure to meet these DSM and efficiency targets could make system operations more challenging.

Consequently, dependable capacity resources may be subject to greater price volatility and become scarcer in the future as compared to the present situation.

2.5 Recent BC Hydro Resource Planning Initiatives

Since FortisBC's last Resource Plan was reviewed by the Commission in 2005, BC Hydro has completed two iterations of its long term resource planning process: the 2006 Integrated Energy Plan, and the 2008 Long Term Acquisition Plan. BC Hydro's efforts help provide the context within which FortisBC must plan for its own resource requirements.

2.5.1 BC HYDRO 2006 INTEGRATED ENERGY PLAN

In 2006, BC Hydro submitted to the Commission an Integrated Electricity Plan and a Long-Term Acquisition Plan. The regulatory review process culminated on May 11, 2007 in the Commission's issuance of Order No. G-29-07. The Reasons for Decision issued concurrently with Order G-29-07 reinforce the content of the Commission's Resource Planning Guidelines and are instructive for FortisBC in its own resource planning process in a number of respects, including the following:

- **Stakeholder involvement** – While the Commission instructs utilities to engage stakeholders in their resource planning, at the same time it requires those utilities to set the objectives and own the management of their respective plans.[30]
- **Load forecast instructions** – The Commission stated that "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."[31]
- **Self Sufficiency** – The Commission observed that the government's self-sufficiency policy applies to the Province, not just to BC Hydro, and is targeted for achievement in 2016.[32]

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[30] BCUC *Decision on BC Hydro 2006 Integrated Energy Plan (IEP) and Long Term Acquisition Plan (LTAP)*. May 11, 2007, Page 31.

[31] BCUC *Decision on BC Hydro 2006 Integrated Energy Plan (IEP) and Long Term Acquisition Plan (LTAP)*. May 11, 2007, Page 43.

[32] BCUC *Decision on BC Hydro 2006 Integrated Energy Plan (IEP) and Long Term Acquisition Plan (LTAP)*. May 11, 2007, Page 128.

2.5.2 BC HYDRO 2008 LONG TERM ACQUISITION PLAN

BC Hydro's 2008 Long-Term Acquisition Plan (BC Hydro 2008 LTAP) was a 10-year plan for meeting electricity demand in British Columbia. It was a follow-up plan to BC Hydro's 2006 Integrated Electricity Plan/Long-Term Acquisition Plan.

The BC Hydro 2008 LTAP included the following targets:

- at least 50 percent of future incremental resource needs are to be met through conservation by 2020;
- 90 percent of electricity is to come from clean or renewable sources and all new electricity generation projects are to have zero net greenhouse gas emissions; and
- BC Hydro is to be self-sufficient by 2016.

BC Hydro anticipated that demand for electricity will grow by approximately 25 to 40 percent over the subsequent 20 years, which (without taking into account the measures proposed by the BC Hydro 2008 LTAP) would result in an energy shortage of approximately 22,000 GWh per year and a capacity shortage of 3,000 MW by 2028.

Table 2.5.2-A lists the measures that BC Hydro proposed to use to mitigate the projected growth in electricity demand. The current status of the proposed measures is also included within the table.

Table 2.5.2-A - 2008 LTAP Objectives and Current Status

2008 LTAP Measure	Current Status
Conservation, which is expected to save more than 10,000 GWh per year by 2020.	In its 2010 Resource Options Update process BC Hydro forecasts DSM Energy savings of between 8,000 GWh and 13,000 GWh depending on selected DSM Options
BC Hydro will seek power from new sources of clean energy. This includes its Clean Power Call and its two-phase Bioenergy Call for Power.	BC Hydro has awarded Energy Purchase Agreements (EPAs) to 27 projects through the 2008 Clean Power Call (approximately 3,300 GWh)[33]. Phase 1 of the Bioenergy call is complete (four EPAs awarded). Phase 2 is currently in the request for proposals stage and nearing completion.

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[33] BC Hydro Press Release, August 3, 2010 (http://www.bchydro.com/news/articles/press_releases/2010/bch_reaches_clean_energy_milestone.html)

2008 LTAP Measure	Current Status
BC Hydro plans to continue to rely on the Burrard Thermal generating plant for capacity support and backup energy supply to the Lower Mainland / Vancouver Island region, at least until completion of the proposed Interior-to-Lower Mainland (ILM) transmission line.	BC Hydro temporarily will rely on the Burrard Thermal generating plant for capacity support and back-up energy until the ILM line is commissioned.
BC Hydro will complete the definition phase work on "Mica Units 5 and 6". This could lead to the addition of two generating units at the Mica Dam, which would add new long-term dependable capacity to the BC Hydro system.	The Mica 5 and 6 expansion project for long-term dependable capacity is underway.
Project definition and consultation phase work on Site C will continue. Site C is a potential third dam on the Peace River, which would take advantage of the large amount of water stored upstream in the existing Williston Reservoir and would have an operating life of more than 100 years. Based on the proposed schedule, the earliest Site C could operate would be 2019.	BC Hydro has submitted a Project Description Report for the Site C project to federal and provincial environmental assessment agencies. The filing is the first step to initiate an environmental assessment for Site C
Demand Side Management[34]	BC Hydro is making efforts to meet or exceed the DSM requirements established by the *Clean Energy Act*.

2.5.3 BC HYDRO LOAD AND RESOURCE FORECAST

In preparation for its 2011 Integrated Resource Plan, BC Hydro set out its load and resource forecasts for both energy and capacity. Figure 2.5.3-A is a copy of BC Hydro's Energy Load Resource Balance chart, and Figure 2.5.3-B is a copy of BC Hydro's Capacity Load Resource Balance chart. In the case of both energy and capacity, BC Hydro's plans call for new resources to meet forecast deficits.

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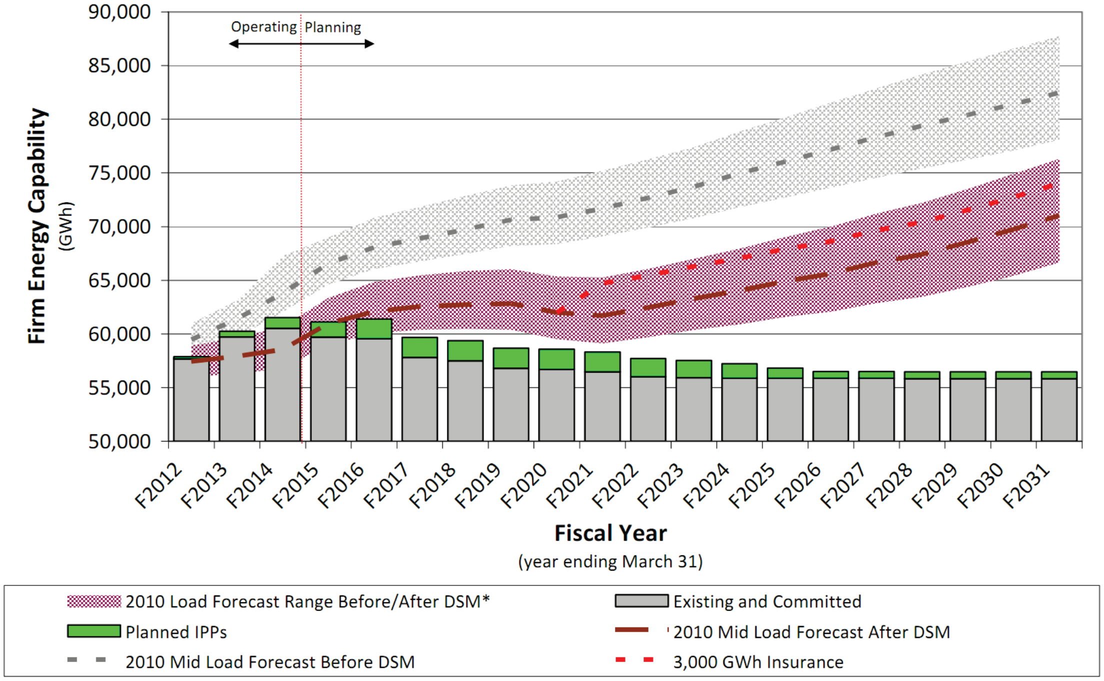
[34] BC Hydro, *Conservation, clean resource options key elements of 2008 Long-Term Acquisition Plan*, press release dated June 13, 2008.

Figure 2.5.3-A - BC Hydro 2011 Integrated Resource Plan Energy / Load Resource Balance[35]



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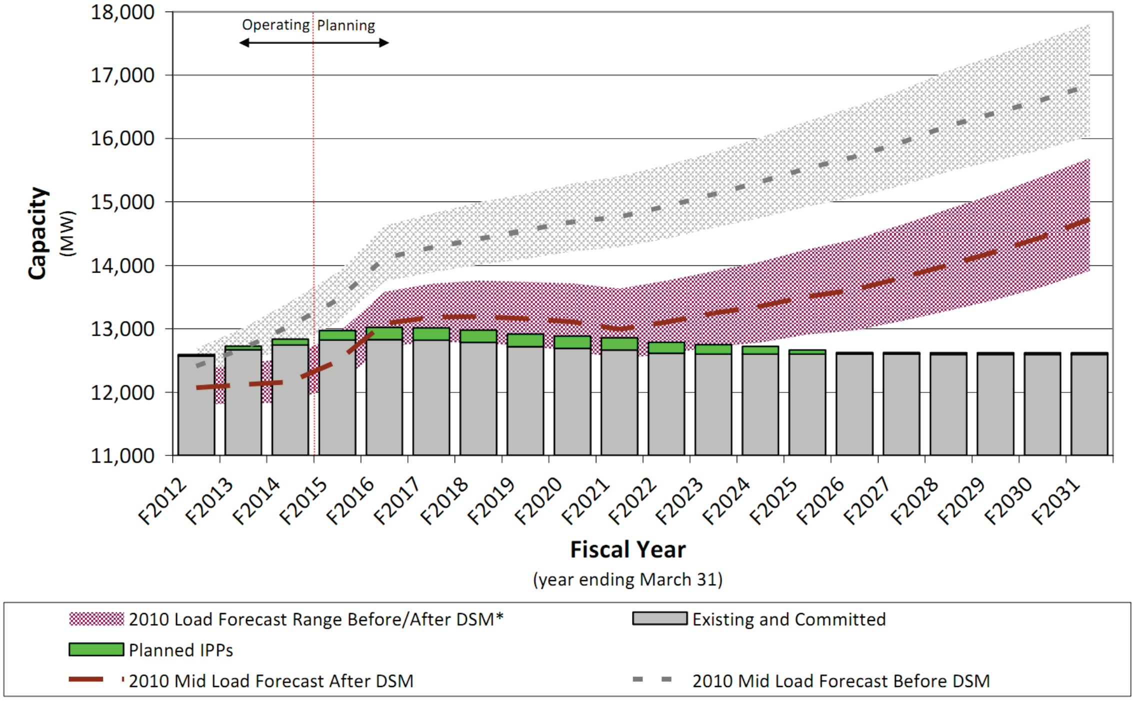
[35] BC Hydro *2011 IRP Technical Advisory Committee Summary Brief: Load Resource Balance* dated December 14, 2010

Figure 2.5.3-B - BC Hydro 2011 Integrated Resource Plan Dependable Capacity Load / Resource Balance[36]



2.6 Stakeholder Consultation

As part of its Integrated System Plan (ISP) public consultation process, FortisBC sought public input on issues that impact resource planning, including planning reserve margin and supply options. During the public consultation process, the most comprehensive feedback was provided through Super Groups, which collected input from a representative sample of customer classes and solicited in-depth feedback from a number of individuals. The following feedback was provided by Super Groups on issues that directly impact the Resource Plan:

- 96 percent of customers support holding a Planning Reserve Margin, with 60 percent willing to pay higher rates for the Planning Reserve Margin.
- 75 percent support the use of contractual agreements to fill small gaps in short term energy supply rather than building new generation resources.
- Electrical rate increases are a concern across all potential ISP related initiatives. Kootenay participants are more price sensitive and consequently, they are less willing to accept rate increases for ISP initiatives.

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[36] BC Hydro *2011 IRP Technical Advisory Committee Summary Brief: Load Resource Balance, dated December 14, 2010*

A report on public consultation undertaken for the Company's 2012 Integrated System Plan, including the 2012 Resource Plan, is found at Appendix K of the 2012 Long Term Capital Plan (2012 Integrated System Plan, Volume 1).

3 ELECTRICITY MARKET ANALYSIS

FortisBC currently relies on its own generation resources and long-term contracts to meet the majority of its power supply requirements. It also relies on the wholesale electricity market to meet power supply gaps. FortisBC feels its strategy of making market purchases to close the gap between its supply and demand has generally been successful.

Midgard Consulting Inc. (Midgard) was engaged in 2010 by FortisBC to assess the expected cost and availability of energy and capacity products in the electricity markets in BC and the surrounding region over the next 30-year period. The Midgard report included the following forecasts:

- British Columbia Wholesale Market Energy (electricity) price curve;
- British Columbia New Resources Market Energy (electricity) cost curve;
- British Columbia Wholesale Market Capacity price curve;
- British Columbia New Resources Market Capacity cost curve;
- Greenhouse Gas cost price curve.

This section draws upon and discusses the conclusions of the Midgard 2011 Energy Market Assessment, which is attached as Appendix B.

3.1 Supply and Demand Overview

3.1.1 AVAILABLE MARKET SUPPLY

FortisBC is a member of the Western Electricity Coordinating Council (WECC), which is a voluntary organization responsible for coordinating and promoting electric system reliability in the region that includes British Columbia and Alberta, the northern portion of Baja California and all or portions of the 14 western American states in between. WECC's purpose is to support efficient, competitive power markets, to assure open and non-discriminatory transmission access among members, to provide a forum for resolving transmission access disputes, and to provide an environment for coordinating the operating and planning activities of its members. WECC has been delegated authority from the North American Electric Reliability Corporation (NERC)[37] to monitor and enforce compliance with United States reliability standards.

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[37] NERC, a nonprofit corporation based in Princeton, NJ, was formed by the electric utility industry to promote the reliability and adequacy of bulk power transmission in the electric utility systems of North America.

As a member of WECC, FortisBC can draw upon a large wholesale electricity market to serve its incremental load requirements. Energy and capacity are available in that market from various utilities and independent power producers who have surplus power available for sale or exchange. The surpluses are typically the result of either those utilities' own loads not being as high as forecast or their supplies of electricity being higher than forecast and/or higher than their needs, such as may be the case during a wet or windy period. Alternatively, energy may be procured from independent asset owners who have under-utilized capacity and available fuel.

WECC is a dual peaking electricity system - the southern part of WECC is summer peaking while the northern part is winter peaking. FortisBC is presently primarily concerned about the availability and cost of energy and capacity during the winter months.

Surplus power is typically available in BC and the Pacific Northwest from hydroelectric plants during the spring freshet or during years of above-average precipitation. Some utilities, BC Hydro being the most prominent, can store energy in their hydroelectric reservoirs and are usually able to provide power to the market at any time for the right price. The market price of energy and capacity is directly related to the amount and timing of this surplus power, the (fuel) input costs, the availability of fuel to generate the surplus power (for example, water stored in a reservoir), and the cost of transmission between the buyer and seller.

3.1.2 CONSTRAINTS ON MARKET AVAILABILITY

Market shortages and transmission constraints can limit the physical availability of power in the wholesale electricity market, which impacts the price at which power can be purchased as well as the duration, terms and conditions of any purchases.

3.1.2.1 Market Shortages

Market shortages occur when supply is inadequate to meet load demand and mandatory operating reserves – this can be caused by a number of factors, including extreme or extended hot or cold weather conditions, regional drought conditions, generating unit or transmission outages, and structural changes in load growth.

Despite short-term load relief that has resulted from the recent economic downturn, FortisBC believes that longer term supply in the WECC region will become increasingly tight, as reflected in the WECC 2010 Power Supply Assessment[38]. Of particular concern to FortisBC is that the WECC-Canada sub-region is expected to fall below NERC's prescribed adequacy reserve

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[38] Western Electricity Coordinating Council 2010 Power Supply Assessment, Amended September 27, 2010. http://www.wecc.biz/Planning/ResourceAdequacy/PSA/Documents/2010%20Power%20Supply%20Assessment.pdf

margins by winter 2012[39]. This places the WECC-Canada sub-region at the very bottom of all NERC sub-regions for this assessment category and exposes FortisBC to price risk and potentially availability risk for any necessary market purchases.

FortisBC directly experienced the impact of market shortages in July 2006, when it was required to purchase 1,680 MWh at an average price of $225 per MWh to serve exceptionally high customer loads during an extended region-wide hot spell. Although the purchase price of this energy was high, the alternative of shedding customer load was not considered a reasonable solution.

In a more recent example, during a regional cold spell that occurred in November 2010 FortisBC purchased a 150 MW block of energy in the day-ahead market to address an anticipated extreme load demand. When FortisBC attempted to purchase an additional 10 MW in the real-time market the following day there was no supply available for purchase in the market (at any price). A similar situation occurred the following week. If during any of these times FortisBC's largest single supply unit (Brilliant) had become unavailable, the Company would have had to draw upon excess BC Hydro PPA capacity (estimated at approximately $1 million) to avoid shedding load.

3.1.2.2 Transmission Interconnection Constraints

A further key consideration for FortisBC is the transmission transfer limit at the three interconnections on the British Columbia / United States border[40] and at the two interconnections on the British Columbia / Alberta border.

The British Columbia / Alberta and the British Columbia / United States transmission interconnections often operate at their maximum available transfer limits; therefore wheeling additional power between utilities in the region is frequently not possible. Given that a key source of wholesale market electricity for FortisBC is the United States, these constraints are becoming increasingly important for FortisBC because they restrict access to wholesale market electricity. Further, as power generation and power demand in the WECC region continues to grow, FortisBC expects that, absent construction of new transmission infrastructure, transfer constraints will become even more severe.

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[39] North American Electric Reliability Corporation, 2010 Long-Term Reliability Assessment, October 2010, page 2. http://www.nerc.com/files/2010_LTRA_v2-.pdf

[40] Including the one merchant transmission line, owned by Teck Resources Limited at Trail, BC.

It should be noted that FortisBC has no transmission facilities that connect directly with markets outside of BC. Accordingly, FortisBC is dependent on the availability of adequate third-party transmission capacity to serve its needs, putting at risk the long-term reliable availability of wholesale market electricity to serve its growing demand.

3.1.3 WESTERN MARKET TRENDS

A number of developments in the WECC market may have a material impact on FortisBC's interests in future years. Some of these trends have the potential to increase reliability and price risks for both capacity and energy, and those impacts will need to be reassessed at the time FortisBC issues its next Resource Plan update.

3.1.3.1 Renewable Portfolio Standards

Many provinces and states in the WECC region are implementing Renewable Portfolio Standards (RPS), which mandate that a specified percentage of their electricity generation must come from specified renewable resources. Of US states that do have a RPS, California's is the most aggressive (33 percent renewables by 2020) while Arizona's is the least (15 percent renewables by 2025)[41]. California's is particularly important given that the state consumes almost one third of WECC's energy annually[42].

Those regions that do have RPS are increasingly looking to wind energy to meet their renewable targets. While wind can generate a generally predictable amount of energy each year, its ability to supply dependable capacity on shorter timeframes is limited. Thus, integration of intermittent wind resources requires dependable capacity resources to "firm" the wind capacity. This need for firming capacity will tax the existing capacity resources in the WECC region as regulating authorities become forced to use what was previously excess capacity to meet this firming requirement. This consumption of capacity resources for firming will decrease the supply of capacity available to the energy market.

3.1.3.2 Demand Side Management

Demand Side Management (DSM) programs are being widely introduced into many WECC jurisdictions. DSM achievement is difficult to measure and there is a time lag before actual DSM success can be quantified through impact analysis. Widespread failure to achieve DSM targets can affect the wholesale capacity market because DSM may be used to rationalize delayed installation of new generation and capacity resources, and the load shaping and peak shaving

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[41] PEW Center on Global Climate Change. http://www.pewclimate.org/what_s_being_done/in_the_states/rps.cfm

42 California Energy Almanac Total System Power Reporting: http://www.energyalmanac.ca.gov/electricity/total_system_power.html

measures of DSM programs may not materialize as expected. If DSM fails to mitigate load growth in the medium to long term, this failure may result in eroded capacity surpluses, increased prices, and a scarcity of wholesale market capacity products.

3.1.3.3 Potential WECC Transmission Construction Delays

NERC data collected on current and future transmission line construction projects show that 6,500 out of 27,000 miles of planned North American high voltage transmission lines are currently delayed[43]. Should WECC construction patterns prove to be consistent with this observation, delays can be expected in the addition of required new transmission capacity. Delaying transmission capacity additions may have an adverse impact upon FortisBC's ability to access wholesale markets in the future because growing regional loads without corresponding transmission infrastructure additions will lead to increased transmission constraints, which in turn will lead to increased wholesale market energy and capacity prices.

3.1.3.4 Clean Energy Act

BC's 2010 *Clean Energy Act* mandates that by 2016 BC Hydro must be self-sufficient, and by 2020 must acquire the rights to 3,000 GWh of energy above its anticipated needs[44], referred to as “insurance” in the *Clean Energy Act*. This amount of energy is equivalent to 5 percent of BC's current annual energy consumption, and applies to BC Hydro's mandate to become energy self-sufficient. Self sufficiency is based upon critical low-water year hydrology, therefore during any better-than-critical water year BC Hydro will have a surplus of energy generation available. These surpluses may mean that BC Hydro (and Powerex, its trading arm) will be active sellers of energy in the medium term, which in turn could translate into conveniently located energy available for which FortisBC could compete.

3.1.3.5 Alberta Energy Market

The Alberta electricity market is approximately the same size as the British Columbia electricity market. Unlike BC however, Alberta is a deregulated market, which means that the prices of electricity can and do vary by the hour, and decisions to add new generation capacity are driven primarily by market forces. Alberta's loads are expected to grow at a rate that is higher than most other sub-regions in WECC. Moreover, a considerable amount of wind generation has been constructed in Alberta over the past fifteen years and more additions are planned, which

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[43] North American Electric Reliability Corporation, 2010 Long-Term Reliability Assessment, October 2010, page 23. http://www.nerc.com/files/2010_LTRA_v2-.pdf

[44] *Clean Energy Act* [SBC 2010] Chapter 22, section 6

will expose Alberta to the constraints associated with integrating wind resources as discussed in Section 3.1.3.1 above.

Given that Alberta and BC are both winter-peaking systems, there is the potential for Alberta to become a competitor for wholesale market capacity resources in the coming years. The extent to which this occurs will depend on how much reliable new capacity Alberta builds, how soon it builds that capacity, and the timely provision of supporting transmission links. FortisBC must be aware of the likelihood of competing with Alberta when considering whether to secure firm capacity supplies from the Wholesale market.

3.2 Market Pricing

The market price in a wholesale electricity market is established by the most costly megawatt hour produced and required at that time to serve load. This price is known as the marginal cost of supply since it is based upon the marginal cost of production by the last generating unit dispatched to serve load.

Generally, during off-peak periods when load demand is low, the marginal cost of production is determined by the incremental operating costs of base-loaded generators such as coal and nuclear plants. On-peak marginal prices in the WECC region (and most other NERC regions) are often set by natural gas fired generators, which historically have more expensive marginal costs than base-loaded coal and nuclear facilities, but this is changing, for reasons explained here.

Intermittent renewable resources such as wind, run-of-river hydro and solar generators comprise an increasing percentage of the generation capacity in the WECC. These generators must sell into the market when their fuel is available since their fuel cannot be stored[45]. Such facilities typically do not directly set the marginal market price because they accept whatever market price is available and are therefore classed as “price takers”. However, although intermittent resources do not directly set the market price, they can influence market price by displacing more costly generation during times of fuel abundance, such as during windy, wet or sunny periods.

Owners of storage hydroelectric facilities will often attempt to shadow price the market clearing price to maximize profit margins, with the exception that when they are at risk of spilling water they will also act as price takers.

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[45] Hydro generators typically pay a water rental fee.

Overall WECC market prices are predominantly driven by three key factors: hydrology, natural gas prices and transmission constraints.

3.2.1 HYDROLOGY

Hydroelectric generation comprises over 30 percent of WECC capacity and almost 55 percent of the capacity in the NWPP region[46]. The total available annual energy from this generation is dependent upon the amount and timing of precipitation in the various WECC drainage basins. Precipitation during maximum water years can be 50 percent greater than in minimum water years, therefore precipitation can materially affect regional market supply and pricing. Differences between basins can create intra-WECC transmission constraints as generation from surplus areas seeks markets in higher priced areas.

3.2.2 NATURAL GAS PRICES

Over 40 percent of the generating capacity in the WECC region is produced from natural gas (or dual fuel) fired generation plants. The cost of natural gas is the single most important factor influencing the variable cost of a gas-fired plant. Therefore the marginal cost of electricity in WECC markets during on-peak load periods tends to be highly correlated with the cost of natural gas[47]. Natural gas prices have fallen substantially with the development of the shale gas plays in recent years, and continue to fall in the short-term.

3.2.3 TRANSMISSION

Another key factor that can influence market price is the availability of transmission. Transmission constraints restrict the free flow of lower priced power into load centres, thus driving up electricity costs. Correspondingly, transmission constraints can depress prices in areas with excess low-cost generation that cannot be moved to higher-priced market areas.

3.3 Cost of Energy and Capacity in British Columbia

Future price curves have been developed for both the “Wholesale” and “New Resources” markets for energy and capacity in the Midgard 2011 Energy Market Assessment (Appendix B). For the purposed of the assessment, the Wholesale market refers to any transaction whereby the power is procured by means of a short term, physically or financially settled transaction tied to an existing generation asset. The New Resources market refers to a transaction that is tied to and dependent upon the construction of a new generation resource.

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[46] North American Electric Reliability Corporation, 2009 Long-Term Reliability Assessment, October 2009, page 139 & 156. http://www.nerc.com/files/2009_LTRA.pdf

[47] See Appendix A of the Midgard 2011 Energy Market Assessment (Appendix B)

The Wholesale market in British Columbia has a limited number of buyers and sellers. As a consequence wholesale pricing in the Province effectively amounts to the wholesale prices for the Mid-Columbia (Mid-C) market adjusted to take into account the costs of moving electricity into BC. Conversely, the New Resources market in the Province has been developing as a result of BC Hydro's power procurement activities over the past decade.

Midgard developed energy and capacity price curves based upon information from multiple sources, including forecast Mid-C annual electricity prices and BC Hydro's forecasts of these same market curves. Also taken into account was the contractual pricing of BC Hydro's Standing Offer Program (SOP) for new clean and renewable generation resources.

A more complete explanation of the development of the price curves is provided in the Midgard 2011 Energy Market Assessment.

3.3.1 FORECAST UNCERTAINTY

Forecasting is a process of making projections about future events or trends which cannot be immediately confirmed or validated. Forecasts contain elements of uncertainty and it is impossible to exactly predict the future due to factors outside of the knowledge or control of the forecaster. However, even with these limitations it is still essential to create price and load forecasts in order to evaluate a resource plan.

Uncertainty increases the further a forecast reaches into the future, as factors which have a modest influence on short-term forecasts (such as inflation, population growth and carbon taxes) become much more important following years of compounded growth. Influences and risk factors that can only be described qualitatively at present, such as those described in Sections 3.1.2 and 3.1.3 above, may become material over the longer-term forecast period. Importantly, most human and natural systems tend to feature dramatic discontinuities over longer forecast periods – market crashes, wars and natural disasters can strongly influence forecast trends, but are almost entirely unpredictable.

In the specific context of the forecast energy and capacity price curves presented in Section 4, the forecasts have three general timeframes:

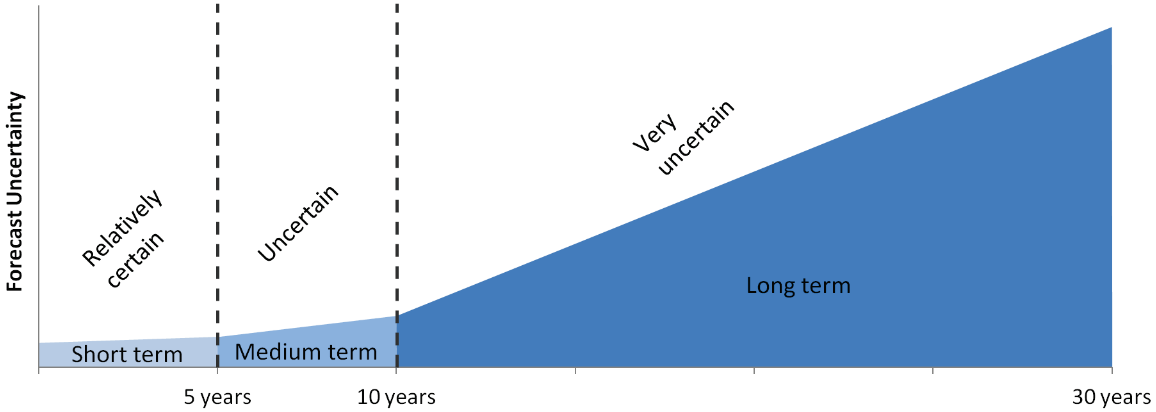
- **Short term:** Zero (0) to five (5) years – high confidence forecasts based upon well understood and reasonably knowable inputs.
- **Medium term:** Six (6) to ten (10) years – reduced confidence forecasts resulting from input uncertainties and the potential impacts of identified but presently unquantifiable risk

factors (such as those discussed in Section 3.1.2 and 3.1.3) that could materially affect the forecast outcomes.

- **Long term:** More than ten (10) years – low-confidence forecasts involving high levels of uncertainty. Many qualitative risk factors can be identified but their impact on forecast outcomes is difficult or impossible to quantify. Additional, previously unconsidered but material risk factors and market discontinuities may become apparent over such extended timeframes.

As the forecast period changes from short through to long term, the uncertainty of the forecast increases. The increasing level of uncertainty over extended forecast ranges is shown graphically in Figure 3.3.1-A.

Figure 3.3.1-A - Forecast Period and Uncertainty



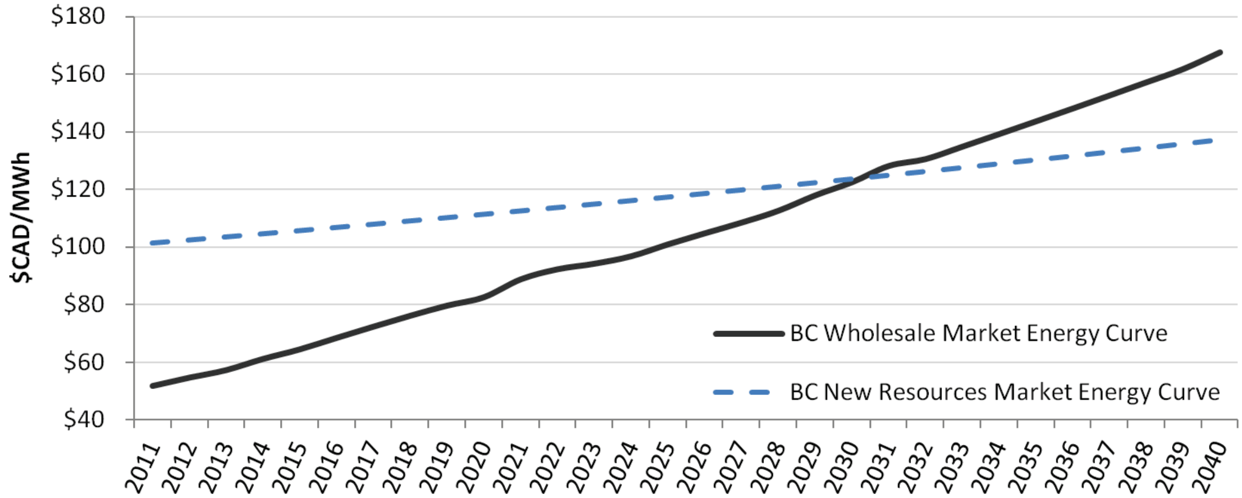
3.3.2 ENERGY PRICE FORECAST CURVES

In order to forecast the price of energy, two BC energy price forecasts were created (see Midgard 2011 Energy Market Assessment in Appendix B). The first curve is the projected price for FortisBC to purchase energy from the Wholesale market based upon an energy product that is delivered into FortisBC territory.

The second price curve is the projected cost for FortisBC to purchase energy from a new or soon to be constructed generation facility.

Figure 3.3.2-A graphically compares the forecast BC Wholesale market energy curve with the BC New Resources market energy curve. Based on current assumptions it shows that until approximately 2030 the BC Wholesale market price for energy is less expensive than the corresponding BC New Resources market price.

Figure 3.3.2-A - BC Wholesale Market Energy Curve vs. BC New Resources Market Energy Curve ($CAD/MWh)



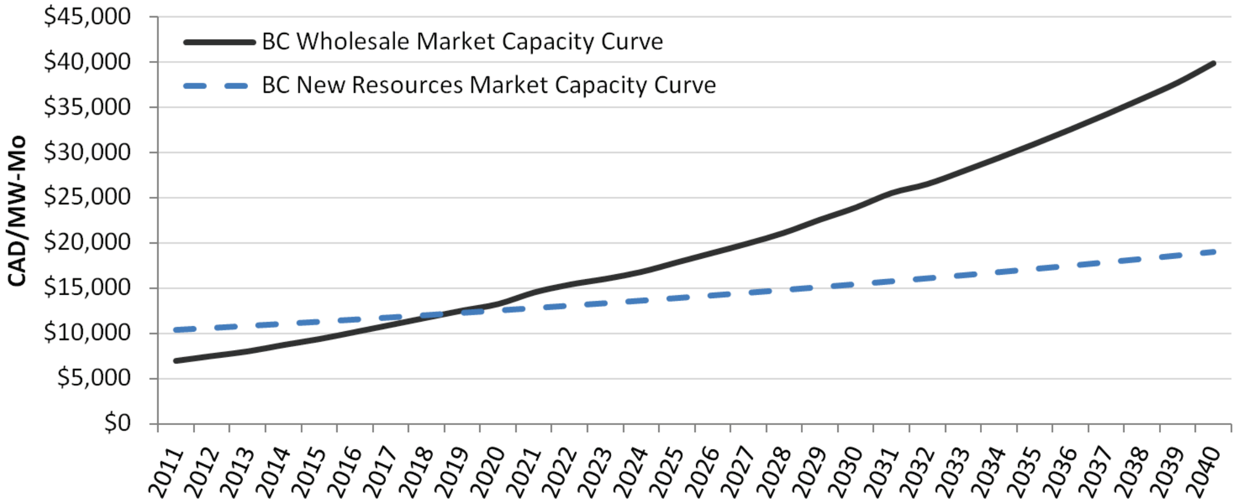
3.3.3 CAPACITY PRICE FORECAST CURVES

Two BC capacity price forecasts were also generated (see Midgard 2011 Energy Market Assessment in Appendix B). The first curve is the projected price for FortisBC to purchase capacity from the Wholesale market based upon a product that is delivered into FortisBC territory.

The second price curve is the projected cost for FortisBC to purchase capacity via the construction of a new capacity resource. The cost of the new capacity resource is based upon the lowest cost new resource determined within the FortisBC 2010 Resource Options Report in Appendix C.

Figure 3.3.3-A graphically compares the forecast BC Wholesale market capacity curve with the BC New Resources market capacity curve. Based on current assumptions, it shows that until approximately 2019 the BC Wholesale market price for capacity is less expensive than the corresponding BC New Resources market price.

Figure 3.3.3-A - BC Wholesale Market vs. BC New Resources Market Capacity ($CAD/MW-month)



3.4 Market Analysis Summary: Risks and Conclusions

3.4.1 ASSESSMENT OF POTENTIAL RISKS

FortisBC must be able to deliver safe, secure, reliable power to serve the Company's customer loads. The Company has historically relied upon the wholesale electricity market for a portion of its load requirements. FortisBC believes that the availability of energy and capacity in the Wholesale market will diminish due to the trends discussed in Section 3.1.3 and that the prices for these products will progressively rise in the years ahead.

The energy and capacity market price comparisons provided in Section 3.3 do not take into account the potential long-term cost implications of the risk factors and trends discussed in Sections 3.1.2 and 3.1.3, such as Renewable Portfolio Standards, Demand Side Management and transmission constraints. Although these trends are presently impossible to quantify they should be recognized as factors which could materially increase the cost of procuring both energy and capacity from the Wholesale market in the medium term to long term future.

3.4.1.1 Short term – 2011 to 2015

FortisBC believes that it is prudent to continue relying upon Wholesale market purchases to satisfy its unmet energy and capacity requirements over the short term, until 2015. Wholesale market prices are expected to be lower than New Resources market prices over this period and the risk factors and trends discussed in Section 3.1.2 and 3.1.3 are not expected to produce a significant deterioration in the reliability of Wholesale market resources within this time frame.

3.4.1.2 Medium term – 2016 to 2020

Between 2016 and 2020 it is presently anticipated that the Wholesale market will continue to be a reliable and cost effective source for energy and capacity procurement. At the time FortisBC's next Resource Plan is issued the impacts of some of the Western Market Trends discussed in Section 3.1.3 will be better understood.

3.4.1.3 Long term – 2021 and beyond

In the longer term, beyond 2021, FortisBC is not confident that the Wholesale market will continue to be a reliable and economical source for its energy and capacity needs. FortisBC anticipates that beyond 2021 the New Resources market will be the most reliable source for satisfying any additional capacity and energy needs.

3.4.2 CONCLUSION

FortisBC's continued reliance upon the Wholesale market to meet its future incremental energy and capacity needs is expected to be a cost effective and reliable strategy in the short term. However this strategy involves increasing price and reliability risks over the medium and long term that will be reassessed in the next FortisBC Resource Plan. It is forecast that the preferred long term strategy for FortisBC requires building new generation resources because the Wholesale market is volatile and the cost of Wholesale market purchases is expected to trend upward. The availability of capacity products, as well as the transmission capability necessary to move power to FortisBC's market is becoming increasingly constrained.

Moreover, the *Clean Energy Act*, Policy Action A, has the objective of ensuring provincial self-sufficiency to meet electricity needs by 2016. Continued reliance upon the Wholesale market over the long term would not satisfy this policy directive.

4 LOAD FORECAST

FortisBC's load forecast is prepared annually and is composed of individual forecasts for each of the residential, wholesale, industrial, commercial and irrigation and lighting classes and well as system losses and DSM savings. The methodology is primarily econometric in nature with survey data also employed. Forecasts of provincial housing starts and provincial Gross Domestic Product (GDP) by sector are primary drivers of sales. GDP and housing starts forecasts are provided by the Conference Board of Canada (CBoC).

Residential load growth is driven by the increase in customer count, which itself is determined econometrically as a function of provincial housing starts. This is then combined with forecast use per customer. Based on recent trends and the results of residential end use surveys, it is assumed that residential use per customer before DSM will remain constant over the forecast period.

The commercial class is comprised of many diverse sectors including commercial enterprises, school, hospitals, other public buildings as well as small industrial sites. As such the energy use in this class has been found to be well correlated with provincial real gross domestic product growth and has been forecast on that basis.

FortisBC's wholesale load is served to the communities of Penticton, Kelowna, Grand Forks, Summerland, Nelson, and two communities in the BC Hydro service territory. These loads are primarily residential and commercial in nature. Wholesale energy use is forecast based on an econometrically derived relationship with provincial real GDP.

Industrial loads are forecast based partly on survey data supplied by customers, and where customer information is not available, by forecast GDP growth rates in each industrial sector. In the long term, composite GDP growth rates of industrial sectors are used to escalate the entire industrial load. Out of 24 listed sectors by CBOC, only 12 sectors contribute to the FBC's industrial load growth rates, with 95 percent of growth determined by five sectors: agriculture, forestry, manufacturing, utilities, and commercial service.

The final two customer classes are irrigation and lighting which combined are less than two percent of gross system load. Irrigation loads are forecast to be constant on a before DSM basis while lighting loads grow based on a trend analysis.

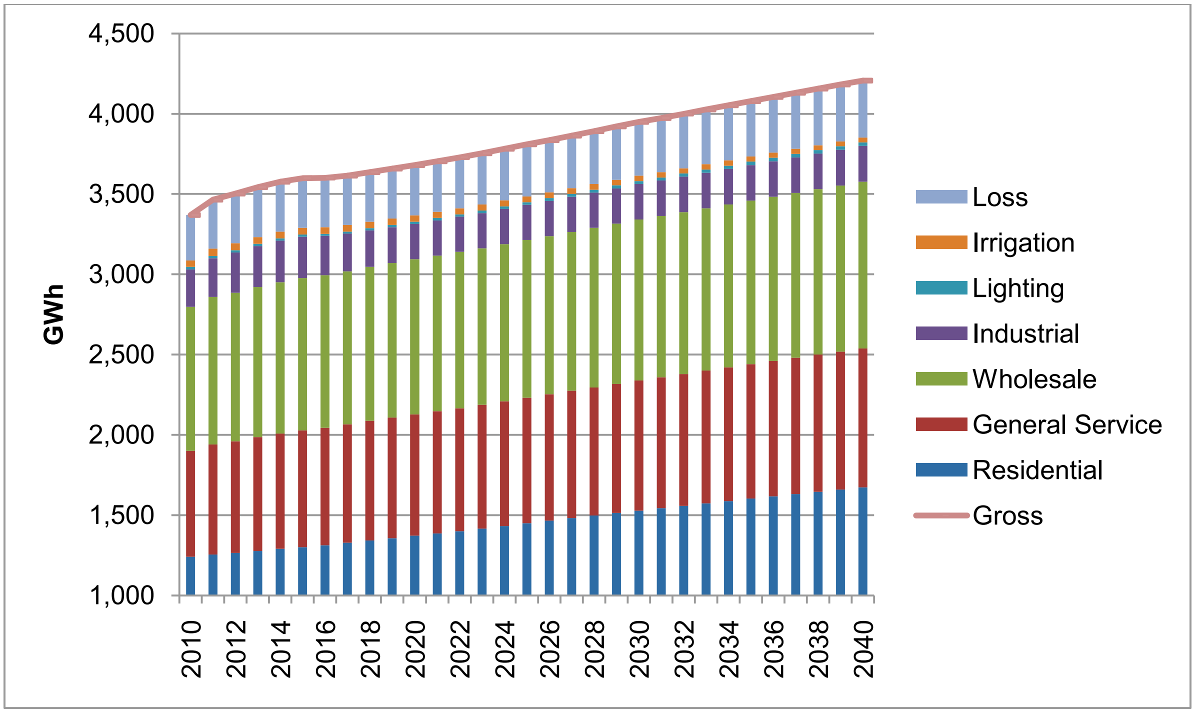
The forecast energy sales for each customer class is reduced by a forecast of annual DSM savings and other non-DSM savings including Customer Portal Information and Residential

Inclining Block. Residential sales are recovered a bit by AMI-based Revenue Protection programs until 2021. Gross system load then becomes the sum of total sales and losses. Losses are calculated as a fixed percentage of sales, adjusted for predicted loss savings from the AMI program.

Peak system demand is calculated by escalating an adjusted ten year average of historical peaks by the forecast annual energy growth rates. Peak demand in the Load Forecast does not include Planning Reserve Margin requirements.

Gross system energy load by customer class after being reduced by DSM is provided below for the forecast period.

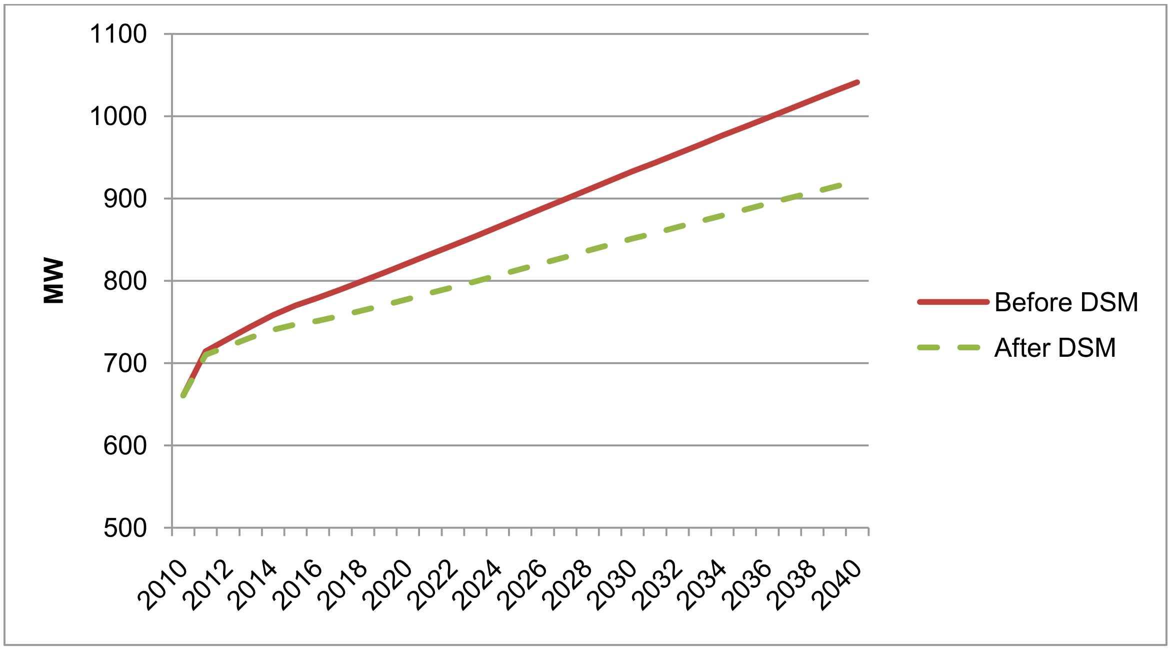
Figure 4.1 - Forecast of Energy Requirements by Customer Class (GWh)



For the first ten years of the forecast gross load after DSM grows at an annual rate of less than 0.9 percent. Industrial, irrigation and lighting loads actually contract very slightly in this period. The decline in industrial growth is largely attributable to a forecast weakening of the forestry sector partly as a result of the mountain pine beetle as well as DSM savings. Irrigation and lighting loads contract because of the impact of PowerSense programs. When considered on a before DSM basis, gross load is forecast to increase at an annual average rate of 1.8 percent in the first ten years of the forecast and by 0.8 percent in the final thirty years of the forecast. By 2040 over half of the energy load growth has been met by DSM.

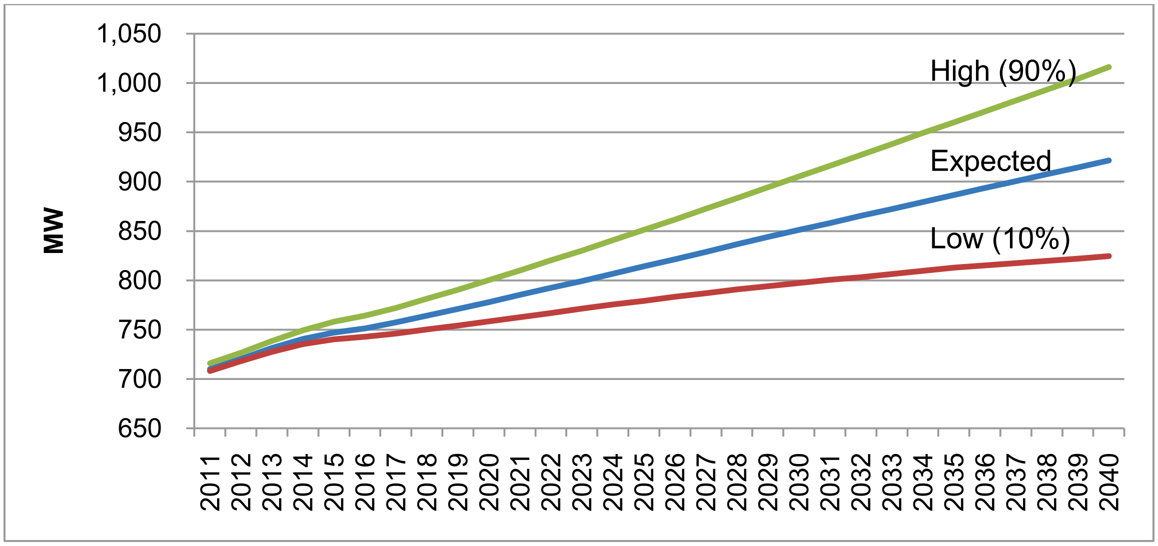
The annual system peak demand before and after DSM is shown in the following graph. Without the FortisBC DSM programs the system peak would be 13 percent higher by the end of the forecast.

Figure 4.2 - Annual System Peak Before and After DSM (MW)



FortisBC recognizes that there are considerable uncertainties regarding forecasts and particularly those which extend far out into the future. As a result FortisBC prepares a Monte Carlo forecast to determine a high forecast which has a 90 percent probability of not being exceeded and a low forecast with a 10 percent probability of not being reached. The Monte Carlo analysis considers probability distributions for each customer class and performs repeated simulations of the load forecasting model. The high, low and expected peaks after DSM are shown below.

Figure 4.3 - Expected, High and Low Peak Load Forecast After DSM (MW)



FortisBC's load forecast methodology is provided at Tab 3 of its 2012-2013 Revenue Requirements Application, filed on June 30, 2011.

5 RESOURCE REQUIREMENTS

5.1 Existing Resources

5.1.1 FORTISBC OWNED RESOURCES

FortisBC owns the Corra Linn, Upper Bonnington, Lower Bonnington and South Slocan generating plants (collectively, the FortisBC Plants) located on the Kootenay River between Nelson and Castlegar, British Columbia. In 2010 the FortisBC Plants supplied about 45 percent of FortisBC's energy requirements and about 28 percent of the Company's peak demand.

FortisBC operates the FortisBC Plants in accordance with the Canal Plant Agreement (CPA). The original CPA was entered into in order to enable the Province of British Columbia to obtain the benefits of water flow regulation provided by the Libby Dam in Montana and the Duncan Dam in BC. The original CPA became effective in 1975 and expired in 2005. In 2005 BC Hydro and the Entitlement Parties (FortisBC Inc., Teck Metals Ltd., Brilliant Power Corporation, Brilliant Expansion Power Corporation and Waneta Expansion Limited Partnership) entered into renewed CPA, which amended and extended the original Canal Plant Agreement for a further 30 year term. The CPA enables BC Hydro and the Entitlement Parties, through coordinated use of water flows and storage reservoirs, and through coordinated operation of generating plants, to generate more power from their combined generating resources than they could if they operated independently. Under the CPA, BC Hydro takes into its system all power actually generated by the Entitlement Parties' plants. In exchange for permitting BC Hydro to determine the output of these facilities, the Entitlement Parties are contractually entitled to their respective "entitlements" of capacity and energy from BC Hydro. The Entitlement Parties receive their entitlements irrespective of actual water flows to the Entitlement Parties' generating plants, and are thus insulated from the hydrology risk of water availability.

FortisBC is currently close to completing an Upgrade and Life Extension Program (ULE Program) on the FortisBC Plants. The ULE Program is an ongoing maintenance and refurbishment program designed to extend the useful production life of 11 of the 15 generating units in the FortisBC Plants. To date, the maintenance and refurbishment work on 10 of the 11 units has been completed. The work on the remaining unit is scheduled to be complete during 2012. The 11 generating units which are the subject of the ULE Program collectively represent approximately 90 percent of the capacity Entitlement of the FortisBC Plants under the Canal Plant Agreement. When complete, the ULE Program will assure power production at the refurbished FortisBC Plants through the planning period of this 2012 Resource Plan.

The remaining four generating units, all of which are installed at the Upper Bonnington Plant, provide the remaining 10 percent of the capacity entitlement of the FortisBC Plants under the Canal Plant Agreement. These units are now due for refurbishment or replacement. FortisBC is currently studying the optimal method of ensuring that the Upper Bonnington plant continues to contribute to the Company's existing generation resources.

5.1.2 LONG AND MEDIUM TERM CONTRACTUAL RESOURCES

5.1.2.1 BC Hydro Power Purchase Agreement

FortisBC is party to the BC Hydro Power Purchase Agreement (BC Hydro PPA, also referred to as the BCH 3808 agreement). The BC Hydro PPA provides FortisBC with electricity for the purpose of supplying FortisBC's load requirements, up to a maximum demand of 200 MW of capacity plus associated energy. FortisBC makes purchases under the BC Hydro PPA at Commission-approved tariffs (Rate Schedule 3808). At year-end 2010, the cost of energy under the BC Hydro PPA was $34.02 per MWh and the cost of capacity was $5,804.24 per MW per month. The BC Hydro PPA is FortisBC's share of the BC Heritage Assets described in Section 5.1.2.1.1. Because of its flexibility, the BC Hydro PPA is the last long-term resource in our portfolio to be called upon when responding to demand.

The BC Hydro PPA represents an important resource for FortisBC, providing approximately 32 percent of FortisBC's annual capacity needs on a planning basis in 2011.

5.1.2.1.1 <u>Background on BC Heritage Assets and Ratepayer Rights</u>

Certain of BC Hydro's generation assets have been designated as "heritage assets" providing a secure, reliable supply of low-cost power for all British Columbians. BC Hydro's "heritage assets" are to be operated pursuant to a Heritage Contract, the purpose of which was described in the 2007 BC Energy Plan as follows:

> *BC Hydro owns the heritage assets, which include historic electricity facilities such as those on the Peace and Columbia Rivers that provide a secure, reliable supply of low-cost power for British Columbians….Under the 2002 Energy Plan, a legislated heritage contract was established for an initial term of 10 years to ensure BC Hydro customers benefit from its existing low-cost resources. With The BC Energy Plan, government confirms the heritage contract in perpetuity to*

> *ensure ratepayers will continue to receive the benefits of this low-cost electricity for generations to come.*[48]

The discussion expanding on Policy Action 16 of the 2007 BC Energy Plan described more specifically the nature of the low-cost benefit that BC Hydro's customers are meant to enjoy by virtue of the operation of the Heritage Contract, in the following language:

> *The Heritage Contract ensures BC Hydro ratepayers receive heritage power that are (sic) based on costs of generation, not market prices.*[49]

The BC Energy Plan goes on to confirm that the benefits of the Heritage Contract are intended to be extended to BC Hydro's customers in perpetuity:

> *The Heritage Contract includes a provision stating the Contract may be terminated with 5 years notice if notice is given any time after April 1, 2009. While no official 'end date' to the Heritage Contract exists, the language of the contract implies the potential for termination and thus creates uncertainty. Government will re-affirm and strengthen its commitment to the Heritage Contract though amendments addressing this uncertainty.*[50]

The *Clean Energy Act* objective 2(e) reaffirms BC Hydro ratepayers' rights to the benefits of the heritage assets:

> *(e) to ensure the authority's ratepayers receive the benefits of the heritage assets and to ensure the benefits of the heritage contract under the BC Hydro Public Power Legacy and Heritage Contract Act continue to accrue to the authority's ratepayers.*

The BC Hydro PPA is FortisBC's allocation of Heritage Assets. FortisBC and BC Hydro are currently in discussions regarding the renewal of the PPA when it expires in 2013.

5.1.2.1.2 BC Hydro Power Purchase Agreement Renewal Scenarios

FortisBC and BC Hydro have been engaged in multi-year negotiations to renew the BC Hydro PPA. Although discussions with BC Hydro are ongoing, For the purpose of this Resource Plan,

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[48] BC Energy Plan, p. 12

[49] BC Energy Plan, Policy Action 16, Electricity Policies, p. 4. http://www.energyplan.gov.bc.ca/PDF/BC_Energy_Plan_Electricity.pdf

[50] BC Energy Plan, Policy Action 16, Electricity Policies, p. 4

FortisBC has assumed the BC Hydro PPA will be renewed on comparable terms to the existing PPA and will be available to the end of the planning period of this Resource Plan.

Although many terms and conditions of the BC Hydro PPA have been agreed to in principal, there are still key terms and conditions which are outstanding. Specific issues such as the term of the PPA, the amount of energy available under the PPA, and the cost of energy under the PPA can have impacts on the timing and nature of the energy resource requirements described in this Resource Plan.

5.1.2.1.3 BC Hydro PPA Export Restriction

The current BC Hydro PPA precludes the export of power by FortisBC during any hour in which it is taking energy from BC Hydro under the BC Hydro PPA[51]. This export restriction makes the development or acquisition by FortisBC of new resources (whether through development of new generation facilities, entering into long-term power purchase agreements, or acquiring other alternative forms of supply) challenging, since with this export restriction, a portion of the power provided by such new resources would displace the (generally lower-cost) supplies of power available under the BC Hydro PPA. This dynamic is at odds with FortisBC’s overall responsibility to obtain cost-effective and secure long-term sources of supply.

In order to maintain the cost-effectiveness of any acquired new resources, FortisBC needs to be able to dispose of surplus power produced by such resources while ensuring that low-cost power under the BC Hydro PPA continues to be available to its customers. BC Hydro and FortisBC have agreed that this restriction would not apply to the WAX Capacity Purchase Agreement (WAX CAPA), and FortisBC is seeking confirmation that this principle would also apply to future resources.

5.1.2.1.4 Implications for the 2012 Resource Plan

The renewed BC Hydro PPA will continue to be a firm resource. If the BC Hydro PPA is renewed on different terms than what has been assumed in the Resource Plan, this may impact the amount of energy that needs to be acquired. This could be a result of such things such as a shorter BC Hydro PPA term, or related to the pricing of incremental energy. The impact on the Resource Plan would be additional purchases from the market, or accelerating the development of new resources to meet any resulting supply/demand gaps.

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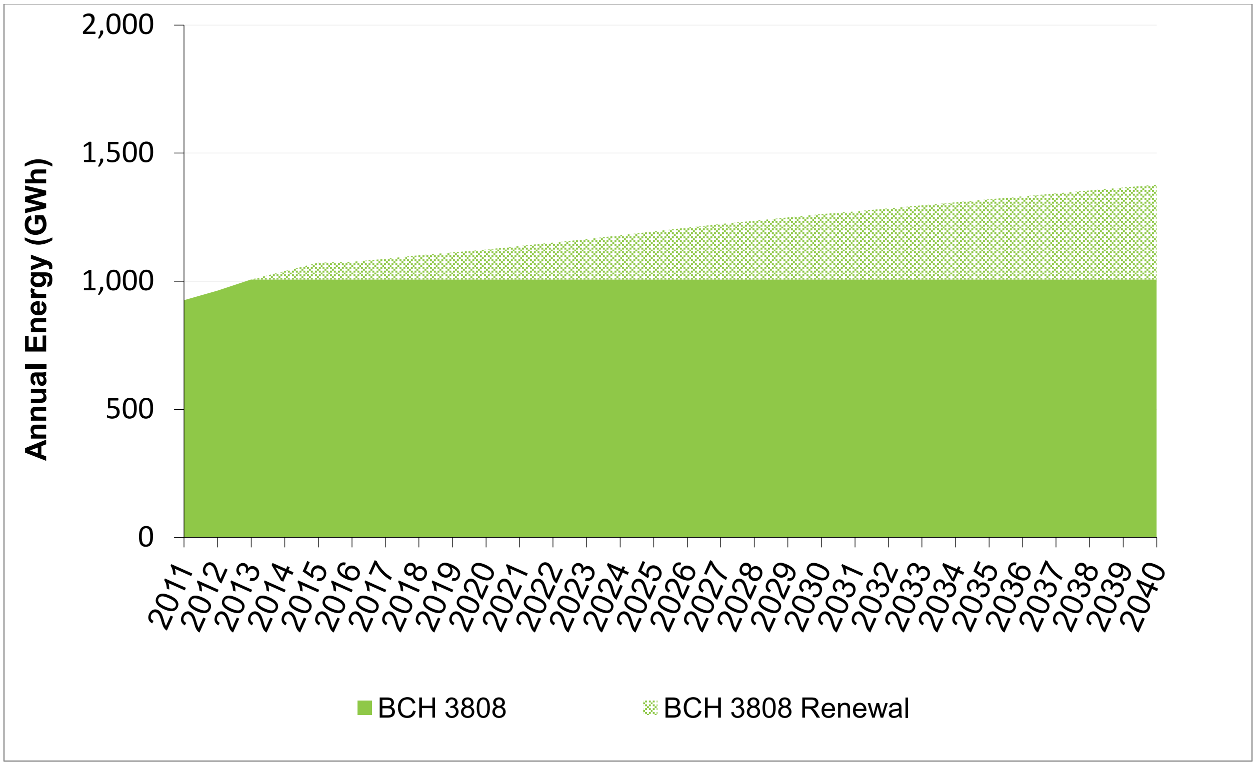
[51] BC Hydro PPA, section 8.9

As discussed, the BC Hydro PPA is for 200 MW and associated energy. The BC Hydro PPA is the last resource dispatched in the FortisBC long-term portfolio, and historically FortisBC has not made use of all of the available energy. Figure 5.1.2.1.4-A illustrates FortisBC's projected energy consumption from the BC Hydro PPA. The "BCH 3808" line demonstrates the baseline usage in 2013 when the contact expires. The "BCH 3808 Renewal" area demonstrated the expected increase in utilization of the Rate Schedule 3808 energy based on forecast load growth.

Figure 5.1.2.1.4-A - Annual Energy from the BC Hydro PPA (GWh)



5.1.2.2 Brilliant Power Purchase Agreement

FortisBC is party to a power purchase agreement with Brilliant Power Corporation made as of April 4, 1996 (Brilliant PPA). Under the Brilliant PPA, which expires in 2056, FortisBC has agreed to purchase (a) the energy and capacity Entitlement allocated to the Brilliant Plant pursuant to the Canal Plant Agreement and (b) after the expiration of the Canal Plant Agreement (which is terminable upon five years' notice any time after December 31, 2030), the actual electrical output generated by the Brilliant plant. The Brilliant PPA uses a take-or-pay structure which requires that FortisBC pay for the Brilliant plant's Entitlement, irrespective of whether FortisBC actually takes it. During the first 30 years of the term of the Brilliant PPA, FortisBC pays to Brilliant Power Corporation, in fixed monthly payments, an amount that covers the operation and maintenance costs of the Brilliant plant, together with a return on capital including original purchase costs, sustaining capital costs and any life extension investments. In 2010, such costs were $36.45/MWh. During the second 30 years of the term of the Brilliant PPA, amounts payable by FortisBC will be adjusted using a market price mechanism based on the depreciated value of the Brilliant plant and then-prevailing operating costs.

The Brilliant PPA provides 129 MW of capacity and 895 GWh of energy, approximately 22 percent of FortisBC's capacity requirements and 25 percent of its energy requirements in 2010.

5.1.2.3 Second Amendment of Brilliant PPA (Upgrade Amendment)

An amendment to the Brilliant PPA made in May 1996 provides for an additional 65 GWh of energy and 20 MW of capacity until 2056. It was priced at $26.55/MWh in 2010. After the first 30 years (ending in 2026), the pricing mechanism will be the same as that set out in the Brilliant PPA.

This amendment provided approximately 4 percent of FortisBC's capacity requirements and 2 percent of its energy requirements in 2010.

5.1.2.4 Waneta Expansion Capacity Purchase Agreement

The Waneta Expansion (WAX) is a project to construct a second powerhouse at the Waneta Dam on the Pend d'Oreille River south of Trail, British Columbia. Located immediately downstream from the Waneta Dam and its existing powerhouse, the 335 MW expansion project will share the existing dam's hydraulic head and generate power from flow that would otherwise be spilled. Output from the units will be delivered to BC Hydro's Selkirk Substation through a new 10 kilometre transmission line. Columbia Power Corporation (CPC) and Columbia Basin Trust (CBT) have formed a partnership with Fortis Inc. (the Waneta Expansion Limited Partnership) for the project.

FortisBC has entered into a 40-year capacity purchase agreement (WAX CAPA) with the Waneta Expansion Power Corporation to purchase all unused WAX-related capacity that remains after BC Hydro has acquired the energy entitlements associated with the plant (as defined by the Canal Plant Agreement). The capacity entitlements obtained by FortisBC under WAX CAPA begin in 2015 and vary by month (see Table 5.1.2.4-A).

The WAX CAPA was reviewed by the Commission in 2010, and approved by Order E-29-10. The WAX CAPA will provide FortisBC with a capacity resource of sufficient size to meet its expected forecast capacity requirements throughout much of the planning period of this 2012 Resource Plan. The capacity entitlements under WAX CAPA become available upon commissioning of the WAX generating units in January 2015 and April 2015. The WAX CAPA is suitably shaped to solve FortisBC's winter and summer peak demand requirements when capacity is needed most and provides less capacity during the three months freshet when it is needed least. This capacity profile is an ideal match for FortisBC's seasonal load shape.

Table 5.1.2.4-A - Monthly WAX CAPA Entitlements (MW)

Month	WAX CAPA (MW)
January	304.4
February	303.6
March	289.1
April	133.3
May	69.7
June	54.0
July	168.7
August	318.5
September	323.7
October	211.3
November	320.1
December	312.1

5.1.2.5 Powerex Capacity Power Block (Powerex CPB)

FortisBC purchased a five-year seasonal capacity block from Powerex (the Powerex Capacity Purchase Block, or Powerex CPB) that temporarily addresses FortisBC's seasonal winter capacity requirements. The contract will terminate in 2015, coinciding with the commencement of the WAX CAPA. The five-year capacity block was selected to provide a 'bridge' allowing FortisBC to source longer-term capacity solutions while still meeting short-term seasonal demands following BC Hydro's acquisition of one-third of Waneta from Teck Resources Limited.

5.1.3 WHOLESALE MARKET RESOURCES

Collectively in 2010, the FortisBC Plants, the BC Hydro PPA, the Brilliant PPA and the Powerex CPB provided approximately 90 percent of the Company's energy requirements, and approximately 92 percent of its peak capacity requirements.

FortisBC presently addresses any short-term capacity and energy shortfalls by making purchases in the Wholesale electricity markets. The details of FortisBC's activities in electricity markets, and the risks associated with the Company's growing dependence on the Wholesale electricity market, are discussed in more detail in Section 3.

5.1.4 DEMAND SIDE MANAGEMENT RESOURCES

FortisBC has set a target to avoid 50 percent of annual load growth via DSM measures. However, given the inherent non-firm nature of DSM resources, and the long lead time required to implement alternative supply resources, the Company has considered a probabilistic approach which targets 50 percent DSM effectiveness with an 80 percent confidence interval that projected demand avoidance will fall within the range of 28 percent to 72 percent of status quo load growth.

This spread of possible actual DSM contributions is an important component in developing the potential range of supply gaps that this 2012 Resource Plan must address (as further discussed in Section 5.2 below).

For a detailed discussion of the Company's DSM programs, see the 2012 Long Term DSM Plan filed June 30, 2011.

5.2 Resource / Load Balance Analysis

With the addition of WAX CAPA to FortisBC's supply portfolio in 2015, FortisBC will have mitigated most of its existing capacity shortfalls. When the Planning Reserve Margin (PRM) is included, the Company still has limited capacity constraints at certain times of the year, as discussed in Section 5.2.1.2, below. In addition, the Company is currently winter energy constrained and the size of the energy gap grows steadily throughout the planning period of this 2012 Resource Plan.

The actual resource / load gap will depend upon load growth, DSM effectiveness and the availability of existing contracts, in particular the renewal terms of the BC Hydro PPA.

- **Load Growth:** FortisBC's load is expected to grow over time. The primary factor influencing the pace of residential load growth is customer count. However, other factors such as widespread adoption of new electric technologies (e.g. electric vehicles) and societal changes (e.g. a move to smaller residences) may have significant impacts. FortisBC recognizes that there are considerable uncertainties regarding forecasts and particularly those which extend far out into the future. As described in greater detail in Section 4, FortisBC prepares a Monte Carlo forecast to determine a high forecast which has a 90 percent probability of not being exceeded and a low forecast with a 10 percent probability of not being reached.

- **DSM Contribution:** As noted in the DSM Strategic Plan found in the 2012 Integrated System Plan, FortisBC is targeting to avoid 50 percent of annual expected load growth via DSM measures.

  As DSM is a non-firm resource with results subject to voluntary customer participation, it is prudent to consider a possible range of DSM impacts on resourcing needs rather than as a single pre-determined percentage of load growth avoidance. FortisBC has therefore established a probabilistic methodology to assess various DSM performance levels in defining its long-term energy and capacity resource gaps (as discussed in Section 5.1.4 above). This produces a range of DSM results on either side of the FortisBC 50 percent DSM target.

- **Contracted Resources:** Brilliant, the Brilliant Upgrades and the WAX PPA are all contracted long-term, and are secure for the term of this 2012 Resource Plan. FortisBC's Power Purchase Agreement with BC Hydro expires in 2013. For the purpose of this Resource Plan, FortisBC has assumed that it will be renewed on similar terms to the existing PPA, which includes the ability to call upon the 200 MW capacity and the associated energy. If there were material differences from this assumption, that would impact the timing and nature of the energy resource requirements.

5.2.1 FORTISBC CAPACITY RESOURCES/LOAD BALANCE

As discussed in Section 5.2, with the addition of WAX CAPA to FortisBC's supply portfolio in 2015, FortisBC will have mitigated most of its existing capacity shortfalls. When the PRM is applied to its load forecast, the Company still has limited capacity constraints at certain times of the year.

5.2.1.1 Application of Planning Reserve Margin (PRM)

The WECC recommends but does not require that utilities plan for positive capacity margins on a long-term basis. FortisBC believes it is prudent to carry an appropriate level of firm PRM and to include those reserve requirements within its long term forecast of capacity requirements.

For the purposes of ascertaining long-term firm PRM requirements, the Company engaged Midgard Consulting to conduct a PRM Study which is attached as Appendix D. In order to mitigate impacts to its ratepayers, FortisBC has modified the PRM calculation methodology recommended by Midgard, as detailed in this section.

There are three potential circumstances that drive the need for PRM:

- **Unavailability of supply due to unplanned generating unit or transmission outage:** Although operating reserves are held in order to allow for moment-to-moment changes in either supply or load, planning reserves are held to protect against any sustained or long-term loss of supply or transmission capability (although maintaining a planning reserve margin will also reinforce operating reserves in real time as well).
- **Unexpectedly high loads, typically due to extreme weather events:** In such circumstances it may not be prudent to rely on market energy to meet supply shortfalls because the market energy is likely to come from geographically proximate areas that may be experiencing the same weather, with the result that prices may be very high or excess supply may simply be unavailable at the time of greatest need.
- **A period of accelerated load growth that outpaces the installation of new power supply resources:** Given the long lead time associated with most electricity generation projects, it is inadvisable for utilities to function reactively and wait until unforeseen load spikes occur to plan more resources. Carrying a PRM provides a buffer which allows a utility adequate time to react to unforeseen load changes and acquire new assets before load becomes unmanageable.

FortisBC’s system is relatively small and its resource stack consists of a portfolio of owned generation assets and long-term contracts. FortisBC’s firm contracted resource stack has for many years been insufficient to meet its expected peak load-serving and reserve obligations. On-peak capacity deficits (including any operating reserve requirements above those already provided for under the CPA and the BC Hydro PPA) have been addressed through spot market energy purchases and seasonal purchases of energy blocks. Up to this point, FortisBC did not require a PRM because our requirement was small and the market was sufficiently robust to supply its capacity needs on a demand basis.

The Company’s resource stack is supported by the Canal Plant Agreement (CPA) and thus has limited hydrological risk, however all supply resources are unit contingent. That is, under the terms of the CPA, if a unit is unable to operate when called upon, CPA entitlements are reduced accordingly. For the purposes of long-term PRM planning, it is prudent for FortisBC to adopt a methodology that considers these unique aspects of the FortisBC system.

The following criterion is applied as the basis for PRM design:

PRM = 5% of Load Responsibility + the Single Largest Utilized Contingency[52]

Where "Load Responsibility" is defined as the monthly system firm peak load demand plus firm sales minus firm purchases for which reserve capacity must be provided by the supplier. For example, the BC Hydro PPA 200 MW is currently considered such a firm purchase. Although the agreement is set to expire in 2013, the renewal agreement will include the same 200 MW capacity allowance. As such, the 200 MW of generation capacity included in the BC Hydro PPA is considered a firm resource and is not included in PRM requirement calculations.

Until commencement of the WAX CAPA in 2015, a Brilliant unit, at 37.5 MW is the single largest contingency. Once the WAX CAPA begins delivery, half of WAX CAPA (the output from one unit) becomes the single largest contingency. This is true throughout most of the year with the exception of the months of May and June, during which period a single Brilliant unit becomes the largest contingency.

In addition, to avoid the situation where PRM is calculated based upon an unutilized unit, the PRM design criterion is calculated based upon the single largest utilized contingency. FortisBC forecasts that there will be a number of months of each year (predominantly during freshet) when WAX CAPA will not be required to serve load. Therefore, during those months it is not reasonable in the FortisBC context to consider WAX CAPA as the single largest unit contingency. This change supports a less stringent reserve margin and will reduce the amount of PRM required in the less critical non-peak months.

FortisBC has chosen to modify the PRM calculation methodology recommended by Midgard in order to reduce ratepayer impacts. Since WAX CAPA is a contractual arrangement that does not necessarily require the WAX units to be dispatched when WAX CAPA entitlements are being utilized, FortisBC has reduced the PRM requirement by notionally splitting the utilized WAX CAPA entitlement between the two WAX units. Splitting the WAX CAPA entitlement results in a smaller utilized contingency, until such time as the entire WAX CAPA entitlement is dispatched. For further explanation of the methodology employed by FortisBC, see the Planning Reserve Margin Report at Appendix E.

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[52] Derived from criterion one of the Power Supply Design Criteria established by the Western Systems Coordinating Council (now known as WECC). See the attached Midgard PRM report "FortisBC Planning Reserve Margin" (Appendix D) for further reference.

Figure 5.2.1.1-A graphically shows the monthly PRM requirements for the years 2020, 2030, and 2040 in MW based upon Midgard's recommended PRM design criterion with FortisBC's utilized contingency modifications. The monthly and annual average PRM is shown in Table 5.2.1.1-A)

Figure 5.2.1.1-A - Monthly PRM in 2020, 2030 and 2040 (MW)

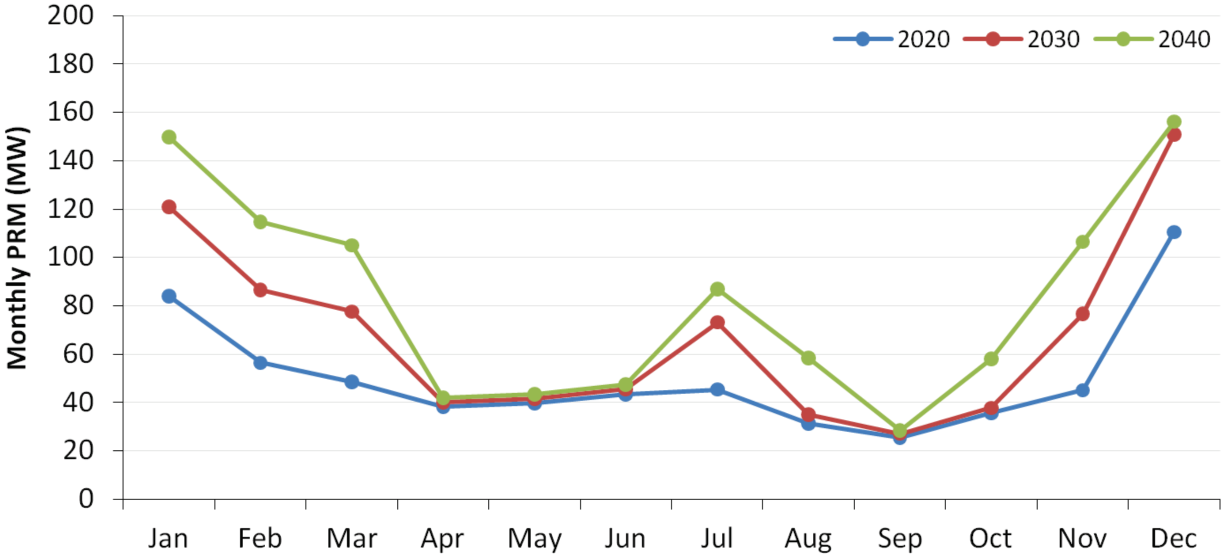

Table 5.2.1.1-A - Monthly PRM in 2020, 2030 and 2040 (MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Mean
2020	84	56	49	38	40	43	45	31	26	36	45	111	**50**
2030	121	86	78	40	42	45	73	35	27	38	77	151	**68**
2040	150	115	105	42	43	47	87	58	29	58	107	156	**83**

Figure 5.2.1.1-B graphically shows the monthly PRM requirements for the years 2020, 2030, and 2040 as a percentage of demand based upon Midgard's recommended PRM design criterion with FortisBC's contingency modifications. The monthly and average annual percentage is shown in Table 5.2.1.1-B.

Figure 5.2.1.1-B - Monthly PRM in 2020, 2030 and 2040 (%)

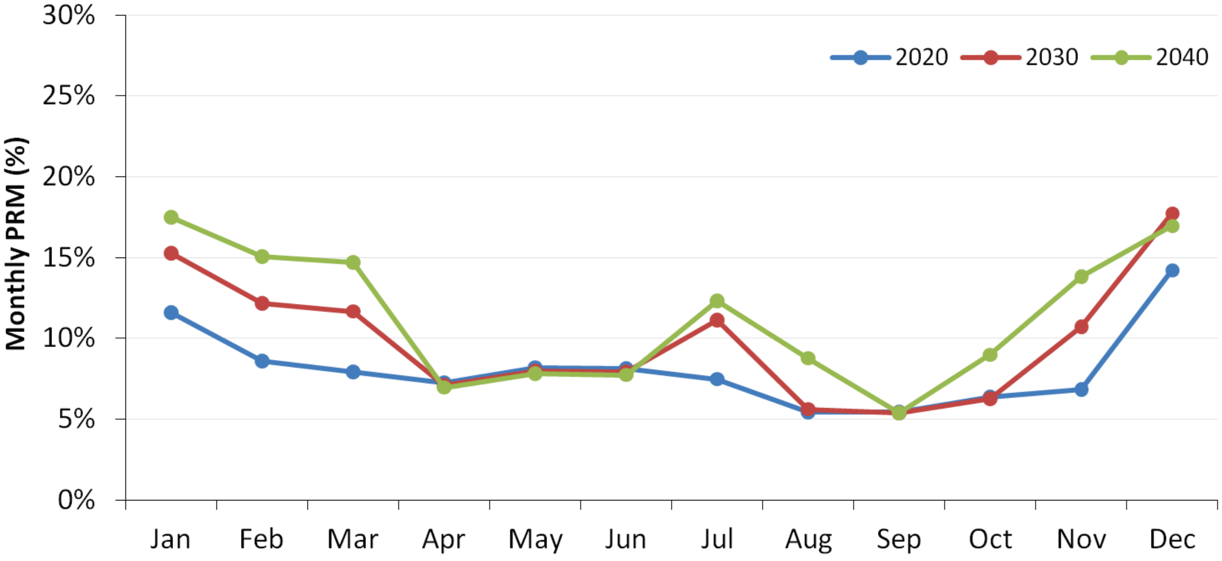

Table 5.2.1.1-B - Monthly PRM in 2020, 2030 and 2040 (%)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Mean
2020	12	9	8	7	8	8	7	5	5	6	7	14	**8**
2030	15	12	12	7	8	8	11	6	5	6	11	18	**10**
2040	18	15	15	7	8	8	12	9	5	9	14	17	**11**

Although it is uncommon to change PRM on a monthly basis, the majority of FortisBC's supply resources vary by month and therefore it is prudent that FortisBC adapt its PRM requirements to match. FortisBC carries more PRM in critical winter months when peak loads require additional PRM coverage and carries less PRM in less critical months, thus resulting in a lower overall cost to FortisBC ratepayers and less exposure to long term market risks.

For reference, the PRM held by nearby utilities is listed in Table 5.2.1.1-C. This table demonstrates that the recommended PRM for FortisBC is comparable to the current industry practice in the region (please refer to Appendix D - Midgard Planning Reserve Margin Report) for a complete explanation.

Table 5.2.1.1-C - Nearby Planning Reserve Margins

Utility	PRM (%)
Avista	15
BC Hydro[53]	14
Idaho Power	10
Northwestern Energy[54]	-
PacifiCorp	12
Portland General Electric	12
Puget Sound Energy	15

FortisBC's demand forecasts used in this Resource Plan are inclusive of the required PRM as set out in this section.

5.2.1.2 Capacity Resource/Load Gaps

The expected and high/low spread forecasts used to calculate capacity resource / load gaps are defined by the following scenarios:

- **Expected Forecast** – Expected load forecast with the application of a targeted 50 percent DSM.
- **High/Low Spread** – A probabilistic analysis was carried out to establish a range (high/low spread) for load growth less DSM that results in an overall 80 percent confidence interval (see Section 5.1.4).

Following the addition of WAX CAPA the only material capacity gap in 2020 is 20 MW in June and 34 MW in December (see Figure 5.2.1.2-A). These exposures are limited to 4 percent of super peak hours[55] in both months (see Table 5.2.1.2-A).[56]

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[53] BC Hydro's 14 percent PRM is calculated after allowing for reserves required to meet a 1 day in 10 year Loss of Load Expectation, so actual the reserve level being carried by BC Hydro is substantially higher than 14 percent; see BC Hydro 2008 Long Term Acquisition Plan Appendix F10: Calculation of Capacity Planning Reserves

[54] Northwestern Energy does not carry Planning Reserves, relying instead on the market to provide required real time reserves or to cover unit contingencies. However, NWE recognizes that its market access is being impacted by an erosion of excess capacity in the Pacific Northwest area, as identified in its 2009 Electric Supply Resource Procurement Plan: "In the past few years the market for ancillary services, such as operating reserves, has tightened which has caused prices to increase substantially. In order to avoid paying steep prices in the market for operating reserves, Northwestern at times has self-provided the reserves by utilizing the capacity from the Basin Creek facility."

[55] "Super-Peak Hours" means the hours commencing at 16:00 PPT and ending at 20:00 PPT Monday through Saturday inclusive, but excluding British Columbia statutory holidays.

[56] The gap is "material" only in terms of size of the gap (MW), not in terms of the hours of exposure.

Figure 5.2.1.2-A - 2020 Monthly Capacity Load / Resource Balance (MW)

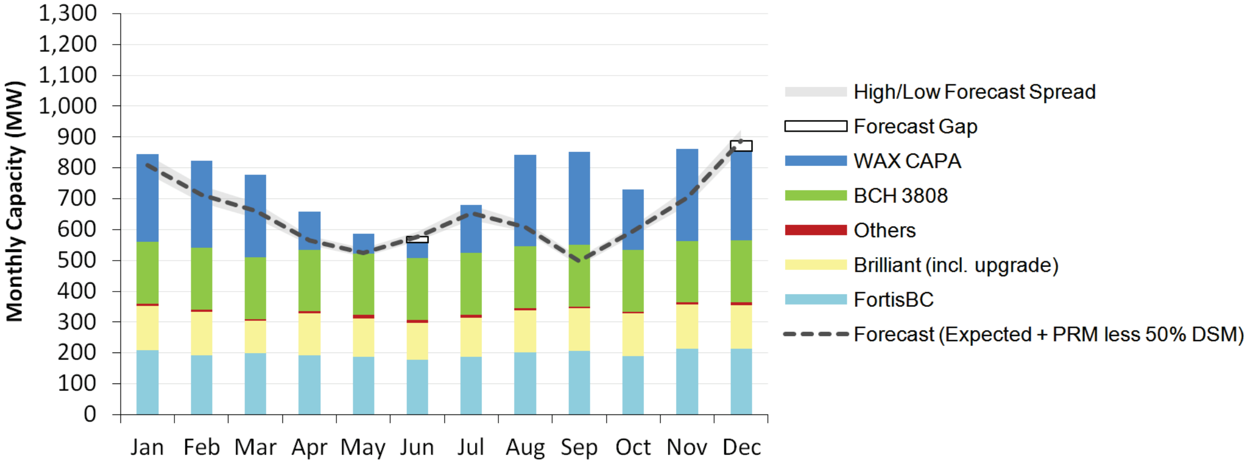


Table 5.2.1.2-A - 2020 Monthly Capacity Gaps and Exposure

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Gap (MW)	-	-	-	-	-	20	-	-	-	-	-	34
Total Hours Exposed	-	-	-	-	-	4	-	-	-	-	-	8
% of Super Peak Hours	-	-	-	-	-	4	-	-	-	-	-	4

In 2030 (see Figure 5.2.1.2-B) the expected forecast results in capacity gaps of 69 MW, 62 MW, 50 MW, and 147 MW for the months of January, June, July, and December, respectively. In the event of higher than expected demands, all months of the year (with the exception of April, August, September, and October) are at risk of capacity shortfalls for some hours of the month.

Table 5.2.1.2-B shows that under the expected forecast in December 2030, FortisBC will be exposed to a capacity deficit for 134 hours of the month, corresponding to 53 percent of the super peak hours. This means that in 2030 FortisBC will be at risk of capacity deficiencies during half of the hours that comprise the most costly annual regional Wholesale market price period, the December super peak hours.

Figure 5.2.1.2-B - 2030 Monthly Capacity Load / Resource Balance (MW)

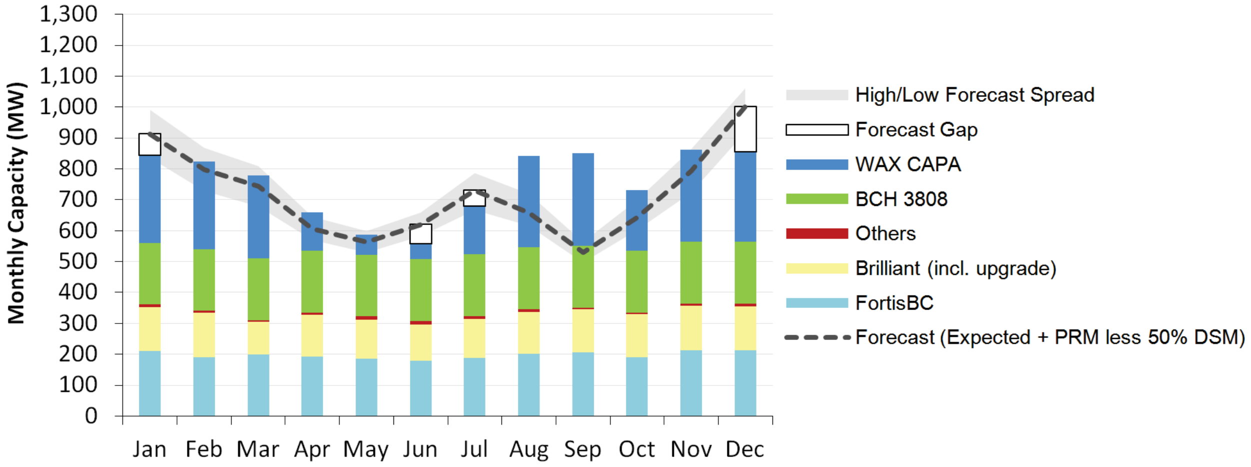


Table 5.2.1.2-B - 2030 Monthly Capacity Gaps and Exposure

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Gap (MW)	69	-	-	-	-	62	50	-	-	-	-	147
Total Hours Exposed	28	-	-	-	-	25	18	-	-	-	-	134
% of Super Peak Hours	14	-	-	-	-	18	15	-	-	-	-	53

In 2040 (see Figure 5.2.1.2-C) the expected forecast predicts a capacity shortfall in the months of January, February, March, May, June, July, November, and December – more than half of the year. In the event of higher than expected loads there is a risk of capacity gaps in all months except August and September.

Table 5.2.1.2-C shows that in December 2040 under the expected load forecast FortisBC will be exposed to a capacity deficit for 245 hours of the month, including 90 percent of the super peak hours. January, June and July are also exposed with monthly super peak hour deficits of 68 percent, 36 percent, and 51 percent respectively.

Figure 5.2.1.2-C - 2040 Monthly Capacity Load / Resource Balance (MW)

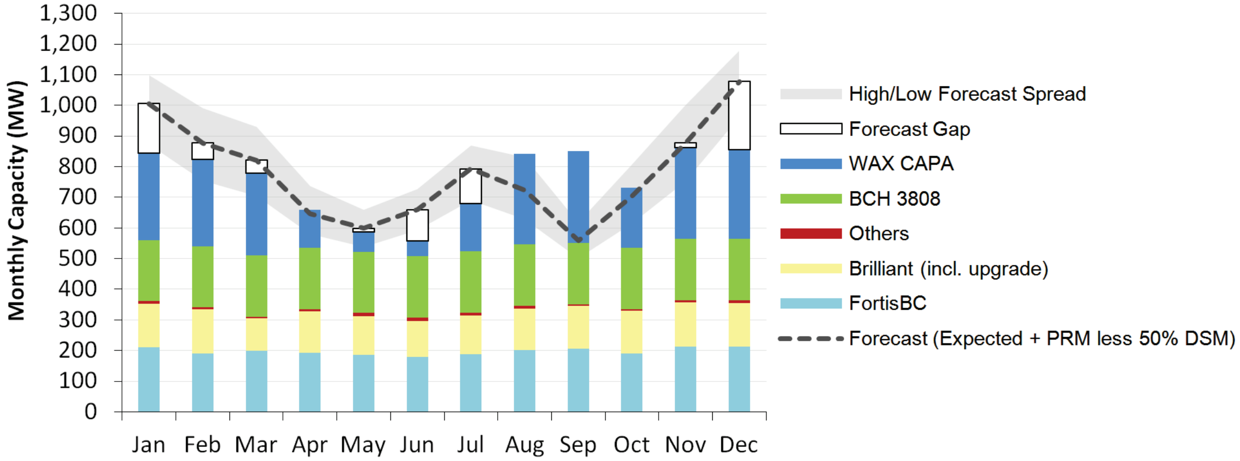


Table 5.2.1.2-C - 2040 Monthly Capacity Gaps and Exposure

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Gap (MW)	161	55	42	-	11	102	112	-	-	-	16	223
Total Hours Exposed	162	32	17	-	2	67	67	-	-	-	1	245
% of Super Peak Hours	68	21	8	-	-	36	51	-	-	-	1	90

By 2040 FortisBC will be at risk of capacity deficiencies for extreme weather or facility contingencies during most of the December super peak hours, which are in the most costly period for purchasing electricity from the regional Wholesale market. Further, there is a high correlation between the peak FortisBC demand and the peak regional demand, meaning that if FortisBC has to purchase from the market during a period of extremely cold weather, this will likely also correspond to a period of unusually high regional market prices, assuming that there is actually electricity available for sale at any price.

5.2.1.3 Capacity Gap Summary

Figure 5.2.1.3-A through Figure 5.2.1.3-D show the growing capacity gap for years 2016, 2020, 2030, and 2040 (see Appendix H for the tabular representation of the low, expected, and high capacity gaps for all years). These graphs display the high/low spread of possible capacity gaps around the expected forecast. Note that the variability around the expected capacity gap grows into the future due to increasing forecast uncertainty.

Figure 5.2.1.3-A - 2016 Forecast Gap + High/Low Spread

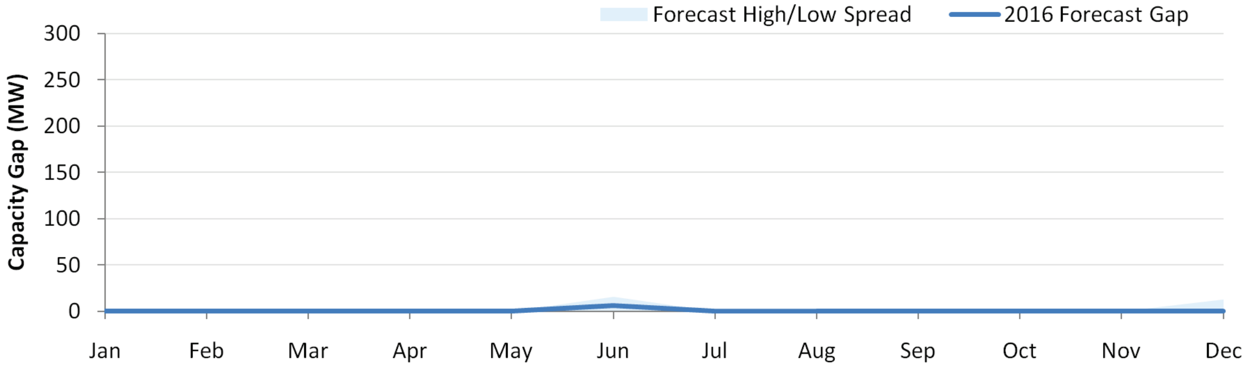


Figure 5.2.1.3-B - 2020 Forecast Gap + High/Low Spread

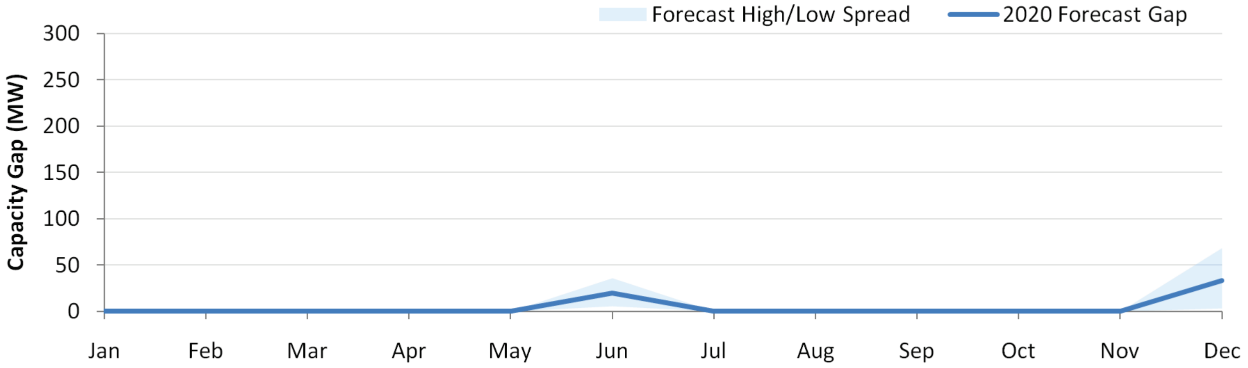


Figure 5.2.1.3-C - 2030 Forecast Gap + High/Low Spread

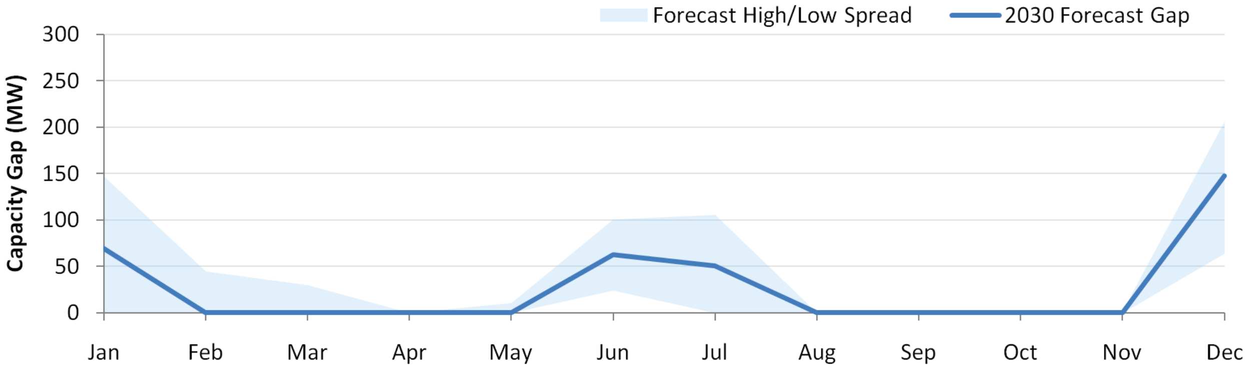
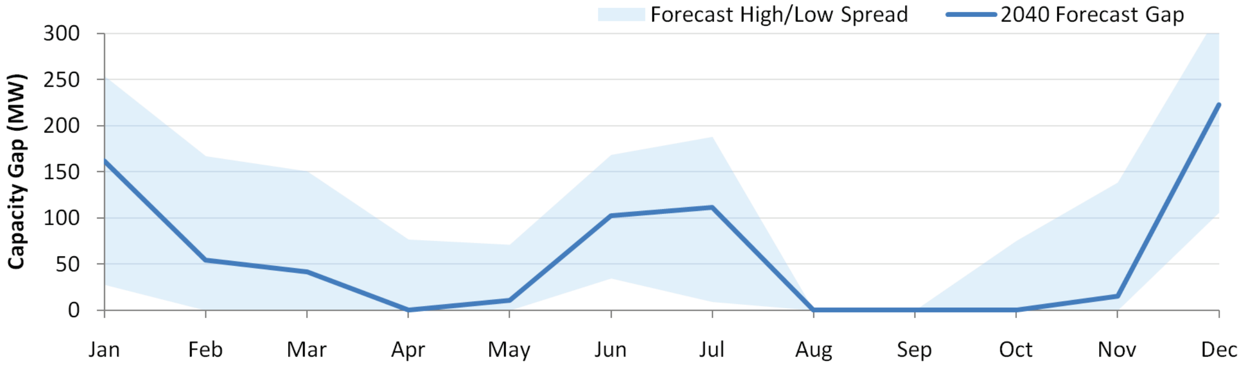


Figure 5.2.1.3-D - 2040 Forecast Gap + High/Low Spread



In summary, FortisBC will have a growing capacity gap in an increasing number of months over the planning period. By 2020, the Company is forecasting capacity gaps of 20 MW in June and 34 MW in December, with a deficit in 4 percent of both months' super peak hours[57]. This seasonal capacity gap will continue to grow as demand increases into the future, with monthly gaps as large as 147 MW and 53 percent of December super peak hours exposed in 2030, increasing to 223 MW and 90 percent of December super peak hours exposed by the end of the planning period in 2040. This means that by 2030 and beyond, FortisBC will face market exposure during the most costly period of the annual regional Wholesale market cycle.

At these levels of exposure, higher than forecast demand, extreme weather events or individual transmission or generation contingencies could force FortisBC into the market for large volume electricity purchases at premium prices. Super peak wintertime prices can rise to several multiples of average or off-peak prices, especially during extremely cold regional weather events.

As a result, FortisBC believes it is consistent with good utility practice to ensure that long lead time capacity resource options are economically maintained so they can be added as required to address future capacity gaps.

5.2.2 FORTISBC ENERGY RESOURCES/LOAD BALANCE

As discussed in the introduction to Section 5.2, the three key input parameters used to establish FortisBC's energy resource / load gaps are the gross load forecast, the actual DSM contribution and the final renewal terms of the BC Hydro PPA. Credible ranges for these important variables have been considered in evaluating the resource portfolios in this 2012 Resource Plan.

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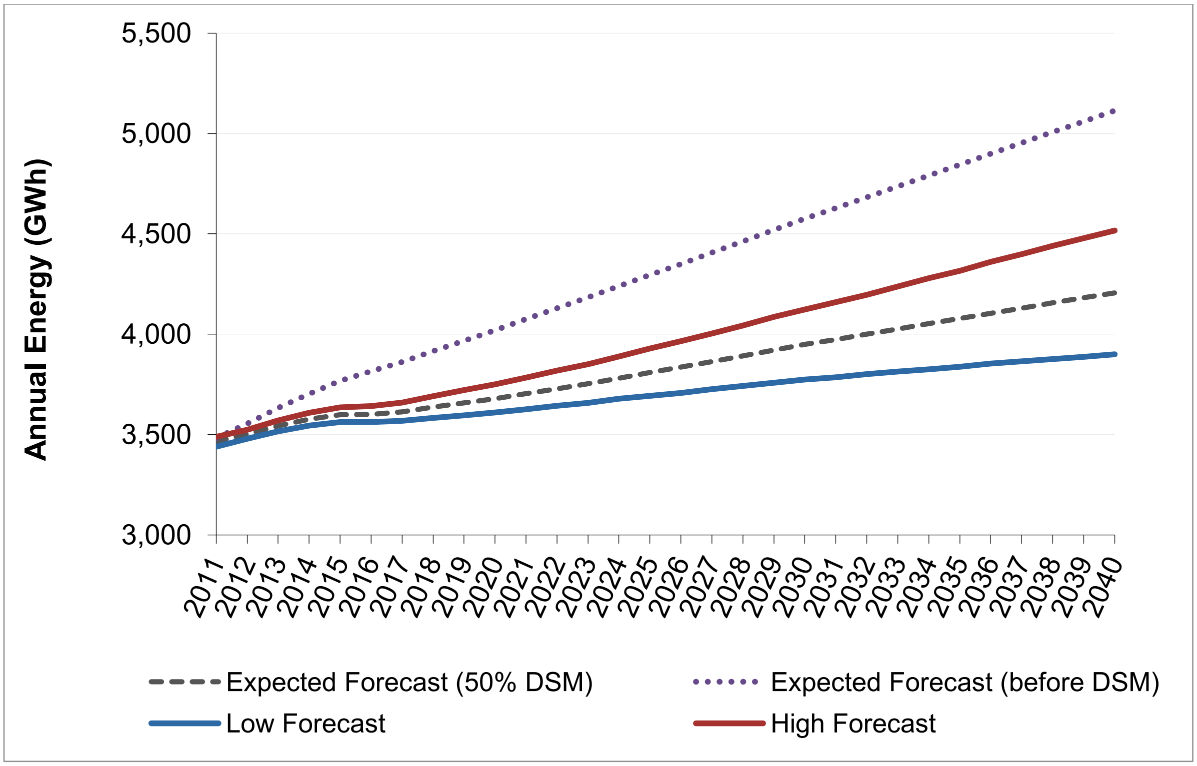
[57] Source: FortisBC Planning Reserve Margin Study (Appendix E)

5.2.2.1 Key Input Parameters

The first key input parameter is the expected load forecast, less the energy avoided by the targeted 50 percent DSM. This result is shown graphically by the solid blue line in Figure 5.2.2.1-A.

Secondly, a probabilistic analysis (see Section 4 for a more detailed discussion) was carried out to determine the 80 percent confidence high/low range around the expected load forecast which includes the potential variability associated with DSM achievement. This range is represented graphically in Figure 5.2.2.1-A.

Figure 5.2.2.1-A - FortisBC Load Forecast (GWh)



Finally, FortisBC has assumed the BC Hydro PPA will be renewed on comparable terms to the existing PPA. This means the 200 MW and associated energy is available to meet demand.

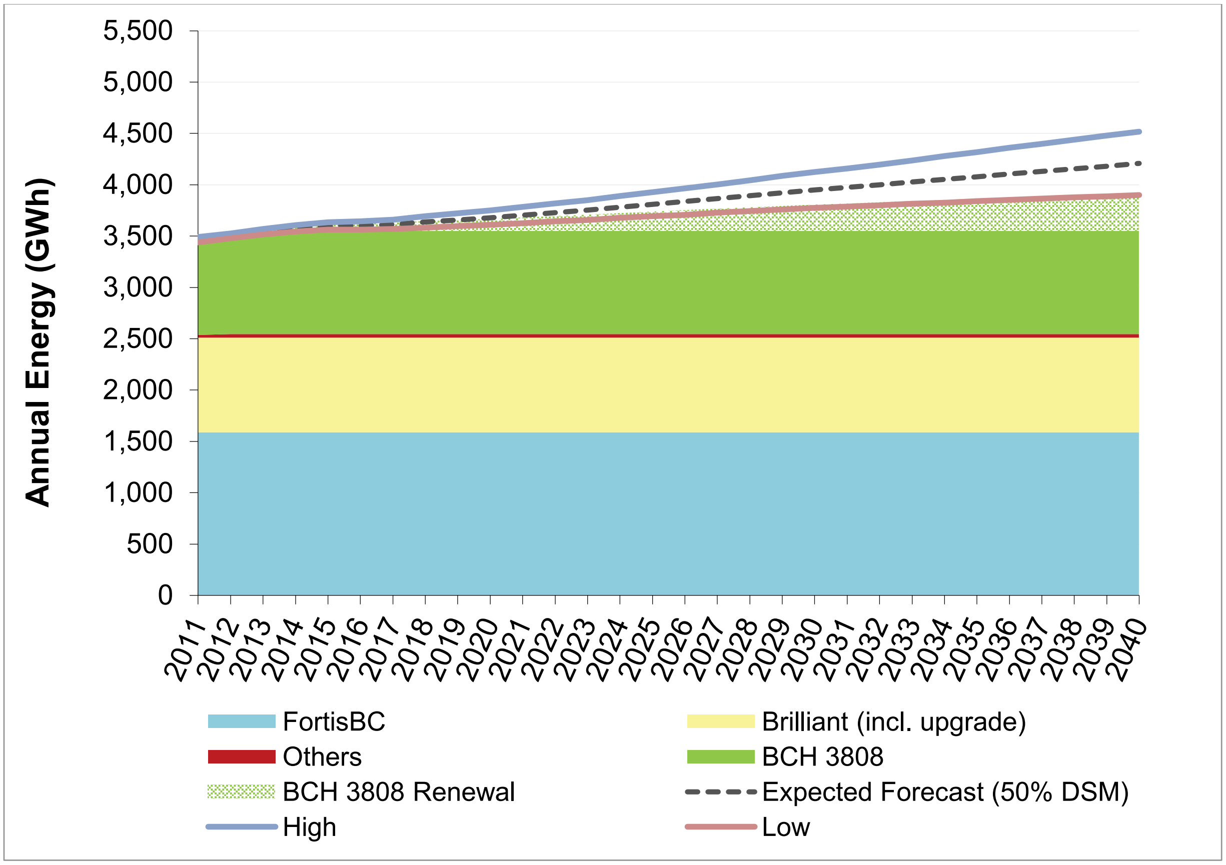
5.2.2.2 Energy Resource/Load Gap

The annual load/resource gap is calculated by comparing the energy forecast with the known supply resources (Figure 5.2.2.2-A). The expected forecast is represented by the dashed line, with the bounds of the High/Low forecasts represented by the upper and lower solid lines.

On the supply side resource stack, the base BC Hydro PPA energy (green) has an additional light green shaded wedge labeled "BCH 3808 Renewal", which represents the amount of energy BC Hydro PPA called upon from the BC Hydro PPA to satisfy FortisBC's load growth after 2013.

Figure 5.2.2.2-A shows how FortisBC's energy demand will grow into the future with and without DSM. If the final terms of the renewed BC Hydro PPA are materially different from the existing PPA, this may affect the resource stack and the timing of the development plans outlined in this 2012 Resource Plan.

Figure 5.2.2.2-A - Annual Energy Resource / Load Gap (GWh)



5.2.2.3 Energy Gap Summary

The Low, Expected, and High energy gap forecasts are provided numerically in Table 5.2.2.3-A.

FortisBC will have a growing energy gap on an annual basis over the planning period of this 2012 Resource Plan. The Company is forecasting a deficit of 5 GWh in 2011, 35 GWh in 2020, 167 GWh in 2030, and 310 GWh in 2040.

Table 5.2.2.3-A - Forecast Low/Expected/High Energy Gap by Year (GWh)

Year	Low	Expected	High
2011	4	5	29.5
2012	6	9	30.9
2013	4	9	33.1
2014	5	12	38.5
2015	1	5	33.5
2016	2	6	36.6
2017	4	9	43.0
2018	7	14	60.9
2019	11	25	79.0
2020	17	35	96.6
2021	24	46	116.2
2022	30	58	137.9
2023	35	70	156.9
2024	42	82	179.8
2025	49	95	204.0
2026	56	107	226.4
2027	65	120	250.2
2028	73	135	277.7
2029	81	151	307.7
2030	88	167	331.8
2031	95	180	356.8
2032	102	195	382.7
2033	109	210	411.4
2034	115	224	441.6
2035	121	239	466.5
2036	129	253	499.9
2037	136	268	526.3
2038	143	282	556.1
2039	150	296	583.0
2040	157	310	609.6

Table 5.2.2.3-B shows the increasing additional cost of purchasing energy in each year of the forecast period using expected Wholesale market prices. The incremental energy deficit would translate into additional annual energy purchase costs of over $2.8 million by 2020, over $20 million by 2030 and over $52 million by 2040.

Table 5.2.2.3-B - Forecast Expected Annual Additional Energy Purchase Costs

Year	Forecast Energy Deficit (GWh)	Expected Market Price ($/MWh)	Additional Energy Cost ($000s)
2011	5	$51.79	$244
2012	9	$54.68	$502
2013	9	$57.30	$535
2014	12	$61.18	$752
2015	5	$64.49	$318
2016	6	$68.47	$438
2017	9	$72.36	$677
2018	14	$76.15	$1,094
2019	25	$79.67	$1,961
2020	35	$82.59	$2,895
2021	46	$88.77	$4,113
2022	58	$92.27	$5,328
2023	70	$94.19	$6,544
2024	82	$96.78	$7,955
2025	95	$100.90	$9,566
2026	107	$104.73	$11,239
2027	120	$108.45	$13,037
2028	135	$112.55	$15,192
2029	151	$117.90	$17,795
2030	167	$122.45	$20,404
2031	180	$128.10	$23,076
2032	195	$130.48	$25,435
2033	210	$134.80	$28,259
2034	224	$139.16	$31,209
2035	239	$143.58	$34,289
2036	253	$148.04	$37,497
2037	268	$152.55	$40,838
2038	282	$157.11	$44,311
2039	296	$161.73	$47,924
2040	310	$167.50	$52,016

5.2.3 CONCLUSION

FortisBC will face growing energy and capacity deficits over the 30-year forecast period.

Capacity gaps will be greatest during the December super peak period each year, when the regional Wholesale market typically experiences its highest price periods, thus exposing the Company to the risk of forced market electricity purchases due to extreme weather conditions or facility contingencies at the least favourable times.

The growing energy deficit will involve additional expected energy purchase costs of over $2.8 million in 2020, increasing to over $20 million by 2030 and over $52 million by 2040 if all the required energy is purchased from the Wholesale market.

Regardless of the strategy chosen to address these deficits it will not be possible to avoid incremental energy and capacity acquisition costs over the forecast period.

6 RESOURCE OPTIONS AND STRATEGIES

FortisBC assessed alternative resource options and each option's ability to address the forecast capacity and energy deficits. These options can be categorized into the following strategic groupings:

1. **New Resources (Build Strategy):** Resource options that cover a variety of generation technologies linked to a newly constructed generation facility.
2. **Wholesale Market (Buy Strategy):** A marketplace based source of capacity or energy. FortisBC has considerable experience with the Buy Strategy, having regularly employed this strategy over the past two decades.
3. **Combination Strategy:** A strategy that balances the attributes and risks of both the Buy and Build strategies over time.

FortisBC evaluated the resource options against the forecast capacity and energy deficits over the short, medium and long term as outlined in Table 6-A.

Table 6-A - Expected Energy and Capacity Gaps in the Short, Medium and Long Terms

Time Period	Capacity Gap	Energy Gap[58]
Short term (2011 – 2015)	Increasing capacity deficits through to 2014, by which time deficits are present in 10 months and range from 17 MW (April) to 125 MW (March). However in 2015 deficits fall to 1 MW in March and 4 MW in June following the commissioning of WAX CAPA.	A small energy gap exists, starting at 5 GWh in 2011.
Medium term (2016 – 2020)	Capacity deficits start building again for the months of June and December, increasing to 20 MW (June) and 34 MW (December) by 2020. There are few hours of capacity gap exposure in any month in 2020.	Gap increasing to a 35 GWh by 2020.

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[58] Assumes the renewal of the BC Hydro PPA on similar terms.

Time Period	Capacity Gap	Energy Gap[58]
Long term (2021 – 2040)	December and June deficits present throughout, eventually expanding to Nov-Mar and May-Jul. Winter max deficit of 147 MW by 2030 and 223 MW by 2040; summer max deficit of 62 MW by 2030 and 112 MW by 2040. By 2030, 53 percent of December super peak hours have a capacity gap, growing to 90 percent by 2040.	Gap increasing to approximately 310 GWh by 2040.

The capacity and energy gaps described in Table 6-A are for the expected load forecast. Complete gap analysis, including consideration of high and low ranges for both energy and capacity, can be found in Section 5.2.

In order to determine the preferred resource option strategy the New Resources (Build Strategy) options are compared to the costs and risks of the Wholesale market (Buy Strategy) options and evaluated in each of the short term, medium term and long term time periods. The Build Strategy timing will be affected by future market prices and the renewal of the BC Hydro PPA.

6.1 Resource Options: New Resources (Build Strategy)

When FortisBC pursues New Resources (Build) strategy, it is assumed that the Company will either construct the new resource itself, or enter into a long term contract with a third party to provide FortisBC the energy and/or capacity output from a new resource. For example, the recently acquired WAX CAPA is a good example of this. Table 6.1-A describes the two alternatives available to FortisBC to acquire new generation and capacity resources.

Table 6.1-A - Acquiring New Resources: Alternatives

Acquisition Method	Description
Clean Call request for proposals (RFP)	Long term power purchase agreements with BC-based suppliers. The resource output would be sold directly to FortisBC. Time of day and monthly prices would be adjusted to match forecast FortisBC demand, with higher prices paid during periods of higher demand (e.g. winter months) than during other times of the year.
FortisBC Owned Infrastructure	A traditional utility self-supply alternative where FortisBC would take on the development of the new resource, including the risks and benefits associated with ownership of the project.

6.1.1 RESOURCE IDENTIFICATION AND PRELIMINARY SCREENING

In preparation for this 2012 Resource Plan, Midgard was engaged to refresh FortisBC's previous resource option analysis and prepare a 2010 Resource Options Report (ROR) (attached as Appendix C). The ROR identified and evaluated the resource options available for consideration by FortisBC by assembling a comprehensive resource stack with each resource option ranked according to its unit capacity cost (UCC) and unit energy cost (UEC) economic comparison metrics, as described below in Section 6.1.1.1. Subsequently, FortisBC filtered the comprehensive resource stack by selecting those resources from the resource stack that rank well on the basis of UEC or UCC and that are practically available to FortisBC. Resources that are both available[59] and most attractive on an economic (UCC or UEC) basis are shown in Table 6.1.1-A for capacity resources and Table 6.1.1-B for energy resources. The key attributes of these resource options are discussed in section 6.1.3.1.

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[59] BC Hydro's Revelstoke, Mica and Resource Smart Bundle are not resources available to FortisBC.

Table 6.1.1-A - FortisBC Capacity Resources Options – Available and Competitive UCC (CAD 2010)

Project	Dependable Capacity (MW)	Capital Cost ($000s)	UCC @6% ($/MW-month)	UCC @8% ($/MW-month)
Simple Cycle Gas Turbine (SCGT)	39	44,269	8,481	10,163
Combined Cycle Gas Turbine (CCGT)	243	329,445	10,624	12,708
Pumped Storage Hydro (PSH)	180	340,000	13,668	17,412
Similkameen Hydroelectric Project with Capacity	60	283,117	29,274	38,003

Table 6.1.1-B - Competitive Unit Energy Cost Resource Options (CAD 2010)

Project	Dependable Capacity (MW)	Average Annual Energy Output (GWh)	Capital Cost ($000s)	UEC @6% ($/MWh)	UEC @8% ($/MWh)
Combined Cycle Gas Turbine (CCGT)	243	1,916	329,445	90	93
Run-Of-River Hydro - Coastal[60]	28	255	248,000	88	108
Similkameen Hydroelectric Project with Capacity	60	234	283,117	97	124
Run Of River Hydro - FortisBC Territory[61]	10	250	280,000	101	124
Biomass - Roadside and Sawmill Woodwaste	15	145	Insufficient Data	108-159	108-159
Wind - Low Cost[62]	3	65.7	61,152	111	127
Wind	3	65.7	76,640	133	154

6.1.1.1 Economic Metrics – Unit Capacity Cost and Unit Energy Cost

To enable consistent evaluation of resources across an array of technologies and fuel sources, the economic characteristics of different resource options were evaluated and quantified using two economic metrics: Unit Capacity Cost and Unit Energy Cost.

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[60] Project location: British Columbia's western coast

[61] Project location: Okanagan or Kootenay regions

[62] "Low cost" refers to a wind resource with high capacity factor and low capital costs. An example would be a wind farm with superior wind conditions and lower than average per unit construction costs due to favourable site access and topography.

Unit Capacity Cost (UCC): This metric, expressed in $/MW-month, represents the annual cost of providing dependable capacity using a specific resource option. The UCC calculation divides:

- the resource's annual costs (interest on debt, return on equity, amortization, fixed operating costs) by
- the average expected annual dependable capacity available from the resource.

UCC is used to rank resources that can address capacity requirements, enabling the assembly of a portfolio of lowest cost dependable capacity resources to address a forecast capacity deficit

Unit Energy Cost (UEC): This metric, expressed in $/MWh, represents the annualized cost of generating a unit of electrical energy using a specific resource option. The UEC calculation divides:

- the sum of the all-in capital, fixed operating, and variable operating costs by
- the total amount of energy expected to be generated over the resource's anticipated service life.

UEC is used to rank a resource's ability to address energy requirements. If an energy shortfall has been identified, the UEC metric can be used to develop a lowest cost energy resource portfolio to meet that need. Representative energy resources include base load facilities such as large thermal plants as well as intermittent resources such as wind, solar and run-of-river hydro generation.

It is important to note that UEC and UCC are not interchangeable metrics. Capacity focused resources tend to rank well on a UCC basis but less well using a UEC metric. Energy rich resources tend to be the opposite, ranking poorly under a UCC metric, but attractively under a UEC metric.

The UEC and UCC values in the ROR were derived using generic operating assumptions. These assumptions include:

- Definitions of dependable capacity, annual energy, and firm energy;
- Financial parameters such as rates of return expectations, economic life of asset, and inflation indexation; and

- Natural gas fuel price.

For a full discussion of the assumptions and how they are applied to the resource options, please see Appendix C – FortisBC 2010 Resource Options Report.

6.1.2 RESOURCE OPTIONS RANKING AND EVALUATION CRITERIA

FortisBC further refined its resource option rankings by putting the resources options that passed initial economic screening through a final set of filters that represent key FortisBC resource option priorities and requirements:

1. **Appropriate Size**

   The resource option must be appropriately sized to fit the forecast FortisBC capacity and energy need. Because new infrastructure is constructed in fixed blocks of installed capacity, a resource option may only be cost effective if the size of the requirement approximately matches the unit size of the new resource. For example, although a CCGT resource scores well using both the UCC and UEC metrics, it would not be desirable for FortisBC unless the capacity and energy gaps were large enough to match the size of the installed energy resource. Scalable, flexible resource alternatives are preferred.

2. **Environmental Impact and Adherence to the Directives of the *Clean Energy Act***

   Environmental impacts – particularly greenhouse gas emissions and land use impacts associated with transmission – must be minimized. Furthermore, the resource options and implementation strategy must be consistent with the objectives of the *Clean Energy Act*. The *Clean Energy Act* objectives are summarized in Table 2.4.2.1-A.

3. **Appropriate Energy Shape (Energy Resource Evaluation Only)**

   Energy has a higher value during heavy load hours and high demand seasons than during light load hours and low demand seasons. The expected seasonal and diurnal production pattern, relative to the Company’s system’s ability to shape that production, is an important consideration evaluating the suitability of an energy resource.

4. **Comparative Resource Economics Test**

FortisBC will target the least cost solution, conditional upon fidelity with the other criteria.

FortisBC assessed each resource option against its ability to meet these criteria. FortisBC applied a score ranging from one to three for each of the criteria, with a one representing the most attractive score and three the least attractive. The lower the cumulative score of the resource, the more attractive the resource was deemed to be for meeting FortisBC forecast needs. Table 6.1.2-A summarizes the results of applying the rating criteria to the capacity resource options from Table 6.1.1-A and Table 6.1.2-B summarizes results of applying the rating criteria to the energy resource options from Table 6.1.1-B. The full analysis is found in Appendix I – Detailed Resource Option Rating.

Table 6.1.2-A - Capacity Resource Rating Table (Sorted by Rating)

	Criterion 1: Gap Closure and Size	**Criterion 2: Environmental Impacts**	**Criterion 3: Resource Economics**	**Score**
Simple Cycle Gas Turbine (SCGT)	1	2[63]	1	**4**
Similkameen Hydroelectric Project	1	1	3	**5**
Pumped Storage Hydro (PSH)	2	1	2	**5**
Combined Cycle Gas Turbine (CCGT)	3	3	1	**7**

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[63] When operating in a reserve capacity with limited expected production.

Table 6.1.2-B - New Clean Energy Resource Rating Table (Sorted by Rating)

	Criterion 1: Gap Closure and Size	Criterion 2: Environmental Impacts	Criterion 3: Resource Economics	Criterion 4: Energy Shape	Score
Similkameen Hydroelectric Project	1	1	2	1	**5**
Run-Of-River Hydro - Coastal[64]	1	1	1	2	**5**
Biomass - Roadside and Sawmill Woodwaste	1	1	3	1	**6**
Run Of River Hydro - FortisBC Territory[65]	1	1	2	3	**7**
Wind - Low Cost[66]	1	1	2	3	**7**
Combined Cycle Gas Turbine (CCGT)	2[67]	3	1	1	**7**
Wind	1	1	3	3	**8**

6.1.3 NEW RESOURCES (BUILD STRATEGY)

FortisBC has determined its preferred New Resources (Build Strategy) options based on the ranking process described in Section 6.1.2. Table 6.1.3-A lists these preferred resource options.

Table 6.1.3-A - FortisBC – Preferred Build Strategy Resource Options

Rank	Capacity Requirements	Energy Requirements
1	Simple Cycle Gas Turbine	Similkameen Hydroelectric Project
2	Similkameen Hydroelectric Project	New Clean Energy Resources
3	Pumped Storage Hydro	Combined Cycle Gas Turbine

6.1.3.1 Key Attributes of FortisBC's Preferred Build Strategy Resource Options

Simple Cycle Gas Turbines (SCGTs) are a cost-effective capacity resource with the added benefit of being able to provide energy if needed. However, SCGTs are not typically considered to be economical energy resources due to low fuel to electricity conversion efficiencies. Aero-derivative SCGT technology is available in relatively small sizes, and when a future need for capacity resources is identified a scalable facility can be economically designed to meet those future needs.

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[64] Project location: British Columbia's west coast

[65] Project location: Okanagan or Kootenay region

[66] "Low cost" refers to a wind resource with high capacity factor and low capital costs. An example would be a wind farm with superior wind conditions and lower than average per unit construction costs due to favourable site access and topography.

[67] While the CCGT energy production is too large compared to the Company's expected energy gap forecast, if the actual gap trends towards the high gap forecast then the CCGT production could match needs.

Since SCGTs generate greenhouse gases, obtaining the social contract needed to permit and site SCGTs is often difficult. However, once permits are obtained SCGTs can be constructed in a relatively short period of time.

In the FortisBC context, an SCGT has the lowest environmental footprint when operated as a planning reserve margin (PRM) resource because only a small volume of greenhouse gasses would be produced due to the low utilization rate. Nevertheless, FortisBC may be required to purchase carbon offsets to compensate for greenhouse gas emissions.

In summary, the attributes of the SCGT that demand FortisBC's attention when considering them as potential resource options include:

- Quick start/stop: SCGTs can be turned on or off quickly, responding to immediate changes in load.
- Small footprint, not tied to specific sites: The fuel is natural gas, and therefore not tied to sites predefined by a fuel source, as are hydro or wind facilities, for example. These facilities can be located close to load centers and therefore this option involves minimal transmission impacts and may defer otherwise necessary transmission reinforcements to the load center.
- Fuel diversity: FortisBC's existing fleet of owned and contracted firm supply sources all depend upon water as the fuel – SCGTs do not, therefore injecting fuel diversity into the Company's portfolio.

Pumped Storage Hydro (PSH) is a method of storing and producing electricity to supply high peak demands by moving water between reservoirs at different elevations. PSH can pump water into its upper storage reservoir using low cost off-peak market energy or surplus renewable resource production, and then generate during system peak hours using this stored energy.

PSH is a unique capacity-only resource that has the ability to shape power demand within the system. Although PSH is a net consumer of energy, such a facility would provide FortisBC considerable operational flexibility. A PSH facility can rapidly switch from consuming excess energy (pump mode) to injecting energy (generation mode), thereby providing both operating reserves and planning reserve margin. A PSH facility is also able to provide other important ancillary services including voltage and frequency support.

PSH has no direct greenhouse gas emissions associated with its operation and is well suited to facilitate the integration of intermittent green resources such as wind because it can both “firm up” and “firm down” such intermittent resources. The ability of PSH to switch between pumping and generating modes enables it to offset the sudden changes in production that are typical of wind and other intermittent renewable resources. This capability also enables the electric system to absorb and balance significant amounts of customer-owned distributed generation resources, such as small wind mills or roof-top solar panels.

PSH facilities involve long lead times for siting, permitting and construction due to the requirement for water storage sites, therefore development activities must be pursued prudently long in advance of actual project commissioning.

In summary, the attributes of PSH as a resource option that attract FortisBC’s interest include:

- Rapid pump/generate mode change: PSH is able to firm intermittent renewable resources such as wind and solar, and balance customer-owned distributed generation.
- Ancillary services: PSH can provide regulating and contingency operating reserves, planning reserve margin, frequency support and reactive power/voltage support.
- Green resource: PSH does not directly generate greenhouse gases.

Similkameen Hydroelectric Project is a potential hydroelectric facility with water storage, located near Princeton, British Columbia. As a result, this project is both a capacity resource option and an energy resource option. The Similkameen Hydroelectric Project is appropriately sized for FortisBC’s forecast needs, and located within FortisBC’s service territory.

No material greenhouse gases would be associated with energy produced by this facility. This project would potentially increase Similkameen River stream flows during the dry summer months by storing freshet water, thereby improving summertime water availability for downstream users and aquatic life in both Canada and the United States.

Storage hydro projects typically have higher capital costs than other resource option alternatives, and require long lead times to identify, design, permit and construct prior to commissioning. In summary, the attractive attributes of the Similkameen Hydroelectric Project as part of FortisBC’s resource portfolio are:

- Energy production: The Similkameen Hydroelectric Project will produce incremental energy that is well sized to fit within the projected FortisBC energy gap in the medium to long term forecast period.

- Firm capacity: The Similkameen Hydroelectric Project represents firm capacity since its storage capabilities will enable energy to be dispatched as required, within the limits of its storage volumes.
- Ancillary services: Similar to PSH, the Similkameen Hydroelectric Project can provide regulating and contingency operating reserves, planning reserve margin, frequency support and reactive power/voltage support.
- Green project: The Similkameen Hydroelectric Project will have positive environmental attributes, including no material greenhouse gas production and favourable seasonal stream flow enhancement.

Combined Cycle Gas Turbines (CCGT) are cost-effective energy resources that operate as base load energy resources. Since CCGTs are base load resources that continuously generate greenhouse gases, obtaining the social contract needed to permit and site CCGTs is often difficult. However, once permits are obtained, CCGTs can be constructed in a relatively short period of time. It is reasonable to expect that FortisBC would be required to purchase carbon offsets to compensate for greenhouse gas emissions.

In the FortisBC context, CCGTs are typically large relative to the forecast energy gaps. For example, a 243 MW CCGT can be expected to generate approximately 1,900 GWh[68] of energy annually. This level of new energy output would only be required if actual load exceeded the Company's current high gap forecast. For example, if new uses of electricity, such as a general take up of electric vehicles, were to become prevalent, then new significant sources of electricity generation would be required. In that instance, power production costs from a CCGT would compete favourably against the increased Wholesale market purchases.

In summary, the attractive attributes of a CCGT as part of FortisBC's resource options portfolio include:

- Cost-effective energy production: CCGTs represent the most cost effective method of producing energy (on a per-unit basis) of the New Resources options reviewed, assuming that the minimum energy block size is required.
- Rapid deployment: CCGTs can be rapidly developed once environmental permitting is complete.

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[68] Actual energy output can be expected to decrease over time as the CCGT ages. Estimated energy output for a 243 MW CCGT is 1,944 GWh in year one falling to 1,888 GWh in year 25 – Reference FortisBC 2010 ROR (see Appendix C).

New Clean Energy Resources (wind, run of river, biomass, etc.) represent a collection of clean energy resources that would be developed and constructed. The typical resources would consist of intermittent energy resources such as wind and run of river hydro, but could also include biomass or other resources. Intermittent energy is supplied if and when fuel is available, meaning such resources have limited capacity value. Run of river projects with high freshet flows supply energy in spring when Wholesale market prices are low, wind project generation varies considerably from hour to hour with little predictability and its high ramp rates can cause difficulties managing the transmission grid. These intermittent resources require commensurate "balancing" firm capacity system capabilities. In contrast, biomass projects are similar to base load energy resources because their fuel supply is controlled. However, unlike wind and water projects, biomass fuel is not "free" so the cost of biomass energy is comparatively high.

In summary, the attributes of new clean energy resources that are of interest to FortisBC include:

- Flexible size and timing: run-of river hydro, wind and biomass can be sized and timed to meet the actual energy gap.
- Green energy: Projects would be "BC Clean" projects.

6.2 Resource Options: Wholesale Market (Buy Strategy)

FortisBC can purchase capacity and energy products directly from the US electricity market, assuming that they are available for sale and no transmission constraints exist. Alternatively, FortisBC can purchase capacity and energy products from BC Hydro's trading subsidiary Powerex within the limits of the existing transmission interconnections between the FortisBC and BC Hydro systems. Significant additional draws may require commensurate reinforcements to these transmission interconnections. Transactions with Powerex are typically cost comparable with prevailing Mid-C prices plus the cost of wheeling to FortisBC's service area (see Section 3.3).

Reliance on market purchases of energy and capacity exposes FortisBC to market prices and market price volatility. Although the recession that began in 2008 has dampened electricity demand in the US and Canada, longer term economic growth will erode the region's resource surplus and could quickly increase prices for energy and capacity in the Wholesale market. Therefore, although the market prices of energy and capacity appear attractive today, these prices are subject to upward pressures in the future.

A more complete discussion of market risks is covered in Section 3.4 as well as in Appendix B - Midgard 2011 Energy Market Assessment.

In summary, assuming that transmission constraints do not prevent FortisBC from accessing the Wholesale energy market, FortisBC can purchase the capacity and energy products it requires from the market under a Wholesale market (Buy Strategy).

6.3 Resource Options: Combined Build and Buy

6.3.1 BUILD STRATEGY VS. BUY STRATEGY: TIMING

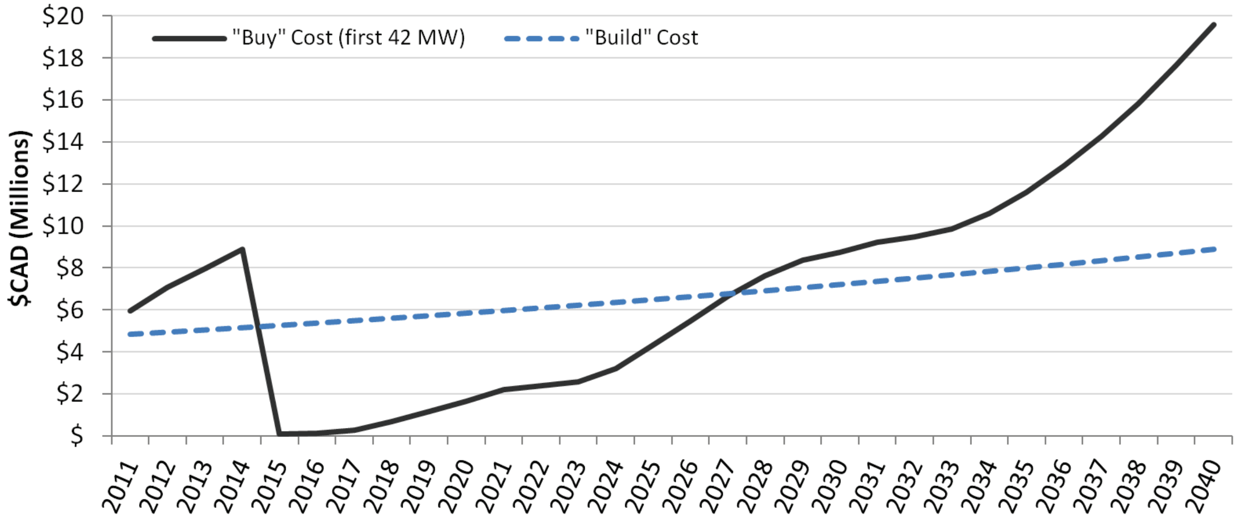
The Combined Strategy envisions selecting from both options. Making the correct strategy decision depends largely on the projected relative economics of each for the timeframe and gap involved. The recent addition of the WAX CAPA to FortisBC's capacity supply portfolio means that the Company's capacity needs are no longer immanent.

6.3.2 CAPACITY COSTS COMPARISON

FortisBC compared the forecast cost of capacity obtained in the Wholesale market with the cost of building new capacity resources (Section 3.3.3). Based on current assumptions, on a per unit basis ($/MW-month) the BC Wholesale market price for capacity is less expensive than the corresponding BC New Resources price until approximately 2019. When the Company's currently forecast capacity gap requirements are taken into consideration, the cost of the Build Strategy becomes cost competitive with the forecast Buy Strategy cost in the late 2020s.

Figure 6.3.2-A, below, demonstrates this comparison by matching the Buy Strategy costs associated with filling up to 42 MW of the forecast capacity gap with the Build Strategy's least-cost resource – a 42 MW SCGT. In the figure, the annual costs associated with building the SCGT appear immediately, and continue throughout the planning period – because once built it has to be paid for regardless of actual need. Conversely, Buy Strategy costs only appear when there is a gap and with WAX CAPAs the majority of the forecast capacity gap for a time following 2015 is eliminated, and the associated potential market purchase costs disappear. The cost curves do not cross again until the late 2020s, when the forecast peak capacity gap has grown enough to justify building the 42 MW capacity asset used in the comparison. The actual timing of resource additions will take into account other factors such as price, demand, opportunity, export opportunities, etc.

Figure 6.3.2-A - Buy Strategy vs. Build Strategy – Capacity Costs (First 42 MW Block)



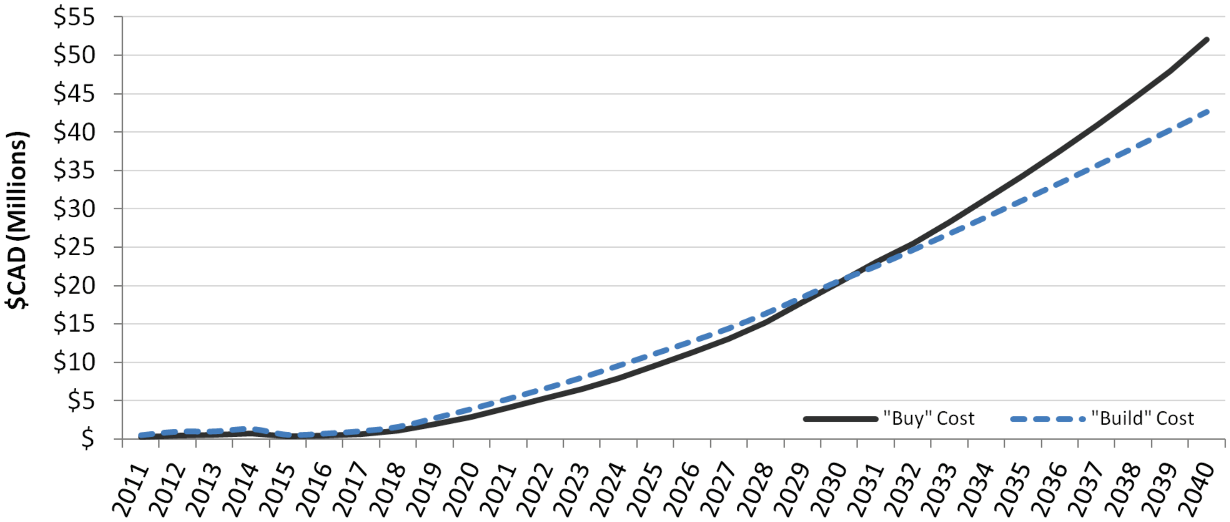
Based upon this cost comparison, FortisBC expects that the pursuit of a Buy Strategy for acquiring capacity resources during the short term and medium term periods is a prudent approach. Further, the Company expects that implementation of a Build Strategy for capacity will become economical in the long term.

6.3.3 ENERGY COSTS COMPARISON

FortisBC calculated the costs of purchasing energy to address the expected forecast energy gaps from the Wholesale market (Buy Strategy) using the Wholesale market price curves presented in Section 3.3.2 and compared them against the costs of purchasing energy from a new clean energy resources (Build Strategy) option.

Figure 6.3.3-A graphically depicts this comparison.

Figure 6.3.3-A - Buy vs. Build – New Clean Energy Resources



Based on the current market assessment and demand, the cost of purchasing energy from the market is initially lower than the comparable cost of purchasing from a newly constructed facility. This cost advantage persists until approximately 2030, at which time new clean energy resources energy is forecast to become less expensive than market-based energy purchases. Based upon this cost comparison, in the short term and medium term FortisBC should plan to follow a Buy Strategy for purchasing energy resources. However, in the long term FortisBC should expect to transition to a Build Strategy.

6.3.4 RISK CONSIDERATIONS IN THE MEDIUM AND LONG TERM

In addition to the economic evaluation detailed in Sections 6.3.2 and 6.3.2, FortisBC also evaluated the future resource option strategies in the context of the potential risks that the Buy Strategy and the Build Strategy each face. The critical risks to consider are price risk and availability risk.

Price Risk

Section 3.3.1 highlighted that the reliability of forecasts diminishes with time. Therefore, in the short term (2011-2015) FortisBC has a reasonable expectation that the forecast BC Wholesale market prices will remain accurate. However, in the medium term (2016-2020) and especially in the long term (2021+), FortisBC can expect increasingly large deviations from the BC Wholesale market price forecast.

Similarly, the cost of BC New Resources is also subject to price deviations from forecast. However, BC New Resource pricing does not display the same price volatility as BC Wholesale market pricing. Rather, BC New Resource prices tend to move higher with the general rate of inflation because development costs are tied to a spectrum of inputs (such as labour and manufactured equipment) whose costs have historically escalated with inflation.

Availability Risk

Section 3.1.2 and 3.1.3 also discussed availability risk as a result of market shortages and transmission constraints. These risks are a greater threat to Wholesale market supplies than they are to the New Resources market. New Resources tend to be built locally for local consumption, which minimizes the risks associated with transmission constraints. The construction of New Resources is, of course, a natural solution to market shortages.

The renewal of the BC Hydro PPA is still under discussions. This Resource Plan assumes that the BC Hydro PPA will be renewed on essentially the same terms and conditions. If this is not the case, there may be a change to the timing or the nature of the resources needed. This will be re-evaluated once the BC Hydro PPA is renewed.

In light of the relatively greater price and availability risks that threaten Wholesale market supplies, FortisBC must take a prudent approach to mitigating these risks, particularly as the risks increase in the medium term and long term.

Therefore, FortisBC’s resource options must weigh quantifiable economic factors more heavily in the short term and less heavily in the long term. By contrast, the price and availability risks must be weighed more heavily in the long term and less heavily in the short term. Table 6.3.5-A and Table 6.3.5-B list FortisBC’s approach to addressing the short, medium and long term gaps in capacity and energy needs. Section 6.4 will translate these recommendations into a preferred strategy.

6.3.5 SOLUTIONS SUMMARY

Table 6.3.5-A - Recommended Capacity Solutions

Time Period	Expected Capacity Gap	Capacity Solution
Short term (2011 – 2015)	Increasing deficits through 2014, by which time deficits are present in 10 months and range from 17 MW (April) to 125 MW (March). In 2015 there are only small deficits of 1 MW in March and 4 MW in June due to the commencement of WAX CAPA.	• Wholesale market purchases as required • Continue assessment of potential capacity resources
Medium term (2016 – 2020)	Deficits continues in June and appears in December starting in 2017, increasing to 20 MW (June) and 34 MW (December) by 2020. There are few hours of capacity gap exposure in any month in 2020.	• Wholesale market purchases (anticipated) • Option to accelerate construction of new resources dependent upon previous development work.
Long term (2021 – 2040)	December and June deficits present initially, eventually expanding to November through March and May throughJuly. Winter max deficit of 147 MW by 2030 and 223 MW by 2040; summer maximum deficit of 62 MW by 2030 and 112 MW by 2040. By 2030, 53 percent of December super peak hours have a capacity gap, growing to 90 percent by 2040.	• Anticipate building new resources by mid-late 2020s • Additional new capacity resources required in the 2030s

Table 6.3.5-B - Recommended Energy Solutions

Time Period	Expected Energy Gap	Energy Solutions
Short term (2011 – 2015)	No gap with the exception of 4 GWh in 2011.	• Wholesale market purchases • Continue assessment work on new clean energy resources (run-of-river hydro, wind, biomass)
Medium term (2016 – 2020)	No gap through to 2018, increasing to a 13 GWh gap in 2020.	• Wholesale market purchases (anticipated) • Option to accelerate new clean energy resources
Long term (2021 – 2040)	24 GWh in 2021, increasing by approximately 14 GWh/year to 287 GWh by 2040.	• new clean energy resources • CCGT

6.4 Preferred Resource Strategy

The previous section compared the Wholesale Market (Buy Strategy) and the New Resources (Build Strategy), and considered a Combined Strategy for acquiring resources to meet FortisBC's forecast energy and capacity gaps from 2012 through 2040. A variety of resource options that could be acquired by FortisBC were analyzed under the Build Strategy and then compared to the Buy Strategy for energy and capacity.

While it is FortisBC's objective to achieve 100 percent self sufficiency through a owned or long-term contracted power supply resource stack, as a result of this comparison and based on the forecast expected capacity and energy gaps following the commencement of the WAX CAPA, in the short to medium term the Build Strategy is not expected to be cost competitive compared to buying these products in the wholesale marketplace. Specifically, given the modest size of the forecast energy and capacity gaps that FortisBC expects to fill in the next decade and especially considering that there are few actual hours of exposure to capacity gaps, purchasing from the Wholesale market in the short to medium term is the economically prudent solution for FortisBC and its ratepayers.

However, it must be recognized that Wholesale Market prices are subject to more volatility than the price of New Resources markets because Wholesale Market price behaviour is non-linear when constraints or capacity shortages occur. Consequently, if FortisBC finds that in practice its market purchases are correlated with Wholesale market price spikes, it may be prudent to shorten its timelines for building new generation assets. In addition, if there are changes to the contracted resources such as the BC Hydro PPA, this may also affect the timing or the nature of the resource acquisitions. Similarly, if actual load growth exceeds expected load growth, energy and capacity gaps will be larger than expected and the timing of new resource commissioning will need to be advanced. In the interim, this caveat underlines the need for the Company to maintain its Planning Reserve Margin at the levels defined in Section 5.2.1.1.

Consequently, FortisBC must maintain a portfolio of New Resources options to support shortened timelines for New Resources commissioning because developing new facilities typically involves many years of permitting, design, stakeholder engagement and construction before these facilities can be put into service.

6.4.1 COMBINED BUILD AND BUY

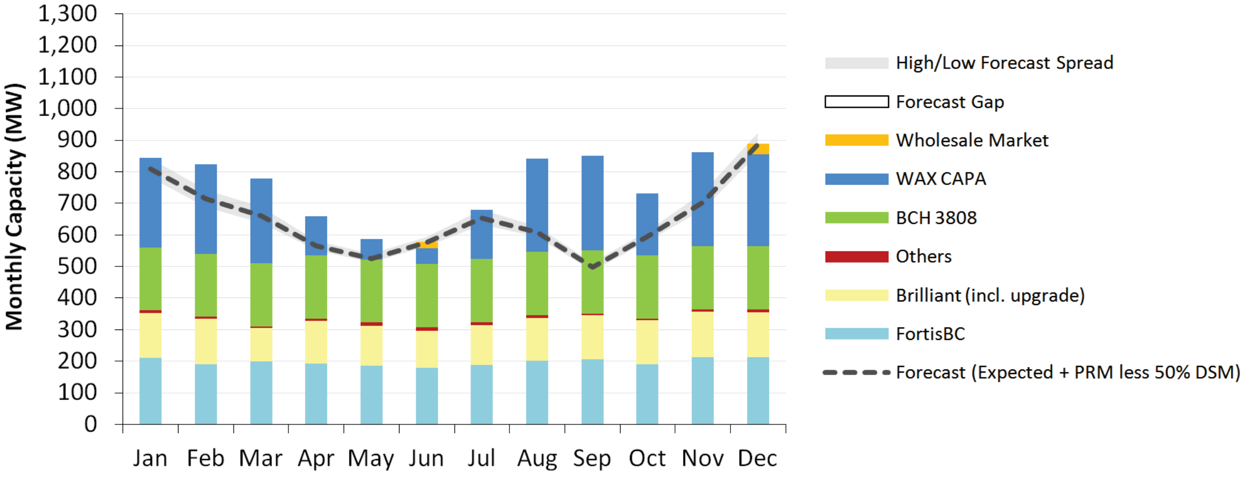
Table 6.4.1 outlines the Company's preferred resource acquisition strategy (Preferred Strategy). This strategy represents a balanced and prudent solution to address FortisBC's expected forecast capacity and energy requirements while maintaining the flexibility required of an uncertain future.

1 **Table 6.4.1 - FortisBC Preferred Strategy**

Time Period	Capacity Solution	Energy Solutions
Short term (2011 – 2015)	• Wholesale market purchases of Capacity (Buy Strategy) as required • Early stage assessment of capacity resource options: iv. SCGT v. PSH vi. 60 MW Similkameen Hydroelectric Project	• Wholesale market purchases of Energy (Buy Strategy) • Early stage assessment of energy resource options: ii. 234 GWh/year Similkameen Hydroelectric Project
Medium term (2016 – 2020)	• Wholesale market purchases of Capacity (Buy Strategy) as required • Be prepared to accelerate the commissioning of one or more capacity resources (Build Strategy): iv. SCGT v. PSH vi. 60 MW Similkameen Hydroelectric Project	• Wholesale market purchases of Energy (Buy Strategy) • Early stage development of energy resource options: iii. 234 GWh/year Similkameen Hydroelectric Project iv. 200 – 500 GWh New Clean Energy Resources
Long term (2021 – 2040)	• New Resources (Build Strategy) capacity resources by mid 2020s. One or more of: iv. 1-2 x 42 MW SCGT v. 100 - 200 MW PSH vi. 60 MW Similkameen Hydroelectric Project • Additional New Resources (Build Strategy) capacity resource in the 2030s. • Wholesale market purchases (Buy Strategy) remain an option to fill small residual gaps after capacity resource are commissioned.	• New Resources (Build Strategy) energy resources. One or both of: iii. 234 GWh/year Similkameen Hydroelectric Project iv. New Clean Energy Resources • Wholesale market purchases (Buy Strategy) remain an option to fill small residual gaps after energy resources are commissioned.

The Preferred Strategy relies on the Wholesale capacity market to fill expected capacity gaps in the short term (2011-2015) and medium term (2016-2020).

Figure 6.4.1-A - FortisBC – Preferred Strategy Energy Gap Closure



In the long term (2021-2040) FortisBC will transition from the Buy Strategy to a Build Strategy to provide capacity. Because of the higher uncertainties associated with forecasting far into the future and the market price risks, FortisBC is not currently planning specific commissioning dates for specific capacity resources. Rather, FortisBC is planning to assess and maintain the set of capacity resource options listed in the Preferred Strategy Table 6.4.1 and summarized as follows:

- 1 to 2 x 42 MW SCGT
- 100 - 200 MW PSH
- 60 MW Similkameen Hydroelectric Project

Depending on actual load growth, BC Wholesale market prices and estimated market risks, FortisBC will re-evaluate when and which resources to commission in the next FortisBC Resource Plan to be filed with the Commission.

In conclusion, this Resource Plan contains no planned capital expenditures for capacity resources at this time.

The Preferred Strategy also relies on the wholesale energy market in the short term (2011-2015) and medium term (2016-2020). In the long term (2021-2040), FortisBC plans to transition from the Buy Strategy (purchasing from the Wholesale market) to the Build Strategy. The Preferred Strategy contemplates new clean energy resources and the Similkameen Hydroelectric Project.

New clean energy resources will likely stagger project commissioning over multiple years (e.g. three years) to better match load growth with supplied energy. New Resource requirements may vary in size from 200 GWh up to 500 GWh. This scalable resource solution can be sized closer to the time of need to better align with the actual energy deficit.

The Similkameen Hydroelectric Project timing will depend on FortisBC's need for both capacity and energy. Therefore, depending on actual load growth and associated energy and capacity gaps, the Similkameen Hydroelectric Project is expected to be commissioned in the mid 2020s to early 2030s.

Similar to the resources identified for closing the forecast long term capacity gap, depending on actual load growth, Wholesale market prices and estimated market risks, FortisBC will re-evaluate when and which resources to commission in the next Resource Plan to be filed with the BC Utilities Commission.

In conclusion, this Resource Plan contains no capital expenditures for assessment of energy resources at this time.

6.5 Community Energy Development Program

In addition to the preferred resource strategy for closing the forecast energy and capacity gaps, FortisBC proposes to investigate the merits of establishing a Community Energy Development Program (FortisBC CEDP). The FortisBC CEDP would allow FortisBC the flexibility to negotiate power purchase agreements with small, community and/or First Nation based project proponents

The FortisBC CEDP concept is aligned with the *Clean Energy Act* goals:

- to foster innovative technologies that support energy conservation and the use of clean or renewable resources and distributed generation;
- to encourage local economic development and the creation and retention of jobs; and
- to foster the economic growth of First Nation and rural communities through the development and operation of clean or renewable resources.

The intent of the FortisBC CEDP concept is to facilitate the development of small community scale renewable resource power projects in the FortisBC service territory by assuring a dependable income stream for the project(s). It is anticipated that the program will foster innovative technology and/or innovative uses of existing technology on small scales.

The FortisBC CEDP concept is not expected to generate a material quantity of either energy or capacity, and individual power purchase agreements coming out of the program are not expected to provide long term contractual resources to the Company's system. Therefore, the FortisBC CEDP concept is not included in the resource plan as a source of capacity or energy.

FortisBC will continue to investigate the concept, potential design and costs of the CEDP. If, in the Company's opinion, the concept has merit, FortisBC will submit the final design FortisBC CEDP to the BC Utilities Commission for review and acceptance.

7 ACTION PLAN

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

i. Continuing to review and optimize the energy and capacity portfolio resources, which includes completing the renewal of the BC Hydro PPA, integrating the WAX CAPA into the FortisBC resource stack, and assessing the potential requirements and timing for new resource options;

ii. Continuing to monitor and evaluate FortisBC's customer load growth, and assessing the PRM requirements; and

iii. Liaising with provincial, regional and national energy and climate related policy makers, providing the FortisBC Utilities' expertise in energy issues and planning to the development of policy that will impact British Columbia's energy customers.

Appendix A

GLOSSARY

Appendix A - Glossary

BC Clean Energy: Resources and technological applications that may qualify as a source for Clean or Renewable Electricity production may include: Biogas Energy, Biomass Energy, Energy Recovery Generation (ERG), Geothermal Energy, Hydrocarbon Energy, Hydro Energy, Hydrogen, Municipal Solid Waste (MSW), Solar Energy, Tidal Energy, Wave Energy, and Wind Energy, if they meet the definition of clean as prepared by the Ministry of Energy and Mines. This refers to energy technologies that result in a net environmental improvement relative to existing energy production.

BC Energy Plan: A statement of British Columbia government policy related to provincial energy matters issued by the Minister of Energy and Mines in February 2007.

Bioenergy: A type of renewable energy made available from materials derived from biological sources.

Canal Plant Agreement (CPA): The CPA aggregates the power production from multiple hydro generation facilities located upon the Kootenay and Pend d'Oreille Rivers, and apportions that production for the use of the owners of those hydro facilities in the form of entitlements of capacity and energy. This usage effectively eliminates the hydrological risk normally associated with individual hydroelectric generation facilities. In return for providing these CPA Entitlements, BC Hydro receives the right to dispatch plant generation to maximize the benefits to the overall Provincial system.

Canal Plant Agreement (CPA) Entitlement: The average water year generation of the generating facilities included in the Canal Plant Agreement. Provided each unit is in-service, the related entitlements are provided by BC Hydro regardless of the actual generation dispatched by BC Hydro from the facilities.

Capacity:

(1) The instantaneous output of a power plant at any given time, normally measured in kilowatts (kW) or megawatts (MW).

(2) The instantaneous system electricity demand at any given time, normally measured in kilowatts (kW) or megawatts (MW).

(3) The amount of electrical power that can be safely transmitted by a transmission facility at any instant.

Related terms:

- **Maximum Capacity** - The highest generating plant output or transmission loading that can actually be achieved in situ.
- **Dependable Capacity** - The amount of megawatts of generation available assuming all units are in service for three peak hours per day during the coldest two-week period each year. In BC, system peak electrical demand typically occurs in December or January sometime between the hours of 5 pm and 9 pm. Factors external to the plant affect its dependable capacity. For example, streamflow conditions can restrict the dependable capacity of hydro plants and fuel supply constraints can impact thermal plant dependable capacity.

Planned and forced outage rates are not included.

- **Installed Capacity** (Also referred to as Nameplate Rating) - The maximum rating of a generator or transmission station equipment as identified by the manufacturer under specified conditions.

Capacity Purchase: The purchase of capacity without energy.

Certificate of Public Convenience and Necessity (CPCN): A certificate issued to a public utility by the British Columbia Utilities Commission for the construction or operation of a generating plant or other facility.

Columbia River Treaty: A treaty signed in 1961 between Canada and the United States of America that enabled storage reservoirs to be built and operated in British Columbia to regulate Columbia River flows into the United States for power production and flood control.

Demand Reduction: A Demand Side Management (DSM) action taken to reduce consumer electricity demand, in response to price, monetary incentives, or utility directives so as to maintain reliable electric service or avoid high electricity prices.

Demand Side Management (DSM): Actions that modify customer demand for electricity, helping to defer the need for new utility energy and capacity supply additions.

Discount Rate: A rate used to determine the present value of receipts and/or expenditures that will occur over a period of time, reflecting the cost of capital.

Distributed Generation Resources: Individual-use generation resources, such as solar or small wind turbines, distributed amongst and utilized by customers. Typically offsets individual customer power consumption and is connected to the utility system via some form of net metering facility.

Energy Information Administration (**EIA):** A branch of the United States Department of Energy that collects, analyzes, and disseminates energy information.

Energy: The electricity produced or used over a period of time, usually measured in kWh, MWh or GWh.

Entitlement Adjustment Agreement (EAA): An agreement related to the CPA that defines FortisBC entitlements. See also Canal Plant Agreement Entitlement.

Exchange Accounts: Accounts established under the Canal Plant Agreement to track the varying use of energy entitlements during the Storage Draft Season and the Storage Refill Season, to ensure that entitlement usage is maintained within agreed bounds during each season.

Firm Market Purchase: The highest degree of reliable market power that can be purchased. It can only be curtailed due to the most severe contingencies such as the loss of the transmission path. See also Long-Term Firm Resource.

Gigawatt-Hour (GWh): One billion watt hours, one million kilowatt hours (an amount of electric energy that will serve about 100 residential customers for one year).

Green Energy: A term describing what are thought to be environmentally friendly sources of power and energy. Typically, this refers to renewable and non-polluting energy sources. Green energy includes natural energetic processes that can be harnessed with little pollution. Anaerobic digestion, geothermal power, wind power, small-scale hydropower, solar power, biomass power, tidal power and wave power fall under such a category. Some versions may also include power derived from the incineration of waste.

Greenhouse Gases (GHG): Gases that are thought to contribute to global climate change, or the greenhouse effect, including carbon dioxide (CO2), carbon monoxide (CO) and methane (CH4).

Heavy Load Hours (HLH): The time of day in which peak demand occurs. Heavy Load Hours are from 0600h through 2200h, Monday to Saturday, excluding holidays.

Heat Rate: A measure of generating station thermal efficiency, computed by dividing the heat content of the fuel by the resulting net electric energy generated.

Heritage Contract: A 49,000 GWh per year contract (in perpetuity) between BC Hydro’s Generation and Distribution Lines of Business to ensure BC Hydro customers (including FortisBC) benefit from the existing low-cost hydroelectric and thermal resources in the BC Hydro system.

Independent Power Producer (IPP): A privately owned electricity generating facility that produces electricity for sale to utilities or other customers.

Kilowatt (kW): One thousand watts, the commercial unit of measurement of electric power. A kilowatt is the flow of electricity required to light ten 100-watt light bulbs.

Kilowatt Hour (kWh): One thousand watts used for a period of one hour, the basic unit of measurement of electric energy. On average, residential customers in British Columbia use about 10,000 kWh per year.

Levelized Cost, Levelized Price: Levelizing is a method of converting a non-uniform stream of energy costs (or prices) into a present value equivalent uniform cost (or price).

Light Load Hours (LLH): All hours that are not Heavy Load Hours. See Heavy Load Hours.

Load: The amount of electricity required by a customer or group of customers.

Load Forecast: The expected load requirements that an electricity system will have to meet in the future.

Load Duration Curve: The variation in electrical load over time, usually hour-by-hour for a month or a year. The curve is sorted with the highest load over the period in question first followed by the next highest load and so on. This provides an effective way to determine how many hours loads exceeded a certain level.

Long-Term Firm Resource: A generation facility, Market Energy

Block purchase or other power contract intended to meet load more than five years in advance. See also Firm Market Purchase.

Market: The network of electricity trading options that allows the purchase of wholesale electricity.

Market Volatility: Market prices vary considerably depending on the time of day, weather, fuel costs, and regional resource availability. This leads to potential market price shock risk.

Medium-Term Purchase: Energy Block market purchases made three to five years in advance.

Megawatt (MW): 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 delivered.

Megawatt Hour (MWh): 1,000 kWh.

Net Present Value (NPV): The sum of the present values (PVs) of a series of individual cashflows.

Nominal Dollars: Amounts that have not been adjusted to remove the effect of changes in the purchasing power of the dollar.

Non-spinning Reserve: The non-spinning or supplemental reserve is the extra generating capacity that is not presently connected to the system but can be brought online after a short delay. This typically equates to the power available from fast-start generators, however could also include the power available on short notice by importing power from other systems or retracting power that is presently being exported to other systems.

Off-Peak: See Light Load Hours.

Operating Reserve: The operating reserve is the generating capacity available to the system operator within a short interval of time to meet demand in case a generator is lost or there is another disruption to the supply. Most power systems are designed so that under normal conditions the operating reserve is always at least the capacity of the largest generator plus a fraction of the peak load.

The operating reserve can be divided into two kinds of reserve power: the spinning reserve and the non-spinning or supplemental reserve. Generators that intend to provide either spinning or non-spinning reserve should be able to reach their promised capacity within ten or so minutes.

Peaking Plant: A generation plant that typically only runs at times of peak demand. See also Super-Peaking.

Peaking Purchase: The purchase of energy that is required to meet load due to system capacity constraints during peak load days.

Planning Margin: Planning margin is the difference between the electricity supply capacity available and the capacity required to serve the load over a planning period. Intended to protect against a 1 day in 10 year loss of load possibility, the planning margin typically is between 10–30 percent over forecast load requirements, dependent upon the type and size of generation resources employed.

Power: The instantaneous rate at which electrical energy is produced, transmitted or consumed, typically measured in watts (W), kilowatts (kW), or megawatts (MW). See also Capacity.

Pumped Storage Hydro (PSH): A Pumped Storage Hydro facility is a method of storing and producing electricity to supply high peak demands by moving water between reservoirs at different elevations.

Present Value (PV): Today's discounted value of future receipts and/or expenditures. Often also called net present value. See also Discount Rate.

Real Dollars: In economics, the nominal values of something are its money values in different years. Real values adjust for differences in the price level in those years. Examples include a bundle of commodities, such as gross domestic product, and income. For a series of nominal values in successive years, different values could exist because of differences in the price level, an index of prices. But nominal values do not specify how much of the difference is from changes in the price level. Real values remove this ambiguity. Real values convert the nominal values as if prices were constant in each year of the series.

Reliability: A measure of the adequacy and security of electric service. Adequacy refers to the existence of sufficient facilities in the system to satisfy the load demand and system operational constraints. Security refers to the system's ability to respond to transient disturbances in the system.

Resource: A source of electricity that is available to help meet or reduce electricity demand, including generation, purchases, demand side management and transmission facilities.

Short-Term Purchase: Energy Block market purchases made several months, up to a year, in advance.

Spinning Reserve: The extra generating capacity that is available by increasing the power output of generators that are already connected to the power system.

Spot Market: Real-time (hourly) and day-ahead market purchases and sales of electricity.

Super-Peaking Purchase: Electricity required to meet Load during peak usage periods. Generally considered to be approximately four to six hours of highest demand during the standard HLH block each day.

Upgrade: An improvement to an existing facility, which generally results in an increased performance of the integrated system.

Watt: The basic unit of measurement of electric power, indicating the rate at which electric energy is generated or consumed.
(1 watt = 1 joule per second).

Watt-hour (Wh): An electrical energy unit of measure equal to one watt of power supplied to, or taken from, an electric circuit steadily for one hour.

WAX CAPA: The Waneta Expansion Capacity Purchase Agreement, a 40 year capacity purchase agreement with the Waneta Expansion Power Corporation to purchase all unused WAX-related capacity that remains after BC Hydro has acquired the energy entitlements associated with the plant (as defined by the CPA). The capacity entitlements obtained by FortisBC under WAX CAPA begin in 2015 and vary by month.

Appendix B

MIDGARD 2011 ENERGY MARKET ASSESSMENT

2011 FortisBC Energy & Capacity Market Assessment

Submitted By: Midgard Consulting Inc.

Date: May 26, 2011

TABLE OF CONTENTS

FIGURES AND TABLES

1 Executive Summary

FortisBC Inc. ("**FortisBC**") has retained Midgard Consulting Inc. ("**Midgard**") to assess the future outlook of the electricity markets in BC and surrounding areas and forecast the cost and availability of energy and capacity products accessible to FortisBC.

FortisBC is a regulated electric utility serving approximately 161,000 customers in the southern interior of British Columbia. In 2010 it sold 3,046,000 MWh of electricity to its customers, of which approximately half (1,530,000 MWh) came from the energy entitlements of its four hydroelectric generating facilities on the Kootenay River. Peak demand in 2010 was 707 MW, 223 MW of which was met by the four Kootenay River facilities[1].

FortisBC's service area peak system loads have exceeded the utility's reliable capacity resources since the 1990s. At that time it was both economical and reliable to address the relatively minor capacity gaps with market purchases. Since then the service area loads have grown significantly and the winter peak capacity gap presently exceeds 140 MW[2]. During this period historical regional capacity surpluses have eroded and regional transmission has become more constrained. Market prices have increased, as has market price volatility, especially during extreme regional weather conditions.

The recent acquisition of surplus capacity from the Waneta Expansion ("**WAX**") Project will satisfy FortisBC's capacity deficit after the project is commissioned in 2015. The WAX capacity is provided under the terms of the Canal Plant Agreement. FortisBC has acquired contractual capacity rights from Powerex to satisfy its capacity requirements in the interim.

The measures mentioned in the previous paragraph addresses FortisBC's capacity requirements in the medium term however they do not fully address immediate or long term capacity needs. As well, the measures do not address FortisBC's energy gaps in the short, medium, or long term (see Sections 3.2 and 3.4). FortisBC will choose to fill these gaps either by purchasing energy and/or capacity from the wholesale market, or by causing the construction of a new generation facility (referred to within this analysis as the new resources market).

1.1 Cost of Energy and Capacity in British Columbia

British Columbia is an integral member of the Western Electricity Coordination Council ("**WECC**"). Key factors influencing the traded price of electricity in the WECC region and consequently the electricity markets of British Columbia include the amount of annual precipitation in the region, the price of natural gas and regional transmission constraints. An abundance of precipitation, low natural gas prices, and

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[1] FortisBC 2010 Annual Information Form

[2] Based upon the December 2011 peak load forecast and pre-Waneta Expansion Capacity Purchase Agreement (WAX CAPA) resource stack. The interim capacity purchase from Powerex arranged as part of the WAX CAPA has now addressed most of this gap.

lack of transmission constraints will lead to lower overall power prices in WECC while low precipitation levels, high natural gas prices and an abundance of transmission constraints push power prices higher.

The wholesale electricity market in British Columbia has a limited number of buyers and sellers and as a consequence wholesale pricing in the province essentially amounts to the wholesale prices for the Mid-Columbia ("**Mid-C**") market adjusted to take into account the costs of moving electricity into BC. Conversely, the pricing of the new resources market in the Province is derived by estimating the energy or capacity price that would be necessary to incent the construction of a new generation facility.

Figure 1.1-A graphs the forecast BC Wholesale Market Energy Curve against the BC New Resources Market Energy Curve, while Figure 1.1-B graphs the forecast BC Wholesale Market Capacity Curve against the BC New Resources Market Capacity Curve.

Figure 1.1-A: BC Wholesale Market Energy Curve vs. the BC New Resources Market Energy Curve

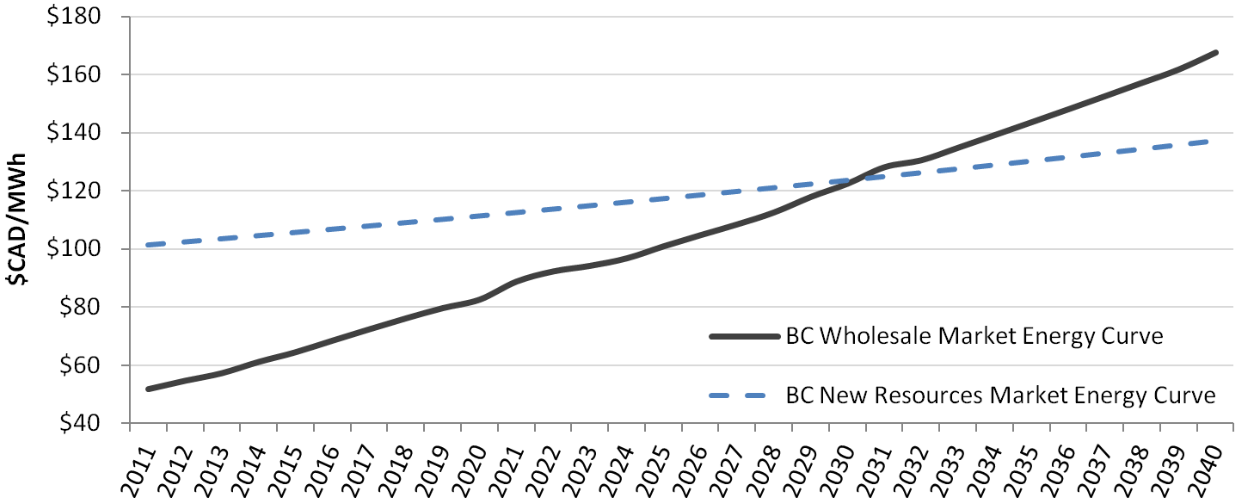
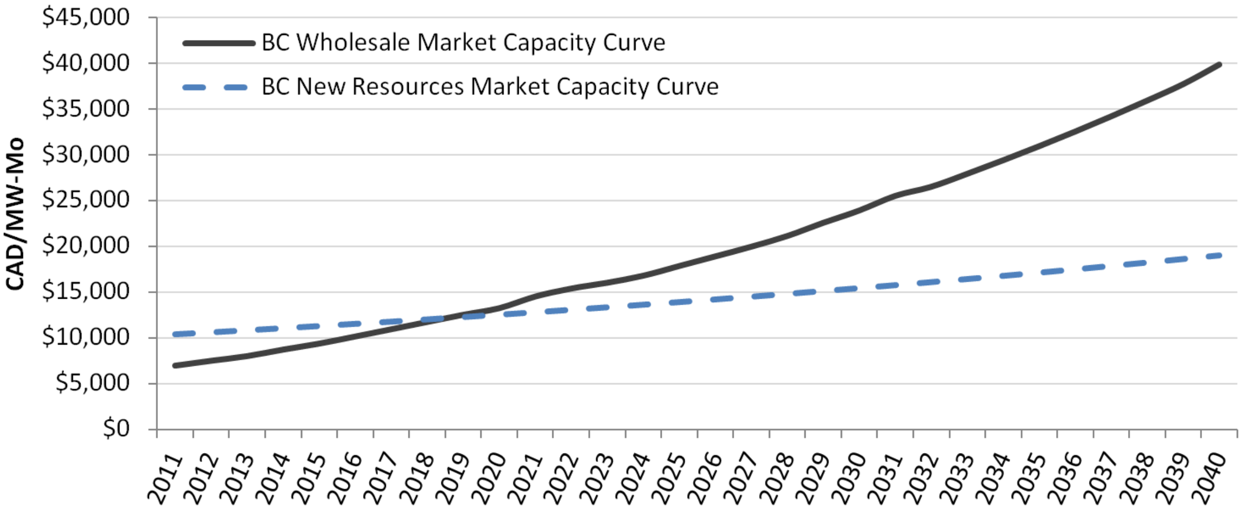


Figure 1.1-B: BC Wholesale Market Capacity Curve vs. BC New Resources Market Capacity Curve



1.2 WECC Trends Influencing the Wholesale and New Resources Markets

The market for energy and capacity in western North America is undergoing significant change, much of which is related to the integration of renewable generation resources into the grid. Table 1.2-A summarizes the potential impacts of key trends on the wholesale market and new resources market of British Columbia.

Table 1.2-A: Potential Impacts of Market Trends on BC Markets

WECC Market Trend	Wholesale Market	New Resources Market
Renewable Portfolio Standards & Additional Intermittent Resources	Risk to supply-certainty; risk of higher wholesale capacity prices	Limited impact
Demand Side Management Programs	Limited risk to supply certainty	Limited impact, but potential upward price pressure in long-term
Delays in New Transmission Construction	Risk to supply certainty; risk of higher wholesale market prices	Potential impact, resulting in upward price pressures
Clean Energy Act: • ***Generation Surplus*** • ***Export Mandate***	Potential positive impact for FortisBC / BC Wholesale Market energy and capacity buyers	Potential upward price pressures in medium-term
Alberta Market – Current State	Price risk and supply-certainty risk	Limited impact

1.3 Summary Conclusions

Midgard concludes as follows:

- FortisBC's continued reliance upon the wholesale electricity market to meet current and future needs is not an unreasonable strategy - especially in light of the modest sizes of FortisBC's energy and capacity deficits.
    - BC Wholesale Energy Market prices are projected to remain less expensive than comparable BC New Resources Market Energy prices until approximately 2030.
    - BC Wholesale Capacity Market prices for capacity products are projected to remain less expensive than comparable BC New Resources Market Capacity prices until approximately 2019.
- Overall market trends in the WECC region – chiefly renewable portfolio standards ("**RPS**"), DSM and the current state of the Alberta electricity market – are of a greater threat to the price and supply availability of capacity and energy in the wholesale markets than they are to the price and supply availability of energy and capacity from the new resources markets. Meanwhile, the impact of transmission delays and the BC *Clean Energy Act* are more ambiguous for both the wholesale

and new resources markets; they appear to have the potential to improve the relative cost competitiveness of the BC Wholesale Markets over the BC New Resources Markets.

- The BC New Resources Capacity Market is less expensive than the BC Wholesale Capacity Market when longer term transactions are evaluated. Up*ward price press*ures and product availability concerns in both the wholesale market energy and wholesale market capacity markets make new resources more competitive on a long term basis.

2 Introduction

FortisBC Inc. ("**FortisBC**") engaged Midgard Consulting Inc. ("**Midgard**") to perform a 30 year assessment of the electricity market in British Columbia. Midgard will also evaluate the relative risk of competing procurement strategies in the context of FortisBC's future energy and capacity needs.

The report contains the following deliverables:

1. British Columbia Wholesale Market Energy (electricity[3]) forecast curve
2. British Columbia New Resources Market Energy (electricity) forecast curve
3. British Columbia Wholesale Market Capacity forecast curve
4. British Columbia New Resources Market Capacity forecast curve
5. Natural Gas forecast price curve
6. Greenhouse Gases forecast price curve

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[3] Throughout the analysis, the term energy is defined as the electricity produced or used over a period of time, usually measured in KWh, MWh, or GWh.

3 Background on the Energy and Capacity Needs of FortisBC

FortisBC is a regulated electric utility serving approximately 161,000 customers in the southern interior of British Columbia. In 2010 it sold 3,046,000 MWh of electricity to its customers, of which 1,530,000 MWh came from the energy entitlements of its four hydroelectric generating facilities on the Kootenay River. Peak demand in 2010 was 707 MW, 223 MW of which was provided by the four Kootenay River facilities. FortisBC also owns a transmission and distribution network consisting of 1,400 km of high voltage transmission lines, 5,600 km of distribution lines and 64 substations[4].

As a member of Western Electricity Coordinating Council ("**WECC**"), FortisBC can, theoretically, draw upon a large wholesale electricity market to help serve its load requirements. Energy and capacity are available in the WECC market from various utilities and independent power producers that have surplus power available for sale or exchange. These surpluses are typically the result of either the load demand not being as high as forecast or the supplies of electricity being higher than forecast and/or higher than needed. Additionally, energy may be procured from non-utility generation asset owners who have under-utilized generation capacity and available fuel.

The WECC region is a dual peaking electricity system, with the south peaking in the summer and the north peaking in the winter. FortisBC is primarily concerned about the availability and cost of energy and capacity during the winter months when FortisBC experiences its peak demand.

Surplus power is typically available in BC and the Pacific Northwest ("**PNW**") during the spring freshets (high river flows due to thaws and precipitation) and/or during years of above-average precipitation. Some utilities, with BC Hydro being the most prominent, can store energy in their hydroelectric reservoirs and for the right price are usually able to provide power to the market at any time.

3.1 Differentiating Between Energy and Capacity

The difference between energy and capacity is important to understand and key to thinking about the requirements of a utility. Put simply, energy is the consumable and capacity is the assurance that the consumable is available as and when required.

In practice, it is often impractical to completely separate energy from capacity since any agreement to procure energy will include provisions addressing the delivery of the energy.

To the extent the energy is delivered at a time, rate and place of the buyer’s preference, it inherently includes capacity characteristics. In other words, if the buyer dictates how much energy it receives and where and when it receives that energy then in the act of buying, the buyer has purchased capacity by having bought ‘the assurance’ that the consumable is available as and when required.

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[4] FortisBC 2010 Annual Information Form

Similarly, to the extent that energy is delivered at the seller's discretion (time, rate & place), the product will be characterized as an energy only product with poor capacity characteristics (i.e. energy that cannot be reliably called upon when needed). An energy product that is not reliably available for the buyer's use to meet actual demand will not be as valuable to that buyer as an energy product with embedded capacity characteristics[5].

FortisBC obtains most of its capacity and energy through a combination of self-supply, long term power purchase agreements and other contractual arrangements including the Canal Plant Agreement[6]. In this report, these sources of capacity and energy are considered FortisBC resources.

After reaching the limits of its own resources, FortisBC covers its energy and capacity shortfalls with purchases from the wholesale electrical energy market. Generally, wholesale electrical energy market purchases are done by buying power in the spot market or through buying blocks of guaranteed delivered power (or 'firm power').

As described in Sections 3.2 and 3.3, FortisBC is facing both energy gaps and capacity gaps in the coming 30 years. This energy market analysis pays particular attention to the winter peak months, those months which are deemed to be the highest demand months for the northern portion of the WECC region and are therefore of greater importance to FortisBC.

3.2 FortisBC Energy Outlook

FortisBC is expected to require small but increasing amounts of new energy supplies over the coming three decades. The energy requirements are anticipated to grow by approximately 11 GWh per annum from a starting point of 5 GWh in 2011 to a gap of 311 GWh by 2040. FortisBC's energy load is expected to outpace its available resources at a rate outlined in Table 3.2-A. It is important to note that this forecast includes the effects of expected demand side management ("**DSM**") programs.

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[5] BC Hydro's recent Clean Power Call contracts include provisions to ensure that BC Hydro pays a different price for the energy that is certain to be delivered (firm energy) and the energy that is not certain to be delivered (non-firm energy). The price differential between the firm energy and the non-firm energy is approximately $75-100/MWh higher for the firm energy than for non-firm energy.

[6] Under the Canal Plant Agreement, FortisBC is permitted to instruct BC Hydro to provide delivery of energy at a time of FortisBC's choosing, subject to certain capacity limitations – namely how much energy can be delivered in a given hour.

Table 3.2-A: Forecast FortisBC Energy Gap by Year (GWh)

Year	Energy Gap	Year	Energy Gap	Year	Energy Gap
2011	5	2021	46	2031	180
2012	9	2022	58	2032	195
2013	9	2023	69	2033	210
2014	12	2024	82	2034	224
2015	5	2025	95	2035	239
2016	6	2026	107	2036	253
2017	9	2027	120	2037	268
2018	14	2028	135	2038	282
2019	25	2029	151	2039	296
2020	35	2030	167	2040	311

3.3 FortisBC Capacity Outlook

Similar to energy, FortisBC faces capacity shortfalls over the next three decades. Until 2014 FortisBC faces expected capacity gaps of up to 107 MW in the summer (July 2014) and 125 MW in the winter (March 2014) (see Table 3.3-A).

After the Waneta Expansion Capacity Purchase Agreement comes into effect in 2015, FortisBC's expected peak summer and winter capacity gaps essentially fall to zero. The summer gap grows from 4 MW in 2015 to 112 MW in 2040. The winter gap remains at zero until 2017, but then expands at approximately 10 MW per year, reaching 223 MW in 2040. It is important to note that these forecasts take into account both the effects of DSM as well as FortisBC's planning reserve margin requirements.

Table 3.3-A: Forecast FortisBC Capacity Gaps By Month and Year (MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2011	4	39	101	0	0	34	84	36	0	29	40	74
2012	14	47	108	4	0	40	91	43	0	35	48	85
2013	24	56	117	11	0	47	100	50	0	43	58	96
2014	34	64	125	17	0	53	107	57	0	49	66	106
2015	0	0	1	0	0	4	0	0	0	0	0	0
2016	0	0	0	0	0	6	0	0	0	0	0	0
2017	0	0	0	0	0	9	0	0	0	0	0	2
2018	0	0	0	0	0	12	0	0	0	0	0	13
2019	0	0	0	0	0	16	0	0	0	0	0	23
2020	0	0	0	0	0	20	0	0	0	0	0	34
2021	0	0	0	0	0	24	0	0	0	0	0	45
2022	0	0	0	0	0	28	0	0	0	0	0	56

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	0	0	0	0	0	32	0	0	0	0	0	67
2024	6	0	0	0	0	36	3	0	0	0	0	79
2025	17	0	0	0	0	41	11	0	0	0	0	90
2026	27	0	0	0	0	45	18	0	0	0	0	101
2027	37	0	0	0	0	49	26	0	0	0	0	113
2028	48	0	0	0	0	54	34	0	0	0	0	125
2029	59	0	0	0	0	58	42	0	0	0	0	136
2030	69	0	0	0	0	62	50	0	0	0	0	147
2031	78	0	0	0	0	66	57	0	0	0	0	156
2032	89	0	0	0	0	70	65	0	0	0	0	164
2033	99	0	0	0	0	74	72	0	0	0	0	171
2034	109	7	0	0	0	78	80	0	0	0	0	179
2035	118	15	3	0	0	82	87	0	0	0	0	186
2036	128	23	11	0	0	86	92	0	0	0	0	194
2037	138	31	19	0	1	90	97	0	0	0	0	201
2038	148	39	27	0	4	94	102	0	0	0	0	208
2039	155	47	34	0	8	98	107	0	0	0	7	216
2040	161	55	42	0	11	102	112	0	0	0	16	223

4 Fundamentals of Market Pricing in the WECC Region

This section discusses the Western Electricity Coordinating Council region and factors that influence the price of WECC traded electricity.

4.1 Western Electricity Coordinating Council

As its website reports, WECC is the "…Regional Entity responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection…(and) is geographically the largest and most diverse of the eight Regional Entities that have Delegation Agreements with the North American Electric Reliability Corporation ("**NERC**"). WECC's service territory extends from Canada to Mexico...(including) the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 Western states between. Due to the vastness and diverse characteristics of the region, WECC and its members face unique challenges in coordinating the day-to-day interconnected system operation and the long-range planning needed to provide reliable electric service across nearly 1.8 million square miles."[7]

In 2010, the Total Internal Demand[8] (or coincidental peak demand) for the WECC region was 148,000 MW[9] while the available generation was 184,000 MW; annual energy use is projected at 863,355 GWh for 2010[10]. WECC is a dual peaking system, with the southern region experiencing peak demand during the summer months, and the northern region, which includes British Columbia, Alberta and the Pacific Northwest, experiencing peak demand during the winter months.

Within WECC, the two most heavily traded electricity hubs are SP-15 and Mid-Columbia ("**Mid-C**")[11]. SP-15 is the electricity trading hub for Southern California; Mid-C the trading point for the Pacific Northwest.

The composition of generation within WECC is characterized by large amounts of thermal generation (coal and natural gas fired generation), nuclear generation, and significant hydroelectric generation capacity. In recent years, the quantity of renewable generation, particularly wind generation, has grown appreciably.

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[7] http://www.wecc.biz/About/Pages/default.aspx

[8] "Total Internal Demand is the sum of the metered (net) outputs of all generators within the system and the metered line that flows into the system, less the metered line that flows out of the system. Total Internal Demand includes adjustments for indirect Demand-Side Management programs such as conservation programs, improvements in efficiency of electric energy use, and all non-dispatchable demand response programs."

[8] North American Electric Reliability Corporation, 2010 Long-Term Reliability Assessment, October 2010, page 28, Table 4.

[9] North American Electric Reliability Corporation, 2010 Long-Term Reliability Assessment, October 2010, page 267

[10] North American Electric Reliability Corporation, 2010 Long-Term Reliability Assessment, October 2010, page 272

[11] Federal Energy Regulatory Commission, 2008 State of the Markets Report, August 2009, page 54

4.2 Market Forecasting

In a market where electricity is traded, the prices are set by the marginal cost of the last megawatt hour that was produced in order to meet the load requirement at that point in time. That marginal cost determines the clearing price in the marketplace.

The marginal cost of electricity generated from a natural gas fired generator is typically more expensive than the comparable cost of electricity from a nuclear or coal-fired plant. Load demand frequently rises during on-peak periods to a level where the output of natural gas generation facilities is required and that in turn determines the marginal cost of electricity in the wholesale market. Consequently, market electricity prices (especially on-peak prices) in WECC and across much of North America are strongly correlated to the price of natural gas that is fuelling that electrical generation.

During low demand periods, such as daily off-peak hours or certain days during the spring and fall seasons, the marginal cost of electricity will be determined by the marginal cost of base load generation. Base load generators include nuclear generators and coal-fired generators that produce power at a low marginal cost and are designed to be operated at or near their full output all hours of the day and night.

Intermittent generators such as wind, run-of-river (or must-run) hydro and solar fueled generation facilities are price takers. They sell their generation into the marketplace regardless of prevailing market prices because their fuel is ‘free’. Their intermittent nature means that regardless of market price they will generate when they have fuel - wind, water or sun - and will not generate when they do not have fuel. They are never considered to be the marginal cost assets for forecasting purposes. However, during times of abundant intermittent generation, such as during spring freshet or optimal wind conditions, the quantity of power produced will depress market prices since the marginal cost of electricity generated will be determined by the base load generators, rather than higher cost natural gas generators.

Hydroelectric assets will either behave as price takers - as described in the previous paragraph - or will ’shadow price‘ the highest marginal cost generation asset at the time of production. Shadow pricing is defined as the pricing of the generation at or just below the highest cost generation asset expected to be dispatched. Asset owners shadow price in order to capture the highest expected profit margin.

Other smaller generation technologies like biomass and geothermal do not represent a large enough source of energy to influence the forecast market price for electricity in the WECC region.

Transmission is required to move power from one location within the WECC region to another. The cost of transmission to get power from a generator to a trading point and from a trading point to the point of delivery adds to the price of electricity at the specified point of delivery (e.g. FortisBC territory). During certain times of year, such as extreme weather events in July or January, the transmission system can become fully utilized, at which point in time a transmission constraint is created. These transmission constraints force the constrained sub-region’s load demands to be met by a limited number of alternative electrical sources (that still have unconstrained transmission access to the load). The impact of transmission constraints is often to increase the market clearing price of electricity within the sub-region.

Forecasts of future electricity prices in the WECC region and sub-regions must account for the following key factors:

- Hydrology
- Natural Gas Prices
- Transmission Availability (to facilitate intra-regional energy trade).

4.2.1 Precipitation (Hydrology)

Over 30% of the generating capacity in the WECC region is hydroelectric generation and almost 55% of its northern region's generation capacity is fueled by water[12]. There are multiple major river basins in the WECC region that feed hydroelectric generation and, depending on precipitation levels, the amount of marketable energy available in a given year can vary dramatically in the different drainage basins. For example, BC Hydro's Heritage Hydro assets can experience annual generation variations of 10,000 GWh between BC's wettest and driest years (annual BC generation is approximately 60,000 GWh[13]). The variation in energy generated by the US Federal hydroelectric generation facilitates administered by Bonneville Power Administration (BPA) varies by approximately 24,500 GWh between the region's wettest and driest years (97,900GWh to 73,400 GWh)[14].

4.2.2 Natural Gas

Over 40% of the generating capacity in the WECC region is produced from either natural gas fired generation plants or dual fired generation plants (which typically use natural gas as the default fuel). Within the Pacific Northwest region, approximately 60% of merchant generation capacity is natural gas fuelled (see Table 4.2.2-A)[15]. A merchant plant owner will sell to the market when the market price of electricity will cover or exceed the variable cost of production; that cost is primarily dependent on the cost of natural gas and the plant's efficiency (heat rate) but also includes secondary non-fuel cost items like operating and maintenance costs (e.g. shut down / start up costs, overhaul costs etc.).

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[12] North American Electric Reliability Corporation, 2009 Long-Term Reliability Assessment, October 2009, page 139 & 156

[13] BC Hydro, 2011 IRP Technical Advisory Committee Summary Brief: Exports, January 2011, page 1

[14] Bonneville Power Administration, 2010 Pacific Northwest Loads and Resources Study, May 2010, page 32, Table 6

[15] Bonneville Power Administration, 2010 Pacific Northwest Loads and Resources Study, May 2010, page 63, Table 15

Table 4.2.2-A: Expected Uncommitted PNW IPP[16] Resources

Project	Peak (MW)	% Total Peak	Energy (GWh)	% Total Energy	Fuel Type
Big Hanaford CCCT	248	6.9%	1964	7.1%	Natural Gas
Hermiston Power Project	630	17.4%	4979	17.9%	Natural Gas
Klamath Cogeneration Project	484	13.4%	3822	13.7%	Natural Gas
Klamath Peaking Unit	100	2.8%	123	0.4%	Natural Gas
Satsop	650	18.0%	5128	18.4%	Natural Gas
SP Newsprint Cogen	104	2.9%	912	3.3%	Natural Gas
Natural Gas Subtotal	**2216**	**61.3%**	**16927**	**60.8%**	
Centralia #1	670	18.5%	5487	19.7%	Coal
Centralia #2	670	18.5%	4856	17.4%	Coal
Coal Subtotal	**1340**	**37.1%**	**10344**	**37.1%**	
Sierra Pacific Aberdeen (Sierra Pacific)	15	0.4%	123	0.4%	Wood Waste
Weyerhaeuser Longview (Weyerhaeuser)	44	1.2%	307	1.1%	Wood Waste
Wood Waste Subtotal	**59**	**1.6%**	**430**	**1.5%**	
Star Point	0	0.0%	140	0.5%	Wind
White Creek Wind (1.5%)	0	0.0%	9	0.0%	Wind
Wind Subtotal	**0**	**0.0%**	**149**	**0.5%**	
Total	**3615**	**100.0%**	**27849**	**100.0%**	

4.2.3 Transmission Availability and Constraints

As noted WECC is a dual peaking system with seasonal demand diversity; the southern portion of WECC is summer peaking and the northern portion is winter peaking. This dual peaking system with demand diversity means that power flows tend to be from north to south during the summer months and south to north during winter months. Given these transfer patterns it is common that these summer and winter peaks result in regional or localized transmission constraints. For example, during the summer months when freshet energy is abundant in the Pacific Northwest and the economic dispatch of this energy to the southern and southwestern WECC regions makes sense, total southbound transmission is constrained at several key points, notably the California-Oregon border[17]. Numerous other constraints occur

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[16] Independent Power Producer

[17] North American Electric Reliability Corporation, 2010 Long-Term Reliability Assessment, October 2010, page 275

throughout the WECC region, including localized constraints both within British Columbia as well as between British Columbia and its neighbours, Alberta and the US[18].

Seasonal North-South transmission constraints can be amplified by extreme weather events such as an extended cold snap in the north during the winter peak. During a cold snap, local hydroelectric assets typically do not produce enough energy to satisfy sub-regional needs and additional energy is imported from the south, potentially creating transmission constraints.

In response to emerging renewable portfolio standards (and generous US tax incentives), substantial amounts of intermittent generation are being built in the WECC region. Because these intermittent generation resources are primarily energy sources characterized by poor capacity attributes, local balancing authorities and utilities will be required to introduce measures to effectively manage them. These measures may include tapping into existing capacity resources to firm the energy produced by intermittent generation resources[19]. The need to retain and access additional capacity resources will likely change historical transmission flow patterns and potentially create new transmission constraints.

Although additional transmission has been added in recent years in WECC, and further additions are planned for the coming decade, north-south transmission constraints are expected to persist in both directions for the foreseeable future, dependent upon the season and the sub-regional electrical supply/demand balances.

4.3 Competition with Neighbouring Jurisdictions

The FortisBC service territory abuts BC Hydro service territory, which in turn interconnects with Alberta and the US Pacific Northwest. The transmission transfer limit at the three interconnections on the British Columbia / United States border[20] and at the two interconnections on the British Columbia / Alberta border are:

- British Columbia / United States: 2,000 MW northbound into British Columbia and 3,150 MW southbound into the United States. These limits reflect the combined capability of the two 500 kV lines between BC Hydro's Ingledow substation and Bonneville Power Administration's Custer substation, and the two 230 kV lines between Boundary and Nelway near Trail, BC.
- British Columbia / Alberta: 1000 MW westbound into British Columbia and 1200 MW eastbound into Alberta. These limits reflect the combined capability of two 138 kV lines and one 500 kV line connecting the Alberta and BC Hydro integrated systems. In practice, the transfer capabilities with Alberta are far lower (approximately half) due to transmission constraints within Alberta[21].

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[18] As part of their Integrated Resource Plan, BC Hydro is examining transmission requirements to facilitate export activities.

[19] North American Electric Reliability Corporation, 2010 Long-Term Reliability Assessment, October 2010, page 279

[20] Includes the one merchant transmission line owned by Teck Metals at Trail, BC.

[21] Alberta Electric System Operator, AESO Long-term Transmission System Plan, 2009, Appendix H, page 303

Both the British Columbia / Alberta[22] and the British Columbia / United States interconnections are often at their maximum transmission limit, which means wheeling additional power between utilities in the region is frequently not possible. Given that the key source of external (non-BC) wholesale market electricity for FortisBC is the United States, these constraints are a potential problem for FortisBC because they restrict access to the energy and capacity from the US market. As electricity demand continues to grow, absent sufficient new transmission infrastructure, transmission constraints between British Columbia and the United States will become ever more restrictive.

Figure 4.3-A illustrates that the summer peak demand and winter peak demand periods in the Pacific Northwest coincides with the demand peaks within FortisBC territory. This coincidence of demand peaks is of particular interest during the winter peak because during extreme regional weather events, such as an extended cold period, both FortisBC and the Pacific Northwest region would seek additional power supplies to meet their increased local demands. As a result it is reasonable to expect that FortisBC will be in competition with nearby regions for both energy supplies and transmission capacity during such peak demand periods.

Figure 4.3-A: Projected Loads in the FortisBC and PNW Regions

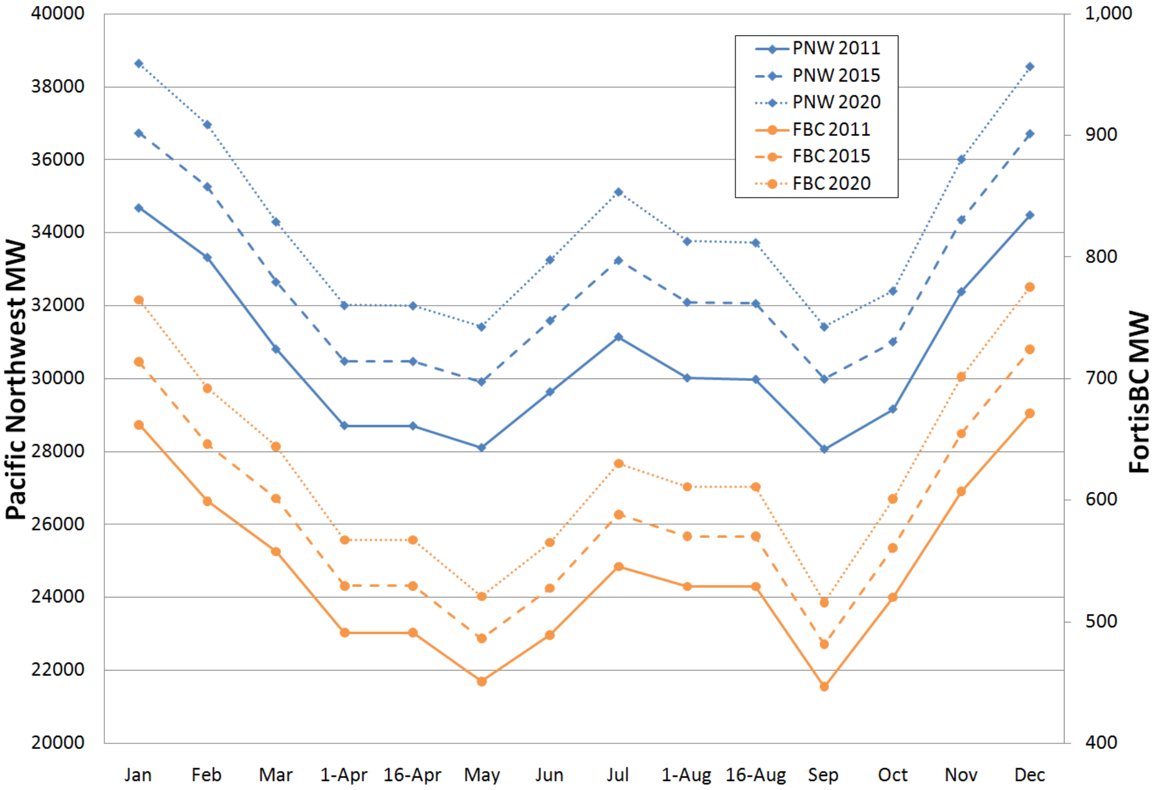

Figure 4.3-A also shows that the forecast monthly loads for the PNW region and for FortisBC will continue to grow into the future, resulting in increased competition for generation and transmission resources. This

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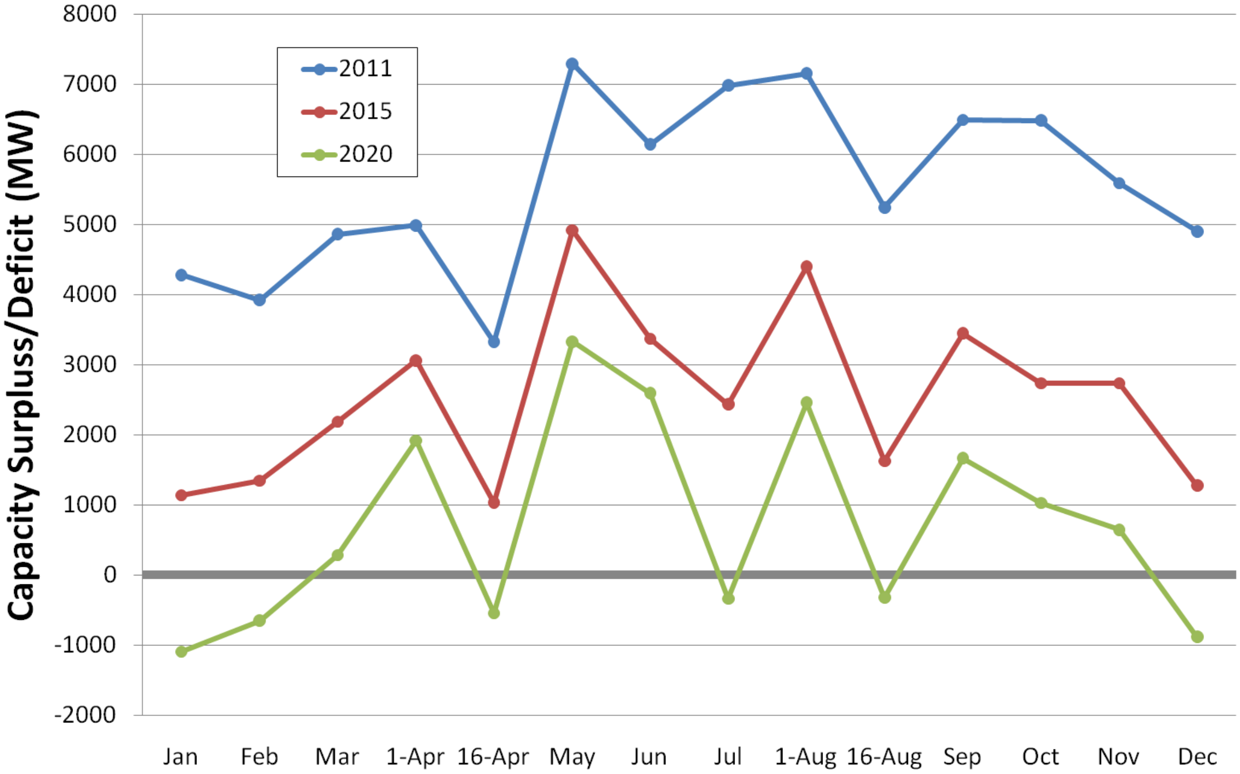
[22] The current Alberta market situation will be discussed in more detail in Section 7 – Market Trends

potential scarcity of accessible energy is further illustrated in Figure 4.3-B[23], which shows the trend towards a deficit of one hour capacity resources in the Pacific Northwest region. In the 2011 operating year, the Pacific Northwest region has a forecast surplus one hour capacity but by the 2020 operating year the region is forecast to be in a deficit position during both the winter peak and summer peak months. Moving from surplus to deficit implies that during critical winter peak and summer peak months the Pacific Northwest region will move from a potential net source of one hour capacity to a net consumer of one hour capacity, thus becoming a competitor to FortisBC.

Figure 4.3-B: Projected Pacific Northwest Trends in 1-Hour Capacity Surplus/Deficit



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[23] Bonneville Power Administration, 2010 Pacific Northwest Loads and Resources Study, May 2010, pg 66

5 British Columbia Energy Market Analysis

FortisBC has two broad alternatives they can employ to address their forecast energy shortfalls:

1. **BC Wholesale Market Energy Purchases**: FortisBC can continue to purchase energy in the wholesale electricity market as it has historically done in recent years.
2. **New Resource Market Energy**: FortisBC could contract for new generation resources either by developing and constructing a new generation resource that is owned and operated by FortisBC, or by entering into a long term Power Purchase Agreement[24] with a third party to supply FortisBC energy from a new generation resource.

This section will discuss the BC Wholesale Market Energy prices relevant to FortisBC, the forecast market price for new resources in BC, and then compare the two energy price curves.

5.1 BC Wholesale Market Energy Analysis

Pricing of BC Wholesale Market Energy is influenced by the cost of electricity in neighbouring jurisdictions. The BC market has two immediate neighbours: Alberta to the east and the United States to the south. Because of the limited transmission linkages (see Section 4.3) between BC and Alberta relative to those between BC and the United States, Alberta's electricity market price curves play only a limited role in determining the expected cost of energy (and capacity) in British Columbia. As a result, in this report it is the Mid-Columbia electricity market and not the Alberta market that serves as the primary driver for forecast wholesale electricity prices in BC.

5.1.1 Mid-Columbia Electricity Market

The Mid-Columbia electricity market is one of the most important electricity trading hubs in North America and, as measured by volume on the Intercontinental Exchange, the third largest electricity trading point in the US and second largest in the WECC region[25]. FortisBC benefits from its proximity to this large liquid and price transparent Mid-C market and, if it chooses, is able to obtain market supplies of energy priced against the Mid-C index.

The Mid-C market is dominated by bilateral trading, which is generally the case throughout the WECC region. Mid-C has traditionally been influenced by large asset owning entities that engage in physical transactions of power, including BC Hydro in the form of Powerex, Bonneville Power Administration and other investor owned utilities. However, a growing quantity of the trading transaction volume in the electricity market is moving to the financial arena, typically the purview of banks and financial trading houses. This trend underpins the liquidity of the Mid-C market and expands the number of potential

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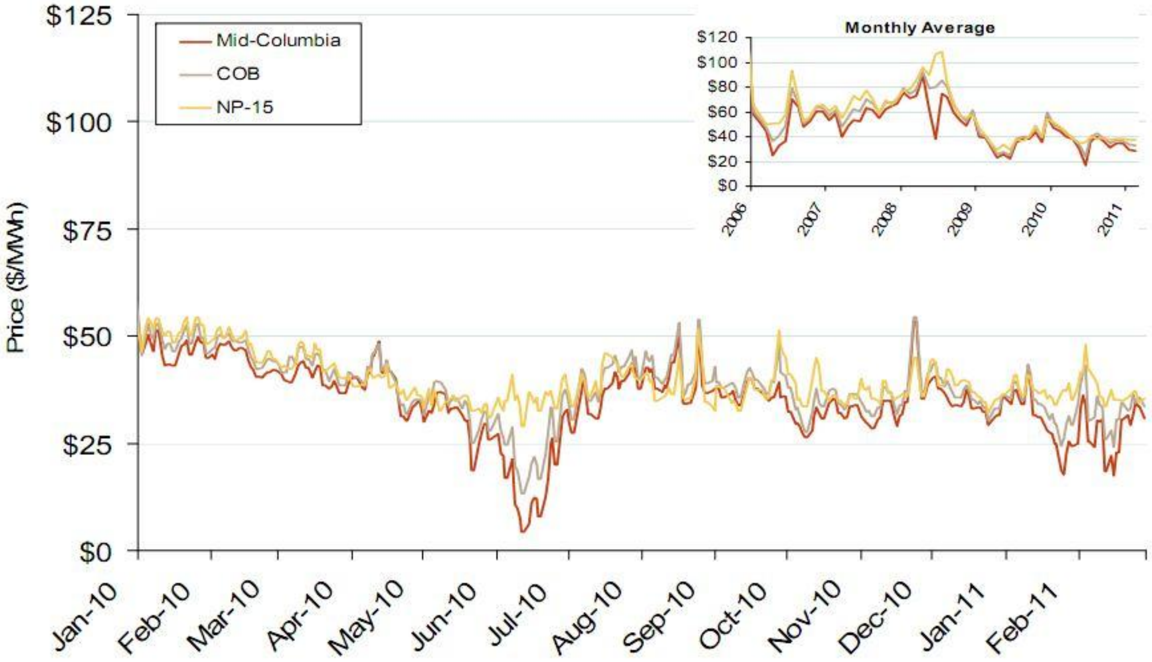
[24] It is common for the contract for new generation to have a term of 20 years or longer.

[25] Federal Energy Regulatory Commission, 2008 State of the Markets Report, August 2009, page 52

energy market counterparts with whom FortisBC could conduct business. In 2008, the volume of Mid-C financial transactions was larger than the volume of physical transactions[26].

Similar to most other electricity markets, electricity prices are prone to spiking during high demand periods, such as those induced by extreme weather events (e.g. a cold spell in December, or a heat wave in July), or during times of supply scarcity. Given the large quantity of hydro capacity in the WECC region in general, and the Pacific Northwest region in particular, a large freshet tends to depress electricity prices, while a drought boosts prices. Figure 5.1.1-A provides a snapshot of historical market prices and a sketch of the price volatility in the Mid-C market. Figure 5.1.1-A also shows the historical prices of the California-Oregon border (COB) electricity index as well as the Northern California (North Path 15 or NP-15) index, both of which are highly correlated to Mid-C.

Figure 5.1.1-A: Historical Mid-C Electricity Price (Daily and Monthly Averages)



Energy markets in general and electricity markets in particular have experienced substantial price volatility over the past decade. The most infamous bout of electricity price volatility in WECC occurred in 2000 and 2001 when California suffered a series of rotating blackouts and the western electricity market experienced unprecedented price spikes that were facilitated by factors including high natural gas prices, capacity shortages and transmission constraints.

The western transmission system continues to remain very constrained, and as growth returns to the economy and electricity demand rises, price volatility should continue to worry electricity buyers in the foreseeable future.

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[26] Federal Energy Regulatory Commission, 2008 State of the Markets Report, August 2009, page 52, Figure 26

5.1.2 Mid-Columbia Forecast Price Curve

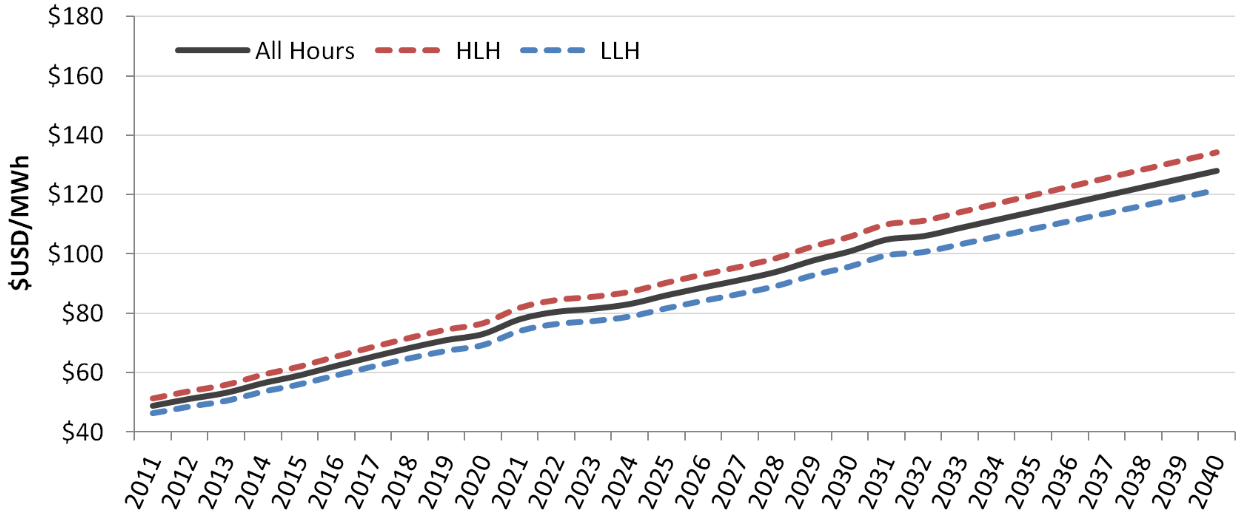
As part of their 2011 Integrated Resource Plan activities, BC Hydro established several projections for the Mid-C forecast price curve. Midgard used BC Hydro's "mid scenario" price curve as the basis for this report's Mid-C forecast price curve. For the years 2032 through 2040, Midgard extrapolated the forecast curve based upon the "mid scenario" price forecast for the years 2022 through 2031[27].

The BC Hydro Mid-C "mid-scenario" price forecast was constructed based upon the following key assumptions[28]:

- A "mid scenario" projected natural gas prices (discussed further in Appendix A)
- A "mid scenario" projected greenhouse gas prices (discussed in Appendix B)
- Projections of other project fuel costs, including coal and uranium
- A description of the architecture of WECC, the sub-regional demand forecasts and the transmission constraints.

Figure 5.1.2-A and Table 5.1.2-A shows the 30 year BC Hydro Mid-C forecast price curve[29]. The black line represents the all-hours price forecast, the red line represents the high-load hours price forecast and the blue line represents the low-load hours price forecast.

Figure 5.1.2-A: BC Hydro Mid-C Forecast Price Curve (30 Years) (USD)



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[27] In Addition to the "mid scenario" Mid-C price forecasts, BC Hydro also published four other scenarios and their subsequent price forecasts. The scenarios combined various permutations of high, medium, and low price forecasts for natural gas and greenhouse gas prices. Midgard selected the "mid scenario" as the base case for the purposes of this report.

[28] BC Hydro, 2011 IRP Technical Advisory Committee Summary Brief: Electricity Spot Market Price Forecast, January 2011, page 2-3, and 2011 IRP Presentation to the Technical Advisory Committee, Meeting #2 – Day 1, January 2011

[29] Note that the years 2032 to 2040 of the Mid-C Forecast Price Curve were interpolated from the previous 10 years (2022-2031).

Table 5.1.2-A: BC Hydro Mid-C Forecast Price Curve (30 Years) (USD)

Year	Expected	HLH	LLH
2011	$48.91	$51.31	$46.42
2012	$51.26	$53.78	$48.65
2013	$53.31	$55.93	$50.60
2014	$56.53	$59.31	$53.66
2015	$59.16	$62.07	$56.15
2016	$62.38	$65.45	$59.21
2017	$65.46	$68.68	$62.13
2018	$68.39	$71.75	$64.91
2019	$71.03	$74.52	$67.42
2020	$73.08	$76.67	$69.37
2021	$78.05	$81.89	$74.08
2022	$80.54	$84.50	$76.45
2023	$81.57	$85.58	$77.42
2024	$83.18	$87.27	$78.95
2025	$86.11	$90.34	$81.73
2026	$88.74	$93.10	$84.23
2027	$91.23	$95.72	$86.59
2028	$94.02	$98.64	$89.24
2029	$97.82	$102.63	$92.85
2030	$100.90	$105.86	$95.77
2031	$104.85	$110.01	$99.52
2032	$106.01	$111.23	$100.62
2033	$108.76	$114.11	$103.23
2034	$111.51	$116.99	$105.84
2035	$114.26	$119.88	$108.45
2036	$117.01	$122.76	$111.06
2037	$119.76	$125.64	$113.67
2038	$122.50	$128.53	$116.28
2039	$125.25	$131.41	$118.89
2040	$128.00	$134.30	$121.50

The high load hours ("**HLH**") and low load hours ("**LLH**") price forecasts were derived by multiplying the all-hours forecast price curve by 104.9% and 94.9% respectively. The HLH premium (and LLH discount) is the average of the monthly variations for HLH (and LLH) versus the annual mean forecast price. The monthly variation of Mid-C forecast prices versus the all hours annual forecast prices is detailed in Table 5.1.2-B[30].

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[30] BC Hydro, 2011 IRP Presentation to the Technical Advisory Committee, Meeting #2 – Day 1, January 2011, page 86

Table 5.1.2-B: BC Hydro Monthly Mid-C Price Variations

Month	HLH Multiplier	LLH Multiplier
Jan	116%	105%
Feb	111%	102%
Mar	104%	96%
Apr	95%	89%
May	89%	81%
Jun	90%	82%
Jul	105%	91%
Aug	113%	97%
Sep	102%	94%
Oct	107%	95%
Nov	111%	101%
Dec	116%	106%
Average	**104.9%**	**94.9%**

For the purposes of this analysis, Midgard's Mid-C wholesale market forecast price curve is the exact same as the BC Hydro Mid-C Forecast Price Curve, as represented in Table 5.1.2-A. The forecast Mid-C wholesale market price curve is the starting point from which the BC Wholesale Market forecast price curve was generated.

5.1.3 Translating the Mid-C Forecast Price Curves to the BC Wholesale Market Energy

5.1.3.1 Forecast Curves

Midgard calculated the British Columbia Wholesale Market Energy Forecast Curve by taking the Mid-C Forecast Price Curve as the starting point, adding the cost of transmitting power from Mid-C to FortisBC territory, and then converting the resulting price into Canadian dollars.

5.1.3.2 Transmission Costs

The projected cost of transmitting a megawatt hour of electrical energy from Mid-Columbia to FortisBC territory is $1.917/MWh[31]. Midgard assumed that the transmission tariff will escalate in cost at 100% of CPI[32].

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[31] Bonneville Power Administration, 2010 Transmission and Ancillary Service Rate (summary), October 2009, page 1

[32] The consumer price index - or CPI - utilized throughout this analysis is pegged at 2.1% per annum. Not coincidentally, this is the CPI projection commonly employed by BC Hydro.

In addition to the transmission tariff, the cost of moving electricity must also take into account the line losses. Line losses were forecast at 1.9%[33]. Midgard assumed that the transmission losses would remain constant for the 30 year period.

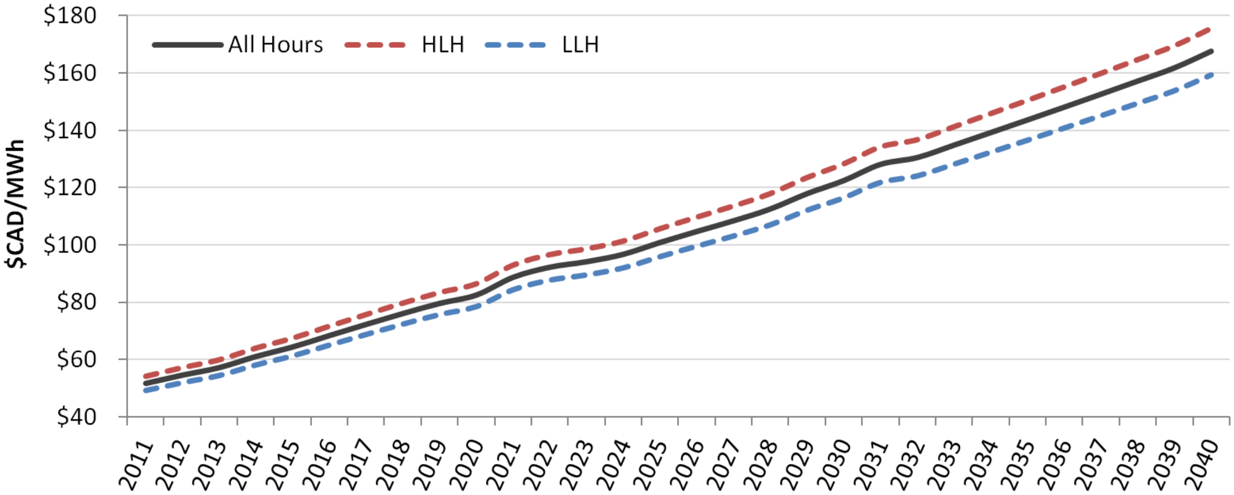
Midgard also assumed that the power would be delivered from the US to Teck Metals' Line 71 and then transmitted into FortisBC territory at no additional cost or charge to FortisBC. Teck Metals' Line 71 has a transmitting capacity of several hundred megawatts. Teck Metals does not use the line to import power and BC Hydro has no import transmission rights on the line. Consequently, Midgard has assumed that the transmission capacity on the line would be available unconstrained to FortisBC for imports of energy from the US.

5.1.3.3 Foreign Exchange Conversion

Midgard forecast the USD to CAD conversion rate as a linear trend starting at 1 USD = 1 CAD in 2011 and ending at 1 USD = 1.25 CAD in 2040. This foreign exchange conversion rate was employed to recognize the historical norm of the Canadian dollar trading at a discount to the US dollar. Midgard chose to represent this foreign exchange conversion forecast in a simplistic manner because a more elaborate foreign exchange forecast, in Midgard's opinion, would not significantly improve the validity of the final BC Wholesale Market Energy Curve.

The resultant British Columbia Wholesale Market Energy Curves (all hours, HLH, and LLH) are shown in Figure 5.1.3.3-A and Table 5.1.3.3-A.

Figure 5.1.3.3-A: BC Wholesale Market Energy Curves (CAD)



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[33] Bonneville Power Administration, Open Access Transmission Tariff, August 2010, Schedule 9 "Real Power Loss Calculation"

Table 5.1.3.3-A: British Columbia Wholesale Market Energy Curve (CAD)

Year	Expected	HLH	LLH
2011	$51.79	$54.24	$49.26
2012	$54.68	$57.27	$52.00
2013	$57.30	$60.01	$54.49
2014	$61.18	$64.08	$58.17
2015	$64.49	$67.55	$61.32
2016	$68.47	$71.73	$65.11
2017	$72.36	$75.81	$68.80
2018	$76.15	$79.77	$72.40
2019	$79.67	$83.46	$75.74
2020	$82.59	$86.52	$78.52
2021	$88.77	$93.00	$84.39
2022	$92.27	$96.68	$87.72
2023	$94.19	$98.68	$89.54
2024	$96.78	$101.40	$92.00
2025	$100.90	$105.72	$95.92
2026	$104.73	$109.73	$99.56
2027	$108.45	$113.63	$103.09
2028	$112.55	$117.93	$106.99
2029	$117.90	$123.53	$112.07
2030	$122.45	$128.31	$116.40
2031	$128.10	$134.23	$121.77
2032	$130.48	$136.72	$124.03
2033	$134.80	$141.25	$128.13
2034	$139.16	$145.82	$132.28
2035	$143.58	$150.45	$136.47
2036	$148.04	$155.12	$140.72
2037	$152.55	$159.85	$145.00
2038	$157.11	$164.63	$149.34
2039	$161.73	$169.47	$153.72
2040	$167.50	$175.52	$159.22

5.2 BC New Resources Market Energy Analysis

The alternative approach to procuring energy in the BC Wholesale Market is to self supply (or contract with a third party) to provide energy from a newly constructed generation resource.

BC Hydro has been actively procuring new generation resources from independent power producers ("**IPPs**") for the past decade. As such, the cost and conditions of competitive new generation procurement can be rationally forecast because activity over the past decade has created a well-developed IPP industry in BC with market tested pricing.

At present, BC Hydro is operating a Standard Offer Program ("**SOP**") that presents IPP developers the opportunity to sign long-term contracts with BC Hydro whereby the IPP may sell their generation output to BC Hydro at a preset price. The SOP has recently been through a two-year review which produced a number of changes and updates. The eligibility requirements for the program include a 15MW maximum size limit, the need for generation to meet government defined clean or renewable qualification standards and for the generation to be located within British Columbia[34].

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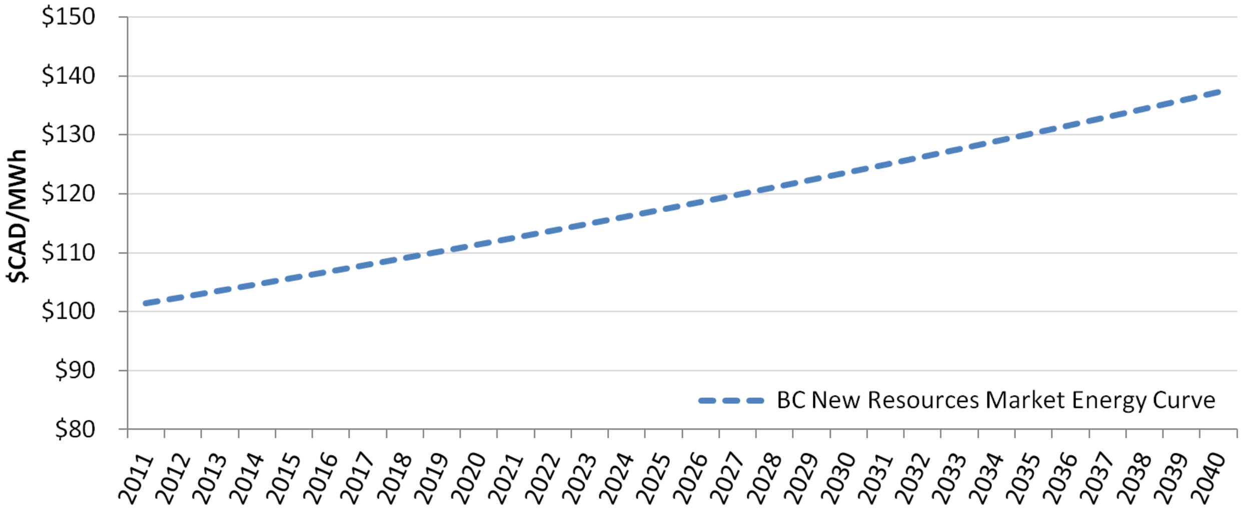
[34] BC Hydro, Standard Offer Program: Program Rules, Version 2.0, January 2011, page 1

Unlike the recent BC Hydro Clean Power Call, the SOP does not discriminate between firm energy and non-firm energy. Consequently, after adjusting for month of delivery and time of day, all energy generated under an SOP contract receives the same preset price regardless of the certainty of production[35]. Stated another way, BC Hydro assumes the intermittent and volumetric risk on the generation and therefore is in essence procuring an energy only product.

As a result, the current BC Hydro SOP represents an accurate estimate of the cost of procuring a BC based energy only product (with the added benefit of being consistent with the prescriptions of the *Clean Energy Act*). Because of this, Midgard has estimated the forecast price curve for the BC New Resources Market Energy based on the current SOP price offering which is $101.39/MWh in 2011 CAD[36]. Therefore the 2011 price point for the Midgard British Columbia New Resources Market Energy curve is $101.39/MWh. This price was escalated at 50% of CPI[37] annually between 2011 and 2040 to generate the remainder of the BC New Resources Market Energy Curve. The BC New Resources Market Energy Curve is represented in Figure 5.2-A and Table 5.2-A.

Figure 5.2-A: BC New Resources Electricity Market Curve (CAD)



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[35] In contrast with this treatment, BC Hydro's Clean Power Call contract stipulates a different price for power that is certain to be provided (i.e. firm power) than for power that is uncertain to be generated (i.e. non-firm power). Consequently, the prices paid for firm power can be a multiple of that paid for non-firm power. The firm power price notionally includes a premium for the inherent capacity of that power.

[36] $99.30/MWh in 2010 CAD

[37] The 50% of CPI escalation factor was selected to match the escalation factor embedded in an executed SOP contract. A 100% CPI escalation factor would overstate the future cost of contracted energy, although it might better represent the starting price for the energy at the time it is first contracted.

Table 5.2-A: BC New Resources Market Energy Curve (CAD)

Year	Price	Year	Price	Year	Price
2011	$101.39	2021	$112.55	2031	$124.94
2012	$102.45	2022	$113.73	2032	$126.25
2013	$103.53	2023	$114.92	2033	$127.58
2014	$104.61	2024	$116.13	2034	$128.92
2015	$105.71	2025	$117.35	2035	$130.27
2016	$106.82	2026	$118.58	2036	$131.64
2017	$107.94	2027	$119.83	2037	$133.02
2018	$109.08	2028	$121.09	2038	$134.42
2019	$110.22	2029	$122.36	2039	$135.83
2020	$111.38	2030	$123.64	2040	$137.26

5.3 BC Wholesale Market Energy vs. BC New Resources Market Energy

The analysis has taken two distinct approaches to valuing the price of energy in British Columbia. The first approach started with a forecast Mid-C electricity curve and translated it into an electricity price equivalent for delivery into FortisBC territory. The second approach estimated the required contractual price to procure energy from a newly constructed generation resource. Figure 5.3-A graphs these two curves together.

Figure 5.3-A: Projected BC Wholesale vs. BC New Resources Market Energy (CAD)

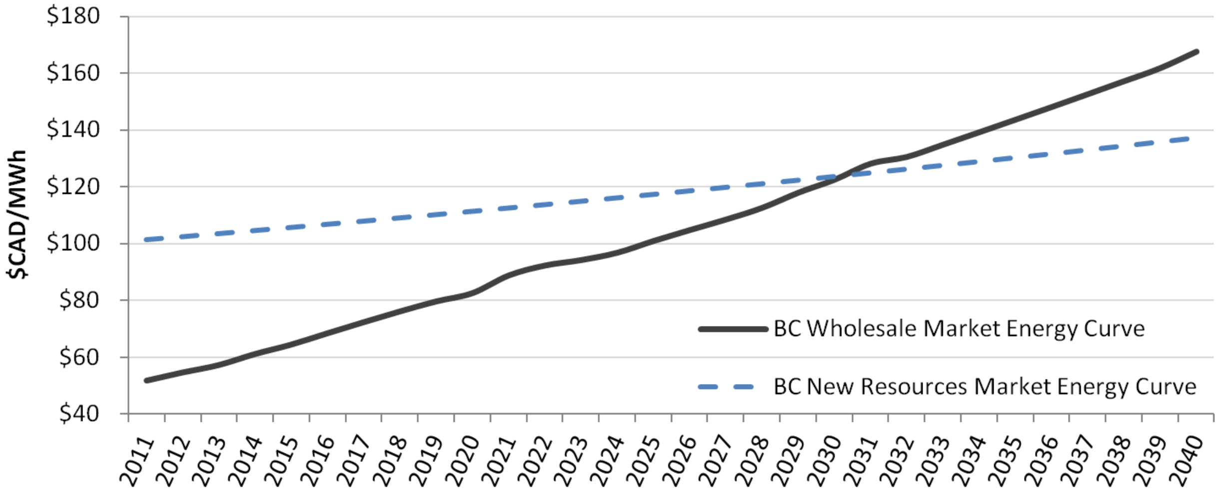

Figure 5.3-A shows that BC Wholesale Market Energy costs are projected to remain less expensive than BC New Resources Market Energy costs until 2030. Therefore, from an energy only product standpoint BC Wholesale Market Energy solutions are projected to be less expensive that new contracted generation solutions from BC New Resources Market sources until 2030.

6 British Columbia Capacity Market Analysis

FortisBC has two alternatives to address their forecast capacity shortfalls. One strategy is to purchase capacity in the wholesale market and the other strategy is to acquire it from new generation resources.

Purchasing capacity in the wholesale market is a strategy that FortisBC has historically employed. Typically this can only be done on a short term basis and is achieved by contracting for short-term supplies of firm power[38] to be delivered to FortisBC during the peak demand months of December, January, and/or February. The advantage of this procurement method is that FortisBC has flexibility with regards contract timings, quantity of contracts and contract durations. The disadvantage of this strategy is that FortisBC may misread the market and either pay a high price for the firm power or be unable to secure the quantity and quality of firm power that FortisBC is seeking. Short term market prices of electricity can be volatile (see Section 5.1.1) and unanticipated spikes in prices or scarcity of available supply cannot be predicted. Consequently, relying upon short term market purchases in the wholesale electricity market entails certain cost and supply-certainty risks for FortisBC and its ratepayers.

The second strategy is to contract for new generation resources either by developing and constructing a new firm capacity generation resource that is owned and operated by FortisBC, or by contracting with a third party to provide long term supply of firm capacity to FortisBC from a new generation resource. Similar to the case for energy, it is common for the power purchase agreement to have a term of 20 years or longer.

This section will discuss the wholesale market price curve for capacity available to FortisBC, the forecast market price for new contracted generation in BC and compare the two BC capacity price curves with each other.

6.1 BC Wholesale Capacity Price Curve

Capacity is essentially the timing and rate of energy delivery.

6.1.1 Translating the BC Wholesale Market Energy Curve into the BC Wholesale Market Capacity Curve

Starting from the BC Wholesale Market Energy Curve that was presented in Section 5.1.3, the cost (in $/MW-month) of a series of wholesale market purchases of firm delivered power can be estimated. This assumes that a block of firm energy could and would be procured today for delivery over multiple years into the future.

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[38] In practice, FortisBC has been unable to procure a pure capacity option product whereby they could call on the energy as and when needed. Rather FortisBC has had to contract for firm power deliveries in order to ensure delivery and then resell any unneeded power back to the spot market at the then prevailing market price.

The block of energy would cover the high load hours of the four FortisBC high load months of January, July, November, and December. The notional cost of procuring this block of power for a year is summed and then divided by twelve months to obtain an annualized price ($/MW month) estimate.

The wholesale market price for high load hours during the months of January, July, November, and December was estimated by multiplying the annual BC Wholesale Market Energy Curve by the monthly average premiums for these four months. 112% is the average premium that these four months trade above the annual average price, as per Table 5.1.2-b (Jan=116%, Jul = 105%, Nov=111%, and Dec=116%).

Wholesale markets tend to be very liquid in the short term but increasingly less so in the medium and long term, as you move further out the forecast curve. The cost premium of purchasing a ten year hedge is far more than the premium for purchasing a one year hedge. These additional costs relate to a number of factors including:

- Credit costs required to secure the transaction (such as letters of credit requirements)
- The low number of credit worthy counterparts with whom to transact
- The liquidity cost premium that long-term transactions incur
- The wider bid/ask spreads that extraordinary transactions attract

Consequently, the cost of a wholesale market transaction was adjusted upwards to take into account the above factors. Specifically, the annual price estimates were increased by 2% per year to represent the increasingly costly nature of long term wholesale market transactions.

Table 6.1.1-A shows the results of all these calculations and includes a subjective assessment of the likelihood of being able to find a party with whom to transact. The table reveals that today's cost of procuring wholesale market supply of capacity becomes increasingly expensive as the term of the transaction extends into the future.

Table 6.1.1-A: BC Wholesale Market Capacity Curve Estimations (CAD)

Year	Expected Fortis BC: On-Peak for Jan-Jul-Nov-Dec incl. Fin. Costs (CAD/MW.mo)	Likelihood of actually procuring a hedge
2011	$6,942	very likely
2012	$7,476	likely
2013	$7,991	likely
2014	$8,702	potentially
2015	$9,356	potentially
2016	$10,133	difficult
2017	$10,923	difficult
2018	$11,724	difficult
2019	$12,512	difficult
2020	$13,230	difficult
2021	$14,504	unlikely
2022	$15,379	unlikely
2023	$16,012	unlikely
2024	$16,781	unlikely
2025	$17,846	unlikely
2026	$18,894	unlikely
2027	$19,955	unlikely
2028	$21,125	unlikely
2029	$22,571	unlikely
2030	$23,912	unlikely
2031	$25,515	unlikely
2032	$26,509	unlikely
2033	$27,934	unlikely
2034	$29,415	unlikely
2035	$30,955	unlikely
2036	$32,555	unlikely
2037	$34,219	unlikely
2038	$35,947	unlikely
2039	$37,742	unlikely
2040	$39,872	unlikely

6.2 BC New Resources Market Capacity Curve

The alternative strategy for closing FortisBC's forecast capacity gaps is to procure the capacity product from a new power generation facility (e.g. self-supply or IPP). A new power generation facility is a more concrete means of ensuring long term supply-certainty, especially if the facility is constructed close to the load requirement. Nevertheless, this strategy carries its own risks; the cost of fixing the price of long-term supply may prove to be more expensive than the cost of a series of short term wholesale market purchases.[39]

6.2.1 Resources Options Report

In 2010, FortisBC contracted Midgard to renew the Company's resource option analysis and prepare a 2010 Resource Options Report ("2010 ROR"). The 2010 ROR reviewed potential resources and estimated various resource costs for both capacity and energy. This section will draw on the 2010 ROR

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[39] This opportunity cost can only be assessed after the fact, and is not dissimilar to the decision that households face when they decide whether to lock in a fixed rate or a floating rate mortgage.

findings, specifically the conclusions of the least costly capacity resources that met FortisBC's requirements; it will use those findings to help generate the BC New Resources Market Capacity Curve.

6.2.1.1 Evaluation Criteria

To enable consistent evaluation of resources that represent a wide range of technologies and fuel sources, the 2010 ROR employed a simplified cost metric named Unit Capacity Cost ("**UCC**"). The metric condensed the economic characteristics of the different resource options[40] into a resource specific Unit Capacity Cost.

The Unit Capacity Cost is the annual cost of providing dependable capacity using each resource option, expressed in $/MW-month units. Annual costs used in the calculation include the interest on debt, return on equity and amortization, all derived from the project capital cost. Annual costs also include the fixed operating costs that must be spent to keep the project's dependable capacity available regardless of the amount of energy generated each year. UCC was used to rank the various capacity resources under consideration.

Non-Economic Criteria

In addition to economic criteria the resources identified in the 2010 ROR were passed through additional filters that measured the resource's effectiveness in meeting FortisBC's planning needs. The filters included an assessment to ensure that the resources:

- Were based upon proven commercially viable technology
- Adhered to the directives and principles of the *Clean Energy Act* including assessing the resources' environmental impacts
- Were assessed based upon the ancillary benefits[41] they might provide to the FortisBC system

6.2.1.2 Results of the 2010 Resource Options Report

Table 6.2.1.2-A summarizes the least expensive capacity resources available to FortisBC, ranked using the UCC metric. The list includes a simple cycle gas turbine followed by a combined cycle gas turbine, pumped storage hydro, and a small hydro resource with capacity.

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[40] Representative capacity resources included Simple Cycle Gas Turbines ("**SCGT**") and pumped storage hydro plants.

[41] Examples of ancillary benefits include reactive power/voltage support, AGC/load following, spinning reserves, dispatch ability and most notably Transmission Must Run service, where the resource can be dispatched as required to relieve transmission path congestion.

Table 6.2.1.2-A: Competitive Unit Capacity Cost Resource Options (CAD 2010)

Project	Dependable Capacity (MW)	Capital Cost (k$)	UCC @6% ($/MW-month)	UCC @8% ($/MW-month)
Simple Cycle Gas Turbine	39	44,269	8,481	10,163
Combined Cycle Gas Turbine	243	329,445	10,624	12,708
Potential Pumped Storage Hydro	180	340,000	13,668	17,412
Similkameen - Small Hydro with Capacity	60	283,117	29,274	38,003

6.2.1.3 Translating UCC Results into a BC New Resources Market Capacity Curve

The result of the 2010 ROR analysis was that a simple cycle gas turbine would be FortisBC’s most cost effective capacity resource solution. Based upon this conclusion, and the UCC metric of $10,163/MWh-month, Midgard derived a BC New Resources Market Capacity Curve.

The UCC derived cost of $10,163 was used as the starting point and escalated at 100% of CPI for years 2011 through 2040. Table 6.2.1.3-A depicts the results of the exercise.

Table 6.2.1.3-A: BC New Resources Market Capacity Curve: Based on Escalated UCC Cost of SCGT (CAD)

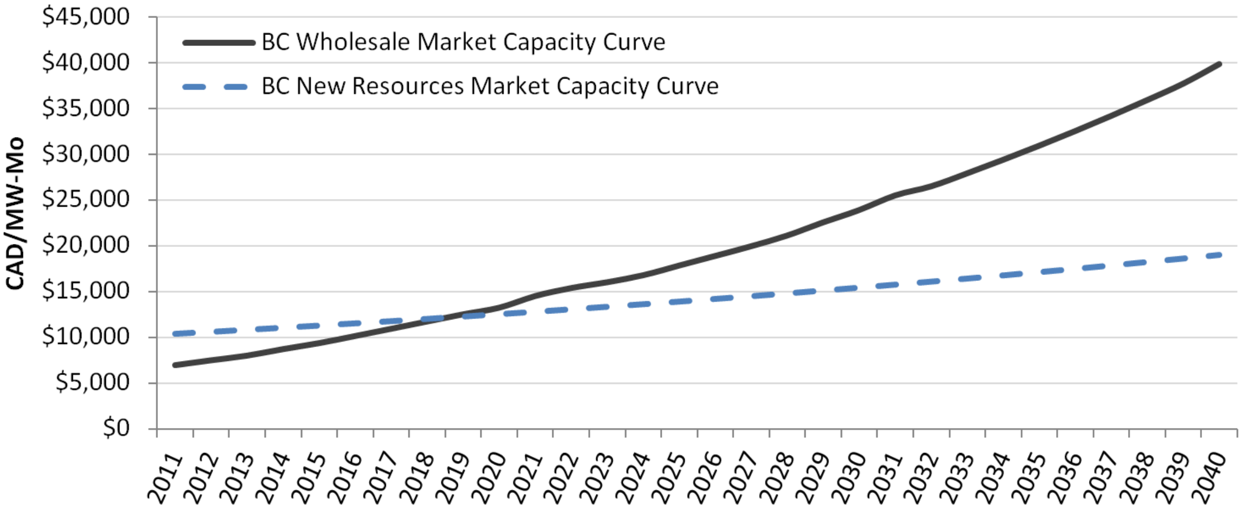
Year	New Resources: UCC Costs (SCGT) (CAD/MW-Mo)
2011	$10,376
2012	$10,594
2013	$10,817
2014	$11,044
2015	$11,276
2016	$11,513
2017	$11,754
2018	$12,001
2019	$12,253
2020	$12,511
2021	$12,773
2022	$13,042
2023	$13,315
2024	$13,595
2025	$13,881

Year	New Resources: UCC Costs (SCGT) (CAD/MW-Mo)
2026	$14,172
2027	$14,470
2028	$14,774
2029	$15,084
2030	$15,401
2031	$15,724
2032	$16,054
2033	$16,391
2034	$16,736
2035	$17,087
2036	$17,446
2037	$17,812
2038	$18,186
2039	$18,568
2040	$18,958

6.3 BC Wholesale Market Capacity vs. BC New Resources Market Capacity

Figure 6.3-A compares the capacity cost of the two methods of deriving British Columbia based capacity cost curves.

Figure 6.3-A: BC Wholesale Market Capacity Curve vs. BC New Resources Market Capacity Curve (CAD)



Comparing the "wholesale" and "new resources" curves shows that wholesale market capacity is more cost effective than building new resources until 2019.

This conclusion must be qualified by two important considerations:

1. Contracting a new resource (the "BC New Resources" curve is intended to represent the cost of this option) is typically done on a long term basis of up to 20 years or more. In contrast, contracting in the wholesale market is typically done on a one to five year basis. Consequently, if FortisBC is looking to secure long term sources of capacity, the BC New Resources Market Capacity becomes progressively more cost competitive versus the BC Wholesale Market Capacity as the term length increases.

2. The potential price volatility of wholesale markets tends to be higher than is the case for the price volatility of new resources markets. This is because the underlying price drivers for wholesale markets, such as the price of natural gas, tends to display much greater price volatility than the underlying price drivers for new resources markets[42] (e.g. labour costs and cost of equipment).

Section 7 will take a closer look at several market trends that could have an impact upon the availability and price of energy and capacity products within wholesale markets and for new resources markets in the future.

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[42] Note that the price of natural gas does not affect the capacity cost estimate (UCC calculation) of a SCGT. See Appendix 3 for details.

7 Market Trends

The market for energy and capacity in western North America is undergoing significant change. This section is an overview of the current trends impacting the energy and capacity markets in the WECC region that may have a material impact upon FortisBC's interests.

The trends that will be examined are:

- Changes to WECC supply mix due to mandatory Renewable Portfolio Standards ("**RPS**")
- Potential impact of DSM on energy and capacity markets
- Delays to new transmission construction in WECC
- British Columbia's *Clean Energy Act*
- The current state of the Alberta electricity market

Note that these regional trends are more likely to have an impact upon wholesale market prices than they are to impact new resources market prices. Wholesale market prices are influenced, as discussed in Section 4, by regional factors, such as natural gas prices and regional transmission constraints.

In contrast, new resources market prices (in BC) are influenced to a great extent by factors local to British Columbia, such as labour costs, the cost of permitting new projects, and competition in BC for new generation resources. The closer the capacity resource is installed to the load centre, the easier it becomes for the load to access it as a capacity or energy resource. Therefore, construction of new generation is largely built to serve local needs.

7.1 Renewable Portfolio Standards

Table 7.1-A displays the current NERC resource mix and the resource mix that is anticipated in 2019. The percentages indicate the contribution to the on-peak capacity for each type of generation resource. Renewables' capacity is anticipated to experience a fivefold increase between 2010 and 2019. The changes to the supply mix are being driven to a great extend by Renewable Portfolio Standards.

Table 7.1-A: On-Peak Capacity by Resource Type: 2010 and 2019[43]

Fuel Type	2010	2019 Projected
Coal	31%	26%
Gas	29%	30%
Nuclear	11%	12%
Hydro	13%	9%
Renewables	1%	5%
Dual Fuel	11%	13%
Other	4%	5%
TOTAL	100%	100%

Most provinces and states in the WECC region have a mandated Renewable Portfolio Standard or a renewable energy goal. Table 7.1-B lists the US states that are WECC members and their RPS mandates[44].

Table 7.1-B: RPS Standards in WECC US States

State	RPS
Arizona	15% by 2025
California	33% by 2020
Colorado	30% by 2020
Idaho	none
Montana	15% by 2015
Nevada	25% by 2025
New Mexico	20% by 2020
Oregon	25% by 2025
Utah	20% by 2025
Washington	15% by 2020
Wyoming	none

States that have adopted an RPS have chosen a minimum of 15% of energy to come from renewable resources, with the latest of those occurring by 2025 (Arizona). California has the most aggressive standard at 33% of energy supplied from renewables by 2020.

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[43] North American Electric Reliability Corporation, 2010 Long-Term Reliability Assessment, October 2010, page 45

[44] PEW Center on Global Climate Change: http://www.pewclimate.org/what_s_being_done/in_the_states/rps.cfm

California's RPS is arguably the most significant in the WECC region (if not the US) given that the state consumes almost 300,000 GWh[45] of energy annually (approximately one third of WECC's annual load). As of 2009 the state received 13.9% of its power from renewables, leaving a further 19.1% requirement to be fulfilled. This suggests a need to more than double its current installed renewable generation capacity in the 11 years leading up to 2020.

7.1.1 Wind Resource Introduction

Wind is being increasingly relied upon to meet the demand for renewable resources in WECC, with 19,000 MW of capacity planned for installation in the WECC region by 2019[46]. Wind can be expected to generate a reliable amount of yearly energy but it is not dependable because its capacity is entirely dependent on the weather; hence only a small fraction of its installed capacity amount is being counted upon.

The majority of the non-construction/transmission costs associated with integrating wind into the grid relate to reserving flexible resources to ensure reliable service despite wind's variability[47]. Integration of wind power requires some firming of its energy. Although short-term wind forecasting techniques have diminished the need for regulating reserves, there remain challenges associated with integrating an intermittent resource such as wind into the transmission grid.

Impact upon Energy and Capacity Availability

Larger quantities of intermittent resources are likely to consume currently available wholesale market capacity resources within WECC as regulating authorities are required to commit what was previously excess capacity to act as regulating reserves for wind capacity. This will threaten the supply certainty of wholesale market capacity resources for FortisBC. As it pertains to wholesale market energy resources, the new intermittent resources will add energy supply to the market and create downward pressure on wholesale market energy prices during periods of optimal wind and/or renewable fuel conditions.

RPS standards generally require that the renewable generation resources be located within the jurisdiction mandating the RPS standard. Therefore, the impact upon BC New Resources Markets is expected to be immaterial (aside from those impacts discussed in section 7.4 below).

7.2 Demand Side Management

Demand Side Management programs are being widely introduced into WECC jurisdictions. Actual measurement of DSM results can be difficult given that actual consumption levels can only be compared to projected consumption levels that would have existed in the absence of the DSM program. It may be some years before actual DSM successes can be properly discerned from theoretical successes as many

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[45] California Energy Almanac Total System Power Reporting: http://www.energyalmanac.ca.gov/electricity/total_system_power.html

[46] North American Electric Reliability Corporation, 2010 Long-Term Reliability Assessment, October 2010, page 271, Table WECC-4

[47] Utility Wind Integration Group Northwest Wind Integration Action Plan, 2007

of the DSM measures do not have a long ‘in service’ history, particularly for proactive ‘demand response’ programs. Aggressive DSM targets are a potential peril to the wholesale capacity markets because:

- they may be used to rationalize the delay of installing new resources
- load shaping and peak shaving measures of DSM programs may not materialize in practice as theorized (not the least because voluntary DSM participants may simply decide not to abide by their promised behaviour)

Impact upon Energy and Capacity Availability

DSM programs will have a material impact upon resource planning for the foreseeable future as they are predicted to have a mitigating impact upon load growth. However, there may be a gap between the theoretical impact and the reality. Consequently, DSM programs may end up tying up currently available capacity resources within the WECC region in the event that the load that DSM is intended to displace does not get fully displaced. This may jeopardize supply certainty of wholesale market capacity resources for FortisBC. That said the impact of DSM programs on the wholesale markets is likely to be less than that of RPS.

The impact of DSM programs on the new resources markets for energy and capacity is unlikely to be material, although their failure, or partial failure, may put pressure on new resource markets in the medium to long term if it triggers a boom in the construction of new resources.

7.3 Potential Delays in WECC Transmission Construction

Table 7.3-A lists transmission construction plans in NERC. Although WECC totals may seem high in comparison to other NERC jurisdictions, the physical distances involved with the western grid mean that longer transmission lines are generally needed to make any given supply-load connection.

Table 7.3-A: Current and Planned Transmission in NERC by Circuit Mile Additions[48]

Area	2009 Existing	Planned Additions	Total by 2019
FRCC	12,016	377	12,393
MRO	49,763	4,773	54,536
NPCC	59,294	2,289	61,583
RFC	60,088	1,831	61,919
SERC	98,296	5,013	103,309
SPP	23,814	2,766	26,580
TRE	28,665	5,090	33,755
WECC	**120,763**	**17,249**	**138,012**

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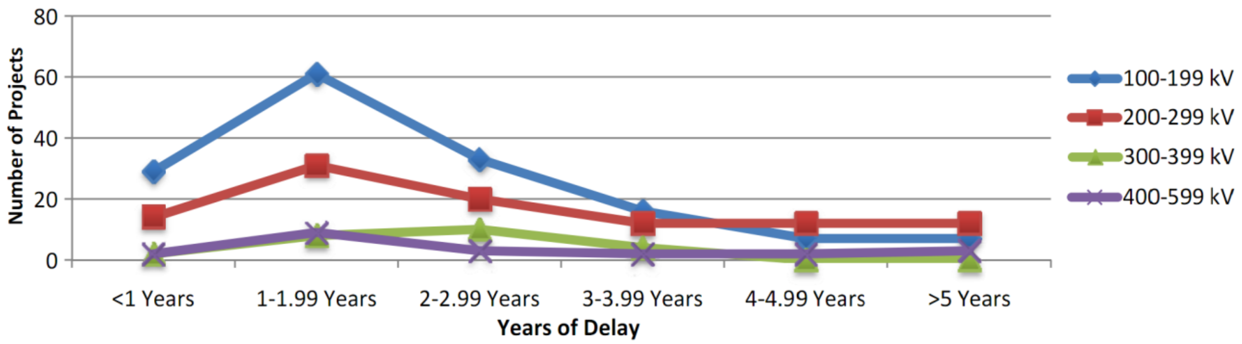
[48] North American Electric Reliability Corporation, 2010 Long-Term Reliability Assessment, October 2010, page 22

Of the 27,000 miles of transmission projects in NERC that are either under construction or in the planning stage, roughly 6,500 miles of these transmission projects are currently considered "delayed"[49] (as illustrated by Figure 7.3-A). In the event that the transmission construction patterns in WECC (and British Columbia) prove to be consistent with those of NERC, delays can be expected in the addition of new transmission capacity, especially for higher voltage lines.

Figure 7.3-A: Transmission Project Delays in Currently Planned Projects[50]



Impact upon Energy and Capacity Availability

Delays in new transmission construction will have an adverse impact upon FortisBC's ability to access wholesale markets. Growing regional loads without corresponding additional transmission capacity will certainly lead to more serious transmission constraints. This trend will generally have a negative impact upon both wholesale energy markets and wholesale capacity markets.

The impact on the new resources markets for energy and capacity in BC is unlikely to be material unless it increases the transmission constraints between the location of the new resources and FortisBC. In other words, if transmission constraints to move power from the interior of the Province to the Lower Mainland become more severe, it does not necessarily have an adverse impact upon FortisBC. However, if transmission constraints made it more difficult to move power from a newly constructed facility to FortisBC territory, it would have a negative impact upon the new resources market prices that FortisBC's would face.

7.4 British Columbia's Clean Energy Act

The *Clean Energy Act* was passed into law by the BC government in 2010. The *Clean Energy Act* advanced 16 specific energy objectives, which can be grouped into three priority areas[51]:

1. Ensuring Electricity Self-Sufficiency at Low Rates
2. Harnessing B.C.'s Clean Power Potential to Create Jobs in every Region

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[49] North American Electric Reliability Corporation, 2010 Long-Term Reliability Assessment, October 2010, page 23

[50] North American Electric Reliability Corporation, 2010 Long-Term Reliability Assessment, October 2010, page 24

[51] BC news release 2010PREM0090-000483:http://www2.news.gov.bc.ca/news_releases_2009-2013/2010PREM0090-000483.htm

3. Strengthening Environmental Stewardship and Reducing Greenhouse Gases

The two provisions within the *Clean Energy Act* that will be examined here are:

i. The provision for BC Hydro to target creating an energy surplus[52]
ii. The provision for BC Hydro to facilitate the export of power out of BC[53]

The *Clean Energy Act* also mandates aggressive DSM targets; however these were covered earlier in this section and will therefore not be repeated here.

Under the *Clean Energy Act*, BC Hydro is mandated to secure, by 2020, rights to 3,000 GWh of energy above its anticipated needs. This amount of energy is equivalent to approximately 5% of BC's current annual energy consumption. This is on top of the fact that BC Hydro has been mandated to become self-sufficient, defined as being able to meet their domestic electricity demand during a critical water year (i.e. a low water year) by 2016. The combination of the 3,000 GWh surplus energy with the surplus energy BC Hydro would have available for sale in the average year would mean that BC Hydro (and Powerex) will be active sellers of energy in the medium term.

Related to the above, BC Hydro is mandated "to be a net exporter of electricity from clean or renewable resources with the intention of benefiting all British Columbians and reducing greenhouse gas emissions in regions in which British Columbia trades electricity". Increased exports from British Columbia would obviously be facilitated by the construction of new transmission both within BC and inter-regionally.

Impact upon Energy and Capacity Availability

BC Hydro's securing of 3,000 GWh of energy beyond their critical water year requirements suggests an abundance of conveniently located energy potentially available for sale to FortisBC. Improvements to BC's interconnection infrastructure with neighbouring jurisdictions also implies potentially positive impacts for FortisBC and their ability to access to wholesale markets outside of BC.

BC Hydro may be active in the BC New Resources Markets in order to secure the 3,000 GWh of surplus energy and achieve self-sufficiency. As they contract for the most cost effective new resources (the 'low hanging fruit'), their activities are likely to put upwards pressure on the BC New Resources Market Capacity and Energy curves.

7.5 Alberta Electricity Market

The Alberta electricity market is approximately the same size as the British Columbia electricity market.

The Alberta electricity market is deregulated, which means that the price of electricity can and does vary by the hour and that decisions to add new generation capacity are driven by market forces.

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[52] Clean Energy Act, Part 1, 6 (2) (b)

[53] Clean Energy Act, Part 1, 2 (n)

The Alberta projected 2010-2011 winter reserve margin is equal to or below the prescribed target reserve margin of 13.2%[54], highlighting the need for Alberta to add generation resources. Alberta loads are expected to grow by 2.6% annually[55] for the next decade, a rate that is higher than most other sub-regions in WECC. Moreover, a considerable amount of wind generation has been constructed in Alberta over the past fifteen years, with more planned. This wind generation adds limited dependable capacity despite the much larger nameplate capacity of the generators[56].

Alberta, like British Columbia, is a winter-peaking system. There is a high coincidence between British Columbia (including FortisBC territory) and Alberta for extreme winter weather events.

From a transmission point of view, Alberta can theoretically export 1000 MW to British Columbia and import 1200 MW from British Columbia. However, the transfer capabilities are rated at approximately half these amounts due to transmission constraints within Alberta[57]. (Alberta also has a 150 MW intertie with Saskatchewan.)

Alberta's electrical system faces some challenges in the coming years.

Impact upon Energy and Capacity Availability

The combination of healthy economic growth, tight reserve margins, and intermittent generation resource additions suggest that Alberta requires new generation capacity (and transmission additions) sooner rather than later. To the extent Alberta does not construct new capacity in its own jurisdiction it sets the stage for the province to be a potential competitor for WECC wholesale market capacity resources in the coming years. Given the similarity of Alberta's peak demand patterns with those of FortisBC, FortisBC must be aware of the likelihood of competing with Alberta when seeking to secure firm capacity supplies (and potentially energy supplies) from the wholesale markets.

The impact on the new resources markets in BC for energy and capacity is unlikely to be material, since Alberta is unlikely to seek to have new resources constructed in British Columbia that are meant to service domestic Alberta requirements.

7.6 Market Trend Conclusions

Overall, the risks of the market trends have limited or delayed impact upon the expected cost of procuring energy and capacity from the new resources markets. This is because new resources markets are more prone to local cost influences and, particularly in the short run, region wide trends do not tend to impact

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[54] North American Electric Reliability Corporation, 2010 Long-Term Reliability Assessment, October 2010, page 284

[55] North American Electric Reliability Corporation, 2010 Long-Term Reliability Assessment, October 2010, page 284

[56] North American Electric Reliability Corporation, 2010 Long-Term Reliability Assessment, October 2010, page 287;
"the WECC-Canada sub-region [currently] has 591 MW[of installed nameplate capacity –wind], which is derated to 33 MW during the summer peak period."

[57] Alberta Electric System Operator, AESO Long-term Transmission System Plan, 2009, Appendix H, page 303

local new resources markets. The exception to this is the *Clean Energy Act*, which will have an important impact upon BC and will influence the cost of constructing new resources in BC.

These same market trends could have a more serious impact upon prices in the wholesale markets. This is particularly true with wholesale capacity markets as all the trends, except the *Clean Energy Act* and certain BC transmission line delays, could have an adverse impact upon the availability of capacity resources in the BC Wholesale Market. The potential impacts of all five trends are summarized in Table 7.6-A.

Table 7.6-A: Summary of Market Trends' Impacts on BC Markets

WECC Market Trend	Wholesale Market	New Resources Market
Renewable Portfolio Standards & Additional Intermittent Resources	Risk to supply-certainty; risk of higher wholesale capacity prices	Limited impact
Demand Side Management Programs	Limited risk to supply certainty	Limited impact, but potential upward price pressure in long-term
Delays in New Transmission Construction	Risk to supply certainty; risk of higher wholesale market prices	Potential impact, resulting in upward price pressures
Clean Energy Act: • ***Generation Surplus*** • ***Export Mandate***	Potential positive impact for FortisBC / BC Wholesale Market energy and capacity buyers	Potential upward price pressures in medium-term
Alberta Market – Current State	Price risk and supply-certainty risk	Limited impact

8 Conclusions

FortisBC faces some gaps between its currently contracted supply of energy and capacity and its forecast load requirement over the next 30 years. Midgard Consulting Inc. was contracted to assess the future outlook of the electricity markets in BC and surrounding areas and assess the cost and availability of energy and capacity products therein. This report analyzed the cost and availability of power supply to FortisBC over the next 30 years and compared the cost of procuring these power supplies from either British Columbia's Wholesale Market or its New Resources Market.

For the purposes of this paper, the wholesale market referred to any transaction whereby the power is procured by means of a short term, physically or financially settled transaction that is tied to a notional or actual existing generation assets. The new resources market referred to a transaction that would lead to the installation of new generation resources, which is to say 'steel in the ground'.

Given the findings of this report, Midgard concludes as follows:

- FortisBC's continued reliance upon the wholesale electricity market to meet current and future needs is not an unreasonable strategy, particularly given the size of FortisBC's energy and capacity gaps over the next few years.
    - BC Wholesale Energy Market prices are projected to remain less expensive than comparable BC New Resources Market Energy prices until approximately 2030.
    - BC Wholesale Capacity Market prices for capacity products are projected to remain less expensive than comparable BC New Resources Market Capacity prices until approximately 2019.
- Overall WECC market trends – chiefly RPS, DSM and the current state of the Alberta electricity market – are of a greater threat to the price and supply availability of capacity and energy in the wholesale markets than they are to the price and supply availability of energy and capacity from the new resources markets.
- The impact of transmission delays and the BC *Clean Energy Act* are more ambiguous for both the wholesale and new resources markets, although they potentially improve the relative cost competitiveness of the BC Wholesale Markets versus the BC New Resources Markets.
- The BC New Resources Capacity Market is less expensive than the BC Wholesale Capacity Market when longer term transactions are evaluated. Up*ward price press*ures and product availability concerns in both the wholesale market energy and wholesale market capacity markets make new resources more competitive on a long term basis.

Appendix A: Natural Gas and Greenhouse Gas Forecast Price Curves

Natural gas generation resources rank higher in the dispatch stack than base load generation resources. In other words, the marginal cost of electricity generated from a natural gas fired generator is typically more expensive than the comparable cost of electricity from a nuclear or coal-fired plant. Load demand frequently rises during on-peak periods to the point where natural gas generation facilities are required and hence determine the marginal cost of electricity in the wholesale market. Consequently, market electricity prices (and especially on-peak prices) in the ("**WECC**") region, and across much of North America, are strongly correlated to the price of natural gas.

Over 40% of the generating capacity in the WECC region is produced from natural gas fired generation plants (or dual fired generation plants, which typically use natural gas as the default fuel). In addition, as per WECC's 2008 Information Summary, almost 50% of new resources in the WECC region are expected to be natural gas-fired[58]. A plant owner will sell to the market when the expected market price of electricity will cover the variable cost of production, which is primarily dependent of the cost of natural gas and the efficiency or heat rate of the plant[59].

Natural gas prices have a history of volatility as evidenced by the experience of the last 10 years. On an annual average basis from 1997 to 2008 the price ranged from US$1.96 to US$8.07 with an annual average price of US$4.63 and a standard deviation of $2.10 (all in nominal US dollars)[60]. Mid-2008 spot prices were near to or at an all-time high (over US$13 per MMBtu in July 2008 for example), while current prices, US$4.38[61], are significantly lower. Long-term forecasts tend to be influenced by current spot prices, suggesting that current pricing would tend to have brought longer term price forecasts down relative to forecasts in 2008. In short, natural gas prices are unpredictable, potentially causing material variations in their price forecasts from one year to the next.

The remainder of this section presents a forecast curve for natural gas spot pricing. A statistical analysis has been prepared to define an upper and lower bound for the natural gas forecast curve to account for the commodity's historical price volatility.

Sourcing a Base Case Forecast Curve

The Base Case Curve relies on the early release of the United States Department of Energy's Energy Information Agency's (EIA) Annual Energy Outlook 2011 (AEO2011), specifically the Henry Hub natural gas price forecast[62]. The EIA is the primary US Federal Government authority on energy statistics and

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[58] Western Electricity Coordinating Council, 2008 Information Summary

[59] There are other contributing factors such as non-fuel operating, overhaul and maintenance costs.

[60] EIA Historic Natural Gas Wellhead Prices

[61] NYMEX Henry Hub price as of March 23, 2011

[62] US Energy Information Administration, AEO 2011 Early Release Overview, December 2010, Table 13: Natural Gas Supply, Disposition, and Price

analysis. EIA data and forecasts are a widely quoted and relied upon source of energy data throughout the world.

The AEO2011 projections are based on results from the EIA's National Energy Modeling System (NEMS). NEMS is a computer-based, energy-economy modeling system of the US (looking forward until 2035). NEMS projects the production, imports, conversion, consumption, and prices of energy (prices subject to assumptions on macroeconomic and financial factors). NEMS also projects world energy markets, resource availability, resource costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies and the demographics. The EIA has been forecasting natural gas prices since 1982, although the NEMS model has only been in use since 1994[63].

Midgard views the AEO2011 Henry Hub price forecast as a reasonable estimate of natural gas pricing. This view is based on the following facts:

- The AEO2010 forecast price curve is transparent and readily available. The forecast is derived from a model based upon fundamental inputs. Furthermore, the EIA is a non-political entity and is recognized as an independent agent. The EIA has no inherent bias in forecasting natural gas spot prices.
- Henry Hub natural gas is the benchmark trading point for natural gas in North America, with other natural gas trading (or transfer) points being priced as a basis (that is, as a premium or discount) to Henry Hub natural gas prices.
- The benchmark natural gas futures contract that trades on the New York Mercantile Exchange (NYMEX), North America’s primary energy commodities exchange, physically settles at the Henry Hub natural gas delivery point.
- The EIA forecast price curve resembles the current short-term NYMEX natural gas futures curve although it escalates less acutely than does the NYMEX natural gas futures curve. While the NYMEX futures curve is not necessarily a more accurate predictor of future spot prices as compared to forecasts derived from a computer model, it is a legitimate reference against which the base case price curve should be checked. In particular, the shorter end of the NYMEX curve (where trading is more frequent) represents a fair and transparent measure to assess the wider markets’ valuation of expected spot prices.
- The EIA forecast price is frequently referenced by natural gas industry stakeholders throughout North America. For example, California’s key energy regulatory agencies, namely the California Energy Commission and the California Public Utilities Commission frequently reference the EIA price forecasts in their analysis and decisions. As a significant consumer of energy, California and its regulatory agencies invest a great deal of resources in assessing the future prices of

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[63] Description taken from “The National Energy Modeling System: An Overview” found at: http://www.eia.doe.gov/oiaf/aeo/overview/index.html

energy. In Canada, our Federal and Provincial regulatory agencies also rely frequently on the data and analysis produced by the EIA.

There are a number of potential sources of natural gas price forecasts from government organizations as well as private sector consultants. Nevertheless, weighing the sum of the advantages and disadvantages of the various sources, Midgard is confident in the reasonableness of the EIA natural gas price forecast. Consequently, it forms the basis of the base case natural gas price forecast for this 2011 FortisBC Energy and Capacity Market Assessment.

Accounting for Price Volatility

Given the uncertainty inherent in forecasting it is helpful to forecast a range of possibilities in order to improve the usefulness of the forecast. The objective of this exercise is to present a range within which natural gas spot prices are expected to fall 19 times out of 20, that is to say a 95% confidence interval.

The EIA has been forecasting natural gas prices since 1982, and has been using the NEMS model since 1994. Annually, the EIA reviews its prior years' forecasts, measures their accuracy versus the actual results and summarizes their findings in a document called "Annual Energy Outlook Retrospective Review: Evaluation of Reference Case Projections in Past Editions"[64]. The review analyses the accuracy of the AEO forecasts and compares the actual figures versus the forecast figures. It is worth noting that the accuracy of the forecasts has improved measurably since 1994. It is also important to note that the underpinning assumption from which the NEMS results are derived is that the major factors impacting the supply and demand (and hence price) of natural gas will continue to trend in a manner that resembles their recent historical record.

In order to derive the high case and low case natural gas price curves, Midgard assumed that the AEO forecasts going forward will be approximately as accurate as they have been going back to 1994. That is to say, Midgard believes that the accuracy of the AEO2011 natural gas price forecast will be similar to its accuracy for the years 1994 to 2008[65].

In order to derive the high and low natural gas curves, Midgard assessed the variance of previous years' forecasts versus the actual natural gas price, grouping the data into forecasts by years into the future. For example, the AEO1994 forecast for the 1994 natural gas price was bucketed into the 1 year-ahead grouping, the AEO1994 forecast for the 1995 natural gas price was bucketed into the 2 year-ahead grouping, and so forth. The sample size for the 1 year-ahead grouping was the largest (at 15) and the sample sizes for each proceeding year was reduced by one (i.e. the sample size for the 2 year-ahead was 14, the sample size for the 3 year-ahead grouping was 13, and so forth).

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[64] Located at: http://www.eia.doe.gov/oiaf/analysispaper/retrospective/index.html

[65] 2009 figures were not analyzed as part of the most recent Retrospective Review.

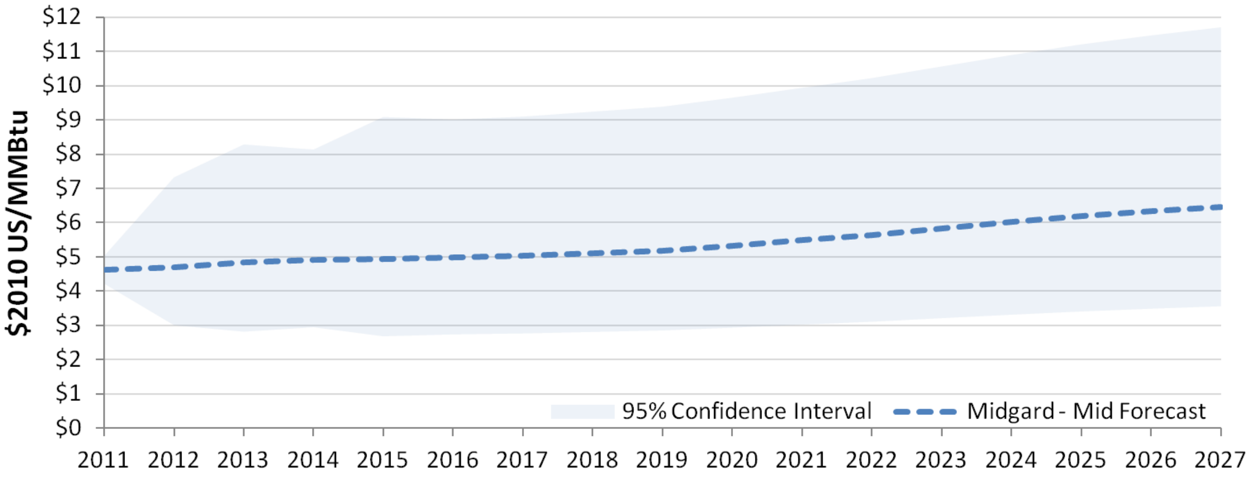
Once the standard deviations for each grouping were assessed (using a normalized data set)[66], Midgard calculated a 95% confidence interval based upon the forecast price curve acting as the mean price[67]. The calculation of the high and low price curves for the years 2016 to 2040 assumes a standard deviation equal to that calculated for 2016 (the 6th year-ahead)[68].

The end result is a long-term low case price scenario that is approximately 45% lower than the base case, and a long-term high case scenario that is approximately 80% higher than the base case.

Final Midgard Natural Gas Forecast Curve (with High & Low Cases)

Given the statistical price volatility analysis performed in the previous section, a final FortisBC natural gas forecast curve (with high and low boundaries) was established. The Figure A-1 below graphically represents the low/mid/high curves. Table A-1 presents the same data in tabular form.

Figure A-1: Midgard Henry Hub Natural Gas Price Forecast (2010 USD/MMBtu)



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[66] Specifically, the differences between forecast and actual were translated into a percentage of actual

[67] Given that natural gas pricing cannot fall below zero, its pricing curve is expected to resemble that of a log-normal distribution curve. Therefore, the calculated confidence interval was based upon a log-normal distribution.

[68] The 7th year-ahead grouping and longer had a sample sizes which Midgard judged to be too small to use for this exercise.

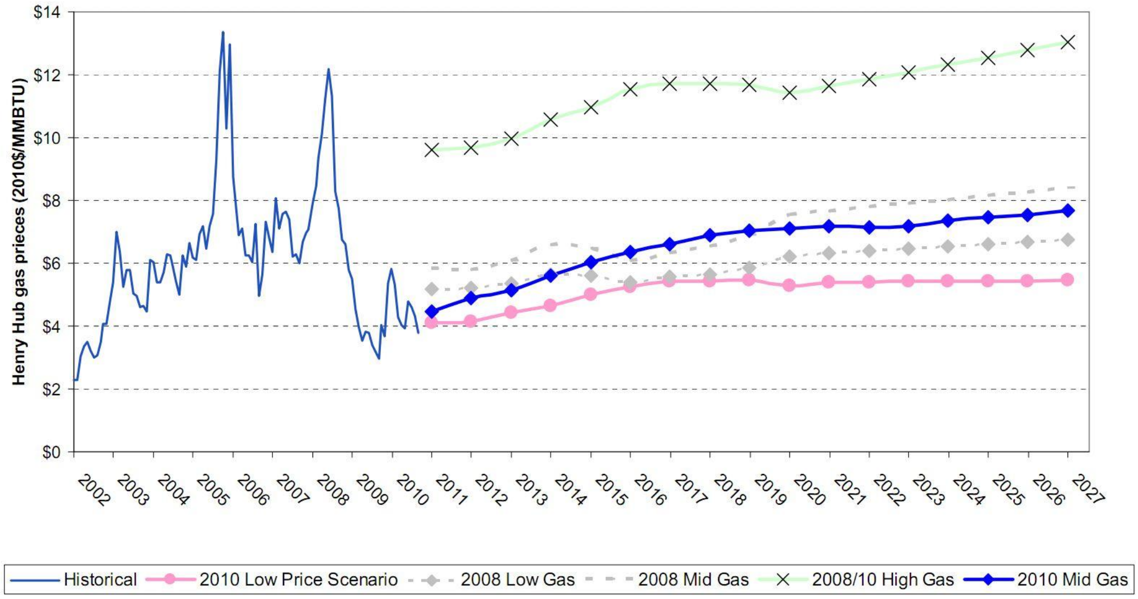
Table A-1: Midgard Henry Hub Natural Gas Price Forecast: Expected and High and Low Boundaries [95% Confidence Interval] (2010 USD/MMBtu)

Year	Expected	Low End	High End
2011	$4.61	$4.23	$5.03
2012	$4.70	$3.02	$7.33
2013	$4.84	$2.83	$8.29
2014	$4.91	$2.96	$8.14
2015	$4.95	$2.69	$9.09
2016	$4.98	$2.75	$9.02
2017	$5.03	$2.77	$9.10
2018	$5.11	$2.82	$9.25
2019	$5.19	$2.86	$9.39
2020	$5.33	$2.94	$9.66
2021	$5.49	$3.03	$9.94
2022	$5.65	$3.12	$10.23
2023	$5.83	$3.22	$10.57
2024	$6.02	$3.32	$10.90
2025	$6.19	$3.42	$11.21
2026	$6.33	$3.50	$11.47
2027	$6.47	$3.57	$11.71

BC Hydro Natural Gas Forecast Curves

In preparation for its 2011 Integrated Resource Plan, BC Hydro produced and released a set of forecast price projections for natural gas. Their predictions are based on a California Energy Commission price forecast and accounts for the introduction of abundant supplies of shale gas into the natural gas market (predicted to lower the long-term price of natural gas). Figure A-2 represents BC Hydro's forecast natural gas curves for 2010 as well as those used in the 2008 LTAP.

Figure A-2: BC Hydro Henry Hub Natural Gas Price Forecast: 2011 IRP (2010 USD/MMBtu)



It is noteworthy that the 2010 BC Hydro forecast natural gas curves are lower than the natural gas price forecasts used in the 2008 LTAP (except for the high case, which is the same).

Figure A-3 graphs BC Hydro's expected natural gas forecast against the Midgard expected natural gas forecast. Prices are in US dollars per MMBtu. Table A-2 compares the differences in the two data sets (and also includes the differences from the respective high and low forecasts).

Figure A-3: BC Hydro vs. Midgard Henry Hub Natural Gas Price Forecast (2010 USD/MMBtu)

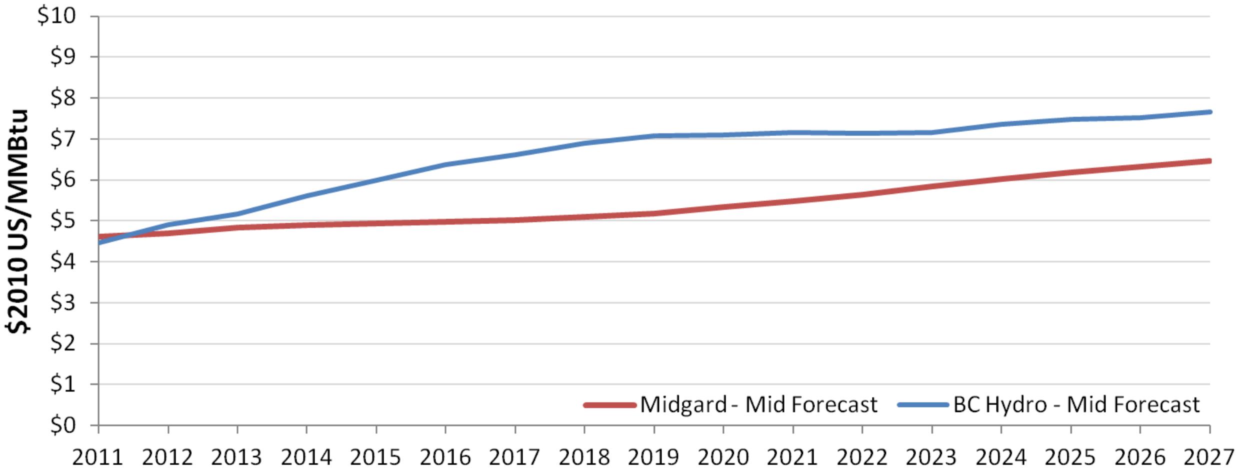


Table A-2: Hydro vs. Midgard Henry Hub Natural Gas Price Forecast (2010 USD/MMBtu)

BCH Curve - Midgard Curve ($)			
Date	**Expected**	**Low**	**High**
2011	($0.25)	($0.22)	n/a[69]
2012	$0.09	$1.08	$2.17
2013	$0.21	$1.57	$1.49
2014	$0.60	$1.63	$2.26
2015	$0.94	$2.25	$1.68
2016	$1.28	$2.46	$2.33
2017	$1.47	$2.60	$2.39
2018	$1.68	$2.58	$2.27
2019	$1.77	$2.54	$2.06
2020	$1.65	$2.29	$1.56
2021	$1.55	$2.30	$1.47
2022	$1.36	$2.23	$1.41
2023	$1.19	$2.13	$1.29
2024	$1.20	$2.02	$1.18
2025	$1.15	$1.92	$1.09
2026	$1.03	$1.87	$1.05
2027	$1.04	$1.80	$1.04

BCH Curve - Midgard Curve (%)			
Date	**Expected**	**Low**	**High**
2011	-5%	-5%	n/a[71]
2012	2%	35%	29%
2013	4%	54%	18%
2014	12%	54%	27%
2015	19%	82%	18%
2016	25%	87%	25%
2017	29%	91%	26%
2018	32%	90%	24%
2019	33%	87%	21%
2020	30%	76%	16%
2021	28%	74%	14%
2022	23%	70%	13%
2023	20%	64%	12%
2024	20%	59%	11%
2025	18%	55%	9%
2026	16%	52%	9%
2027	16%	49%	9%

Midgard’s natural gas price forecasts are consistently below those used by BC Hydro, although for the most important of these pairings, the mid scenario, the forecasts are similar.

Interestingly, the BC Hydro mid scenario natural gas forecast begins at a similar spot but is thereafter consistently higher than the Midgard mid-scenario natural gas forecast. This is not unlike how the NYMEX Henry Hub natural gas futures curve compares with the Midgard mid scenario natural gas forecast curve.

Despite differences, it is Midgard’s opinion that the similarities between the two sets of natural gas curves – and particularly the mid scenario curves – are sufficient to conclude that the BC Hydro natural gas curves are both reasonable and viable. And as such they represent a pragmatic basis from which the Mid-Columbia electricity curves could justifiably be derived.

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[69] The Midgard methodology of generating high scenario natural gas curve renders the comparison of the 2011 high case findings with the BC Hydro method of generating the high scenario natural gas curve for 2011 moot.

Appendix B: Greenhouse Gas Cost Forecast Curve

Background

With various levels of government policy increasingly favoring and encouraging renewable and clean energy sources, there has been growing consideration of taxing carbon emissions. Such taxes are meant to discourage carbon emissions and, in some cases, provide funding for investment in cleaner energy generation sources.

In BC the *Carbon Tax Act* taxes greenhouse gas emissions and sets price increases through 2012 (increasing $5/Tonne CO2 per year to $30/Tonne CO2 in 2012[70]) with the price set to remain at 2012 levels until further notice.

BC is currently one of few regions in North America to have a carbon tax system, with neither Canada nor the US having national policies[71]. The futures of such national policies will have a direct impact on greenhouse gas ("**GHG**") prices. It should be highlighted that there is a limited history to the pricing of GHGs and that pricing is largely a function of government regulation rather than being driven by a genuine market demand.

BC Hydro Forecast GHG Curves

Consultants Black and Veatch (B&V) were retained by BC Hydro to forecast GHG prices[72]. Their analysis focused on policy and economic recovery as the main influencing factors of GHG prices.

BC currently has aggressive GHG reduction policies (specified in the *Clean Energy Act*). The B&V report suggests that in the future, US policy will have a strong impact on worldwide GHG prices (given the size and importance of their economy in the global context). However, it also suggests that a US national GHG policy is unlikely in the near future. Given Canada’s propensity to align its national policies with those of the US, a national GHG pricing policy in Canada is equally unlikely in the near future.

The report also links GHG prices to economic recovery, suggesting that the increased GHG emissions resulting from strong economic growth, combined with increased public and government interest in GHG reduction resulting from said growth, would result in aggressive environmental policies. Conversely, slow economic growth is predicted to mean slower growth of GHG emissions which, combined with government focus on issues other than environmental protection, would reduce interest in such environmental policies.

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[70] BC Budget and Fiscal Plan 2011/12-2013/14

[71] US National Renewable Energy Laboratory, "Carbon Taxes: A Review of Experience and Policy Design Considerations", 2009

[72] BC Hydro, 2011 IRP Technical Advisory Committee Summary Brief: GHG Price Forecast, January 2011

Using a variety of scenarios that combine possible outcomes of the above factors, B&V developed the following forecast (see Figure B-1and Table B-1), with the various lines representing the different scenarios presented.

Figure B-1: BC Hydro Forecast GHG Price Curves (2010 CAD)

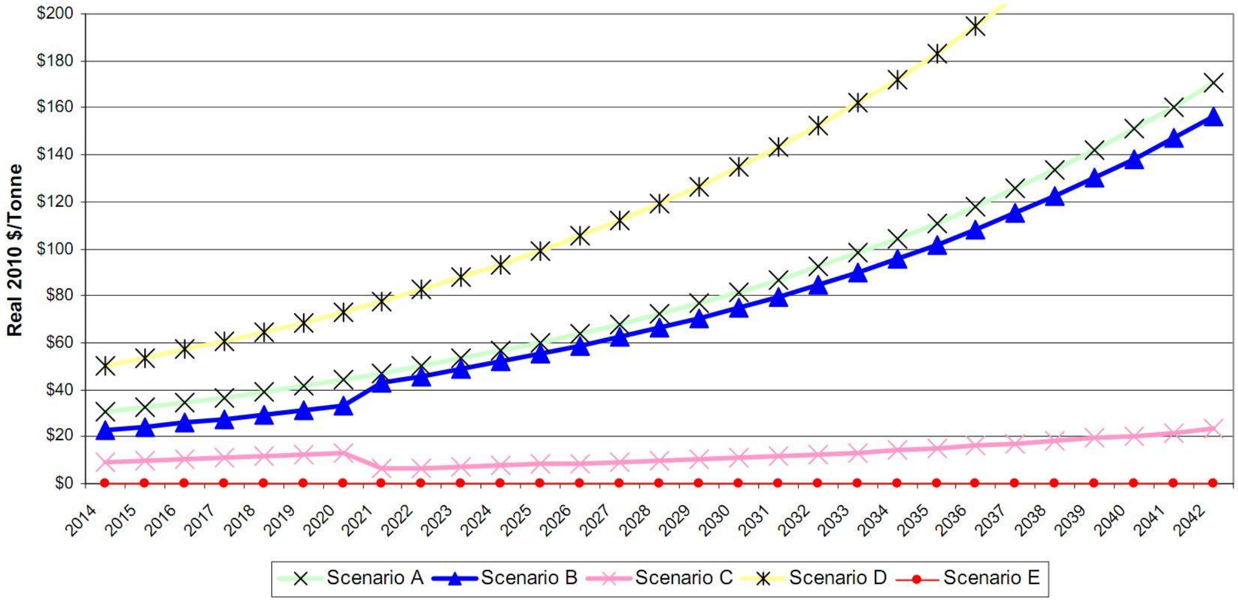

Table B-1: BC Hydro Forecast GHG Price Curves (2010 CAD)

Year	A	B	C	D	E
2014	$50.07	$22.19	$8.82	$30.44	$0.00
2015	$53.20	$23.90	$9.39	$32.43	$0.00
2016	$57.18	$25.89	$10.24	$34.14	$0.00
2017	$60.31	$27.31	$10.81	$36.42	$0.00
2018	$64.30	$29.02	$11.38	$38.98	$0.00
2019	$68.28	$31.29	$11.95	$41.54	$0.00
2020	$72.83	$33.29	$12.80	$44.10	$0.00
2021	$77.38	$42.67	$6.26	$46.66	$0.00
2022	$82.50	$45.23	$6.26	$49.79	$0.00
2023	$87.62	$48.65	$6.83	$53.20	$0.00
2024	$93.03	$51.78	$7.40	$56.33	$0.00
2025	$99.00	$55.19	$8.25	$59.46	$0.00
2026	$105.55	$58.32	$8.25	$63.73	$0.00
2027	$111.81	$62.30	$8.82	$67.43	$0.00

Year	A	B	C	D	E
2028	$118.92	$66.29	$9.39	$72.26	$0.00
2029	$126.32	$69.99	$9.96	$76.53	$0.00
2030	$134.85	$74.82	$10.81	$81.37	$0.00
2031	$143.10	$79.37	$11.38	$86.49	$0.00
2032	$152.20	$84.50	$11.95	$92.46	$0.00
2033	$162.16	$89.62	$12.80	$98.15	$0.00
2034	$171.83	$95.59	$13.94	$104.13	$0.00
2035	$182.93	$101.28	$14.51	$110.67	$0.00
2036	$194.59	$107.82	$15.93	$117.78	$0.00
2037	$207.15	$115.22	$16.79	$125.46	$0.00
2038	$220.30	$122.62	$17.92	$133.43	$0.00
2039	$234.30	$130.30	$19.35	$141.68	$0.00
2040	$249.18	$137.98	$19.91	$151.07	$0.00
2041	$265.01	$147.08	$21.05	$160.17	$0.00
2042	$281.84	$156.19	$23.04	$170.70	$0.00

BC Hydro defines the five scenarios as follows[73]:

- *Scenario A: High global economic growth leads to high commodity demand and broad environmental regulation*
- *Scenario B: Slow but steady global economic growth sees regional leaders paving the way for national GHG markets*
- *Scenario C: Low economic growth delays national GHG market development*
- *Scenario D: Delayed high economic growth and lower international cooperation stifles national action, leaving the regions to regulate GHG emissions*
- *Scenario E: Low economic growth and activity lead to lower GHG emissions and the absence of market prices*

Validation of GHG Curves

While the B&V report was prepared for BC Hydro, it addresses GHG costs in a very general, regional context. Forecasting GHG prices is inherently uncertain, perhaps even more so than most commodities given the greater influence of politics in their price setting. Despite the very wide range of the B&V

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[73] BC Hydro, 2011 IRP Technical Advisory Committee Summary Brief: GHG Price Forecast, January 2011

predictions (an unavoidable product of said uncertainty), Midgard finds no fault with their logic and consequently no reason to disagree with their conclusions.

Midgard recommends the use of the Scenario B GHG price curve as the most likely GHG price forecast.

Appendix C

FORTISBC 2010 RESOURCE OPTIONS REPORT

MIDGARD
CONSULTING INC.

FortisBC
2010 Resource Options Report

Submitted By:
Midgard Consulting Inc.

Date:
17 August 2010

Fortis BC – 2010 Resource Options Report

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1 Introduction

This report provides an evaluation of the cost metrics and feasibility of various capacity and energy resource options that are expected to be available to FortisBC over a 30 year planning period. These resource options include potential projects that could be developed within the FortisBC service area, as well as projects that would be situated outside the service area and would therefore require external transmission arrangements to serve FortisBC load. Also included in this evaluation are large projects under consideration by others that may materially impact the market for capacity and energy within British Columbia ("**BC**"), such as BC Hydro's Peace River Site C project and prospective unit additions at Mica and Revelstoke.

In its 2009 Resource Plan, FortisBC anticipated a peak capacity shortfall of 145 MW in 2009 and predicted that this capacity gap would increase to nearly 240 MW by 2028 based on forecast load growth. The same plan identified a 2009 energy shortfall of 18 GWh growing to over 130 GWh by 2028.

Since filing the 2009 Resource Plan, FortisBC has purchased a seasonal block of firm capacity through February 2015 that alleviates short-term winter capacity shortfalls. After accounting for system operating reserves, this capacity block provides for dispatch of 50 MW of capacity in November, 125 MW in December, 150 MW in January, and 75 MW in February. FortisBC will still experience lesser capacity shortfalls during their summer demand sub-peak.

The 2009 Resource Plan used a 20 year planning period. FortisBC has now extended its planning horizon to 30 years. An update to the forecast load / resource balance has been completed using this 30 year planning period and taking the recently acquired seasonal capacity block into account. This 30 year forecast update now predicts a capacity shortfall growing from 42 MW in 2010 (which occurs during the July summer demand sub-peak) to 263 MW in 2039 (during the January winter demand peak). The updated forecast also predicts an annual energy shortfall growing from 64 GWh in 2010 to 304 GWh in 2039.

In conformity with the BC Energy Plan,[1] FortisBC stated its intention to achieve 50% of its incremental resource needs by 2020 through implementing Demand Side Management ("**DSM**") measures. To address the remaining post-DSM resource gap the FortisBC 2009 Resource Plan evaluated three different resource option portfolios: "P1 – BC Markets", "P2 – Gas" and "P3 – Hybrid", ultimately determining that portfolio option "P3 – Hybrid" provided the optimum solution in terms of environmental protection, operating flexibility and long term generation capacity sustainability.

On June 3, 2010, the BC Clean Energy Act ("**CEA**") was passed into law. The Act contains a revised set of 16 specific energy objectives for the Province of BC. Overall, the CEA provides a guide to assist the Province to meet its self-sufficiency goals, to support job creation and retention, and to reduce greenhouse gas ("**GHG**") emissions. In the context of resource planning, the CEA sets a more aggressive DSM target of 66% avoidance (up from the previous 50% objective) for BC Hydro's future electricity demand growth.

In light of these recent developments, FortisBC engaged Midgard Consulting Inc. to update and validate the resource option cost and feasibility information used for resource planning.

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[1] "The BC Energy Plan: A vision for clean energy leadership", Government of BC, February 27, 2007

The Resource Options information in this report draws extensively upon BC Hydro's 2008 Long Term Acquisition Plan ("**LTAP**") and 2006 Integrated Electricity Plan ("**IEP**") as primary sources. The resource evaluation methodology and technical data presented in these comprehensive and well-researched BC Hydro documents has been validated by the British Columbia Utilities Commission ("**BCUC**"), and can therefore be treated as reliable reference material. Where appropriate and excepting specific projects for which new cost information has been made available by project proponents, costs drawn from these BC Hydro sources have been escalated to current Canadian dollars using the consumer price index ("**CPI**").

In addition to information originally sourced from the LTAP and IEP documents, this report has been supplemented with current cost information for projects which are now under development or undergoing feasibility assessment by FortisBC, BC Hydro and others. Since the LTAP and IEP were first prepared, BC Hydro has also undertaken the Clean Power Call, Phase I of the Bioenergy Call for Power, and the ongoing Standing Offer Program. BC Hydro has also advanced its Peace River Site C project through an initial Project Definition Consultation Phase. Publicly available material related to these important initiatives has been incorporated in this report. Midgard knowledge of the current BC market for construction labour, equipment and materials has also been utilized as noted in the Resource Option sheets.

Resource options such as nuclear and non-sequestered coal that are not permitted in BC under the BC Energy Plan are not evaluated in this report.

2 Evaluation Methodology

2.1 Resource Categories

Depending on the type of energy conversion technology and fuel source, prospective resources can be grouped into three distinct dispatch categories: base load resources, peaking resources, and intermittent resources.

1. **Base Load Resources** – provide dependable capacity and are expected to operate at a high capacity utilization rate, generating significant amounts of electrical energy over the entire year. Such resources can be reasonably evaluated for both energy and capacity attributes. Examples include:

    - Hydroelectric installations with large storage reservoirs and mandatory water releases
    - Nuclear and coal fired thermal generation
    - Combined Cycle Gas Turbines ("**CCGT**")
    - Biomass wood waste thermal generation
    - Geothermal generation

2. **Peaking Resources** – provide dependable capacity but are expected to operate at a low capacity utilization rate, generating electricity when it is needed and/or highly valued. Peaking plant resources typically have a low cost to construct per unit of capacity, but high per unit of energy costs. These plants can also act as planning margin assets – assets that can be brought into service quickly following a contingency event (e.g. loss of a base load facility), or if short term system load growth materially

outstrips forecast growth. Although these resources produce energy when generating, they are primarily evaluated for their capacity attributes. Examples include:

- Simple Cycle Gas Turbines ("**SCGT**")
- Hydro generation with moderate or limited storage
- Pumped Storage Hydro ("**PSH**")

3. **Intermittent Resources** – do not provide dependable capacity and typically operate at medium to low capacity utilization rates. Intermittent resources – which are often renewable resources – generate electricity when their fuel source is present. Their generation may not coincide with high system load demand or high market prices. Intermittent resources' generation is more consistent and predictable when averaged over a long period of time, or when bundled into a portfolio of geographically diverse intermittent resources. Although most intermittent resources provide at least a small quantity of dependable capacity, these facilities are not dispatchable and therefore are primarily valued for their (non-greenhouse gas emitting) energy attributes. Examples include:

   - Wind turbines
   - Small run-of-river hydro generation
   - Solar (both photoelectric and thermal)

A balanced resource portfolio will normally consist of a combination of these resource types to provide an environmentally sound, reliable and economical electrical supply to address daily and seasonal variations in system load.

2.2 Unit Cost Metrics

To enable consistent evaluation of resources that represent a wide range of technologies and fuel sources, the economic characteristics of the different resource options are condensed into three simplified cost metrics: Unit Construction Cost, Unit Capacity Cost and Unit Energy Cost.

Unit Construction Cost – a metric to rank the capital intensity of different resource options, expressed as $/MW. It is calculated by dividing the capital cost of a project by its Dependable Capacity (defined below). The capital cost includes the direct development costs and the interest that is incurred on funds spent during construction (interest during construction, or "**IDC**"). It does not consider operating costs or plant capacity utilization rates.

The Unit Construction Cost can be used to evaluate the capital intensity of any resource, regardless of the technology employed.

Unit Capacity Cost ("**UCC**") – the annual cost of providing Dependable Capacity using each resource option, expressed as $/MW-month. Annual costs include the interest on debt, return on equity ("**ROE**") and amortization, which are derived from the project capital cost. Annual costs also include the fixed operating costs that must be spent to keep the project's dependable capacity available regardless of the amount of energy generated each year.

UCC is used to rank resources being considered to address capacity requirements. If a capacity shortfall has been identified, the UCC metric can be used to assemble a portfolio of lowest cost capacity resources to address that need. Representative capacity resources include Simple Cycle Gas Turbines and Pumped Storage Hydro plants.

Unit Energy Cost (“**UEC**”) – the annualized cost of generating a unit of electrical energy using a specific resource option, expressed as $/MWh. The UEC calculation divides the all-in capital, fixed operating and variable operating costs by the total amount of energy expected to be generated over the resource’s anticipated service life.

UEC is used to rank resources under consideration to address energy requirements. If an energy shortfall has been identified, the UEC metric can be used to develop a lowest cost energy resource portfolio to address that need. Representative energy resources include base load facilities such as large thermal plants and must-run hydro (such as facilities on the Columbia River that must release minimum flows as per the downstream flow provisions of the Columbia River Treaty), along with intermittent or non-dispatchable resources such as wind, solar and run-of-river hydro.

UEC and UCC are not interchangeable metrics for use when comparing unlike resources. It is important to note that the UEC and UCC values in this report are derived using generic operating assumptions. When resources are actually operated to meet specific system demands their unit costs may vary from the standardized results.

2.3 Generation Operational Parameters

Since the available capacity and actual energy production of different resources can vary materially from unconstrained nameplate values the following definitions are used:

Dependable Capacity – defined as generation available for three peak hours per day during the coldest two-week period each year. In BC, system peak electrical demand typically occurs in December or January sometime between the hours of 5 pm and 9 pm.

Annual Energy – defined as the total energy that can be generated annually on average for the entire expected service life of each resource.

Firm Energy – defined as the total energy that can be generated reliably every year using conservative plant availability and fuel supply assumptions[2].

2.4 Key Evaluation Assumptions

The following legislative, financial and fuel cost assumptions were used in the resource option evaluations.

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[2] BC Hydro considers firm energy for its hydro facilities to be the total energy that could be generated during the lowest flow water year (October to September) on record.

The BC Energy Plan and the Clean Energy Act

The Assessment has been conducted to be consistent with the 2007 BC Energy Plan and the Clean Energy Act. These requirements apply predominantly to the Provincial Crown owned utility and its resource planning, however FortisBC also considers those requirements when it makes its own planning decisions.

Important elements that were considered in this report are:

- *BC must be self-sufficient in electricity by 2016* – There must be adequate BC-based generation to supply the BC requirement for electrical energy. Consequently, the evaluations in this report are restricted to BC-based resources.
- *93% of electricity must come from clean or renewable sources* – This directive limits to a maximum of 7% of its generation resources, FortisBC's ability to add thermal natural gas plants and other fossil fuel plants to meet its load growth.
- *Coal-fired generation facility will only be permitted in BC if the plant's CO_2 emissions are fully sequestered* – A detailed evaluation of a CO_2 emissions sequestered coal plant as a resource option was not conducted because the technology to sequester CO_2 emissions is not yet commercially available on a utility scale.

Financial Assumptions

The financial assumptions used to calculate the cost metrics have been standardized to ensure that all resource options are evaluated consistently, regardless of the return expectations and cost of capital that might be applicable to a given project. The assumptions used throughout this report are:

a. Pre-tax cashflows are in real (un-inflated) dollars and discounted using real pre-tax discount rates of 6% and 8% (2006 Integrated Electricity Plan Appendix F – Chapter 4.2.1).
b. The same discount rate is applied to all resource options regardless of the developer of the resource (2006 Integrated Electricity Plan Appendix F – Chapter 4.2.2).
c. Economic life (or "project life" or "service life") rather than contract life is used when calculating the future costs and benefits of all projects (2006 Integrated Electricity Plan Appendix F – Chapter 4.2.3).
d. Federal government subsidies are excluded from cost calculations (2006 Integrated Electricity Plan Appendix F – Chapter 4.2.4).
e. All costs are escalated to 2010 Canadian dollars ("**CAD**") using year-on-year January CPI values (2008 = 111.8; 2009 = 113.0; and 2010 = 115.1).
f. Construction costs escalate at CPI.
g. Cost estimates taken from BC Hydro's previous resource options reports escalated to 2010 dollars at CPI.
h. All financial results are expressed in pre-tax dollars.

Fuel Cost Assumptions

Forward Gas Curves – Forward natural gas prices used in this report were referenced against the Henry Hub Spot Price curve provided in the *2010 Annual Energy Outlook – Early Release* ("**AEO 2010**") produced by the Energy Information Administration ("**EIA**") of the US Department of Energy.

The 2010 EAO Henry Hub curve extends to 2035. To enable full life-cycle costing of gas fuelled resources, gas prices were assumed to hold constant at the 2035 price for 2036 through 2041. The resulting forward curve is shown in the table below, and represents Henry Hub prices expressed in US dollars ("**USD**") $2008/MMBtu.[3]

In Midgard's opinion the EIA's Henry Hub forward price curve represents a credible benchmark for future gas prices (see Appendix A for more detail).

Table 2.1: Natural Gas Forward Price Curve

(USD/MMBtu) $2008 Spot Price at Henry Hub

Year	Price	Year	Price
2010	4.50	2026	7.15
2011	5.68	2027	7.29
2012	6.17	2028	7.53
2013	6.13	2029	7.77
2014	6.09	2030	8.05
2015	6.27	2031	8.39
2016	6.38	2032	8.50
2017	6.38	2033	8.53
2018	6.43	2034	8.75
2019	6.51	2035	8.88
2020	6.64	2036	8.88
2021	6.74	2037	8.88
2022	6.93	2038	8.88
2023	6.96	2039	8.88
2024	6.91	2040	8.88
2025	6.99	2041	8.88

For the purpose of calculating the UCC for gas fuelled generation resources this curve was converted to CAD/GJ using a forward exchange rate (see below) and a unit conversion of 1 MMBtu = 1.055 GJ. The prices were then escalated to 2010 dollars using CPI (financial assumption e.) and the resulting forward price curve was used as a reference proxy for the cost of natural gas delivered to a plant gate in South Central BC.[4]

Forward USD/CAD Fx Curve – The following forward looking exchange rates between USD and CAD were used to convert the USD gas prices in the forward gas curve into CAD:

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[3] This price curve is similar to the base case natural gas price curve that BC Hydro used in the 2008 LTAP.

[4] Midgard assumed that the cost of natural gas delivered to a large user in South Central BC would be slightly higher than the cost of natural gas delivered to the Sumas natural gas hub. The Sumas natural gas hub is located near the BC – Washington border. The forward price curve for Sumas delivered gas trades at an approximately U$0.10/MMBtu discount to Henry Hub prices.

2010 to 2014 = 0.95 USD/CAD
2015 to 2041 = 0.90 USD/CAD

Cost of Carbon Emissions – The prevailing BC tax on carbon emissions was used as a proxy for carbon offset costs. The tax is set at:

2010 = $20
2011 = $25
2012 and beyond = $30
CAD per metric tonne of CO2 emissions.

2.5 Discounted Cashflow and Annualized Cost Method Calculations

In the 2006 IEP and 2008 LTAP, BC Hydro identified two methods to calculate UCC and UEC: the Discounted Cashflow Method (“**DCF**”) and the Annualized Cost Method (“**ACM**”)[5].

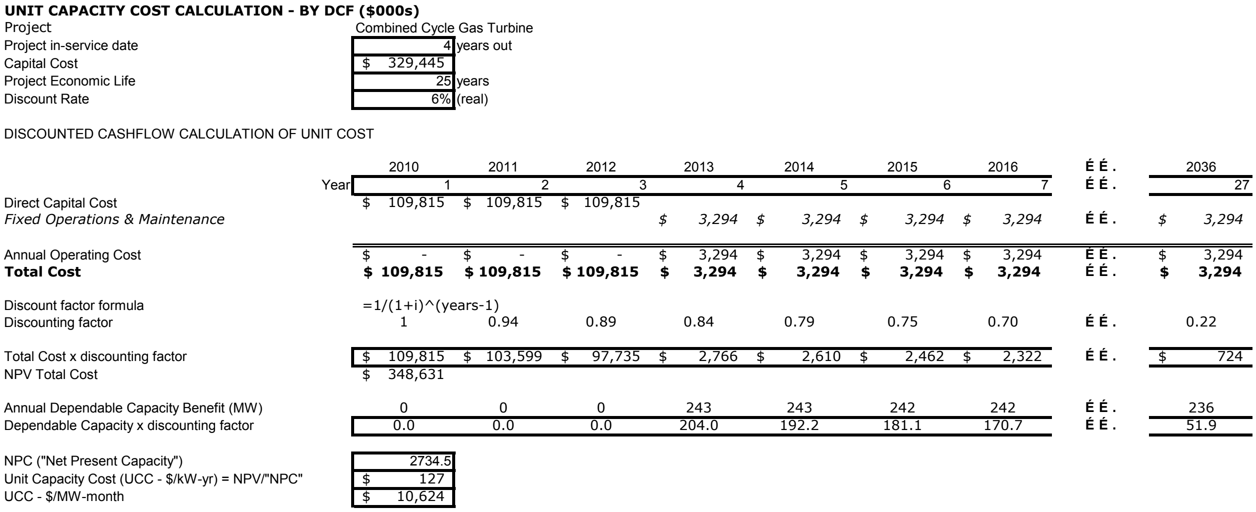
Discounted Cashflow Method (DCF)

The DCF method sums the discounted future costs to determine the Net Present Value (“**NPV**” of these cashflows. Only the direct capital cost is included, as the inferred interest during construction (“**IDC**”) is captured through discounting. Each future year’s capacity benefits or energy benefits are also discounted at the discount factor to create a notional Net Present Capacity (“**NPC**”) or Net Present Energy (“**NPE**”).

The UCC or UEC is simply the NPV divided by the NPC or NPE as the case may be. This method allows for changing future costs or unequal benefits over time.

An example calculation of UCC is presented below:

Figure 2.1 - Example of DCF UCC Calculation



UNIT CAPACITY COST CALCULATION - BY DCF ($000s)

Project	Combined Cycle Gas Turbine	
Project in-service date	4	years out
Capital Cost	$ 329,445	
Project Economic Life	25	years
Discount Rate	6%	(real)

DISCOUNTED CASHFLOW CALCULATION OF UNIT COST

	2010	2011	2012	2013	2014	2015	2016	É É .	2036
Year	1	2	3	4	5	6	7	É É .	27
Direct Capital Cost	$ 109,815	$ 109,815	$ 109,815						
Fixed Operations & Maintenance				*$ 3,294*	*$ 3,294*	*$ 3,294*	*$ 3,294*	É É .	*$ 3,294*
Annual Operating Cost	$ -	$ -	$ -	$ 3,294	$ 3,294	$ 3,294	$ 3,294	É É .	$ 3,294
Total Cost	**$ 109,815**	**$ 109,815**	**$ 109,815**	**$ 3,294**	**$ 3,294**	**$ 3,294**	**$ 3,294**	É É .	**$ 3,294**
Discount factor formula	=1/(1+i)^(years-1)								
Discounting factor	1	0.94	0.89	0.84	0.79	0.75	0.70	É É .	0.22
Total Cost x discounting factor	$ 109,815	$ 103,599	$ 97,735	$ 2,766	$ 2,610	$ 2,462	$ 2,322	É É .	$ 724
NPV Total Cost	$ 348,631								
Annual Dependable Capacity Benefit (MW)	0	0	0	243	243	242	242	É É .	236
Dependable Capacity x discounting factor	0.0	0.0	0.0	204.0	192.2	181.1	170.7	É É .	51.9

NPC ("Net Present Capacity")	2734.5
Unit Capacity Cost (UCC - $/kW-yr) = NPV/"NPC"	$ 127
UCC - $/MW-month	$ 10,624

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[5] The methodology of these two calculations is further described in BC Hydro’s 2006 Integrated Electricity Plan Appendix F – Chapter 4 – Financial Assumptions.

Annualized Capital Cost ("ACC")

The ACC method is applicable when all future annual costs and energy/capacity benefits are constant from year to year. Interest incurred during construction is capitalized and the full capital cost is then amortized over the economic life of the project at the discount rate. A levelized annual capital cost for the project is added to the annual operating costs. The result is divided by the average annual energy or dependable capacity as the case may be. An example calculation of UCC is presented below.

Figure 2.2 - Example of ACC UCC Calculation

PROJECT	Run-Of-River Hydro - Coastal
RESOURCE	Hydro - Greenfield
REFERENCE	Midgard Files, BC MOE Water License Apps, Water Survey Canada
CALCULATION METHOD	Annualized Cost

TECHNICAL PARAMETERS	
Installed Capacity (MW)	62
Average Annual Energy (GWh/yr) - Note 1	255
Dependable Capacity (MW) - Note 2	28
Annual Firm Energy (GWh/yr) - Note 1	229
Heat Rate (GJ/GWh)	

FINANCIAL PARAMETERS (FISCAL 2010 $)	
Direct Capital Cost (k$) - Note 3	248,000
Project Life (years) - Note 4	40
Project Lead Time (years)	3

OPERATING COSTS:	
Fixed OMA (k$/yr) - Note 5	3,720
Variable OMA ($/MWh)	0
Grants-in-lieu of Taxes ($/kW-yr)	0
Fixed Taxes (k$/yr) - Note 6	722
Variable Taxes ($/MWh)	0
Water Rentals - Capacity ($/kW-yr)	4.095
Water Rentals - Energy ($/MWh)	1.229
Fuel Price ($/GJ)	0
Fuel Tax (%)	0%
Firm Fuel Transporation ($/GJ)	0

CONSTRUCTION CASH FLOW :			
Year	Direct	6%	8%
1	82,667	92,884	96,422
2	82,667	87,627	89,280
3	82,667	82,667	82,667
4		0	0
5		0	0
6		0	0
7		0	0
8		0	0
9		0	0
10		0	0
11		0	0
12		0	0
13		0	0
14		0	0
15		0	0
16		0	0
17		0	0
18		0	0
19		0	0
20		0	0
Total	248,000	263,178	268,369
Annualized		17,491	22,505

UCC Based on Dependable Capacity:		
	6%	8%
Investment Cost (Annualized Capital) (k$/yr)	17,491	22,505
Fixed Investment ($/kW-yr)	622	800
Fixed Operations ($/kW-yr)	162	162
Variable Operations ($/kW-yr)	0	0
Fuel Cost ($/kW-yr)	0	0
Unit Capacity Cost ($/MW-month)	65,350	80,212
Unit Capacity Cost ($/kW-yr)	784	963

UEC Based on Average Energy Capability:		
	6%	8%
Investment Cost (Annualized Capital) (k$/yr)	17,491	22,505
Fixed Investment ($/MWh)	69	88
Fixed Operations ($/MWh)	18	18
Variable Operations ($/MWh)	1	1
Fuel Cost ($/MWh)	0	0
Unit Energy Cost ($/MWh)	88	108

3 Resource Options

The summary table below identifies the resource options that were considered in this report. Detailed data sheets are provided on the following pages for resource options considered to be feasible resource portfolio candidates and for which detailed evaluations were conducted. A listing of the resource options that were not deemed to be presently technically or commercially feasible candidates and the reasons for their exclusion is provided at the end of this section.

Table 3.1: Resource Options List

Fuel Source	Resource	Project Details	Resource Type	Status
Natural Gas	CCGT	Generic	Base Load	Evaluated
Natural Gas	SCGT	Generic	Peaking Plant	Evaluated
Natural Gas	Co-generation	Generic	Base Load	Not Evaluated
Hydroelectric	Large Hydro – Capacity Only	Mica 5	Peaking Plant	Evaluated
Hydroelectric	Large Hydro – Capacity Only	Mica 6	Peaking Plant	Evaluated
Hydroelectric	Large Hydro – Capacity Only	Revelstoke 6	Peaking Plant	Evaluated
Hydroelectric	Large Hydro – Capacity with Energy	Site C	Base Load	Evaluated
Hydroelectric	Hydro – Capacity Only	Resource Smart Bundle (w/o Mica & Revelstoke)	Peaking Plant	Evaluated
Hydroelectric	Large Hydro – Capacity with Energy	Waneta – BC Hydro Acquisition of 1/3 interest from Teck	Base Load	Evaluated
Hydroelectric	Small Hydro – With Storage	Similkameen	Base Load	Evaluated
Hydroelectric	Run-of-River	Cluster of ROR within FortisBC Service Area	Intermittent	Evaluated
Hydroelectric	Run-of-River	Generic BC Coastal Cluster	Intermittent	Evaluated
Hydroelectric	Pumped Storage	Generic Project in FBC Service Area	Peaking Plant	Evaluated
Biomass	Cogeneration	Roadside Wood Waste and Sawmill Woodwaste	Base Load	Evaluated
Biomass	Municipal Solid Waste	MSW	Base Load	Not Evaluated
Biomass	Biogas	Biogas	Base Load	Not Evaluated
Wind	Onshore	Generic	Intermittent	Evaluated
Wind	Coastal	Generic	Intermittent	Not Evaluated
Coal	Coal	Generic with Carbon Sequestration	Base Load	Not Evaluated
Tidal	Tidal	Generic	Intermittent	Not Evaluated
Wave	Wave	Generic	Intermittent	Not Evaluated

Geothermal	Geothermal	Generic	Base Load	Not Evaluated
Solar	PV Array	Generic	Intermittent	Not Evaluated
Solar	Solar Collection	Generic	Intermittent	Not Evaluated
Nuclear	Nuclear	Generic	Base Load	Not Evaluated

3.1 Natural Gas – CCGT

PROJECT: Generic Combined Cycle Gas Turbine – 250 MW

Resource Category: Base Load
Level of Study: Conceptual Level

PROJECT DESCRIPTION:

This project involves a generic greenfield combined cycle power station located in the southern interior of BC, based upon a similar resource described in BC Hydro's 2008 LTAP. The project consists of an F Class 1x1x1 Combined Cycle Gas Turbine ("**CCGT**") configuration with nominal output of 250 MW. Combined cycle generation involves recovery of exhaust heat from a natural gas-fired turbine generator to produce steam which then drives a steam turbine generator.

TECHNICAL INFORMATION

Installed Capacity (MW)	243
Average Annual Energy (GWh/year)	1,916
Dependable Capacity (MW)	243 to 236*
Annual Firm Energy (GWh/yr)	1,944 to 1,888*
Average Heat Rate (GJ/GWh)	7,460 to 7,241*

*NOTE: Dependable Capacity, Firm Energy and Heat Rate degrade over time

FINANCIAL INPUTS (CAD 2010)

Capital Cost ($000s)	$329,445
Fixed Operating & Maintenance Cost ($000s/year)	$3,294
Variable Operating & Maintenance Cost ($/MWh)	$4.60

Direct Capital Cost excludes Interest during Construction ("**IDC**") and Corporate Overhead.

Fuel Cost ($/MMBtu)	as per AEO forward curve
Fuel Tax	7%
BC Carbon Tax (from 2012) ($/tonne equivalent)	$30
Firm fuel transport cost ($/GJ)	N/A

Project Life (Years)	25
Project Construction Lead Time (Years)	3

FINANCIAL SUMMARY (CAD 2010)

	6% (real) WACC*	8% (real) WACC*
Unit Construction Cost ($000s/MW)	$1,356	$1,356
Annualized Unit Energy Cost ($/MWh)	$91	$93
Annualized Unit Capacity Cost ($/MW-month)	$10,624	$12,708

*Weighted Average Cost of Capital ("**WACC**")

GHG FOOTPRINT

Meets Eco-Logo Criteria	No
GHG Emission Factor (tonnes CO2 equivalent/GWh)	365
Upstream GHG Emission (tonnes CO2 equivalent/GWh)	unknown

UNCERTAINTY

Development	Medium
Price Uncertainty (UCC)	Low
Price Uncertainty (UEC)	Medium-High

DISCUSSION:

The installed capacity provided is net of auxiliary plant losses. Dependable capacity is 97% of net capacity to account for 3% average degradation over the project life. Availability is assumed to be 91.3% or 8,000 hours per year. Dependable capacity estimates were based on the assumption that a firm fuel contract (transportation and commodity) would be available.

The heat rate estimate is expressed in terms of the higher heating values ("**HHV**") for natural gas, which is the basis for natural gas purchases. Over time there will be degradation in the "clean and new" heat rate on the order of 1% to 3% depending on the location of the unit, the maintenance schedule and time between turbine overhauls. The above estimate assumes the clean and new value adjusted for 3% average degradation over the project life.

The assumed heat rate is within +/-4% of estimated heat rates used in the Energy Information Administration/Assumption to the Annual Energy Outlook 2009, page 89; Conventional Combined Cycle and Advanced Combined Cycle turbines/generators.

Unit Costs were calculated using the DCF method. The change in plant efficiency was modelled using clean and new conditions in year 1 and the stated degradation at end of life, with straight-line interpolation in the intervening years.

The capital cost is an "all-in" estimate that includes an allowance of $9.2 million for all permitting and infrastructure connection costs (e.g. transmission, gas, water supply and effluent). The capital costs also include an allowance for Selective Catalytic Reduction ("**SCR**") equipment, which will reduce the plant's NOx emissions by up to 90%.

Social and environmental approval of large natural gas projects can depend on site location. Sites located away from populations are estimated as having medium development risk. Based on recent regulatory and public acceptance experience, the development risk for other sites could be high.

No site specific studies have been conducted; however, the capital cost for CCGT turbines is well established. Therefore, price uncertainty is judged to be low but would be subject to some variation with exchange rates and market conditions. The price uncertainty rating is based on the capital cost and does not include uncertainty in gas prices. Natural gas prices have displayed significant volatility in recent years. Quoting from a recent California Energy Commission report on this topic: "historic [natural gas price] forecast results have been poor vis-à-vis actual prices, and unfortunately, the future may include more market volatility and even greater forecasting uncertainty." Therefore, the price uncertainty regarding the UEC – in which the natural gas price forecast plays an important part – is deemed to be medium to high.

REFERENCES:

Project Identification	Appendix F1 to the 2008 BC Hydro Long Term Acquisition, Resource Options Database Sheets ("**RODAT**")
Capacity and Energy	Appendix F1 to the 2008 BC Hydro Long Term Acquisition, Resource Options Database Sheets ("**RODAT**")
Construction and O&M Costs	Appendix F1 to the 2008 BC Hydro Long Term Acquisition, Resource Options Database Sheets ("**RODAT**")
Gas Price Forward Curve	EIA – AEO 2010 Early Release future curve for spot prices at Henry Hub
Firm Fuel Transport Cost	Appendix F1 to the 2008 BC Hydro Long Term Acquisition, Resource Options Database Sheets ("**RODAT**")
View on gas price volatility	"Natural Gas Price Volatility", Randy Roesser, CEC-200-2009-009-SD, June 2009, page 42

3.2 Natural Gas – SCGT

PROJECT: Generic Simple Cycle Gas Turbine – 40 MW

Resource Category: Peaking Plant
Level of Study: Conceptual Level

PROJECT DESCRIPTION:

This project involves a generic greenfield 40 MW (nominal) General Electric LM 6000 PD Simple Cycle Gas Turbine ("**SCGT**"), based upon a similar resource described in BC Hydro's 2008 LTAP. It is assumed that this unit would be equipped with a dry low NO_x ("**DLN**") emission control system. SCGT plants are typically employed to meet peak load because of their high heat rates and resulting relatively high UECs, when compared with Combined Cycle Gas Turbines ("**CCGT**") that would normally be used to meet base load energy requirements because of their superior heat rate and lower UECs.

TECHNICAL INFORMATION

Installed Capacity (MW)	42
Average Annual Energy (GWh/year)	16.7
Dependable Capacity (MW)	39 to 38*
Annual Firm Energy (GWh/yr)	68 to 66*
Average Heat Rate (GJ/GWh)	9,843 to 9,745*

*NOTE: Dependable Capacity, Firm Energy and Heat Rate degrade over time

FINANCIAL INPUTS (CAD 2010)

Capital Cost ($000s)	$44,269
Fixed Operating & Maintenance Cost ($000s/year)	$515
Variable Operating & Maintenance Cost ($/MWh)	$4.00

Direct Capital Cost excludes Interest during Construction ("**IDC**") and Corporate Overhead.

Fuel Cost ($/MMBtu)	as per AEO forward curve
Fuel Tax	7%
BC Carbon Tax (from 2012) ($/tonne equivalent)	$30
Firm fuel transport cost ($/GJ)	$0.30

Project Life (Years)	30
Project Construction Lead Time (Years)	2

FINANCIAL SUMMARY (CAD 2010)

	6% (real) WACC*	8% (real) WACC*
Unit Construction Cost ($000s/MW)	$1,147	$1,147
Annualized Unit Energy Cost ($/MWh)	$167	$180
Annualized Unit Capacity Cost ($/MW-month)	$8,481	$10,163

*Weighted Average Cost of Capital ("**WACC**")

GHG FOOTPRINT

Meets Eco-Logo Criteria	No
GHG Emissions relative to CCGT	1.37
GHG Emission Factor (tonnes CO2 equivalent/GWh)	500
Upstream GHG Emission (tonnes CO2 equivalent/GWh)	Unknown

UNCERTAINTY

Development	Medium
Price Uncertainty (UCC)	Low
Price Uncertainty (UEC)	Medium-High

DISCUSSION:

This is a conceptual level generic greenfield project located in the southern interior of BC. The capital cost is an “all-in” estimate including an allowance of $4 million for all permitting and infrastructure connection costs (e.g. transmission, gas, water supply, and effluent). Fixed operation and maintenance costs assume unattended operation and remote supervision with periodic site inspection by operating staff. Variable operation and maintenance costs are for the power plant only and do not include fuel costs.

The installed capacity of 42.3 MW is net of auxiliary plant losses, based on integrated system operator (“**ISO**”) conditions at sea level. Dependable capacity is adjusted for 2% degradation and assuming an ambient annual mean temperature of 15° C at elevation 600 m. As this is a peaking plant, a maximum probable annual dispatch duration of 20% is used to estimate a firm energy value for calculation of a representative UEC. The actual annual dispatch duration is more likely to be near 5% and the average annual energy production will be proportionately less. Firm energy estimates were based on the assumption that a firm fuel contract would be available.

The heat rate estimate is expressed in terms of the higher heating values (“**HHV**”) for natural gas which is the basis for natural gas purchases. Over time there will be degradation of the “clean and new” heat rate of 1% to 3% depending on the unit location, maintenance schedule and time between turbine overhauls. Consistent annual maintenance would limit heat rate degradation to 1% to 2%. The above estimate of the average heat rate assumes the clean and new value adjusted by an average degradation of 1% over the project life.

Unit Costs were calculated using the DCF method. The change in plant efficiency was modelled using clean and new conditions in year 1 and the stated degradation at end of life, with straight-line interpolation in the intervening years.

Social and environmental approval of large natural gas projects can depend on site location. Sites located away from population centres are assumed to have a medium development risk. Based on recent regulatory and public acceptance experience, the development risk for more densely populated sites could be high.

No site specific studies have been conducted. However, this is a proven technology with a large number of similar projects in service in North America. Information from BC Hydro’s Fort

Nelson facility and information received from BC Hydro's 2004 Vancouver Island Call for Tenders ("**VICFT**") are consistent with the information used in this evaluation.

Natural gas prices have displayed significant volatility in recent years. Quoting from a recent California Energy Commission report on this topic: "historic [natural gas price] forecast results have been poor vis-à-vis actual prices, and unfortunately, the future may include more market volatility and even greater forecasting uncertainty." Therefore, the price uncertainty regarding the UEC – in which the natural gas price forecast plays an important part – is deemed to be medium to high.

REFERENCES:

Project Identification	Appendix F1 to the 2008 BC Hydro Long Term Acquisition, Resource Options Database Sheets ("**RODAT**")
Capacity and Energy	Appendix F1 to the 2008 BC Hydro Long Term Acquisition, Resource Options Database Sheets ("**RODAT**")
Construction and O&M Costs	Appendix F1 to the 2008 BC Hydro Long Term Acquisition, Resource Options Database Sheets ("**RODAT**")
Gas Price Forward Curve	EIA – AEO 2010 Early Release future curve for spot prices at Henry Hub
Firm Fuel Transport Cost	Appendix F1 to the 2008 BC Hydro Long Term Acquisition, Resource Options Database Sheets ("**RODAT**")
View on gas price volatility	"Natural Gas Price Volatility", Randy Roesser, CEC-200-2009-009-SD, June 2009, page 42

3.3 Similkameen Hydroelectric Project – Small Hydro with Capacity

PROJECT: Similkameen Hydroelectric Project

Resource Category: Base Load with some Potential Peaking Capability
Level of Study: Conceptual Level

PROJECT DESCRIPTION:

This project involves a 60 MW Hydroelectric Plant with a small reservoir located on the Similkameen River upstream of Princeton, BC.

TECHNICAL INFORMATION

Installed Capacity (MW)	60
Average Annual Energy (GWh/year)	234
Dependable Capacity (MW)	60
Annual Firm Energy (GWh/yr)	174

FINANCIAL INPUTS (CAD 2010)

Capital Cost ($000s)	$283,117
Fixed Operating & Maintenance Cost ($000s/year)	$1,670
Variable Operating & Maintenance Cost ($000s/year)	$0

Direct Capital Cost excludes Interest during Construction ("**IDC**") and Corporate Overhead.

Fixed Taxes ($000s/year)	$824
Variable Taxes ($000s/year)	$0
Water Rental – Installed Capacity ($/kW-year)	$4.095
Water Rental – Annual Energy Production ($/MWh)	$6.896

Project Life (Years)	70
Project Development Lead Time (Years)	5
Project Construction Lead Time (Years)	3

FINANCIAL SUMMARY (CAD 2010)

	6% (real) WACC*	8% (real) WACC*
Unit Construction Cost ($000s/MW)	$5,007	$5,106
Annualized Unit Energy Cost ($/MWh)	$97	$124
Annualized Unit Capacity Cost ($/MW-month)	$29,274	$38,003

*Weighted Average Cost of Capital (“**WACC**”)

GHG FOOTPRINT

Meets Eco-Logo Criteria	Yes
GHG Emission Factor (tonnes CO2 equivalent/GWh)	0
Upstream GHG Emission (tonnes CO2 equivalent/GWh)	0

UNCERTAINTY

Development	Medium-High
Price Uncertainty (UCC)	Medium-High
Price Uncertainty (UEC)	Medium-High

DISCUSSION:

The project concept is based on engineering and environmental studies and stakeholder consultation carried out since the early 1990s that indicate a hydro storage facility could be feasible upstream of Princeton.

REFERENCES:

Conceptual Design, Capacity and Energy	Hatch Engineering Report
Construction and O&M Costs	Hatch Engineering Report
Water Rental Rates	BC MOE Web Site rev Dec 2009
Property Taxes	Assumed general rural mill rate of $4.16 per $1000 of 70% of fixed capital cost.

3.4 Hydro – Run of River – In FortisBC Service Area

PROJECT: Cluster of 9 Run-of-River Projects within FortisBC's Service Area

Resource Category: Intermittent
Level of Study: Inventory Level

PROJECT DESCRIPTION:

A 70 MW cluster of 9 run-of-river projects within FortisBC's service area which are presently under early stage development by Independent Power Producers.

TECHNICAL INFORMATION

Installed Capacity (MW)	70
Average Annual Energy (GWh/year)	250
Dependable Capacity (MW)	10
Annual Firm Energy (GWh/yr)	205

FINANCIAL INPUTS (CAD 2010)

Capital Cost ($000s)	$280,000
Fixed Operating & Maintenance Cost ($000s/year)	$4,200
Variable Operating & Maintenance Cost ($000s/year)	$0

Direct Capital Cost excludes Interest during Construction ("**IDC**") and Corporate Overhead.

Fixed Taxes ($000s/year)	$815
Variable Taxes ($000s/year)	$0
Water Rental – Installed Capacity ($/Kw-year)	$4.095
Water Rental – Annual Energy Production ($/MWh)	$1.229

Project Life (Years)	40
Project Development Lead Time (Years)	5
Project Construction Lead Time (Years)	3

FINANCIAL SUMMARY (CAD 2010)

	6% (real) WACC*	8% (real) WACC*
Unit Construction Cost ($000s/MW)	$29,714	$30,300
Annualized Unit Energy Cost ($/MWh)	$101	$124
Annualized Unit Capacity Cost ($/MW-month)	$206,704	$253,881

*Weighted Average Cost of Capital ("**WACC**")

GHG FOOTPRINT

Meets Eco-Logo Criteria	Yes
GHG Emission Factor (tonnes CO2 equivalent/GWh)	0
Upstream GHG Emission (tonnes CO2 equivalent/GWh)	0

UNCERTAINTY

Development	High
Price Uncertainty (UCC)	Medium
Price Uncertainty (UEC)	Medium

DISCUSSION:

There have been 9 water licence applications for water power projects within FortisBC's service area. These are on Koch Creek, Norns Creek, Goat River, Next Creek, Midge Creek, Woodbury Creek, Bernard Creek, Powder Creek and Enterprise Creek. These water license applications are not held by FortisBC, nor are they expected to be acquired by FortisBC.

For the purpose of this report, it is assumed that the diversion quantity applied for was determined through reasonable analysis on the part of the individual project proponents and represents an optimal flow based on the hydrological characteristics of the individual creeks.

A cursory map search was used to determine the magnitude of available head for the individual projects based on the specified Point of Diversion and relative topography.

Midgard's professional experience suggests that these types of projects typically have an optimal utilization factor of 40%.

These assumptions were used to derive the bundle's installed capacity and annual average energy potential.

A representative creek in the south Kootenays with a long-term hydrometric record (Keen Creek) was selected as a proxy for hydrograph characteristics for the bundle of creeks and its hydrometric record was used to model dependable capacity and annual firm energy for the bundle.

REFERENCES:

Project Identification	BC MOE – Water Licence Applications
Flow, Head, Capacity and Energy	BC MOE, TRIM map search, Water Survey of Canada and Midgard professional judgement
Construction and O&M Costs	Midgard files for 2010 unit construction costs suggest a range of cost between \$3.8 million to \$4.2 million per installed MW.
Water Rental Rates	BC MOE Web Site rev Dec 2009
Property Taxes	Assumed general rural mill rate of \$4.16 per \$1000 of 70% of fixed capital cost.

3.5 Hydro – Small Run of River with Minor Storage – Coastal

PROJECT: Cluster of 5 Run-of-River Projects in the Coastal BC Region

Resource Category: Intermittent
Level of Study: Inventory Level

PROJECT DESCRIPTION:

This project would involve a 62 MW cluster of 5 run-of-river hydro projects in the coastal BC region, with minor lake tap storage.

TECHNICAL INFORMATION

Installed Capacity (MW)	62
Average Annual Energy (GWh/year)	255
Dependable Capacity (MW)	28
Annual Firm Energy (GWh/yr)	229

FINANCIAL INPUTS (CAD 2010)

Capital Cost ($000s)	$248,000
Fixed Operating & Maintenance Cost ($000s/year)	$3,720
Variable Operating & Maintenance Cost ($000s/year)	$0

Direct Capital Cost excludes Interest during Construction ("**IDC**") and Corporate Overhead.

Fixed Taxes ($000s/year)	$722
Variable Taxes ($000s/year)	$0
Water Rental – Installed Capacity ($/kW-year)	$4.095
Water Rental – Annual Energy Production ($/MWh)	$1.229

Project Life (Years)	40
Project Development Lead Time (Years)	5
Project Construction Lead Time (Years)	3

FINANCIAL SUMMARY (CAD 2010)

	6% (real) WACC*	8% (real) WACC*
Unit Construction Cost ($000s/MW)	$9,360	$9,545
Annualized Unit Energy Cost ($/MWh)	$88	$108
Annualized Unit Capacity Cost ($/MW-month)	$63,350	$80,212

*Weighted Average Cost of Capital ("**WACC**")

GHG FOOTPRINT

Meets Eco-Logo Criteria	Yes
GHG Emission Factor (tonnes CO2 equivalent/GWh)	0
Upstream GHG Emission (tonnes CO2 equivalent/GWh)	0

UNCERTAINTY

Development	High
Price Uncertainty (UCC)	Medium-High
Price Uncertainty (UEC)	Medium-High

DISCUSSION:

A 62 MW cluster of small run-of-river projects that recently won a BC Hydro EPA as part of the 2008 Clean Power Call has been selected as a proxy for other similar potential clusters that are anticipated to exist in the coastal region. This project cluster consists of a combination of pure run-of-river projects and projects with some storage due to the presence of an intake tap in an existing lake.

This project will require transmission wheeling to the FortisBC service area. Energy and Dependable Capacity have both been de-rated 6.28% to account for average system losses on BC Hydro's transmission grid as per BCTC Rate schedule 101. It is assumed that wheeling will be accomplished by scheduling on a Non-firm or Short Term Firm basis to minimize wheeling costs. Counter flow transmission from the coastal region into FortisBC's service area is not expected to encounter scheduling constraints under most operating conditions because the notional flow will result in a reduction of normal bulk system transmission flows from the BC Interior towards the Lower Mainland.

The economic life of these projects has been assumed to be the maximum tenure of a water licence in BC. In reality, this represents the maximum amortization practical for most IPP developers and is reflected in the costs expected to seen by FortisBC.

REFERENCES:

Project Identification	Proponent submission to BC EAO
Capacity and Energy	Proponent submission to BC EAO
Construction and O&M Costs	Midgard files for 2010 unit construction costs suggest a range of cost between $3.8 million to $4.2 million per installed MW.
Water Rental Rates	BC MOE Web Site rev Dec 2009
Property Taxes	Assumed general rural mill rate of $4.16 per $1000 of 70% of fixed capital cost.
Transmission and Wheeling Costs	BCTC Rate Schedule 01 rev Jan 14, 2010 and Rate Schedule 110 rev Oct 21 2009.

3.6 Hydro – Site C – BC Hydro

PROJECT: 900 MW Storage Hydro Project on the Peace River

Resource Category: Base Load
Level of Study: Project Definition

PROJECT DESCRIPTION:

The Site C project has been proposed by BC Hydro as the third major hydroelectric dam on the Peace River. The project would be located approximately seven kilometres southwest of Fort St. John, downstream of the Peace River's confluence with the Moberly River. The reservoir would be 83 kilometres long and would inundate just over 5,300 hectares.

As currently proposed, the Site C project would consist of a 1.1 km earth fill dam across the Peace River valley, with 300 m wide concrete spillway and power intake structures located on the south bank. The powerhouse would incorporate 900 MW of hydro generation capacity and would produce 4,600 GWh annually on average.

TECHNICAL INFORMATION

Installed Capacity (MW)	900
Average Annual Energy (GWh/year)	4,600
Dependable Capacity (MW)	888
Annual Firm Energy (GWh/yr)	4,000

FINANCIAL INPUTS (CAD 2010)

Capital Cost ($000s)	$5,907,788
Fixed Operating & Maintenance Cost ($000s/year)	$9,909
Variable Operating & Maintenance Cost ($000s/year)	$0

Direct Capital Cost excludes Interest during Construction ("**IDC**") and Corporate Overhead.

Fixed Taxes ($000s/year)	$2,879
Variable Taxes ($000s/year)	$0
Water Rental – Installed Capacity ($/kW-year)	$4.095
Water Rental – Annual Energy Production ($/MWh)	$6.896

Project Life (Years)	70
Project Development Lead Time (Years)	5
Project Construction Lead Time (Years)	6

FINANCIAL SUMMARY (CAD 2010)

	6% (real) WACC*	8% (real) WACC*
Unit Construction Cost ($000s/MW)	$7,733	$8,133
Annualized Unit Energy Cost ($/MWh)	$102	$137
Annualized Unit Capacity Cost ($/MW-month)	$40,921	$56,058

*Weighted Average Cost of Capital ("**WACC**")

GHG FOOTPRINT

Meets Eco-Logo Criteria	Yes
GHG Emission Factor (tonnes CO2 equivalent/GWh)	0
Upstream GHG Emission (tonnes CO2 equivalent/GWh)	0

UNCERTAINTY

Development	Medium-Low
Price Uncertainty (UCC)	Medium
Price Uncertainty (UEC)	Medium

DISCUSSION:

The Site C project has been under study for several decades and the project concept and general configuration are well understood. On April 19, 2010, the BC Government announced that it will move forward with the Site C project. BC Hydro has since moved into a detailed regulatory review phase, which is stage 3 of a 5 stage development process leading through completion of construction.

The project is expected to have a very high capacity factor due to the multiyear storage capacity of the upstream Williston Reservoir. The project will also have its own reservoir and will therefore be considered as a dispatchable capacity resource.

REFERENCES:

Project Identification	BC Hydro LTAP
Capacity and Energy	BC Hydro LTAP
Construction and O&M Costs	BC Hydro Peace River Site C Hydro Project, Round 2 Summary Report
Water Rental Rates	BC MOE Web Site rev Dec 2009
Property Taxes	Assumed general rural mill rate of $4.16 per $1000 of 70% of fixed capital cost.
Transmission and Wheeling Costs	BCTC Rate Schedule 01 rev Jan 14, 2010 and Rate Schedule 110 rev Oct 21 2009.

3.7 Hydro – Waneta - BC Hydro Purchase of 1/3 Interest From Teck

PROJECT: BC Hydro Purchase of 1/3 Interest in Waneta from Teck

Resource Category: Base Load
Level of Study: Not Applicable (Asset in Operation)

PROJECT DESCRIPTION:

Waneta is an existing hydroelectric asset in BC of which BC Hydro acquired a 1/3 interest from Teck. It does not represent a direct resource option for FortisBC but is included herein as an indicator of future market based prices for capacity and energy in BC.

TECHNICAL INFORMATION

Installed Capacity (MW)	256 to 162*
Average Annual Energy (GWh/year)	1008 to 884*
Dependable Capacity (MW)	256 to 162*
Annual Firm Energy (GWh/yr)	1008 to 884*

*NOTE: The dependable capacity and annual energy benefit is reduced over time

FINANCIAL INPUTS (CAD 2010)

Capital Cost ($000s)	$850,000[6]
Fixed Operating & Maintenance Cost ($000s/year)	Variable – See DCF Calculation
Variable Operating & Maintenance Cost ($000s/year)	$0

Direct Capital Cost excludes Interest during Construction ("**IDC**") and Corporate Overhead.

Fixed Taxes ($000s/year)	Incl. above
Variable Taxes ($000s/year)	$0
Water Rental – Installed Capacity ($/kW-year)	$4.095
Water Rental – Annual Energy Production ($/MWh)	$6.896

Project Life (Years)	30[7]
Project Development Lead Time (Years)	None
Project Construction Lead Time (Years)	None

FINANCIAL SUMMARY (CAD 2010)

	6% (real) WACC*	8% (real) WACC*
Unit Construction Cost ($000s/MW)	$3,320**	$3,320**
Annualized Unit Energy Cost ($/MWh)	$76	$88
Annualized Unit Capacity Cost ($/MW-	$21,054	$24,854

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[6] BCUC Current Application "BC HYDRO - Application dated July 06, 2009 for the Acquisition from Teck Metals Ltd. of an Undivided One-third Interest in its Waneta Dam and Associated Assets", Project No. 3698565, Section 1.1.1

[7] BCUC Current Application "BC HYDRO - Application dated July 06, 2009 for the Acquisition from Teck Metals Ltd. of an Undivided One-third Interest in its Waneta Dam and Associated Assets", Project No. 3698565, Exhibit B-13: BC Hydro response to CECBC IR 1.3.9.6

month)		

*Weighted Average Cost of Capital ("**WACC**")

**Note: This transaction is financial and no construction occurs

GHG FOOTPRINT

Meets Eco-Logo Criteria	Yes
GHG Emission Factor (tonnes CO2 equivalent/GWh)	0
Upstream GHG Emission (tonnes CO2 equivalent/GWh)	0

UNCERTAINTY

Development	Low
Price Uncertainty (UCC)	Low
Price Uncertainty (UEC)	Low

DISCUSSION:

The calculation of UCC for the Waneta Acquisition by BC Hydro ("**WAN**") used the discounted cashflow method because the ACM requires that the annual benefits be uniform over the economic life of the project (BC Hydro 2006 Integrated Electricity Plan Appendix F – Chapter 4 – Financial Assumptions). The Waneta acquisition is not expected to have uniform annual capacity or energy benefits nor does it have constant future operating expenses and capital reinvestments. The decision was made to use the DCF method exclusively rather than attempting to annualize these future different capacities and expenses.

REFERENCES:

Project Identification	BCUC Current Application "BC HYDRO - Application dated July 06, 2009 for the Acquisition from Teck Metals Ltd. of an Undivided One-third Interest in its Waneta Dam and Associated Assets", Project No. 3698565
Capacity and Energy	BCUC Current Application "BC HYDRO - Application dated July 06, 2009 for the Acquisition from Teck Metals Ltd. of an Undivided One-third Interest in its Waneta Dam and Associated Assets", Project No. 3698565
Construction and O&M Costs	BCUC Current Application "BC HYDRO - Application dated July 06, 2009 for the Acquisition from Teck Metals Ltd. of an Undivided One-third Interest in its Waneta Dam and Associated Assets", Project No. 3698565
Water Rental Rates	BC MOE Web Site rev Dec 2009

3.8 Hydro – Mica 5 – BC Hydro

PROJECT: Proposed 500 MW Unit Addition at BC Hydro's Mica Dam

Resource Category: Peaking Plant
Level of Study: Project Definition

PROJECT DESCRIPTION:

The existing Mica Generating Station consists of four 450 MW generating units and includes empty bays for two additional units. This project involves the addition of a fifth generating unit at the existing powerhouse.

TECHNICAL INFORMATION

Installed Capacity (MW)	500
Average Annual Energy (GWh/year)	130
Dependable Capacity (MW)	465
Annual Firm Energy (GWh/yr)	130

FINANCIAL INPUTS (CAD 2010)

Capital Cost ($000s)	$347,432
Fixed Operating & Maintenance Cost ($000s/year)	$1,030
Variable Operating & Maintenance Cost ($000s/year)	$0

Direct Capital Cost excludes Interest during Construction ("**IDC**") and Corporate Overhead.

Grants in lieu of taxes ($/kW/year)	$0.58
Variable Taxes ($000s/year)	$0
Water Rental – Installed Capacity ($/kW-year)	$4.095
Water Rental – Annual Energy Production ($/MWh)	$6.896

Project Life (Years)	50
Project Development Lead Time (Years)	Incl. below
Project Construction Lead Time (Years)	7

FINANCIAL SUMMARY (CAD 2010)

	6% (real) WACC*	8% (real) WACC*
Unit Construction Cost ($000s/MW)	$831	$860
Annualized Unit Energy Cost ($/MWh)	$221	$284
Annualized Unit Capacity Cost ($/MW-month)	$4,965	$6,435

*Weighted Average Cost of Capital ("**WACC**")

GHG FOOTPRINT

Meets Eco-Logo Criteria	Yes
GHG Emission Factor (tonnes CO2 equivalent/GWh)	0
Upstream GHG Emission (tonnes CO2 equivalent/GWh)	0

UNCERTAINTY

Development	Medium-Low
Price Uncertainty (UCC)	Medium
Price Uncertainty (UEC)	Medium

DISCUSSION:

The project would provide additional capacity but relatively little incremental energy.

REFERENCES:

Project Identification	BC Hydro LTAP
Capacity and Energy	BC Hydro LTAP
Construction and O&M Costs	BC Hydro LTAP
Water Rental Rates	BC MOE Web Site rev Dec 2009

3.9 Hydro – Mica 6 – BC Hydro

PROJECT: Proposed Second 500 MW Unit Addition at BC Hydro's Mica Dam

Resource Category: Peaking Plant
Level of Study: Project Definition

PROJECT DESCRIPTION:

The existing Mica Generating Station consists of four 450 MW generating units and includes empty bays for two additional units. This project involves the addition of a sixth generating unit at the existing powerhouse.

TECHNICAL INFORMATION

Installed Capacity (MW)	500
Average Annual Energy (GWh/year)	50
Dependable Capacity (MW)	460
Annual Firm Energy (GWh/yr)	50

FINANCIAL INPUTS (CAD 2010)

Capital Cost ($000s)	$347,432
Fixed Operating & Maintenance Cost ($000s/year)	$1,030
Variable Operating & Maintenance Cost ($000s/year)	$0

Direct Capital Cost excludes Interest during Construction ("**IDC**") and Corporate Overhead.

Grants in lieu of taxes ($/kW/year)	$0.58
Variable Taxes ($000s/year)	$0
Water Rental – Installed Capacity ($/kW-year)	$4.095
Water Rental – Annual Energy Production ($/MWh)	$6.896

Project Life (Years)	50
Project Development Lead Time (Years)	Incl. below
Project Construction Lead Time (Years)	7

FINANCIAL SUMMARY (CAD 2010)

	6% (real) WACC*	8% (real) WACC*
Unit Construction Cost ($000s/MW)	$840	$870
Annualized Unit Energy Cost ($/MWh)	$564	$728
Annualized Unit Capacity Cost ($/MW-month)	$5,015	$6,501

*Weighted Average Cost of Capital ("**WACC**")

GHG FOOTPRINT

Meets Eco-Logo Criteria	Yes
GHG Emission Factor (tonnes CO2 equivalent/GWh)	0
Upstream GHG Emission (tonnes CO2 equivalent/GWh)	0

UNCERTAINTY

Development	Medium-Low
Price Uncertainty (UCC)	Medium
Price Uncertainty (UEC)	Medium

DISCUSSION:

The project would provide additional capacity but relatively little incremental energy.

REFERENCES:

Project Identification	BC Hydro LTAP
Capacity and Energy	BC Hydro LTAP
Construction and O&M Costs	BC Hydro LTAP
Water Rental Rates	BC MOE Web Site rev Dec 2009

3.10 Hydro – Revelstoke 6 – BC Hydro

PROJECT: Proposed 500 MW Unit Addition at BC Hydro's Revelstoke Dam

Resource Category: Peaking Plant
Level of Study: Project Definition

PROJECT DESCRIPTION:

The existing Revelstoke Generating Station consists of four generating units with a combined capacity of 1,980 MW. A fifth 500 MW is slated to come on line in October 2010. This project would involve filling the sixth and final open generating unit position in the Revelstoke dam.

TECHNICAL INFORMATION

Installed Capacity (MW)	500
Average Annual Energy (GWh/year)	26
Dependable Capacity (MW)	470
Annual Firm Energy (GWh/yr)	26

FINANCIAL INPUTS (CAD 2010)

Capital Cost ($000s)	$317,767
Fixed Operating & Maintenance Cost ($000s/year)	$1,030
Variable Operating & Maintenance Cost ($000s/year)	$0

Direct Capital Cost excludes Interest during Construction ("**IDC**") and Corporate Overhead.

Grants in lieu of taxes ($/kW/year)	$0.58
Variable Taxes ($000s/year)	$0
Water Rental – Installed Capacity ($/kW-year)	$4.095
Water Rental – Annual Energy Production ($/MWh)	$6.896

Project Life (Years)	50
Project Development Lead Time (Years)	5
Project Construction Lead Time (Years)	5

FINANCIAL SUMMARY (CAD 2010)

	6% (real) WACC*	8% (real) WACC*
Unit Construction Cost ($000s/MW)	$733	$752
Annualized Unit Energy Cost ($/MWh)	$977	$1,248
Annualized Unit Capacity Cost ($/MW-month)	$4,445	$5,696

*Weighted Average Cost of Capital ("**WACC**")

GHG FOOTPRINT

Meets Eco-Logo Criteria	Yes
GHG Emission Factor (tonnes CO2 equivalent/GWh)	0
Upstream GHG Emission (tonnes CO2 equivalent/GWh)	0

UNCERTAINTY

Development	Medium-Low
Price Uncertainty (UCC)	Medium
Price Uncertainty (UEC)	Medium

DISCUSSION:

The project would provide additional capacity but relatively little incremental energy.

REFERENCES:

Project Identification	BC Hydro LTAP
Capacity and Energy	BC Hydro LTAP
Construction and O&M Costs	BC Hydro LTAP
Water Rental Rates	BC MOE Web Site rev Dec 2009

3.11 Hydro – Resource Smart Bundle (w/o Mica & Revelstoke) – BC Hydro

PROJECT: Proposed expansions at various existing BC Hydro assets

Resource Category: Peaking Plant
Level of Study: Varies across different projects

PROJECT DESCRIPTION:

The Resource Smart Bundle of opportunities only consist of expansion projects:

1. Duncan Dam New Generation - 103 GWh/yr (30 MW added)
2. Kootenay Canal-Grohman Narrows - 28 GWh/yr (0 MW added)
3. Strathcona Additional Unit - 0 GWh/yr (30 MW added)
4. Ashe River Additional Unit - 30 GWh/yr (9 MW added)
5. Puntledge Additional Unit - 18.2 GWh/yr (10 MW added)
6. Lajoie Additional Unit - 80 GWh/yr (30 MW added).

TECHNICAL INFORMATION

Installed Capacity (MW)	109
Average Annual Energy (GWh/year)	259
Dependable Capacity (MW)	109
Annual Firm Energy (GWh/yr)	259

FINANCIAL INPUTS (CAD 2010)

Capital Cost ($000s)	$279,904
Fixed Operating & Maintenance Cost ($000s/year)	3,642
Variable Operating & Maintenance Cost ($000s/year)	$0

Direct Capital Cost excludes Interest during Construction ("**IDC**") and Corporate Overhead.

Grants in lieu of taxes ($/kW/year)	$0
Variable Taxes ($000s/year)	$0
Water Rental – Installed Capacity ($/kW-year)	$4.095
Water Rental – Annual Energy Production ($/MWh)	$6.896

Project Life (Years)	50
Project Development Lead Time (Years)	Not Stated
Project Construction Lead Time (Years)	3 (Estimate)

FINANCIAL SUMMARY (CAD 2010)

	6% (real) WACC*	8% (real) WACC*
Unit Construction Cost ($000s/MW)	$2,725	$2,779
Annualized Unit Energy Cost ($/MWh)	$95	$118
Annualized Unit Capacity Cost ($/kW-yr)	$17,534	$22,055

*Weighted Average Cost of Capital ("**WACC**")

GHG FOOTPRINT

Meets Eco-Logo Criteria	Yes
GHG Emission Factor (tonnes CO2 equivalent/GWh)	0
Upstream GHG Emission (tonnes CO2 equivalent/GWh)	0

UNCERTAINTY

Development	High
Price Uncertainty (UCC)	High
Price Uncertainty (UEC)	High

DISCUSSION:

BC Hydro has stated that this bundle of projects is comprised of expansion projects, not maintenance projects, and therefore individual projects do not have planned implementation dates. The project bundle would provide additional capacity and energy, but the primary purpose of these expansions would be to provide additional capacity. Although the construction period of the entire bundle of projects will likely take longer than 3 years, each individual project will be developed in 3 years or less.

The bundle does not represent direct resource options for FortisBC but is included herein as an indicator of potential future market based pricing for capacity in BC.

REFERENCES:

Project Identification	BC Hydro LTAP
Capacity and Energy	BC Hydro LTAP
Construction and O&M Costs	BC Hydro LTAP
Water Rental Rates	BC MOE Web Site rev Dec 2009

3.12 Hydro – Pumped Storage – Indicative Estimate in the Okanagan

PROJECT: Generic 180 MW Pumped Storage Hydro Project – Okanagan

Resource Category: Peaking Plant
Level of Study: Project Identification Level

PROJECT DESCRIPTION:

Several potential pumped storage project sites have been identified in the Okanagan and South eastern BC region. This generic project consists of upper and lower reservoirs and associated dams and other infrastructure. Indicative pricing has been developed based upon cost modelling done for prospective projects at several sites and an average pumped storage project has been provided in this report.

TECHNICAL INFORMATION

Installed Capacity (MW)	180
Average Annual Energy (GWh/year)	N/A
Dependable Capacity (MW)	180
Annual Firm Energy (GWh/yr)	N/A

FINANCIAL INPUTS (CAD 2010)

Capital Cost ($000s)	$340,000
Fixed Operating & Maintenance Cost ($000s/year)	$5,100
Variable Operating & Maintenance Cost ($000s/year)	$0

Direct Capital Cost excludes Interest during Construction ("**IDC**") and Corporate Overhead.

Fixed Taxes ($000s/year)	$990
Variable Taxes ($000s/year)	$0
Water Rental – Installed Capacity ($/kW-year)	$4.095
Water Rental – Annual Energy Production ($/MWh)	N/A

Project Life (Years)	70
Project Development Lead Time (Years)	5
Project Construction Lead Time (Years)	4

FINANCIAL SUMMARY (CAD 2010)

	6% (real) WACC*	8% (real) WACC*
Unit Construction Cost ($000s/MW)	$2,066	$2,128
Annualized Unit Energy Cost ($/MWh)	N/A	N/A
Annualized Unit Capacity Cost ($/MW-month)	$13,668	$17,412

*Weighted Average Cost of Capital (“**WACC**”)

GHG FOOTPRINT

Meets Eco-Logo Criteria	Yes
GHG Emission Factor (tonnes CO2 equivalent/GWh)	0
Upstream GHG Emission (tonnes CO2 equivalent/GWh)	0

UNCERTAINTY

Development	Medium-High
Price Uncertainty (UCC)	Medium-High
Price Uncertainty (UEC)	Medium-High

DISCUSSION:

A pumped storage hydro project uses electric energy from the low cost off peak spot market to pump water from a lower elevation water body to an upper reservoir. The stored water is used to generate power as required.

Overall the project would be a net consumer of electrical energy therefore a UEC was not calculated. Round-trip efficiency for these projects is typically in the range of 70% due to combined hydraulic losses due to pumping and water conduit as well as electrical losses.

A price spread of 35% or greater between high cost on peak spot market prices and low cost off peak spot market prices would enable electrical energy price arbitrage. This in turn could provide a positive economic contribution to subsidize the UCC of the project.

There are numerous other associated benefits to the project such as providing transmission ancillary services and spinning reserve, the discussion of which is beyond the scope of this report.

REFERENCES:

Project Identification	FortisBC Files
Capacity and Energy	Midgard files
Construction and O&M Costs	Midgard files
Water Rental Rates	BC MOE Web Site rev Dec 2009
Property Taxes	Assumed general rural mill rate of $4.16 per $1000 of 70% of fixed capital cost.

3.13 Wind – Within FortisBC Service Area – Low Construction Cost

PROJECT: Low Capital Cost 30 MW Wind Farm in the FortisBC Service Area

Resource Category: Intermittent
Level of Study: Conceptual Level

PROJECT DESCRIPTION:

A 30 MW wind farm pro-rated from a 150 MW southeast Wind bundle as described in the BC Hydro LTAP, using the low end of the construction cost range.

TECHNICAL INFORMATION

Installed Capacity (MW)	30
Average Annual Energy (GWh/year)	65.7
Dependable Capacity (MW)	3
Annual Firm Energy (GWh/yr)	N/A

FINANCIAL INPUTS (CAD 2010)

Capital Cost ($000s)	$61,152
Fixed Operating & Maintenance Cost ($000s/year)	$1,455
Variable Operating & Maintenance Cost ($000s/year)	$0

Direct Capital Cost excludes Interest during Construction ("**IDC**") and Corporate Overhead.

Fixed Taxes ($000s/year)	$174
Variable Taxes ($000s/year)	$0
Water Rental – Installed Capacity ($/kW-year)	N/A
Water Rental – Annual Energy Production ($/MWh)	N/A

Project Life (Years)	20
Project Development Lead Time (Years)	5
Project Construction Lead Time (Years)	3

FINANCIAL SUMMARY (CAD 2010)

	6% (real) WACC*	8% (real) WACC*
Unit Construction Cost ($000s/MW)	$21,632	$22,058
Annualized Unit Energy Cost ($/MWh)	$111	$127
Annualized Unit Capacity Cost ($/MW-month)	$202,405	$232,467

*Weighted Average Cost of Capital ("**WACC**")

GHG FOOTPRINT

Meets Eco-Logo Criteria	Yes
GHG Emission Factor (tonnes CO2 equivalent/GWh)	0
Upstream GHG Emission (tonnes CO2 equivalent/GWh)	0

UNCERTAINTY

Development	Medium
Price Uncertainty (UCC)	Medium
Price Uncertainty (UEC)	Medium

DISCUSSION:

A number of potential wind generation investigative use permits have been taken out by developers within or near the FortisBC service area. None of these projects are presently under construction but it is anticipated that some could be ready for development within the forecast period.

The quality of the wind resource in the FortisBC service area is very site specific due to the rugged topography and the lack of constant prevailing wind. The topography creates development hurdles - access and construction challenges - since the best local wind resource sites are located atop mountain ridges or high plateaux.

For the purpose of this resource option report two hypothetical 30 MW projects are presented to demonstrate the range of unit costs that could be expected from a high quality wind resource site with either low or high construction costs.

Dependable capacity is assumed to be 10% of nameplate capacity as proposed in the WECC 2008 Power Supply Assessment issued November 5, 2008. The assessment stated "[f]or this analysis, summer wind turbine capacity was derated, on average, based on utility submissions, to approximately 16% of nameplate capacity, and winter wind capacity was derated to approximately 10% of nameplate capacity."

REFERENCES:

Project Identification	BC Hydro LTAP
Capacity and Energy	BC Hydro LTAP
Construction and O&M Costs	BC Hydro LTAP
Water Rental Rates	N/A
Property Taxes	Assumed general rural mill rate of $4.16 per $1000 of 70% of fixed capital cost.

3.14 Wind – Within FortisBC Service Area – High Construction Cost

PROJECT: High Capital Cost 30 MW Wind Farm in the FortisBC Service Area

Resource Category: Intermittent
Level of Study: Conceptual Level

PROJECT DESCRIPTION:

A 30 MW wind farm pro-rated from a 150 MW southeast wind bundle as described in the BC Hydro LTAP, using the high end of the construction cost range.

TECHNICAL INFORMATION

Installed Capacity (MW)	30
Average Annual Energy (GWh/year)	65.7
Dependable Capacity (MW)	3
Annual Firm Energy (GWh/yr)	N/A

FINANCIAL INPUTS (CAD 2010)

Capital Cost ($000s)	$76,640
Fixed Operating & Maintenance Cost ($000s/year)	$1,455
Variable Operating & Maintenance Cost ($000s/year)	$0

Direct Capital Cost excludes Interest during Construction ("**IDC**") and Corporate Overhead.

Fixed Taxes ($000s/year)	$218
Variable Taxes ($000s/year)	$0
Water Rental – Installed Capacity ($/kW-year)	N/A
Water Rental – Annual Energy Production ($/MWh)	N/A

Project Life (Years)	20
Project Development Lead Time (Years)	5
Project Construction Lead Time (Years)	3

FINANCIAL SUMMARY (CAD 2010)

	6% (real) WACC*	8% (real) WACC*
Unit Construction Cost ($000s/MW)	$27,110	$27,645
Annualized Unit Energy Cost ($/MWh)	$133	$154
Annualized Unit Capacity Cost ($/MW-month)	$243,432	$281,108

*Weighted Average Cost of Capital ("**WACC**")

GHG FOOTPRINT

Meets Eco-Logo Criteria	Yes
GHG Emission Factor (tonnes CO2 equivalent/GWh)	0
Upstream GHG Emission (tonnes CO2 equivalent/GWh)	0

UNCERTAINTY

Development	Medium
Price Uncertainty (UCC)	Medium
Price Uncertainty (UEC)	Medium

DISCUSSION:

A number of potential wind generation investigative use permits have been taken out by developers within or near the FortisBC service area. None of these projects are presently under construction but it is anticipated that some could be ready for development within the forecast period.

The quality of the wind resource in the FortisBC service area is very site specific due to the rugged topography and the lack of constant prevailing wind. The topography creates development hurdles - access and construction challenges - since the best local wind resource sites are located atop mountain ridges or high plateaux.

For the purpose of this resource option report two hypothetical 30 MW projects are presented to demonstrate the range of unit costs that could be expected from a high quality wind resource site with either low or high construction costs.

Dependable capacity is assumed to be 10% of nameplate capacity as proposed in the WECC 2008 Power Supply Assessment issued November 5, 2008. The assessment stated "[f]or this analysis, summer wind turbine capacity was derated, on average, based on utility submissions, to approximately 16% of nameplate capacity, and winter wind capacity was derated to approximately 10% of nameplate capacity."

REFERENCES:

Project Identification	BC Hydro LTAP
Capacity and Energy	BC Hydro LTAP
Construction and O&M Costs	BC Hydro LTAP
Water Rental Rates	N/A
Property Taxes	Assumed general rural mill rate of $4.16 per $1000 of 70% of fixed capital cost.

3.15 Biomass – Bundle of Woodwaste Projects

PROJECT: Bundle of Potential Sawmill Woodwaste, Roadside Woodwaste and Standing Beetle Kill Wood Projects

Resource Category: Base Load
Level of Study: Conceptual Level

PROJECT DESCRIPTION:

Potential wood based biomass projects have been identified throughout BC based upon various government studies and information derived from recent calls for proposals. The project fuel types fall into three broad categories: sawmill woodwaste, roadside woodwaste, and standing beetle kill timber. It is expected that potential projects will be a combination of co-generation and stand alone projects with a combination of the three project fuel types and sizes ranging from 8 MW to 65 MW.

TECHNICAL INFORMATION

Installed Capacity (MW)	See Discussion
Average Annual Energy (GWh/year)	145 GWh/yr - See Discussion
Dependable Capacity (MW)	15MW - See Discussion
Annual Firm Energy (GWh/yr)	145 GWh/yr - See Discussion

FINANCIAL INPUTS (CAD 2010)

Capital Cost ($000s)	See Discussion
Fixed Operating & Maintenance Cost ($000s/year)	See Discussion
Variable Operating & Maintenance Cost ($000s/year)	See Discussion

Direct Capital Cost excludes Interest during Construction ("**IDC**") and Corporate Overhead.

Fixed Taxes ($000s/year)	See Discussion
Variable Taxes ($000s/year)	See Discussion

Project Life (Years)	20
Project Development Lead Time (Years)	3
Project Construction Lead Time (Years)	1

FINANCIAL SUMMARY (CAD 2010)

	6% (real) WACC*	8% (real) WACC*
Unit Construction Cost ($000s/MW)	See Discussion	See Discussion
Annualized Unit Energy Cost ($/MWh)	$108/MWh to $159/MWh See Discussion	$108/MWh to $159/MWh See Discussion
Annualized Unit Capacity Cost ($/MW-month)	N/A See Discussion	N/A See Discussion

*Weighted Average Cost of Capital ("**WACC**")

GHG FOOTPRINT

Meets Eco-Logo Criteria	Yes
GHG Emission Factor (tonnes CO2 equivalent/GWh)	0
Upstream GHG Emission (tonnes CO2 equivalent/GWh)	0

UNCERTAINTY

Development	Low
Price Uncertainty (UCC)	N/A
Price Uncertainty (UEC)	Low

DISCUSSION:

Escalating the biomass project UEC values provided in the BC Hydro 2008 LTAP Appendix F1 and the Willis Energy Resource Options Report[8] yield a UEC range of $107/MWh to $162/MWh in CAD 2010.

In the recent BC Hydro Bioenergy Call Phase 1, the four successful proponents had levelized plant gate prices in the $101/MW to $108/MW range (CAD 2010); the median bid price for all submissions was $159/MW. The total firm energy provided by the four winning projects was 579 GWh/year and the total dependable capacity was 60 MW.

These results confirm the validity of the biomass energy UEC values calculated by BC Hydro and Willis Energy. A UEC range of $108/MW to $159/MW for new biomass projects with firm energy of 145 GWh/year and dependable capacity of 15 MW is reasonable. Due to a lack of biomass plant construction cost and operating cost details, an estimate of UCC was not calculated for this report.

REFERENCES:

Conceptual Design	BC Hydro 2008 LTAP Appendix F1, Willis Resource Options Report 2009
Capacity and Energy Cost Estimates	BC Hydro 2008 LTAP Appendix F1, Willis Resource Options Report 2009, BCUC Order Number E-8-09

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[8] FortisBC 2009 Resource Plan, Appendix I - 1

3.16 Excluded Resource Options

Although other potential resources options exist for providing energy and/or capacity, detailed evaluations of the resource options identified in the following table were not included in this report for the reasons listed.

Table 3.2: Excluded Resource Options List

Resource Option	Primary Reason For Exclusion	Discussion and Notes
Geothermal	Insufficient Current Cost Information	Potential geothermal projects exist in BC (e.g.: South Meager Creek), but no geothermal projects are in commercial operations within BC and none were bid into the most recent BC Hydro Clean Power Call. As a result, this resource was excluded due to the lack of current commercial operating information.
Nuclear	Not Allowed as per BC Energy Plan	The BC Energy Plan explicitly prohibits nuclear power generation in BC.
Coal (IGCC with CCS)	Not Commercially Available	See IGCC with CCS discussion below this table.
Tidal	Not Utility Scale	Tidal power has not yet been proven commercially viable on a scale that is suitable for a utility such as FortisBC.
Wave	Not Utility Scale	Wave power has not yet been proven commercially viable on a scale that is suitable for a utility such as FortisBC.
Solar – PV and Solar Array	Not Utility Scale	Solar power in BC is not yet commercially viable on a scale that is suitable for a utility such as FortisBC. Solar generation is expensive but viable for some summer peak utilities in high solar irradiance regions, but it is not economically viable in the FortisBC service area.
Biomass – Municipal Solid Waste	Insufficient Current Cost Information	One potential site has been identified in, or near, FortisBC territory. Current cost information about the potential site, its location, fuel quality, tipping fees and other fuel cycle costs are not readily available.
Biomass - Biogas	Not Utility Scale	Biogas sites require larger landfills and generate relatively small total output (e.g. 5-8 MW). As a result, this resource lacks sufficient scale in the FortisBC territory to be considered a material resource option solution.
Co-Generation	Insufficient Current Information	Co-generation projects are highly site specific and utility scale developments are viable only with an appropriately large heat host. As a result, the opportunity to develop co-generation projects may arise on an opportunistic basis but it is not practical to create a generic economic model.

Coal based Integrated Gasification Combined Cycle with carbon capture and sequestration (IGCC with CCS)

There is no coal-fired electrical generation capacity in BC today. Under current BC Government policy[9], the most viable coal-fired generation technology would be an integrated gasification combined cycle coal fired unit equipped with carbon dioxide capture and storage capabilities. Nevertheless, the 2008 BC Hydro LTAP recommended that coal-fired power generation with CCS not be included as a commercially viable option in BC for the purposes of the BC Hydro resources option report. The recommendation was prompted by the conclusions of a Powertech report which was commissioned by BC Hydro. Among the conclusions quoted in the 2008 LTAP:

> "At this time, the state of key components of CCS technology is such that it cannot be considered in commercial application of coal-fired generation. Although pilot plants are being considered and pursued, the viability of these technologies on a commercial application scale may not be known until 2017 or later."[10]
>
> " There are legal, regulatory and public acceptance issues that likely need to be addressed before CO_2 CCS technology can be considered on a commercial scale in B.C."[11]

Since the Powertech study in 2008, there has been insufficient progress in the field of carbon capture to reverse the conclusions reached in the 2008 BC Hydro LTAP. That is to say, IGCC with Carbon Capture remains at a pre-commercial stage, and therefore should not be included in the Resource Option Stack.

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[9] The BC Energy Plan: A Vision for Clean Energy Leadership (http://www.energyplan.gov.bc.ca/) Policy #20 stipulates: "that coal-fired generation must meet a zero green house gas (GHG) emission standard through a combination of 'clean coal' fired generation technology, carbon sequestration and offset for any residual GHG emissions."

[10] BC Hydro 2008 Long Term Acquisition Plan, section 3.3.6.2, page 3-22

[11] Ibid.

4 Capital Cost Confidence Ranges

The following table gives an estimate of the confidence interval surrounding the different capital cost estimates provided in this report.

Table 4.1: Capital Cost Confidence Ranges

Project	Cost Estimate Range	Comments
Mica New Unit 5	N/A	Brownfield Development, Well Defined Scope, Cost estimate by others
Mica New Unit 6	N/A	Brownfield Development, Well Defined Scope, Cost estimate by others
Revelstoke New Unit 6	N/A	Brownfield Development, Well Defined Scope, Cost estimate by others
Waneta - BC Hydro Purchase of 1/3 Interest From Teck	N/A	Capital Cost is defined as part of the financial transaction
Resource Smart Bundle (w/o Mica & Revelstoke)	N/A	Brownfield Development early in scoping stages, Cost estimate by others
Hydro - Site C	N/A	Complex Development, Cost estimate by others
Biomass - Roadside and Sawmill Woodwaste	N/A	Well Defined but Complex Plant Type, Cost estimate by others
Simple Cycle Gas Turbine	-10% to +20%	Well Defined Plant Type
Combined Cycle Gas Turbine	-10% to +20%	Well Defined Plant Type
Similkameen - Small Hydro with Capacity	-20% to +30%	Complex Development
Wind - Low Cost - FortisBC Territory	-20% to +30%	Site Dependent
Wind - High Cost - FortisBC Territory	-20% to +30%	Site Dependent
Run Of River Hydro - FortisBC Territory	-20% to +50%	Site Dependent
Run-Of-River Hydro - Coastal	-20% to +50%	Site Dependent
Indicative Pumped Storage Opportunities for Okanagan	-20% to +50%	Site Dependent

For several resource options, Midgard relied on published cost estimates from a variety of sources, including BC Hydro, which did not indicate confidence ranges on cost. As a result of this Midgard is not in a position to comment the level of cost estimating used and as such no ranges for those resources are proved herein.

Where Midgard developed costs through primary effort, or had access to discussion of level of estimating effort used by others, the cost estimates were classified according to the Association for the Advancement of Cost Engineering ("**AACE**") classification system (18r-97)[12]. These cost estimates typically fell into Class 4 or 5.

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[12] AACE International Recommended Practice No. 18R-97, Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries - TCM Framework: 7.3 – Cost Estimating and Budgeting

5 Resource Options Summary

The key characteristics of the different resource options evaluated in this report are summarized in the following table. Resource options listed in Table 3.2 are not included in this summary.

Table 5.1: Summary of Resource Option Key Characteristics

Project	Resource Type	Installed Capacity (MW)	Dependable Capacity (MW)	Average Annual Energy (GWh)	Greenhouse Gas (CO2) Emissions (t/GWh)	Project Life
Mica New Unit 5	Peaking Plant	500	465	130	0	50
Mica New Unit 6	Peaking Plant	500	460	50	0	50
Revelstoke New Unit 6	Peaking Plant	500	470	26	0	50
Waneta - BC Hydro Purchase of 1/3 Interest From Teck	Base Load	256	256	1008	0	30
Run Of River Hydro - FortisBC Territory	Intermittent	70	10	250	0	40
Similkameen - Small Hydro with Capacity	Base Load	60	60	234	0	70
Run-Of-River Hydro - Coastal	Intermittent	62	28	255	0	40
Resource Smart Bundle (w/o Mica & Revelstoke)	Peaking Plant	109	109	259	0	50
Indicative Pumped Storage Opportunities for Okanagan	Peaking Plant	180	180	0	0	70
Hydro - Site C	Base Load	900	888	4600	0	70
Wind - Low Cost - FortisBC Territory	Intermittent	30	3	65.7	0	20
Wind - High Cost - FortisBC Territory	Intermittent	30	3	65.7	0	20
Simple Cycle Gas Turbine	Peaking Plant	39	39	68	500	25
Combined Cycle Gas Turbine	Base Load	243	243	1944	365	25
Biomass - Roadside and Sawmill Woodwaste	Base Load	Insufficient Information	15	145	0	20

The following table summarizes the Unit Energy Cost ("**UEC**") and Unit Capacity Cost ("**UCC**") for the resource options available to FortisBC. It should be noted that for certain generic resource options, such as SCGT, multiple installations may be required to meet FortisBC's resource planning requirements. For unique or site-specific projects (e.g. Small Hydro with Capacity - Similkameen), only one instance of that project exists for inclusion in the FortisBC resource portfolio. The Capacity or Energy column in the table below indicates whether or not the project primary purpose is to provide energy, capacity or both energy and capacity. The table is sorted in ascending order of UCC.

Table 5.2: Unit Energy Cost and Unit Capacity Cost for Resource Options (CAD 2010)

Project	Energy or Capacity	Dependable Capacity (MW)	Capital Cost (k$)	UEC @6% ($/MWh)	UEC @8% ($/MWh)	UCC @6% ($/MW-month)	UCC @8% ($/MW-month)
Revelstoke New Unit 6	Capacity	470	317,767	977	1,248	4,445	5,696
Mica New Unit 5	Capacity	465	347,432	221	284	4,965	6,435
Mica New Unit 6	Capacity	460	347,432	564	728	5,015	6,501
Simple Cycle Gas Turbine	Capacity	39	44,269	167	180	8,481	10,163
Combined Cycle Gas Turbine	Energy	243	329,445	90	93	10,624	12,708
Indicative Pumped Storage Opportunities	Capacity	180	340,000	N/A	N/A	13,668	17,412
Resource Smart Bundle (w/o Mica & Revelstoke)	Capacity	109	279,904	95	118	17,534	22,055
Waneta - BC Hydro Purchase of 1/3 Interest From Teck	N/A	256	850,000	76	88	21,054	24,854
Similkameen - Small Hydro with Capacity	Energy & Capacity	60	283,117	97	124	29,274	38,003
Hydro - Site C	Energy & Capacity	888	5,907,788	102	137	40,921	56,058
Run-Of-River Hydro - Coastal	Energy	28	248,000	88	108	65,350	80,212
Wind - Low Cost	Energy	3	61,152	111	127	202,405	232,467
Run Of River Hydro - FortisBC Territory	Energy	10	280,000	101	124	206,704	253,881
Wind	Energy	3	76,640	133	154	243,432	281,108
Biomass - Roadside and Sawmill Woodwaste	Energy	15	Insufficient Data	108-159	108-159	N/A	N/A

The following table is a summary of unit construction costs which as defined previously is the Capital Cost divided by the dependable capacity.

Table 5.3: Resource Option Unit Construction Cost (CAD 2010)

Project	Installed Capacity (MW)	Dependable Capacity (MW)	Capital Cost (k$)	Unit Construction Cost @8% (k$/MW)	Project Life
Mica New Unit 5	500	465	347,432	860	50
Mica New Unit 6	500	460	347,432	870	50
Revelstoke New Unit 6	500	470	317,767	752	50
Waneta - BC Hydro Purchase of 1/3 Interest From Teck	256	256	850,000	3,320	30
Run Of River Hydro - FortisBC Territory	70	10	280,000	30,300	40
Similkameen - Small Hydro with Capacity	60	60	283,117	5,106	70
Run-Of-River Hydro - Coastal	62	28	248,000	9,545	40
Resource Smart Bundle (w/o Mica & Revelstoke)	109	109	279,904	2,779	50
Indicative Pumped Storage Opportunities for Okanagan	180	180	340,000	2,128	70
Hydro - Site C	900	888	5,907,788	8,133	70
Wind - Low Cost - FortisBC Territory	30	3	61,152	22,058	20
Wind - High Cost - FortisBC Territory	30	3	76,640	27,645	20
Simple Cycle Gas Turbine	39	39	44,269	1,147	25
Combined Cycle Gas Turbine	243	243	329,445	1,356	25

Appendix A – Natural Gas Curves

The base case natural gas curve that Midgard supports in this appendix is listed in Appendix A - Table 1 below, along with a high case scenario and a low case scenario. The natural gas price curve is quoted in US dollars per million British thermal units ("**MMBtus**") for the average annual price.

The natural gas curve is the estimate of the spot market price for Henry Hub natural gas. Henry Hub natural gas is the benchmark trading point for natural gas in North America[13]. The benchmark natural gas futures contract that trades on the New York Mercantile Exchange ("**NYMEX**") - North America's primary energy commodities exchange - physically settles at the Henry Hub natural gas delivery point.

Appendix A - Table 1 - Annual Average Spot Price of Henry Hub Natural Gas (USD / MMBtu)

	Base Case	Low Case	High Case
2010	$ 4.50	$ 4.13	$ 4.91
2011	$ 5.68	$ 3.81	$ 8.48
2012	$ 6.17	$ 4.34	$ 8.78
2013	$ 6.13	$ 4.19	$ 8.95
2014	$ 6.09	$ 3.99	$ 9.29
2015	$ 6.27	$ 4.09	$ 9.62
2016	$ 6.38	$ 4.16	$ 9.79
2017	$ 6.38	$ 4.16	$ 9.80
2018	$ 6.43	$ 4.19	$ 9.87
2019	$ 6.51	$ 4.24	$ 9.98
2020	$ 6.64	$ 4.33	$ 10.19
2021	$ 6.74	$ 4.39	$ 10.34
2022	$ 6.93	$ 4.51	$ 10.63
2023	$ 6.96	$ 4.53	$ 10.68
2024	$ 6.91	$ 4.51	$ 10.61
2025	$ 6.99	$ 4.56	$ 10.73
2026	$ 7.15	$ 4.66	$ 10.98
2027	$ 7.29	$ 4.75	$ 11.19
2028	$ 7.53	$ 4.91	$ 11.56
2029	$ 7.77	$ 5.07	$ 11.93
2030	$ 8.05	$ 5.25	$ 12.35
2031	$ 8.39	$ 5.47	$ 12.87
2032	$ 8.50	$ 5.54	$ 13.04
2033	$ 8.53	$ 5.56	$ 13.09
2034	$ 8.75	$ 5.70	$ 13.43
2035	$ 8.88	$ 5.79	$ 13.63
2036	$ 8.88	$ 5.79	$ 13.63
2037	$ 8.88	$ 5.79	$ 13.63
2038	$ 8.88	$ 5.79	$ 13.63
2039	$ 8.88	$ 5.79	$ 13.63
2040	$ 8.88	$ 5.79	$ 13.63

Base Case Curve

The Base Case Curve relies on the US Department of Energy's Energy Information Agency's ("**EIA**") Annual Energy Outlook 2010 ("**AEO2010**") - specifically, the Henry Hub natural gas price forecast.[14] The U.S. Energy Information Administration is the primary US Federal Government authority on energy statistics and analysis. EIA data and forecasts are a widely quoted and relied upon source of energy data throughout the world.

The AEO2010 projections are based on results from the EIA's National Energy Modeling System ("**NEMS**"). NEMS is a computer-based, energy-economy modeling system of the U.S.A through 2030. NEMS projects the production, imports, conversion, consumption, and prices of energy, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability, resource costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics. NEMS was designed and implemented by the Energy Information Administration ("**EIA**") of the U.S. Department of Energy ("**DOE**").[15]

The EIA has been forecasting natural gas prices since 1982, although the NEMS model has only been in use since 1994.

Why the AEO2010 EIA Forecast Price?

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[13] Other natural gas trading (or transfer) points throughout North America are priced as a basis (that is, as a premium or discount to) Henry Hub natural gas prices.

[14] Supplemental Tables to the Annual Energy Outlook 2010, Table 114, http://www.eia.doe.gov/oiaf/aeo/supplement/sup_ogc.xls

[15] http://www.eia.doe.gov/oiaf/aeo/overview/index.html

Midgard views the AEO2010 Henry Hub price forecast as the most sensible estimate of natural gas pricing available for this exercise. The view is based upon the following facts:

- The AEO2010 forecast price curve is transparent and readily available. The forecast is derived from a model based upon fundamental inputs. Furthermore, the EIA is a non-political entity and is recognized as an independent agent. The EIA has no inherent bias in forecasting natural gas spot prices.
- The EIA forecast price curve resembles the current NYMEX natural gas futures curve. Although the NYMEX futures curve is not necessarily a more accurate predictor of future spot prices as compared to forecasts derived from a computer model, it is a legitimate reference against which the base case price curve should be checked. In particular, the shorter end of the NYMEX curve - where trading is more frequent - represents a fair and transparent medium to assess the wider markets' valuation of expected spot prices.

Appendix A - Table 2 – Base Case Henry Hub Natural Gas (USD / MMBtu) versus NYMEX Futures Price Curve

	Base Case	NYMEX Fut.	Delta
2010	$ 4.50	$ 4.64	*-$ 0.14*
2011	$ 5.68	$ 5.46	*$ 0.22*
2012	$ 6.17	$ 5.81	*$ 0.36*
2013	$ 6.13	$ 6.07	*$ 0.06*
2014	$ 6.09	$ 6.36	*-$ 0.27*
2015	$ 6.27	$ 6.63	*-$ 0.36*

- The EIA forecast price is frequently referenced by natural gas industry stakeholders throughout North America. For example, California's key energy regulatory agencies, namely the California Energy Commission ("**CEC**") and the California Public Utilities Commission ("**CPUC**") frequently reference the EIA price forecasts in their analysis and decisions. As a significant consumer of energy, California and its regulatory agencies invest a great deal of resources in assessing the future prices of energy. In Canada, our Federal and Provincial regulatory agencies also rely frequently on the data and analysis produced by the EIA.

There are a number of potential sources of natural gas price forecasts from government organizations as well as private sector consultants. Nevertheless, weighing the sum of the advantages and disadvantages of the various sources, Midgard is confident in the reasonableness of the EIA natural gas price forecast. Consequently, it forms the basis of the base case natural gas price forecast for the FortisBC 2010 Resource Options Report.

The Nature of Forecasting

Given the uncertainty inherent in forecasting, it is important to forecast a range of possibilities in order to improve the usefulness of the forecast. In particular, this is the case when forecasting natural gas prices given its highly volatile nature. The objective of this exercise is to present a range within which natural gas spot prices are expected to fall 19 times out of 20, that is to say a 95% confidence interval.

The EIA has been forecasting natural gas prices since 1982, and has been using the NEMS model since1994. Annually, the EIA reviews its prior years' forecasts, measures their accuracy versus the actual results and summarizes their findings in a document which they name: "Annual Energy Outlook Retrospective Review: Evaluation of Reference Case Projections in Past Editions". The review analyses the accuracy of the AEO forecasts and compares the actual figures versus the forecast figures. It is worth noting that the accuracy of the forecasts has improved measurably since 1994. It is also important to note that the underpinning assumption from which the NEMS results are derived is that the major factors impacting the supply and demand (and hence price) of natural gas will continue to trend in a manner that resembles their recent historical record.

In order to derive the high case and low case natural gas price curves, Midgard assumed that the AEO forecasts going forward will be approximately as accurate as they have been going back to 1994. That is to say, Midgard believes that the accuracy of the AEO2010 natural gas price forecast will be similar to its accuracy for the years 1994 to 2008.[16]

In order to derive the high and low natural gas curves, Midgard assessed the variance of previous years' forecasts versus the actual natural gas price, grouping the data into forecasts by years into the future. For example, the AEO1994 forecast for the 1994 natural gas price was bucketed into the 1 year-ahead grouping, the AEO1994 forecast for the 1995 natural gas price was bucketed into the 2 year-ahead grouping, and so forth. The sample size for the 1 year-ahead grouping was the largest (at 15) and the sample sizes for each proceeding year was reduced by one (i.e. the sample size for the 2 year-ahead was 14, the sample size for the 3 year-ahead grouping was 13, and so forth).

Once the standard deviations for each grouping were assessed (based upon a normalized data set, i.e. the differences between forecast and actual were translated into a percentage of actual and then converted into its natural logarithmic value), Midgard calculated a 95% confidence interval based upon the forecast price curve acting as the mean price.[17] The calculation of the high and low price curves for the years 2016 to 2040 assumes a standard deviation equal to that calculated for 2015 (the 6th year-ahead).[18]

The end result is a low case price scenario that is approximately two-thirds the value of the base case price scenario and a high case is approximately 50% higher than the base case scenario.

Sources:

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[16] 2009 figures were not analysed as part of the most recent Retrospective Review.

[17] Given that natural gas pricing cannot fall below zero, its pricing curve is expected to resemble that of a log normal distribution curve. Therefore, the calculated confidence interval was based upon a log-normal distribution.

[18] The 7th year-ahead grouping and longer had a sample sizes which Midgard judged to be too small to use for this exercise.

Appendix B – Resource Option Calculation Summaries

The following are the summary sheets for the resource option calculations.

PROJECT	Mica New Unit 5
RESOURCE	Hydro - Resource Smart
REFERENCE	BC Hydro 2008 LTAP - Appendix F1 adjusted for $2010
CALCULATION METHOD	Annualized Cost

TECHNICAL PARAMETERS	
Installed Capacity (MW)	500
Average Annual Energy (GWh/yr)	130
Dependable Capacity (MW)	465
Annual Firm Energy (GWh/yr)	130
Heat Rate (GJ/GWh)	0

FINANCIAL PARAMETERS (FISCAL 2010 $)	
Direct Capital Cost (k$)	347,432
Project Life (years)	50
Project Lead Time (years)	7

OPERATING COSTS:	
Fixed OMA (k$/yr)	1,030
Variable OMA ($/MWh)	0
Grants-in-lieu of Taxes ($/kW-yr)	0.58
Fixed Taxes (k$/yr)	0
Variable Taxes ($/MWh)	0
Water Rentals - Capacity ($/kW-yr)	4.095
Water Rentals - Energy ($/MWh)	6.896
Fuel Price ($/GJ)	0
Fuel Tax (%)	0%
Firm Fuel Transporation ($/GJ)	0

CONSTRUCTION CASH FLOW :

Year	Direct	6%	8%
1	4,976	7,058	7,896
2	10,724	14,352	15,758
3	19,793	24,989	26,929
4	33,439	39,826	42,123
5	109,810	123,383	128,083
6	132,642	140,600	143,253
7	36,048	36,048	36,048
8		0	0
9		0	0
10		0	0
11		0	0
12		0	0
13		0	0
14		0	0
15		0	0
16		0	0
17		0	0
18		0	0
19		0	0
20		0	0
Total	347,432	386,256	400,089
Annualized		24,506	32,704

UCC Based on Dependable Capacity:		
	6%	8%
Investment Cost (Annualized Capital) (k$/yr)	24,506	32,704
Fixed Investment ($/kW-yr)	53	70
Fixed Operations ($/kW-yr)	7	7
Variable Operations ($/kW-yr)	0	0
Fuel Cost ($/kW-yr)	0	0
Unit Capacity Cost ($/MW-month)	4,965	6,435
Unit Capacity Cost ($/kW-yr)	60	77

UEC Based on Average Energy Capability:		
	6%	8%
Investment Cost (Annualized Capital) (k$/yr)	24,506	32,704
Fixed Investment ($/MWh)	189	252
Fixed Operations ($/MWh)	26	26
Variable Operations ($/MWh)	7	7
Fuel Cost ($/MWh)	0	0
Unit Energy Cost ($/MWh)	221	284

Unit Construction Cost			
		6%	8%
All in Capital Construction (k$)	$	386,256	400,089
Dependable Capacity (MW)		465	465
Unit Construction Cost (k$/MW)	$	831	$ 860

PROJECT	Mica New Unit 6
RESOURCE	Hydro - Resource Smart
REFERENCE	BC Hydro 2008 LTAP - Appendix F1 adjusted for $2010
CALCULATION METHOD	Annualized Cost

TECHNICAL PARAMETERS	
Installed Capacity (MW)	500
Average Annual Energy (GWh/yr)	50
Dependable Capacity (MW)	460
Annual Firm Energy (GWh/yr)	50
Heat Rate (GJ/GWh)	0

FINANCIAL PARAMETERS (FISCAL 2010 $)	
Direct Capital Cost (k$)	347,432
Project Life (years)	50
Project Lead Time (years)	7

OPERATING COSTS:	
Fixed OMA (k$/yr)	1,030
Variable OMA ($/MWh)	0
Grants-in-lieu of Taxes ($/kW-yr)	0.58
Fixed Taxes (k$/yr)	0
Variable Taxes ($/MWh)	0
Water Rentals - Capacity ($/kW-yr)	4.095
Water Rentals - Energy ($/MWh)	6.896
Fuel Price ($/GJ)	0
Fuel Tax (%)	0%
Firm Fuel Transporation ($/GJ)	0

CONSTRUCTION CASH FLOW:

Year	Direct	6%	8%
1	4,976	7,058	7,896
2	10,724	14,352	15,758
3	19,793	24,989	26,929
4	33,439	39,826	42,123
5	109,810	123,383	128,083
6	132,642	140,600	143,253
7	36,048	36,048	36,048
8		0	0
9		0	0
10		0	0
11		0	0
12		0	0
13		0	0
14		0	0
15		0	0
16		0	0
17		0	0
18		0	0
19		0	0
20		0	0
Total	347,432	386,256	400,089
Annualized		24,506	32,704

UCC Based on Dependable Capacity:		
	6%	8%
Investment Cost (Annualized Capital) (k$/yr)	24,506	32,704
Fixed Investment ($/kW-yr)	53	71
Fixed Operations ($/kW-yr)	7	7
Variable Operations ($/kW-yr)	0	0
Fuel Cost ($/kW-yr)	0	0
Unit Capacity Cost ($/MW-month)	5,015	6,501
Unit Capacity Cost ($/kW-yr)	60	78

UEC Based on Average Energy Capability:		
	6%	8%
Investment Cost (Annualized Capital) (k$/yr)	24,506	32,704
Fixed Investment ($/MWh)	490	654
Fixed Operations ($/MWh)	67	67
Variable Operations ($/MWh)	7	7
Fuel Cost ($/MWh)	0	0
Unit Energy Cost ($/MWh)	564	728

Unit Construction Cost				
		6%		8%
All in Capital Construction (k$)	$	386,256		400,089
Dependable Capacity (MW)		460		460
Unit Construction Cost (k$/MW)	$	840	$	870

PROJECT	Revelstoke New Unit 6
RESOURCE	Hydro - Resource Smart
REFERENCE	BC Hydro 2008 LTAP - Appendix F1 adjusted for $2010
CALCULATION METHOD	Annualized Cost

TECHNICAL PARAMETERS	
Installed Capacity (MW)	500
Average Annual Energy (GWh/yr)	26
Dependable Capacity (MW)	470
Annual Firm Energy (GWh/yr)	26
Heat Rate (GJ/GWh)	0

FINANCIAL PARAMETERS (FISCAL 2010 $)	
Direct Capital Cost (k$)	317,767
Project Life (years)	50
Project Lead Time (years)	5

OPERATING COSTS:	
Fixed OMA (k$/yr)	1,030
Variable OMA ($/MWh)	0
Grants-in-lieu of Taxes ($/kW-yr)	0.58
Fixed Taxes (k$/yr)	0
Variable Taxes ($/MWh)	0
Water Rentals - Capacity ($/kW-yr)	4.095
Water Rentals - Energy ($/MWh)	6.896
Fuel Price ($/GJ)	0
Fuel Tax (%)	0%
Firm Fuel Transporation ($/GJ)	0

CONSTRUCTION CASH FLOW:

Year	Direct	6%	8%
1	12,381	15,631	16,844
2	27,646	32,926	34,826
3	81,112	91,137	94,608
4	133,226	141,219	143,884
5	63,403	63,403	63,403
6		0	0
7		0	0
8		0	0
9		0	0
10		0	0
11		0	0
12		0	0
13		0	0
14		0	0
15		0	0
16		0	0
17		0	0
18		0	0
19		0	0
20		0	0
Total	317,767	344,316	353,565
Annualized		21,845	28,901

UCC Based on Dependable Capacity:	6%	8%
Investment Cost (Annualized Capital) (k$/yr)	21,845	28,901
Fixed Investment ($/kW-yr)	46	61
Fixed Operations ($/kW-yr)	7	7
Variable Operations ($/kW-yr)	0	0
Fuel Cost ($/kW-yr)	0	0
Unit Capacity Cost ($/MW-month)	4,445	5,696
Unit Capacity Cost ($/kW-yr)	53	68

UEC Based on Average Energy Capability:	6%	8%
Investment Cost (Annualized Capital) (k$/yr)	21,845	28,901
Fixed Investment ($/MWh)	840	1,112
Fixed Operations ($/MWh)	129	129
Variable Operations ($/MWh)	7	7
Fuel Cost ($/MWh)	0	0
Unit Energy Cost ($/MWh)	977	1,248

Unit Construction Cost		6%	8%
All in Capital Construction (k$)	$	344,316	353,565
Dependable Capacity (MW)		470	470
Unit Construction Cost (k$/MW)	$	733	$ 752

PROJECT	Waneta - BC Hydro Purchase of 1/3 Interest From Teck
RESOURCE	Hydro
REFERENCE	
CALCULATION METHOD	Discounted Cash Flow Method - DCF method employed because benefits from Waneta are not constant over time

UNIT CONSTRUCTION COST CALCULATION

Project	Waneta - BC Hydro Purchase of 1/3 Interest From Teck
Capital Cost	$ 850,000
Dependable Capacity (MW)	256
Unit Construction Cost (k$/MW)	$ 3,320

UNIT CAPACITY COST CALCULATION - BY DCF

Project	Waneta - BC Hydro Purchase of 1/3 Interest From Teck	
Project in-service date	1	years out
Capital Cost	$ 850,000	
Project Economic Life	30	years
Discount Rate	6%	(real)

DISCOUNTED CASHFLOW CALCULATION OF UNIT COST

	2010	2011	2012	2013	2014	2015	2016	2017	...	2038	2039
Year	1	2	3	4	5	6	7	8	...	29	30
Direct Capital Cost	$ 850,000										
Operations & Maintenance	*$ 1,300*	*$ 1,300*	*$ 1,300*	*$ 1,300*	*$ 1,300*	*$ 1,300*	*$ 1,300*	*$ 1,300*	...	*$ 1,300*	*$ 1,300*
Property Taxes	*$ 700*	*$ 700*	*$ 700*	*$ 700*	*$ 700*	*$ 700*	*$ 700*	*$ 700*	...	*$ 700*	*$ 700*
Insurance & Administration	*$ 700*	*$ 700*	*$ 700*	*$ 700*	*$ 700*	*$ 700*	*$ 700*	*$ 700*	...	*$ 700*	*$ 700*
Sustaining Capital	*$ 400*	*$ 400*	*$ 400*	*$ 400*	*$ 400*	*$ 400*	*$ 400*	*$ 400*	...	*$ 400*	*$ 400*
Major Capital (dam anchoring)	*$ -*	*$ -*	*$ -*	*$ -*	*$ 3,695*	*$ -*	*$ -*	*$ -*	...	*$ -*	*$ -*
Major Capital (ULE)	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ 3,623*	*$ -*	*$ -*	...	*$ -*	*$ -*
Water Rental Fees - capacity only (4.095/kW)	*$ 673*	*$ 673*	*$ 673*	*$ 673*	*$ 673*	*$ 673*	*$ 673*	*$ 673*	...	*$ 673*	*$ 673*
Admin Costs	*$ 150*	*$ 150*	*$ 150*	*$ 150*	*$ 150*	*$ 150*	*$ 150*	*$ 150*	...	*$ 150*	*$ 150*
Annual Operating Cost	$ 3,923	$ 3,923	$ 3,923	$ 3,923	$ 7,618	$ 7,546	$ 3,923	$ 3,923	...	$ 3,923	$ 3,923
Total Cost	**$ 853,923**	**$ 3,923**	**$ 3,923**	**$ 3,923**	**$ 7,618**	**$ 7,546**	**$ 3,923**	**$ 3,923**	...	**$ 3,923**	**$ 3,923**
Discount factor formula	=1/(1+i)^(years-1)										
Discounting factor	1	0.94	0.89	0.84	0.79	0.75	0.70	0.67	...	0.20	0.18
Total Cost x discounting factor	$ 853,923	$ 3,701	$ 3,491	$ 3,294	$ 6,034	$ 5,639	$ 2,766	$ 2,609	...	$ 767	$ 724
NPV Total Cost	$ 912,873										
Annual Dependable Capacity Benefit (MW)	256	256	256	256	256	249	249	249	...	162	162
Dependable Capacity x discounting factor	256.0	241.5	227.8	214.9	202.8	186.1	175.5	165.6	...	31.7	29.9

NPC ("Net Present Capacity")	3613.2
Unit Capacity Cost (UCC - $/kW-yr) = NPV/"NPC"	$ 253
UCC - ($/MW-month)	$ 21,054

UNIT CAPACITY COST CALCULATION - BY DCF

Project	Waneta - BC Hydro Purchase of 1/3 Interest From Teck	
Project in-service date	1	years out
Capital Cost	$ 850,000	
Project Economic Life	30	years
Discount Rate	8%	(real)

DISCOUNTED CASHFLOW CALCULATION OF UNIT COST

	2010	2011	2012	2013	2014	2015	2016	2017	…	2038	2039
Year	1	2	3	4	5	6	7	8	…	29	30
Direct Capital Cost	$ 850,000										
Operations & Maintenance	*$ 1,300*	*$ 1,300*	*$ 1,300*	*$ 1,300*	*$ 1,300*	*$ 1,300*	*$ 1,300*	*$ 1,300*	…	*$ 1,300*	*$ 1,300*
Property Taxes	*$ 700*	*$ 700*	*$ 700*	*$ 700*	*$ 700*	*$ 700*	*$ 700*	*$ 700*	…	*$ 700*	*$ 700*
Insurance & Administration	*$ 700*	*$ 700*	*$ 700*	*$ 700*	*$ 700*	*$ 700*	*$ 700*	*$ 700*	…	*$ 700*	*$ 700*
Sustaining Capital	*$ 400*	*$ 400*	*$ 400*	*$ 400*	*$ 400*	*$ 400*	*$ 400*	*$ 400*	…	*$ 400*	*$ 400*
Major Capital (dam anchoring)	*$ -*	*$ -*	*$ -*	*$ -*	*$ 3,695*	*$ -*	*$ -*	*$ -*	…	*$ -*	*$ -*
Major Capital (ULE)	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ 3,623*	*$ -*	*$ -*	…	*$ -*	*$ -*
Water Rental Fees - capacity only (4.095/kW)	*$ 673*	*$ 673*	*$ 673*	*$ 673*	*$ 673*	*$ 673*	*$ 673*	*$ 673*	…	*$ 673*	*$ 673*
Admin Costs	*$ 150*	*$ 150*	*$ 150*	*$ 150*	*$ 150*	*$ 150*	*$ 150*	*$ 150*	…	*$ 150*	*$ 150*
Annual Operating Cost	$ 3,923	$ 3,923	$ 3,923	$ 3,923	$ 7,618	$ 7,546	$ 3,923	$ 3,923	…	$ 3,923	$ 3,923
Total Cost	**$ 853,923**	**$ 3,923**	**$ 3,923**	**$ 3,923**	**$ 7,618**	**$ 7,546**	**$ 3,923**	**$ 3,923**	…	**$ 3,923**	**$ 3,923**
Discount factor formula	=1/(1+i)^(years-1)										
Discounting factor	1	0.93	0.86	0.79	0.74	0.68	0.63	0.58	…	0.12	0.11
Total Cost x discounting factor	$ 853,923	$ 3,632	$ 3,363	$ 3,114	$ 5,599	$ 5,136	$ 2,472	$ 2,289	…	$ 455	$ 421
NPV Total Cost	$ 902,878										
Annual Dependable Capacity Benefit (MW)	256	256	256	256	256	249	249	249	…	162	162
Dependable Capacity x discounting factor	256.0	237.0	219.5	203.2	188.2	169.5	156.9	145.3	…	18.8	17.4

NPC ("Net Present Capacity")	3027.3
Unit Capacity Cost (UCC - $/kW-yr) = NPV/"NPC"	$ 298
UCC - $/MW-month	$ 24,854

UNIT ENERGY COST CALCULATION - BY DCF

Project	Waneta - BC Hydro Purchase of 1/3 Interest From Teck	
Project in-service date	1	years out
Capital Cost	$ 850,000	
Project Economic Life	30	years
Discount Rate	6%	(real)

DISCOUNTED CASHFLOW CALCULATION OF UNIT COST

	2010	2011	2012	2013	2014	2015	2016	2017	…	2038	2039
Year	1	2	3	4	5	6	7	8	…	29	30
Direct Capital Cost	$ 850,000										
Operations & Maintenance	$ 1,300	$ 1,300	$ 1,300	$ 1,300	$ 1,300	$ 1,300	$ 1,300	$ 1,300	...	$ 1,300	$ 1,300
Property Taxes	$ 700	$ 700	$ 700	$ 700	$ 700	$ 700	$ 700	$ 700	...	$ 700	$ 700
Insurance & Administration	$ 700	$ 700	$ 700	$ 700	$ 700	$ 700	$ 700	$ 700	...	$ 700	$ 700
Sustaining Capital	$ 400	$ 400	$ 400	$ 400	$ 400	$ 400	$ 400	$ 400	...	$ 400	$ 400
Major Capital (dam anchoring)	$ -	$ -	$ -	$ -	$ 3,695	$ -	$ -	$ -	...	$ -	$ -
Major Capital (ULE)	$ -	$ -	$ -	$ -	$ -	$ 3,623	$ -	$ -	...	$ -	$ -
Water Rental Fees - capacity only (4.095/kW)	$ 673	$ 673	$ 673	$ 673	$ 673	$ 673	$ 673	$ 673	...	$ 673	$ 673
Water Rental Fees - energy only (6.896/GWh)	$ 6,951	$ 6,951	$ 6,951	$ 6,951	$ 6,220	$ 5,965	$ 5,965	$ 5,965	...	$ 6,096	$ 6,096
Admin Costs	$ 150	$ 150	$ 150	$ 150	$ 150	$ 150	$ 150	$ 150	...	$ 150	$ 150
Annual Operating Cost	$ 10,874	$ 10,874	$ 10,874	$ 10,874	$ 13,838	$ 13,511	$ 9,888	$ 9,888	...	$ 10,019	$ 10,019
Total Cost	**$ 860,874**	**$ 10,874**	**$ 10,874**	**$ 10,874**	**$ 13,838**	**$ 13,511**	**$ 9,888**	**$ 9,888**	...	**$ 10,019**	**$ 10,019**
Discount factor formula	=1/(1+i)^(years-1)										
Discounting factor	1	0.94	0.89	0.84	0.79	0.75	0.70	0.67	...	0.20	0.18
Total Cost x discounting factor	$ 860,874	$ 10,259	$ 9,678	$ 9,130	$ 10,961	$ 10,096	$ 6,971	$ 6,576	...	$ 1,960	$ 1,849
NPV Total Cost	$ 1,003,837										
Annual Energy Benefit (GWh)	1008	1008	1008	1008	902	865	865	865	...	884	884
Annual Energy x discounting factor	1008.0	950.9	897.1	846.3	714.5	646.4	609.8	575.3	...	172.9	163.1
NPE ("Net Present Energy")	13190.9										
Unit Energy Cost (UEC - $/MWh) = NPV/"NPE"	$ 76										

UNIT ENERGY COST CALCULATION - BY DCF

Project	Waneta - BC Hydro Purchase of 1/3 Interest From Teck	
Project in-service date	1	years out
Capital Cost	$ 850,000	
Project Economic Life	30	years
Discount Rate	8%	(real)

DISCOUNTED CASHFLOW CALCULATION OF UNIT COST

	2010	2011	2012	2013	2014	2015	2016	2017	…	2038	2039
Year	1	2	3	4	5	6	7	8	…	29	30
Direct Capital Cost	$ 850,000										
Operations & Maintenance	*$ 1,300*	*$ 1,300*	*$ 1,300*	*$ 1,300*	*$ 1,300*	*$ 1,300*	*$ 1,300*	*$ 1,300*	...	*$ 1,300*	*$ 1,300*
Property Taxes	*$ 700*	*$ 700*	*$ 700*	*$ 700*	*$ 700*	*$ 700*	*$ 700*	*$ 700*	...	*$ 700*	*$ 700*
Insurance & Administration	*$ 700*	*$ 700*	*$ 700*	*$ 700*	*$ 700*	*$ 700*	*$ 700*	*$ 700*	...	*$ 700*	*$ 700*
Sustaining Capital	*$ 400*	*$ 400*	*$ 400*	*$ 400*	*$ 400*	*$ 400*	*$ 400*	*$ 400*	...	*$ 400*	*$ 400*
Major Capital (dam anchoring)	*$ -*	*$ -*	*$ -*	*$ -*	*$ 3,695*	*$ -*	*$ -*	*$ -*	...	*$ -*	*$ -*
Major Capital (ULE)	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ 3,623*	*$ -*	*$ -*	...	*$ -*	*$ -*
Water Rental Fees - capacity only (4.095/kW)	*$ 673*	*$ 673*	*$ 673*	*$ 673*	*$ 673*	*$ 673*	*$ 673*	*$ 673*	...	*$ 673*	*$ 673*
Water Rental Fees - energy only (6.896/GWh)	*$ 6,951*	*$ 6,951*	*$ 6,951*	*$ 6,951*	*$ 6,220*	*$ 5,965*	*$ 5,965*	*$ 5,965*	...	*$ 6,096*	*$ 6,096*
Admin Costs	*$ 150*	*$ 150*	*$ 150*	*$ 150*	*$ 150*	*$ 150*	*$ 150*	*$ 150*	...	*$ 150*	*$ 150*
Annual Operating Cost	$ 10,874	$ 10,874	$ 10,874	$ 10,874	$ 13,838	$ 13,511	$ 9,888	$ 9,888	...	$ 10,019	$ 10,019
Total Cost	**$ 860,874**	**$ 10,874**	**$ 10,874**	**$ 10,874**	**$ 13,838**	**$ 13,511**	**$ 9,888**	**$ 9,888**	...	**$ 10,019**	**$ 10,019**
Discount factor formula	=1/(1+i)^(years-1)										
Discounting factor	1	0.93	0.86	0.79	0.74	0.68	0.63	0.58	...	0.12	0.11
Total Cost x discounting factor	$ 860,874	$ 10,069	$ 9,323	$ 8,632	$ 10,171	$ 9,195	$ 6,231	$ 5,770	...	$ 1,161	$ 1,075
NPV Total Cost	$ 979,182										
Annual Energy Benefit (GWh)	1008	1008	1008	1008	902	865	865	865	...	884	884
Annual Energy x discounting factor	1008.0	933.3	864.2	800.2	663.0	588.7	545.1	504.7	...	102.5	94.9
NPE ("Net Present Energy")	11064.9										
Unit Energy Cost (UEC - $/MWh) = NPV/"NPE"	$ 88										

PROJECT	Run Of River Hydro - FortisBC Territory
RESOURCE	Hydro - Greenfield
REFERENCE	Midgard Files, BC MOE Water License Applications, Water Survey Canada
CALCULATION METHOD	Annualized Cost

TECHNICAL PARAMETERS	
Installed Capacity (MW)	70
Average Annual Energy (GWh/yr)	250
Dependable Capacity (MW)	10
Annual Firm Energy (GWh/yr)	205
Heat Rate (GJ/GWh)	

FINANCIAL PARAMETERS (FISCAL 2010 $)	
Direct Capital Cost (k$) - Note 1	280,000
Project Life (years) - Note 2	40
Project Lead Time (years)	3

OPERATING COSTS:	
Fixed OMA (k$/yr) - Note 3	4,200
Variable OMA ($/MWh)	0
Grants-in-lieu of Taxes ($/kW-yr)	0
Fixed Taxes (k$/yr) - Note 4	815
Variable Taxes ($/MWh)	0
Water Rentals - Capacity ($/kW-yr)	4.095
Water Rentals - Energy ($/MWh)	1.229
Fuel Price ($/GJ)	0
Fuel Tax (%)	0%
Firm Fuel Transporation ($/GJ)	0

CONSTRUCTION CASH FLOW:

Year	Direct	6%	8%
1	93,333	104,869	108,864
2	93,333	98,933	100,800
3	93,333	93,333	93,333
4		0	0
5		0	0
6		0	0
7		0	0
8		0	0
9		0	0
10		0	0
11		0	0
12		0	0
13		0	0
14		0	0
15		0	0
16		0	0
17		0	0
18		0	0
19		0	0
20		0	0
Total	280,000	297,136	302,997
Annualized		19,748	25,409

UCC Based on Dependable Capacity:	6%	8%
Investment Cost (Annualized Capital) (k$/yr)	19,748	25,409
Fixed Investment ($/kW-yr)	1,975	2,541
Fixed Operations ($/kW-yr)	506	506
Variable Operations ($/kW-yr)	0	0
Fuel Cost ($/kW-yr)	0	0
Unit Capacity Cost ($/MW-month)	206,704	253,881
Unit Capacity Cost ($/kW-yr)	2,480	3,047

UEC Based on Average Energy Capability:	6%	8%
Investment Cost (Annualized Capital) (k$/yr)	$19,748	$25,409
Fixed Investment ($/MWh)	$79	$102
Fixed Operations ($/MWh)	$21	$21
Variable Operations ($/MWh)	$1	$1
Fuel Cost ($/MWh)	$0	$0
Unit Energy Cost ($/MWh)	$101	$124

Unit Construction Cost	6%	8%
All in Capital Construction (k$)	$ 297,136	302,997
Dependable Capacity (MW)	10	10
Unit Construction Cost (k$/MW)	$ 29,714	$ 30,300

Notes

1) Range: $266M to $294M
2) Assume project fully amortized over maximum duration of water license
3) Daily O&M - .5% / Capital Maintenance - .5% / Insurance - .5% of cap cost
4) Fixed asset cost (assume 70% of total) x municipal mill rate of $4.16

PROJECT	Similkameen - Small Hydro with Capacity
RESOURCE	Hydro - Greenfield
REFERENCE	Midgard Files, Hatch Engineering Report, BC MOE Water License Applications, Water Survey Canada
CALCULATION METHOD	Annualized Cost

TECHNICAL PARAMETERS	
Installed Capacity (MW)	60
Average Annual Energy (GWh/yr)	234
Dependable Capacity (MW)	60
Annual Firm Energy (GWh/yr)	173.6
Heat Rate (GJ/GWh)	

FINANCIAL PARAMETERS (FISCAL 2010 $)	
Direct Capital Cost (k$)	283,117
Project Life (years)	70
Project Lead Time (years)	3

OPERATING COSTS:	
Fixed OMA (k$/yr)	1,670
Variable OMA ($/MWh)	0
Grants-in-lieu of Taxes ($/kW-yr)	0
Fixed Taxes (k$/yr) - Note 1	824
Variable Taxes ($/MWh)	0
Water Rentals - Capacity ($/kW-yr)	4.095
Water Rentals - Energy ($/MWh)	6.896
Fuel Price ($/GJ)	0
Fuel Tax (%)	0%
Firm Fuel Transporation ($/GJ)	0

CONSTRUCTION CASH FLOW :

Year	Direct	6%	8%
1	94,372	106,037	110,076
2	94,372	100,035	101,922
3	94,372	94,372	94,372
4		0	0
5		0	0
6		0	0
7		0	0
8		0	0
9		0	0
10		0	0
11		0	0
12		0	0
13		0	0
14		0	0
15		0	0
16		0	0
17		0	0
18		0	0
19		0	0
20		0	0
Total	283,117	300,444	306,370
Annualized		18,337	24,622

UCC Based on Dependable Capacity:		
	6%	8%
Investment Cost (Annualized Capital) (k$/yr)	18,337	24,622
Fixed Investment ($/kW-yr)	306	410
Fixed Operations ($/kW-yr)	46	46
Variable Operations ($/kW-yr)	0	0
Fuel Cost ($/kW-yr)	0	0
Unit Capacity Cost ($/MW-month)	29,274	38,003
Unit Capacity Cost ($/kW-yr)	351	456

UEC Based on Average Energy Capability:		
	6%	8%
Investment Cost (Annualized Capital) (k$/yr)	18,337	24,622
Fixed Investment ($/MWh)	78	105
Fixed Operations ($/MWh)	12	12
Variable Operations ($/MWh)	7	7
Fuel Cost ($/MWh)	0	0
Unit Energy Cost ($/MWh)	97	124

Unit Construction Cost				
		6%		8%
All in Capital Construction (k$)	$	300,444		306,370
Dependable Capacity (MW)		60		60
Unit Construction Cost (k$/MW)	$	5,007	$	5,106

Notes
1) Fixed asset cost (assume 70% of total) x municipal mill rate of $4.16

PROJECT	Run-Of-River Hydro - Coastal
RESOURCE	Hydro - Greenfield
REFERENCE	Midgard Files, BC MOE Water License Apps, Water Survey Canada
CALCULATION METHOD	Annualized Cost

TECHNICAL PARAMETERS	
Installed Capacity (MW)	62
Average Annual Energy (GWh/yr) - Note 1	255
Dependable Capacity (MW) - Note 2	28
Annual Firm Energy (GWh/yr) - Note 1	229
Heat Rate (GJ/GWh)	

FINANCIAL PARAMETERS (FISCAL 2010 $)	
Direct Capital Cost (k$) - Note 3	248,000
Project Life (years) - Note 4	40
Project Lead Time (years)	3

OPERATING COSTS:	
Fixed OMA (k$/yr) - Note 5	3,720
Variable OMA ($/MWh)	0
Grants-in-lieu of Taxes ($/kW-yr)	0
Fixed Taxes (k$/yr) - Note 6	722
Variable Taxes ($/MWh)	0
Water Rentals - Capacity ($/kW-yr)	4.095
Water Rentals - Energy ($/MWh)	1.229
Fuel Price ($/GJ)	0
Fuel Tax (%)	0%
Firm Fuel Transporation ($/GJ)	0

CONSTRUCTION CASH FLOW :			
Year	Direct	6%	8%
1	82,667	92,884	96,422
2	82,667	87,627	89,280
3	82,667	82,667	82,667
4		0	0
5		0	0
6		0	0
7		0	0
8		0	0
9		0	0
10		0	0
11		0	0
12		0	0
13		0	0
14		0	0
15		0	0
16		0	0
17		0	0
18		0	0
19		0	0
20		0	0
Total	248,000	263,178	268,369
Annualized		17,491	22,505

UCC Based on Dependable Capacity:		
	6%	8%
Investment Cost (Annualized Capital) (k$/yr)	17,491	22,505
Fixed Investment ($/kW-yr)	622	800
Fixed Operations ($/kW-yr)	162	162
Variable Operations ($/kW-yr)	0	0
Fuel Cost ($/kW-yr)	0	0
Unit Capacity Cost ($/MW-month)	65,350	80,212
Unit Capacity Cost ($/kW-yr)	784	963

UEC Based on Average Energy Capability:		
	6%	8%
Investment Cost (Annualized Capital) (k$/yr)	17,491	22,505
Fixed Investment ($/MWh)	69	88
Fixed Operations ($/MWh)	18	18
Variable Operations ($/MWh)	1	1
Fuel Cost ($/MWh)	0	0
Unit Energy Cost ($/MWh)	88	108

Unit Construction Cost			
		6%	8%
All in Capital Construction (k$)	$	263,178	268,369
Dependable Capacity (MW)		28	28
Unit Construction Cost (k$/MW)	$	9,360	$ 9,545

Notes

1) Energy is derated 6.28% for transmission losses - short term firm and non-firm wheeling is free
2) Dependable capacity has been derated 6.28% to account for BC Hydro average system losses
3) Range = $235 million to $260 million
4) Assume project fully amortized over maximum duration of water license
5) Daily O&M - .5% / Capital Maintenance - .5% / Insurance - .5% of cap cost
6) Fixed asset cost (assume 70% of total) x municipal mill rate of $4.16

PROJECT	Resource Smart Bundle (w/o Mica & Revelstoke)
RESOURCE	Hydro - Resource Smart
REFERENCE	LTAP - Apendix F-1 page 44
CALCULATION METHOD	Annualized Cost

TECHNICAL PARAMETERS	
Installed Capacity (MW)	109
Average Annual Energy (GWh/yr)	259
Dependable Capacity (MW)	109
Annual Firm Energy (GWh/yr)	259
Heat Rate (GJ/GWh)	

FINANCIAL PARAMETERS (FISCAL 2010 $)	
Direct Capital Cost (k$)	279,904
Project Life (years)	50
Project Lead Time (years)	3

OPERATING COSTS:	
Fixed OMA (k$/yr)	3,642
Variable OMA ($/MWh)	0
Grants-in-lieu of Taxes ($/kW-yr)	0
Fixed Taxes (k$/yr)	0
Variable Taxes ($/MWh)	0
Water Rentals - Capacity ($/kW-yr)	4.095
Water Rentals - Energy ($/MWh)	6.896
Fuel Price ($/GJ)	0
Fuel Tax (%)	0%
Firm Fuel Transporation ($/GJ)	0

CONSTRUCTION CASH FLOW:

Year	Direct	6%	8%
1	93,301	104,833	108,827
2	93,301	98,899	100,765
3	93,301	93,301	93,301
4		0	0
5		0	0
6		0	0
7		0	0
8		0	0
9		0	0
10		0	0
11		0	0
12		0	0
13		0	0
14		0	0
15		0	0
16		0	0
17		0	0
18		0	0
19		0	0
20		0	0
Total	279,904	297,034	302,894
Annualized		18,845	24,759

UCC Based on Dependable Capacity:		
	6%	8%
Investment Cost (Annualized Capital) (k$/yr)	18,845	24,759
Fixed Investment ($/kW-yr)	173	227
Fixed Operations ($/kW-yr)	38	38
Variable Operations ($/kW-yr)	0	0
Fuel Cost ($/kW-yr)	0	0
Unit Capacity Cost ($/MW-month)	17,534	22,055
Unit Capacity Cost ($/kW-yr)	210	265

UEC Based on Average Energy Capability:		
	6%	8%
Investment Cost (Annualized Capital) (k$/yr)	$18,845	$24,759
Fixed Investment ($/MWh)	$73	$96
Fixed Operations ($/MWh)	$16	$16
Variable Operations ($/MWh)	$7	$7
Fuel Cost ($/MWh)	$0	$0
Unit Energy Cost ($/MWh)	$95	$118

Unit Construction Cost				
		6%		8%
All in Capital Construction (k$)	$	297,034		302,894
Dependable Capacity (MW)		109		109
Unit Construction Cost (k$/MW)	$	2,725	$	2,779

PROJECT	Indicative Pumped Storage Opportunities for Okanagan
RESOURCE	Pumped Storage
REFERENCE	Midgard Files, FortisBC, BC MOE Water License Apps, Water Survey Can.
CALCULATION METHOD	Annualized Cost

TECHNICAL PARAMETERS	
Installed Capacity (MW)	180
Average Annual Energy (GWh/yr)	0
Dependable Capacity (MW)	180
Annual Firm Energy (GWh/yr)	0
Round Trip Efficiency	70%

FINANCIAL PARAMETERS (FISCAL 2010 $)	
Direct Capital Cost (k$)	340,000
Project Life (years)	70
Project Lead Time (years)	4

OPERATING COSTS:	
Fixed OMA (k$/yr) - Note 1	5,100
Variable OMA ($/MWh)	0
Grants-in-lieu of Taxes ($/kW-yr)	0
Fixed Taxes (k$/yr) - Note 2	990
Variable Taxes ($/MWh)	0
Water Rentals - Capacity ($/kW-yr)	4.095
Water Rentals - Energy ($/MWh)	6.896
Fuel Price ($/GJ)	0
Fuel Tax (%)	0%
Firm Fuel Transporation ($/GJ)	0

CONSTRUCTION CASH FLOW :

Year	Direct	6%	8%
1	85,000	101,236	107,076
2	85,000	95,506	99,144
3	85,000	90,100	91,800
4	85,000	85,000	85,000
5		0	0
6		0	0
7		0	0
8		0	0
9		0	0
10		0	0
11		0	0
12		0	0
13		0	0
14		0	0
15		0	0
16		0	0
17		0	0
18		0	0
19		0	0
20		0	0
Total	340,000	371,842	383,020
Annualized		22,695	30,782

UCC Based on Dependable Capacity:

	6%	8%
Investment Cost (Annualized Capital) (k$/yr)	22,695	30,782
Fixed Investment ($/kW-yr)	126	171
Fixed Operations ($/kW-yr)	38	38
Variable Operations ($/kW-yr)	0	0
Fuel Cost ($/kW-yr)	0	0
Unit Capacity Cost ($/MW-month)	13,668	17,412
Unit Capacity Cost ($/kW-yr)	164	209

Unit Construction Cost

		6%	8%
All in Capital Construction (k$)	$	371,842	383,020
Dependable Capacity (MW)		180	180
Unit Construction Cost (k$/MW)	$	2,066	$ 2,128

Notes

1) Daiily O&M - .5% / Capital Maintenance - .5% / Insurance - .5% of cap cost
2) Fixed asset cost (assume 70% of total) x municipal mill rate of $4.16

PROJECT	Hydro - Site C
RESOURCE	Hydro
REFERENCE	BC Hydro 2008 LTAP - Appendix F1 adjusted for $2010 BC Hydro Peace River Site C Hydro Project, Project Definition Consultation, Round 2 Summary Report, February 9, 2009, Kirk & Co. Consulting Ltd. and Synovate Ltd.
CALCULATION METHOD	Annualized Cost

TECHNICAL PARAMETERS	
Installed Capacity (MW)	900
Average Annual Energy (GWh/yr)	4600
Dependable Capacity (MW)	888
Annual Firm Energy (GWh/yr)	4000
Heat Rate (GJ/GWh)	0

FINANCIAL PARAMETERS (FISCAL 2010 $)	
Direct Capital Cost (k$) - Note 1	5,907,788
Project Life (years)	70
Project Lead Time (years)	6

OPERATING COSTS:	
Fixed OMA (k$/yr)	9,909
Variable OMA ($/MWh)	0
Grants-in-lieu of Taxes ($/kW-yr)	0.59
Fixed Taxes (k$/yr)	2,879
Variable Taxes ($/MWh)	0
Water Rentals - Capacity ($/kW-yr)	4.095
Water Rentals - Energy ($/MWh)	6.896
Fuel Price ($/GJ)	0
Fuel Tax (%)	0%
Firm Fuel Transporation ($/GJ)	0

CONSTRUCTION CASH FLOW:

Year	Direct	6%	8%
1	984,631	1,317,659	1,446,746
2	984,631	1,243,074	1,339,580
3	984,631	1,172,712	1,240,352
4	984,631	1,106,332	1,148,474
5	984,631	1,043,709	1,063,402
6	984,631	984,631	984,631
7		0	0
8		0	0
9		0	0
10		0	0
11		0	0
12		0	0
13		0	0
14		0	0
15		0	0
16		0	0
17		0	0
18		0	0
19		0	0
20		0	0
Total	5,907,788	6,868,117	7,223,185
Annualized		419,183	580,510

UCC Based on Dependable Capacity:		
	6%	8%
Investment Cost (Annualized Capital) (k$/yr)	$419,183	$580,510
Fixed Investment ($/kW-yr)	$472	$654
Fixed Operations ($/kW-yr)	$19	$19
Variable Operations ($/kW-yr)	$0	$0
Fuel Cost ($/kW-yr)	$0	$0
Unit Capacity Cost ($/MW-month)	$40,921	$56,058
Unit Capacity Cost ($/kW-yr)	$491	$673

UEC Based on Average Energy Capability:		
	6%	8%
Investment Cost (Annualized Capital) (k$/yr)	$419,183	$580,510
Fixed Investment ($/MWh)	$91	$126
Fixed Operations ($/MWh)	$4	$4
Variable Operations ($/MWh)	$7	$7
Fuel Cost ($/MWh)	$0	$0
Unit Energy Cost ($/MWh)	$102	$137

Unit Construction Cost			
		6%	8%
All in Capital Construction (k$)	$	6,868,117	7,223,185
Dependable Capacity (MW)		888	888
Unit Construction Cost (k$/MW)	$	7,733	$ 8,133

Notes

1) The range of capital costs is: $5,000M to $6,600M in 2009$. The average was chosen for calculation purposes.

PROJECT	Wind - Low Cost - FortisBC Territory
RESOURCE	Wind
CALCULATION METHOD	Annualized Cost

TECHNICAL PARAMETERS	
Installed Capacity (MW)	30
Average Annual Energy (GWh/yr)	65.7
Dependable Capacity (MW) - Note 2	3
Annual Firm Energy (GWh/yr)	0
Heat Rate (GJ/GWh)	0

FINANCIAL PARAMETERS (FISCAL 2010 $)	
Direct Capital Cost (k$)	61,152
Project Life (years)	20
Project Lead Time (years)	3

OPERATING COSTS:	
Fixed OMA (k$/yr)	1,455
Variable OMA ($/MWh)	0
Grants-in-lieu of Taxes ($/kW-yr)	0
Fixed Taxes (k$/yr)	174
Variable Taxes ($/MWh)	0
Water Rentals - Capacity ($/kW-yr)	0
Water Rentals - Energy ($/MWh)	0
Fuel Price ($/GJ)	0
Fuel Tax (%)	0%
Firm Fuel Transporation ($/GJ)	0

CONSTRUCTION CASH FLOW :

Year	Direct	6%	8%
1	20,384	22,903	23,776
2	20,384	21,607	22,015
3	20,384	20,384	20,384
4		0	0
5		0	0
6		0	0
7		0	0
8		0	0
9		0	0
10		0	0
11		0	0
12		0	0
13		0	0
14		0	0
15		0	0
16		0	0
17		0	0
18		0	0
19		0	0
20		0	0
Total	61,152	64,895	66,175
Annualized		5,658	6,740

UCC Based on Dependable Capacity:		
	6%	8%
Investment Cost (Annualized Capital) (k$/yr)	5,658	6,740
Fixed Investment ($/kW-yr)	1,886	2,247
Fixed Operations ($/kW-yr)	543	543
Variable Operations ($/kW-yr)	0	0
Fuel Cost ($/kW-yr)	0	0
Unit Capacity Cost ($/MW-month)	202,405	232,467
Unit Capacity Cost ($/kW-yr)	2,429	2,790

UEC Based on Average Energy Capability:		
	6%	8%
Investment Cost (Annualized Capital) (k$/yr)	5,658	6,740
Fixed Investment ($/MWh)	86	103
Fixed Operations ($/MWh)	25	25
Variable Operations ($/MWh)	0	0
Fuel Cost ($/MWh)	0	0
Unit Energy Cost ($/MWh)	111	127

Unit Construction Cost		
	6%	8%
All in Capital Construction (k$)	$ 64,895	66,175
Dependable Capacity (MW)	3	3
Unit Construction Cost (k$/MW)	$ 21,632	$ 22,058

Notes

1) FortisBC Territory 30 MW Wind Bundle (modified from BC Hydro 2008 LTAP base case of 150 MW)
A number of possible sites exist in FortisBC territory
2) Excerpt from Western Electricity Coordinating Council 2008 Power Supply Assessment 11/5/2008
"For this analysis, summer wind turbine capacity was derated, on average, based on utility submissions, to approximately 16% of nameplate capacity, and winter wind capacity was derated to approximately 10% of nameplate capacity. "

PROJECT	Wind - High Cost - FortisBC Territory
RESOURCE	Wind
REFERENCE	
CALCULATION METHOD	Annualized Cost

TECHNICAL PARAMETERS	
Installed Capacity (MW)	30
Average Annual Energy (GWh/yr)	65.7
Dependable Capacity (MW) - Note 2	3
Annual Firm Energy (GWh/yr)	0
Heat Rate (GJ/GWh)	0

FINANCIAL PARAMETERS (FISCAL 2010 $)	
Direct Capital Cost (k$) - Note 3	76,640
Project Life (years)	20
Project Lead Time (years)*	3

OPERATING COSTS:	
Fixed OMA (k$/yr)	1,455
Variable OMA ($/MWh)	0
Grants-in-lieu of Taxes ($/kW-yr)	0
Fixed Taxes (k$/yr)	218
Variable Taxes ($/MWh)	0
Water Rentals - Capacity ($/kW-yr)	0
Water Rentals - Energy ($/MWh)	0
Fuel Price ($/GJ)	0
Fuel Tax (%)	0%
Firm Fuel Transporation ($/GJ)	0

CONSTRUCTION CASH FLOW :

Year	Direct	6%	8%
1	25,547	28,704	29,798
2	25,547	27,079	27,590
3	25,547	25,547	25,547
4		0	0
5		0	0
6		0	0
7		0	0
8		0	0
9		0	0
10		0	0
11		0	0
12		0	0
13		0	0
14		0	0
15		0	0
16		0	0
17		0	0
18		0	0
19		0	0
20		0	0
Total	76,640	81,330	82,935
Annualized		7,091	8,447

UCC Based on Dependable Capacity:		
	6%	8%
Investment Cost (Annualized Capital) (k$/yr)	7,091	8,447
Fixed Investment ($/kW-yr)	2,364	2,816
Fixed Operations ($/kW-yr)	558	558
Variable Operations ($/kW-yr)	0	0
Fuel Cost ($/kW-yr)	0	0
Unit Capacity Cost ($/MW-month)	243,432	281,108
Unit Capacity Cost ($/kW-yr)	2,921	3,373

UEC Based on Average Energy Capability:		
	6%	8%
Investment Cost (Annualized Capital) (k$/yr)	7,091	8,447
Fixed Investment ($/MWh)	108	129
Fixed Operations ($/MWh)	25	25
Variable Operations ($/MWh)	0	0
Fuel Cost ($/MWh)	0	0
Unit Energy Cost ($/MWh)	133	154

Unit Construction Cost				
		6%		8%
All in Capital Construction (k$)	$	81,330		82,935
Dependable Capacity (MW)		3		3
Unit Construction Cost (k$/MW)	$	27,110	$	27,645

Notes

1) FortisBC Territory 30 MW Wind Bundle (modified from LTAP base case of 150 MW)
A number of possible sites exist in FortisBC territory
2) Excerpt from Western Electricity Coordinating Council 2008 Power Supply Assessment 11/5/2008
"For this analysis, summer wind turbine capacity was derated, on average, based on utility submissions, to approximately 16% of nameplate capacity, and winter wind capacity was derated to approximately 10% of nameplate capacity.
3) Garrard Hassan Wind Project Assumptions - 2008 LTAP

PROJECT	Simple Cycle Gas Turbine
RESOURCE	Natural Gas
REFERENCE	
CALCULATION METHOD	Discounted Cash Flow Method - DCF method employed because benefits from SCGT are not constant over time

UNIT CONSTRUCTION COST CALCULATION

Project	Simple Cycle Gas Turbine
Capital Cost	$ 44,269
Dependable Capacity (MW)	38.6
Unit Construction Cost (k$/MW)	$ 1,147

DISCOUNTED CASH FLOW COMMON PARAMETERS

Project Simple Cycle Gas Turbine

	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	....	**2040**	**2041**
Dependable Capacity (MW)	*0*	*0*	*38.6*	*38.6*	*38.5*	*38.5*	*38.5*	....	*37.9*	*37.8*
Heat Rate (GJ/GWh)	*0*	*0*	*9843*	*9839.6*	*9836.2*	*9832.9*	*9829.5*	....	*9748.6*	*9745*
Firm Annual Energy (GWh)	*0*	*0*	*68*	*68*	*68*	*67*	*67*	....	*66*	*66*
Fuel Use (GJ)	*0*	*0*	*665342.0929*	*664678*	*664013*	*663349*	*662686*	....	*646847*	*645758*
Fuel Use (MMBtu)	*0*	*0*	*630656.0122*	*630026*	*629396*	*628767*	*628138*	....	*613125*	*612093*
Forward Fuel Curve (Real $USD 2010)	*$ 4.64*	*$ 5.85*	*$ 6.35*	*$ 6.31*	*$ 6.27*	*$ 6.46*	*$ 6.57*	....	*$ 9.14*	*$ 9.14*
Assumed Exchange Rate (USD to Cdn)	*$ 0.95*	*$ 0.95*	*$ 0.95*	*$ 0.95*	*$ 0.95*	*$ 0.90*	*$ 0.90*	....	*$ 0.90*	*$ 0.90*
Forward Fuel Curve (Real $CDN 2010)	$ 4.88	$ 6.16	$ 6.69	$ 6.64	$ 6.60	$ 7.17	$ 7.29	....	$ 10.16	$ 10.16
Fuel Cost ($/MWh)			*$ 62.41*	*$ 61.95*	*$ 61.49*	*$ 66.86*	*$ 67.97*	....	*$ 93.86*	*$ 93.83*
BC Carbon Tax ($/metric ton)	*$ 20.00*	*$ 25.00*	*$ 30.00*	*$ 30.00*	*$ 30.00*	*$ 30.00*	*$ 30.00*	....	*$ 30.00*	*$ 30.00*
Firm Fuel Transport Cost ($/GJ)	*$ 0.30*	*$ 0.30*	*$ 0.30*	*$ 0.30*	*$ 0.30*	*$ 0.30*	*$ 0.30*	....	*$ 0.30*	*$ 0.30*

UNIT CAPACITY COST CALCULATION - BY DCF ($000s)

Project	Simple Cycle Gas Turbine	
Project in-service date	3	years out
Capital Cost	$ 44,269	
Project Economic Life	25	years
Discount Rate	6%	(real)

DISCOUNTED CASHFLOW CALCULATION OF UNIT COST

	2010	2011	2012	2013	2014	2015	2016	....	2040	2041
Year	1	2	3	4	5	6	7	....	31	32
Direct Capital Cost	$ 22,135	$ 22,135								
Fixed Operations & Maintenance			*$ 515*	*$ 515*	*$ 515*	*$ 515*	*$ 515*	....	*$ 515*	*$ 515*
Fuel Transport Cost			$ 73	$ 73	$ 73	$ 73	$ 73	....	$ 72	$ 72
Annual Operating Cost	$ -	$ -	$ 588	$ 588	$ 588	$ 588	$ 588	....	$ 586	$ 586
Total Cost	**$ 22,135**	**$ 22,135**	**$ 588**	**$ 588**	**$ 588**	**$ 588**	**$ 588**	....	**$ 586**	**$ 586**
Discount factor formula	=1/(1+i)^(years-1)									
Discounting factor	1	0.94	0.89	0.84	0.79	0.75	0.70	....	0.17	0.16
Total Cost x discounting factor	$ 22,135	$ 20,882	$ 523	$ 493	$ 465	$ 439	$ 414	....	$ 102	$ 96
NPV Total Cost	$ 50,642									
Annual Dependable Capacity Benefit (MW)			38.582	38.5566594	39	39	38	....	38	38
Dependable Capacity x discounting factor	0.0	0.0	34.3	32.4	30.5	28.8	27.1	....	6.6	6.2

NPC ("Net Present Capacity")	497.6
Unit Capacity Cost (UCC - $/kW-yr) = NPV/"NPC"	$ 102
UCC - $/MW-month	$ 8,481

UNIT CAPACITY COST CALCULATION - BY DCF ($000s)

Project	Simple Cycle Gas Turbine	
Project in-service date	3	years out
Capital Cost	$ 44,269	
Project Economic Life	25	years
Discount Rate	8%	(real)

DISCOUNTED CASHFLOW CALCULATION OF UNIT COST

	2010	2011	2012	2013	2014	2015	2016	....	2040	2041
Year	1	2	3	4	5	6	7	....	31	32
Direct Capital Cost	$ 22,135	$ 22,135								
Fixed Operations & Maintenance	*$ -*	*$ -*	*$ 515*	*$ 515*	*$ 515*	*$ 515*	*$ 515*	....	*$ 515*	*$ 515*
Fuel Transport Cost	*$ -*	*$ -*	*$ 73*	*$ 73*	*$ 73*	*$ 73*	*$ 73*	....	*$ 72*	*$ 72*
Annual Operating Cost	$ -	$ -	$ 588	$ 588	$ 588	$ 588	$ 588	....	$ 586	$ 586
Total Cost	**$ 22,135**	**$ 22,135**	**$ 588**	**$ 588**	**$ 588**	**$ 588**	**$ 588**	....	**$ 586**	**$ 586**
Discount factor formula	=1/(1+i)^(years-1)									
Discounting factor	1	0.93	0.86	0.79	0.74	0.68	0.63	....	0.10	0.09
Total Cost x discounting factor	$ 22,135	$ 20,495	$ 504	$ 467	$ 432	$ 400	$ 370	....	$ 58	$ 54
NPV Total Cost	$ 48,752									
Annual Dependable Capacity Benefit (MW)			38.6	38.6	38.5	38.5	38.5	....	37.9	37.8
Dependable Capacity x discounting factor	0.0	0.0	33.1	30.6	28.3	26.2	24.2	....	3.8	3.5

NPC ("Net Present Capacity")	399.7
Unit Capacity Cost (UCC - $/kW-yr) = NPV/"NPC"	$ 122
UCC - $/MW-month	$ 10,163

UNIT ENERGY COST CALCULATION - BY DCF ($000s)

Project	Simple Cycle Gas Turbine	
Project in-service date	3	years out
Capital Cost	$ 44,269	
Project Economic Life	25	years
Discount Rate	6%	(real)

DISCOUNTED CASHFLOW CALCULATION OF UNIT COST

	2010	2011	2012	2013	2014	2015	2016	....	2040	2041
Year	1	2	3	4	5	6	7	....	31	32
Direct Capital Cost	$ 22,135	$ 22,135								
Operations & Maintenance			*$ 515*	*$ 515*	*$ 515*	*$ 515*	*$ 515*	....	*$ 515*	*$ 515*
Variable Operations and Maintenance ($4/MWh)			*$ 270*	*$ 270*	*$ 270*	*$ 270*	*$ 270*	....	*$ 265*	*$ 265*
Fuel Cost			*$ 4,219*	*$ 4,185*	*$ 4,151*	*$ 4,510*	*$ 4,582*	....	*$ 6,228*	*$ 6,218*
Fuel Tax (%)			*$ 295*	*$ 293*	*$ 291*	*$ 316*	*$ 321*	....	*$ 436*	*$ 435*
BC Carbon Tax			*$ 1,014*	*$ 1,013*	*$ 1,013*	*$ 1,012*	*$ 1,011*	....	*$ 995*	*$ 994*
Firm Fuel Transporation ($/GJ)			*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	....	*$ -*	*$ -*
Annual Operating Cost	$ -	$ -	$ 6,313	$ 6,276	$ 6,239	$ 6,622	$ 6,699	....	$ 8,439	$ 8,427
Total Cost	**$ 22,135**	**$ 22,135**	**$ 6,313**	**$ 6,276**	**$ 6,239**	**$ 6,622**	**$ 6,699**	....	**$ 8,439**	**$ 8,427**
Discount factor formula	=1/(1+i)^(years-1)									
Discounting factor	1	0.94	0.89	0.84	0.79	0.75	0.70	....	0.17	0.16
Total Cost x discounting factor	$ 22,135	$ 20,882	$ 5,618	$ 5,269	$ 4,942	$ 4,949	$ 4,722	....	$ 1,469	$ 1,384
NPV Total Cost	$ 135,404									
Annual Energy Benefit (GWh)				68	68	67	67	....	66	66
Annual Energy x discounting factor	0.0	0.0	0.0	56.7	53.5	50.4	47.5	....	11.6	10.9
NPE ("Net Present Energy")	811.6									
Unit Energy Cost (UEC - $/MWh) = NPV/"NPE"	$ 167									

UNIT ENERGY COST CALCULATION - BY DCF ($000s)

Project	Simple Cycle Gas Turbine	
Project in-service date	3	
Capital Cost	$ 44,269	
Project Economic Life	25	
Discount Rate	8%	(real)

DISCOUNTED CASHFLOW CALCULATION OF UNIT COST

	2010	2011	2012	2013	2014	2015	2016		2040	2041
Year	1	2	3	4	5	6	7	....	31	32
Direct Capital Cost	$ 22,135	$ 22,135								
Operations & Maintenance			*$ 515*	*$ 515*	*$ 515*	*$ 515*	*$ 515*	....	*$ 515*	*$ 515*
Variable Operations and Maintenance ($4/MWh)			*$ 270*	*$ 270*	*$ 270*	*$ 270*	*$ 270*	....	*$ 265*	*$ 265*
Fuel Cost			*$ 4,219*	*$ 4,185*	*$ 4,151*	*$ 4,510*	*$ 4,582*	....	*$ 6,228*	*$ 6,218*
Fuel Tax (%)			*$ 295*	*$ 293*	*$ 291*	*$ 316*	*$ 321*	....	*$ 436*	*$ 435*
BC Carbon Tax			*$ 1,014*	*$ 1,013*	*$ 1,013*	*$ 1,012*	*$ 1,011*	....	*$ 995*	*$ 994*
Firm Fuel Transporation ($/GJ)			*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	....	*$ -*	*$ -*
Annual Operating Cost	$ -	$ -	$ 6,313	$ 6,276	$ 6,239	$ 6,622	$ 6,699	....	$ 8,439	$ 8,427
Total Cost	**$ 22,135**	**$ 22,135**	**$ 6,313**	**$ 6,276**	**$ 6,239**	**$ 6,622**	**$ 6,699**	....	**$ 8,439**	**$ 8,427**
Discount factor formula	=1/(1+i)^(years-1)									
Discounting factor	1	0.93	0.86	0.79	0.74	0.68	0.63	....	0.10	0.09
Total Cost x discounting factor	$ 22,135	$ 20,495	$ 5,412	$ 4,982	$ 4,586	$ 4,507	$ 4,221	....	$ 839	$ 775
NPV Total Cost	$ 115,749									
Annual Energy Benefit (GWh)				67.5512673	67.5068706	67.4624738	67.4180771	....	66.3525558	66.2637624
Annual Energy x discounting factor	0.0	0.0	0.0	53.6	49.6	45.9	42.5	....	6.6	6.1
NPE ("Net Present Energy")	642.4									
Unit Energy Cost (UEC - $/MWh) = NPV/"NPE"	$ 180									

PROJECT	Combined Cycle Gas Turbine
RESOURCE	Natural Gas
REFERENCE	
CALCULATION METHOD	Discounted Cash Flow Method - DCF method employed because benefits from CCGT are not constant over time

UNIT CONSTRUCTION COST CALCULATION

Project	Combined Cycle Gas Turbine
Capital Cost	$ 329,445
Dependable Capacity (MW)	243
Unit Construction Cost (k$/MW)	$ 1,356

DISCOUNTED CASH FLOW COMMON PARAMETERS

Project Combined Cycle Gas Turbine

	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**…….**	**2036**	**2037**
Dependable Capacity	*0*	*0*	*0*	*243*	*242.7*	*242.4*	*242.1*	**…….**	*236.3*	*236*
Heat Rate (GJ/GWh)	*0*	*0*	*0*	*7460*	*7451*	*7442*	*7433*	**…….**	*7250*	*7241*
Firm Annual Energy (GWh)	*0*	*0*	*0*	*1944*	*1942*	*1939*	*1937*	**…….**	*1890*	*1888*
Fuel Use (GJ)	*0*	*0*	*0*	*14502726*	*14467612*	*14432540*	*14397510*	**…….**	*13705860*	*13671724*
Fuel Use (MMBtu)	*0*	*0*	*0*	*13746660*	*13713376*	*13680132*	*13646929*	**…….**	*12991336*	*12958980*
Forward Fuel Curve (Real $USD 2010)	*$ 4.64*	*$ 5.85*	*$ 6.35*	*$ 6.31*	*$ 6.27*	*$ 6.46*	*$ 6.57*	**…….**	*$ 9.14*	*$ 9.14*
Assumed Exchange Rate (USD to Cdn)	*$ 0.95*	*$ 0.95*	*$ 0.95*	*$ 0.95*	*$ 0.95*	*$ 0.90*	*$ 0.90*	**…….**	*$ 0.90*	*$ 0.90*
Forward Fuel Curve (Real $CDN 2010)	$ 4.88	$ 6.16	$ 6.69	$ 6.64	$ 6.60	$ 7.17	$ 7.29	**…….**	$ 10.16	$ 10.16
Fuel Cost ($/MWh)				*$ 46.97*	*$ 46.58*	*$ 50.60*	*$ 51.39*	**…….**	*$ 69.81*	*$ 69.72*
BC Carbon Tax ($/metric ton)	*$ 20.00*	*$ 25.00*	*$ 30.00*	*$ 30.00*	*$ 30.00*	*$ 30.00*	*$ 30.00*	**…….**	*$ 30.00*	*$ 30.00*

UNIT CAPACITY COST CALCULATION - BY DCF ($000s)

Project	Combined Cycle Gas Turbine	
Project in-service date	4	years out
Capital Cost	$ 329,445	
Project Economic Life	25	years
Discount Rate	6%	(real)

DISCOUNTED CASHFLOW CALCULATION OF UNIT COST

	2010	2011	2012	2013	2014	2015	2016	....	2036	2037
Year	1	2	3	4	5	6	7	....	27	28
Direct Capital Cost	$ 109,815	$ 109,815	$ 109,815							
Fixed Operations & Maintenance				*$ 3,294*	*$ 3,294*	*$ 3,294*	*$ 3,294*	....	*$ 3,294*	*$ 3,294*
Annual Operating Cost	$ -	$ -	$ -	$ 3,294	$ 3,294	$ 3,294	$ 3,294	....	$ 3,294	$ 3,294
Total Cost	**$ 109,815**	**$ 109,815**	**$ 109,815**	**$ 3,294**	**$ 3,294**	**$ 3,294**	**$ 3,294**	....	**$ 3,294**	**$ 3,294**
Discount factor formula	=1/(1+i)^(years-1)									
Discounting factor	1	0.94	0.89	0.84	0.79	0.75	0.70	....	0.22	0.21
Total Cost x discounting factor	$ 109,815	$ 103,599	$ 97,735	$ 2,766	$ 2,610	$ 2,462	$ 2,322	....	$ 724	$ 683
NPV Total Cost	$ 348,631									
Annual Dependable Capacity Benefit (MW)	0	0	0	243	243	242	242	....	236	236
Dependable Capacity x discounting factor	0.0	0.0	0.0	204.0	192.2	181.1	170.7	....	51.9	48.9

NPC ("Net Present Capacity")	2734.5
Unit Capacity Cost (UCC - $/kW-yr) = NPV/"NPC"	$ 127
UCC - $/MW-month	$ 10,624

UNIT CAPACITY COST CALCULATION - BY DCF ($000s)

Project	Combined Cycle Gas Turbine
Project in-service date	4
Capital Cost	$ 329,445
Project Economic Life	25
Discount Rate	8% (real)

DISCOUNTED CASHFLOW CALCULATION OF UNIT COST

	2010	2011	2012	2013	2014	2015	2016	....	2036	2037
Year	1	2	3	4	5	6	7	....	27	28
Direct Capital Cost	$ 109,815	$ 109,815	$ 109,815							
Fixed Operations & Maintenance	*$ -*	*$ -*	*$ -*	*$ 3,294*	*$ 3,294*	*$ 3,294*	*$ 3,294*	....	*$ 3,294*	*$ 3,294*
	$ -	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	....	*$ -*	*$ -*
Annual Operating Cost	$ -	$ -	$ -	$ 3,294	$ 3,294	$ 3,294	$ 3,294	....	$ 3,294	$ 3,294
Total Cost	**$ 109,815**	**$ 109,815**	**$ 109,815**	**$ 3,294**	**$ 3,294**	**$ 3,294**	**$ 3,294**	....	**$ 3,294**	**$ 3,294**
Discount factor formula	=1/(1+i)^(years-1)									
Discounting factor	1	0.93	0.86	0.79	0.74	0.68	0.63	....	0.14	0.13
Total Cost x discounting factor	$ 109,815	$ 101,681	$ 94,149	$ 2,615	$ 2,422	$ 2,242	$ 2,076	....	$ 445	$ 412
NPV Total Cost	$ 335,795									
Annual Dependable Capacity Benefit (MW)				243	242.7083333	242.4166667	242.125	....	236.2916667	236
Dependable Capacity x discounting factor	0.0	0.0	0.0	192.9	178.4	165.0	152.6	....	31.9	29.5

NPC ("Net Present Capacity")	2202.0
Unit Capacity Cost (UCC - $/kW-yr) = NPV/"NPC"	$ 152
UCC - $/MW-month	$ 12,708

UNIT ENERGY COST CALCULATION - BY DCF - $000s

Project	Combined Cycle Gas Turbine	
Project in-service date	4	
Capital Cost	$ 329,445	
Project Economic Life	25	
Discount Rate	6%	(real)

DISCOUNTED CASHFLOW CALCULATION OF UNIT COST

	2010	2011	2012	2013	2014	2015	2016	....	2036	2037
Year	1	2	3	4	5	6	7	....	27	28
Direct Capital Cost	$ 109,815	$ 109,815	$ 109,815							
Operations & Maintenance				*$ 3,294*	*$ 3,294*	*$ 3,294*	*$ 3,294*	....	*$ 3,294*	*$ 3,294*
Variable Operations and Maintenance ($4.60/MWh)				*$ 8,942*	*$ 8,932*	*$ 8,921*	*$ 8,910*	....	*$ 8,696*	*$ 8,685*
Fuel Cost				*$ 91,306*	*$ 90,446*	*$ 98,129*	*$ 99,550*	....	*$ 131,965*	*$ 131,636*
Fuel Tax (%)				*$ 6,391*	*$ 6,331*	*$ 6,869*	*$ 6,969*	....	*$ 9,238*	*$ 9,215*
BC Carbon Tax				*$ 21,287*	*$ 21,261*	*$ 21,236*	*$ 21,210*	....	*$ 20,699*	*$ 20,674*
Firm Fuel Transporation ($/GJ)				*$ -*	*$ -*	*$ -*	*$ -*	....	*$ -*	*$ -*
Annual Operating Cost	$ -	$ -	$ -	$ 131,221	$ 130,265	$ 138,449	$ 139,934	....	$ 173,891	$ 173,503
Total Cost	**$ 109,815**	**$ 109,815**	**$ 109,815**	**$ 131,221**	**$ 130,265**	**$ 138,449**	**$ 139,934**	....	**$ 173,891**	**$ 173,503**
Discount factor formula	=1/(1+i)^(years-1)									
Discounting factor	1	0.94	0.89	0.84	0.79	0.75	0.70	....	0.22	0.21
Total Cost x discounting factor	$ 109,815	$ 103,599	$ 97,735	$ 110,176	$ 103,182	$ 103,457	$ 98,648	....	$ 38,223	$ 35,979
NPV Total Cost	$ 1,986,613									
Annual Energy Benefit (GWh)				1944	1942	1939	1937	....	1890	1888
Annual Energy x discounting factor	0.0	0.0	0.0	1632.2	1538.0	1449.2	1365.5	....	415.5	391.5
NPE ("Net Present Energy")	21876.3									
Unit Energy Cost (UEC - $/MWh) = NPV/"NPE"	$ 91									

UNIT ENERGY COST CALCULATION - BY DCF - $000s

Project	Combined Cycle Gas Turbine	
Project in-service date	4	
Capital Cost	$ 329,445	
Project Economic Life	25	
Discount Rate	8%	(real)

DISCOUNTED CASHFLOW CALCULATION OF UNIT COST

	2010	2011	2012	2013	2014	2015	2016	....	2036	2037
Year	1	2	3	4	5	6	7	....	27	28
Direct Capital Cost	$ 109,815	$ 109,815	$ 109,815							
Operations & Maintenance				*$ 3,294*	*$ 3,294*	*$ 3,294*	*$ 3,294*	....	*$ 3,294*	*$ 3,294*
Variable Operations and Maintenance ($4.60/MWh)				*$ 8,942*	*$ 8,932*	*$ 8,921*	*$ 8,910*	....	*$ 8,696*	*$ 8,685*
Fuel Cost				*$ 91,306*	*$ 90,446*	*$ 98,129*	*$ 99,550*	....	*$ 131,965*	*$ 131,636*
Fuel Tax (%)				*$ 6,391*	*$ 6,331*	*$ 6,869*	*$ 6,969*	....	*$ 9,238*	*$ 9,215*
BC Carbon Tax				*$ 21,287*	*$ 21,261*	*$ 21,236*	*$ 21,210*	....	*$ 20,699*	*$ 20,674*
Firm Fuel Transporation ($/GJ)				*$ -*	*$ -*	*$ -*	*$ -*	....	*$ -*	*$ -*
Annual Operating Cost	$ -	$ -	$ -	$ 131,221	$ 130,265	$ 138,449	$ 139,934	....	$ 173,891	$ 173,503
Total Cost	**$ 109,815**	**$ 109,815**	**$ 109,815**	**$ 131,221**	**$ 130,265**	**$ 138,449**	**$ 139,934**	....	**$ 173,891**	**$ 173,503**
Discount factor formula	=1/(1+i)^(years-1)									
Discounting factor	1	0.93	0.86	0.79	0.74	0.68	0.63	....	0.14	0.13
Total Cost x discounting factor	$ 109,815	$ 101,681	$ 94,149	$ 104,167	$ 95,749	$ 94,226	$ 88,182	....	$ 23,510	$ 21,720
NPV Total Cost	$ 1,639,575									
Annual Energy Benefit (GWh)				1944	1941.666667	1939.333333	1937	....	1890.333333	1888
Annual Energy x discounting factor	0.0	0.0	0.0	1543.2	1427.2	1319.9	1220.6	....	255.6	236.4
NPE ("Net Present Energy")	17615.6									
Unit Energy Cost (UEC - $/MWh) = NPV/"NPE"	$ 93									

Appendix D

MIDGARD PLANNING RESERVE MARGIN REPORT

MIDGARD
CONSULTING INC.

FortisBC Planning Reserve Margin

Submitted By: Midgard Consulting Inc.

Date: March 29, 2011

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FIGURES AND TABLES

1 Executive Summary

FortisBC Inc. ("**FortisBC**") has retained Midgard Consulting Inc. ("**Midgard**") to examine Planning Reserve Margin ("**PRM**") in FortisBC's context and to provide recommendations for prudent PRM requirements.

FortisBC's service area peak system loads have exceeded the utility's reliable capacity resources since the 1990's. At that time it was both economical and reliable to address the relatively minor capacity gaps with market purchases. Since then the service area loads have grown significantly and the winter peak capacity gap presently exceeds 140 MW[1]. During this period historical regional capacity surpluses have eroded and regional transmission has become more constrained. Market prices have increased as has market price volatility, especially during extreme regional weather conditions.

The recent acquisition of surplus capacity from the Waneta Expansion ("**WAX**") Project will satisfy FortisBC's capacity deficit after the project is commissioned in 2015. The WAX capacity is provided under the terms of the Canal Plant Agreement and is therefore unit contingent – the available capacity is reduced proportionately when a generating unit is out of service. FortisBC has acquired contractual capacity rights from Powerex to satisfy its capacity requirements in the interim, and those requirements include an allowance for PRM.

PRM is similar to mandatory Operating Reserves, but rather than addressing real-time operations PRM is intended to address load and resource variability over a planning time frame from one year to 20+ years into the future. PRM addresses three main long term risks:

- unavailability of supply due to unplanned generating unit or transmission outages
- unexpectedly high loads, typically due to extreme weather events
- periods of accelerated load growth that outpaces the installation of new power supply resources.

All of these risks are present for FortisBC and all operating utilities.

The FortisBC system is a relatively small power system with a very large unit-contingent resource in the form of the WAX Capacity Purchase Agreement ("**WAX CAPA**") accounting for a significant proportion of its resource portfolio. Given that an outage to a single WAX generating unit has a material impact on the overall resource stack, Midgard recommends that FortisBC uses the following formula to calculate PRM:

PRM = 5% of Load Responsibility + the Single Largest <u>Utilized</u> Contingency

Focusing on the largest utilized contingency yields a recommended PRM for the FortisBC system that changes on a monthly basis as shown in Figure 1-A and listed in Table 1-A (replicates of Figure 7-B and

---

[1] Based upon the December 2011 peak load forecast and pre-Waneta Expansion Capacity Purchase Agreement (WAX CAPA) resource stack. The interim capacity purchase from Powerex arranged as part of the WAX CAPA has now addressed most of this gap.

Table 7-B, respectively). It is uncommon to show PRM changing on a monthly basis, but the material monthly variability of the majority of FortisBC's supply resources (including WAX CAPA) requires that FortisBC adapt its PRM requirements to match the nature of its supply resources. Simply put, FortisBC carries more PRM in the critical winter months when its peak loads require additional PRM coverage and carries less PRM in other less critical months, thus resulting in a lower overall cost to FortisBC ratepayers and less exposure to long term market risks.

Figure 1-A: Monthly PRM (%)

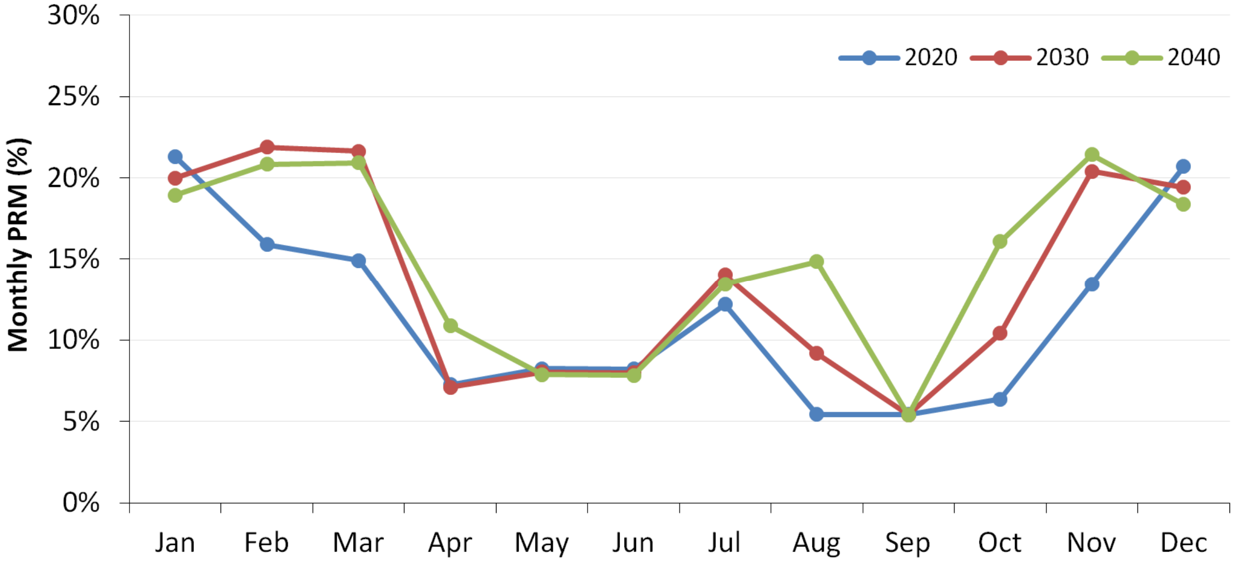

Table 1-A - Monthly PRM (%)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Mean
2020	21	16	15	7	8	8	12	5	5	6	13	21	12
2030	20	22	22	7	8	8	14	9	5	10	20	19	14
2040	19	21	21	11	8	8	13	15	5	16	21	18	15

2 Introduction

FortisBC Inc. ("**FortisBC**") has retained Midgard Consulting Inc. ("**Midgard**") to examine Planning Reserve Margin (“**PRM**”) in FortisBC’s context and to provide recommendations for prudent PRM requirements.

This report defines and differentiates PRM from Operating Reserves and identifies PRM levels carried by other utilities in the region. It provides an introduction to the FortisBC power system, including a review of the various resources that comprise the FortisBC supply resource stack. A review is conducted of the regional market through which FortisBC has historically met its growing capacity deficits, including a discussion of how FortisBC came to depend on the market as a PRM pool. Several risk factors are identified that may lead to decreasing regional market surplus and increasing price volatility. Various PRM calculation methodologies suggested by the Western Electricity Coordinating Council ("**WECC**") are compared and a recommended methodology is selected. Finally, PRM is calculated using the recommended methodology.

3 Resource Reserves

Electric utilities and electric system operators carry resource reserves because of load and generation variability over various timeframes. These resource reserves enable reliable power system operations because every utility is able to meet its own load serving obligations without unreasonably leaning upon its neighbours for extended periods regardless of short or long term changes to its loads and generation resources.

3.1 Load and Resource Variability

3.1.1 Load Variability

Customer demand variability creates a dynamic load serving obligation for an electric utility. Loads can change quite significantly over seconds, hours, days, seasons and years.

In order to meet their household needs for comfort and convenience, residential customers switch appliances, lights and heaters on and off at will. Similarly, industrial and commercial customers change their demand to satisfy their production and business requirements, and in most cases they are not required to notify or ask permission of the system operator to do so.

Throughout each year the aggregate system demand also varies with changing ambient temperatures and daylight conditions, driven primarily by higher air conditioning and irrigation/pumping loads during hot summer days and increased heating and lighting loads (including Christmas lights) during the coldest days of winter. In addition to any seasonal production-related load changes, industrial and commercial customers also exhibit demand variability due to ambient temperature and daylight conditions.

Over the current 30 year planning horizon, longer term load trends are driven by changing population and per capita electricity utilization intensity (e.g.: computers & peripherals, large screen TVs, more & bigger appliances, and in the near future electric and plug-in hybrid vehicles). Large industrial or commercial loads can cause step changes in demand by adding or modifying process or production equipment, and in the extreme case by opening or closing shop.

3.1.2 Generation Variability

The availability and output of generating resources is also variable. Hydroelectric units have seasonal and inter-annual production variability based on the amount of available water and precipitation. Intermittent generation resources only produce power when their fuel supply is available (e.g.: wind generators when the wind blows and solar generators when the sun shines). Both intermittent resources (e.g. wind, solar) and non-intermittent resources (e.g. storage hydro, thermal generators) can experience sudden equipment failures that produce unplanned generation outages.

Consequently, a utility must at all times have access to adequate resources to meet its aggregate instantaneous load serving requirements, including an obligation to carry reserves to address sudden changes in loads or generation.

3.2 Operating Reserves versus Planning Reserve Margin

3.2.1 Operating Reserves

Operating Reserves are defined as the available unused generation capacity that a utility carries above its real-time load serving and export obligations to enable it to rapidly respond to short term variability in loads or the unexpected loss of a generating unit. The North American Electric Reliability Corporation ("**NERC**") publishes Operating Reserve standards for its various sub-regions. FortisBC is situated within the British Columbia Balancing Authority Area which falls under the Western Electricity Coordinating Council ("**WECC**") region. Although FortisBC is not the Balancing Authority for British Columbia, it is still obliged to carry the regionally applicable Operating Reserves for its own resources. The WECC minimum standard[2] governing Operating Reserves requires member utilities to carry:

> *"... adequate generating capacity ... necessary to:*
>
> - *supply requirements for load variations*
> - *replace generating capacity and energy lost due to forced outages of generation or transmission equipment*
> - *meet on-demand obligations*
> - *replace energy lost due to curtailment of interruptible imports"*

The WECC standard further describes the various components that make up a minimum operating reserve, which are:

- **Regulating Reserve:** This is entirely comprised of "spinning reserve" (defined as the unused capacity of generators that are already rotating and interconnected with the grid and are thus able to respond almost instantly) which is called upon automatically in the event of extra generation being required.
- **Contingency Reserve:** An amount of reserve, at least half of which must be spinning, which must be the greater of **(a)** the loss of generating capacity that would occur in the event of the single largest generating or transmission contingency and **(b)** five (5) percent of load capacity served by hydro generation and seven (7) percent of load capacity served by thermal generation. Must be able to respond within ten (10) minutes.
- **Interruptible Import Reserve:** Reserve capacity sufficient to replace all interruptible imports given ten (10) minutes notice.

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[2] WECC Standard BAL-STD-002-0

- **On-demand Obligations:** An amount of reserve sufficient to supply all on-demand obligations to other entities (e.g. other balancing authorities) within ten (10) minutes.

When an event occurs that requires Operating Reserves to be dispatched, the full reserve requirement must be restored as soon as possible and at most within sixty (60) minutes. Reserves can be restored by dispatching additional generating capacity (if available), arranging for additional imports from the electricity market (if available), dispatching off contracted interruptible customer loads or as a last resort by switching off blocks of firm customer load[3].

3.2.2 Planning Reserve Margin

PRM is similar to Operating Reserves, but rather than address real-time operations PRM is intended to address load and resource variability over a planning time frame: from one year to 20+ years into the future.

NERC defines planning reserve margin as "…the difference in deliverable or prospective resources and net internal demand, divided by net internal demand." PRM is typically expressed as a percentage of the expected load during the period of interest, and it must be put in place ahead of the expected time of need because adding new generating resources typically takes years (except for contract resources in systems where existing surplus capacity is available to the market).

It is important to note that PRM is not directly related to operating reserves, with the understanding that carrying a prudent PRM should improve the reliability of real time operations, since PRM improves the likelihood that a utility will have adequate resources available to meet its obligations under credible stressed system scenarios. For example, available PRM can be used to restore the mandatory Operating Reserve margin after initial reserves have been dispatched to address a forced generating unit outage, thereby allowing utility operations to continue without requiring firm load shedding.

There are three (3) potential circumstances that drive the need for PRM:

- **Unavailability of supply due to unplanned generating unit or transmission outage:** Although operating reserves are held in order to allow for moment-to-moment changes in either supply or load, planning reserves are held to protect against any sustained or long-term loss of supply or transmission capability (with the understanding that maintaining a planning reserve margin will also reinforce operating reserves in real time as well).
- **Unexpectedly high loads, typically due to extreme weather events:** In such circumstances it may not be prudent to rely on market energy to meet supply shortfalls because the market energy is likely to come from geographically proximate areas that may be experiencing the same

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[3] This is a very unpopular step. The Alberta Power Pool shed 100 MW of firm load in the fall of 1999 to restore its reserve margins following a series of unplanned outages to several large generating units during a season when several other plants were already unavailable due to extended maintenance shut-downs. The ensuing public debate about the prudence of this action was quite acrimonious, featuring a number of caustic newspaper and TV reports.

weather, with the result that prices may be very high or excess supply may simply be unavailable or inaccessible at the time of need.

- **A period of accelerated load growth that outpaces the installation of new power supply resources:** Given the long lead time associated with most electricity generation projects, it is inadvisable for utilities to function reactively and wait until unforeseen load spikes occur to plan more resources. Carrying a PRM provides a buffer which allows a utility adequate time to react to unforeseen load changes and acquire new assets before load becomes unmanageable.

3.3 PRM Held by Nearby Utilities

Neighbouring regional authorities carry varying amounts of PRM (as presented in Table 3.3-A). This information provides perspective on the current state of the industry in FortisBC's region.

Table 3.3-A: Nearby Planning Reserve Margins

Utility	PRM (%)
Avista	15
BC Hydro[4]	14
Idaho Power	10
Northwestern Energy[5]	0
PacifiCorp	12
Portland General Electric	12
Puget Sound Energy	15

Note that each utility's situation is different and the appropriate level of PRM will vary materially between different utilities. Some factors that affect a utility's PRM requirement include:

- The nature of dispatchable generating units (e.g.: hydroelectric, thermal)
- The age and reliability of generating units
- The saturation level of intermittent generation resources (e.g.: wind, solar)
- The size relationship between the largest generating unit and the load serving obligation
- The reliability of firm supply contracts (counterparty reliability, transmission reliability)
- The weather-based volatility of system loads (saturation of air conditioning or electric heating)
- The population-based volatility of system loads (rapid immigration or emigration)

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[4] BC Hydro's 14% PRM is calculated after allowing for reserves required to meet a 1 day in 10 year Loss of Load Expectation, so actual the reserve level being carried by BCH is substantially higher than 14%; see BC Hydro 2008 Long Term Acquisition Plan Appendix F10: Calculation of Capacity Planning Reserves

[5] Northwestern Energy does not carry Planning Reserves, relying instead on the market to provide required real time reserves or to cover unit contingencies. However, NWE recognizes that its market access is being impacted by an erosion of excess capacity in the Pacific Northwest area, as identified in its 2009 Electric Supply Resource Procurement Plan: "In the past few years the market for ancillary services, such as operating reserves, has tightened which has caused prices to increase substantially. In order to avoid paying steep prices in the market for operating reserves, Northwestern at times has self-provided the reserves by utilizing the capacity from the Basin Creek facility."

4 Introduction to the FortisBC System

FortisBC's system is situated in the southern interior of British Columbia. The largest load centers are located in the populous Okanagan Valley, although there are important customer loads in the Columbia and Kootenay valleys and also outside of these areas. FortisBC's existing generating resources are sited almost exclusively in the Kootenay region.

FortisBC serves its customers via 1,400 kilometres of high voltage transmission lines, 5,600 kilometres of distribution lines and 66 substations.

Peak system demand in 2009 was 714 MW, at which time FortisBC had approximately 580 MW of committed resources, including long-term firm contracts. FortisBC has historically addressed its capacity deficit through a combination of spot market purchases and seasonal firm purchases.

4.1 FortisBC Supply Resource Stack

FortisBC's supply resource stack is atypical among Canadian electric utilities in that it consists predominantly of contracted resources. Table 4.1-A lists all long-term supply resources that will be available to FortisBC following completion of the Waneta Expansion (**"WAX"**) Project in 2015. Most of these resources are covered under the terms of the Canal Plant Agreement ("**CPA**"), which is discussed in Section 4.2.

Table 4.1-A: FortisBC Resources post-WAX CAPA[6] (2015)

Plant	Capacity (MW)[7]	Owner	Location	Included in CPA?	Hydrology Risks?	Unit Contingent?
WAX Capacity Purchase Agreement	324	WAX Limited Partnership[8]	Kootenays	Yes	No	Yes
FortisBC CPA[9]	224	FortisBC	Kootenays	Yes	No	Yes
CPA Plant Upgrades	4	FortisBC	Kootenays	Yes	No	Yes
Brilliant Base	129	CPC & CBT[10]	Kootenays	Yes	No	Yes
Brilliant Upgrade	20	*(see Brilliant)*	*(see Brilliant)*	*(see Brilliant)*	*(see Brilliant)*	*(see Brilliant)*
BRD Tailrace[11]	6	*(see Brilliant)*	*(see Brilliant)*	*(see Brilliant)*	*(see Brilliant)*	*(see Brilliant)*
BC Hydro 3808 PPA[12]	200	BC Hydro	Across BC	No	No	No

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[6] Waneta Expansion Capacity Purchase Agreement

[7] Maximum installed generation capacity or contractual entitlement. These levels are not necessarily available to FortisBC year-round.

[8] Ownership group comprised of: Fortis Inc (51%), Columbia Power Corporation (32.5%), and Columbia Basin Trust (16.5%)

[9] Refers to FortisBC's Kootenay River plants: Corra Linn, Upper Bonnington, Lower Bonnington, and South Slocan

[10] Columbia Power Corporation & Columbia Basin Trust (indirect owner through the Brilliant Power Corporation)

[11] Denotes a capacity increase resulting from the cleanup of the Brilliant Dam "tailrace" (outflow) area

[12] Power Purchase Agreement

FortisBC owns four hydroelectric plants on the Kootenay River and has unit contingent Power Purchase Agreements for energy and capacity from the Brilliant Plant and Upgrades, and a unit contingent capacity purchase agreement for capacity from the Waneta Expansion presently under construction. All of these units operate under the terms of the CPA.

In addition, FortisBC has access to up to 200 MW of non-unit-contingent capacity and associated energy under the 3808 Power Purchase Agreement (further discussed in Section 4.3).

4.2 Canal Plant Agreement

Many of the supply resources available to FortisBC are operated under the terms of the Canal Plant Agreement ("**CPA**"). The CPA is an agreement between BC Hydro and FortisBC, Teck Metals, Brilliant Power Corporation, Brilliant Expansion Power Corporation and Waneta Expansion Power Corporation ("**Entitlement Parties**") which enables BC Hydro and the Entitlement Parties, through coordinated operation of their hydro plants to generate more power than they could if they operated independently.

Under the Canal Plant Agreement, BC Hydro coordinates dispatch of all CPA facilities and takes delivery of all power actually generated by the Entitlement Parties' plants. In exchange for ceding dispatch of these facilities to BC Hydro, the Entitlement Parties can draw defined monthly "entitlements" of capacity and energy from BC Hydro under terms defined in the CPA.

These entitlements are independent of the actual stream flows at the Entitlement Parties' generating plants, and are thus insulated from seasonal or annual hydrology risk. However, the capacity and energy entitlements under the CPA are contingent upon the individual generating units being ready to be dispatched when called upon by BC Hydro, and the entitlements are commensurately reduced should individual generating units not be available for dispatch when called upon.

The entitlements are delivered to the Entitlement Parties at the Kootenay Interconnection, which is a notional delivery point similar to the Mid-Columbia ("**Mid-C**") market hub. The Kootenay Interconnection actually refers to a set of interface points between the FortisBC and BC Hydro systems near the Kootenay Canal Plant, the Selkirk substation and the Nelway substation. CPA entitlements required by FortisBC elsewhere in its system, or for delivery to export markets, must be wheeled on the internal FortisBC transmission system or via wheeling arrangements with BC Hydro or other transmission providers.

4.3 Waneta Expansion Capacity Purchase Agreement

FortisBC has recently entered into a 40-year capacity purchase agreement with the Waneta Expansion Power Corporation to purchase surplus WAX-related capacity. The Waneta Expansion Capacity Purchase Agreement ("**WAX CAPA**") will provide a secure and cost-competitive capacity resource, significantly reducing and even eliminating FortisBC's exposure to market risks for years.

After WAX commissioning is complete in 2015, WAX CAPA will represent a very large component of FortisBC's supply stack (up to 38% in some months). The capacity entitlements provided by WAX CAPA are derived from the CPA and are therefore unit contingent. The size of individual WAX units relative to the rest of FortisBC's resource stack creates a more significant single unit contingency issue for FortisBC than would be the case for a larger utility in which no single unit typically comprises a significant percentage of the overall supply portfolio.

This unusually high ratio of single unit size to system size is an important factor to consider when determining an appropriate PRM for FortisBC.

4.4 3808 PPA[13]

The 3808 PPA provides FortisBC with the right to schedule up to 200 MW of capacity and associated energy from British Columbia's Heritage Assets[14] for delivery at specified interconnection points between the BC Hydro and FortisBC systems. Unlike the CPA, the capacity available to FortisBC through the 3808 PPA is not unit contingent, that is, it does not depend upon specific physical assets being operational.

Under the 3808 PPA[15], BC Hydro agrees to make reasonable efforts to supply FortisBC's service area load requirements even if such deliveries involve exceeding scheduled deliveries. Although this is not equivalent to a firm supply contract for excess capacity, it does provide some comfort that in a worst-case situation BC Hydro will help FortisBC to meet its load requirements if such assistance can reasonably be provided.

The 3808 PPA is scheduled to expire in 2013 and negotiations are presently underway to renew the agreement or establish a successor agreement. Although the terms of the renewed agreement are not finalized, FortisBC is confident that the capacity and energy allowances will not decrease when the contract is renewed. Therefore the 3808 PPA will be treated as an available future resource for the purposes of this report.

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[13] BC Hydro Rate Schedule 3808 and 1993 Power Purchase Agreement (as amended)

[14] BC Hydro's Heritage Assets are described in Section 1 of the BC Clean Energy Act

[15] 3808 PPA, Section 6.3 "B.C. Hydro shall not be obligate to reserve for or supply to [FortisBC] Excess Capacity or andy energy associated with such Excess Capacity. B.C. Hydro shall use reasonable efforts to supply Excess Capacity to meet [FortisBC's] service area load requirements in accordance with Section 2.1 herein."

5 Market Resources

Unlike most utilities in Canada, FortisBC's firm contracted resource stack has for many years been insufficient to meet its expected peak load-serving obligation. On-peak capacity deficits (including any operating reserve requirements above those already provided for under the CPA and the 3808 PPA) have been addressed through spot market energy purchases and seasonal purchases of energy blocks and call-options. Effectively, the market has acted as a reservoir of PRM for FortisBC.

5.1 Historical Context

During the first half of the 1900s FortisBC's predecessor West Kootenay Power ("**WKP**") built new power plants as required to supply growing service area loads, the typical practice of most Canadian utilities. However, after the addition of the fourth Waneta unit in 1966, WKP ceased to expand its generating fleet. The Canal Plant Agreement with BC Hydro was signed in 1972, thereby removing hydrology risk from the generation portfolio but not providing any additional capacity.

In 1987 WKP was acquired by UtiliCorp and was re-branded UtiliCorp Networks Canada (British Columbia) Ltd. in 2001 then as Aquila Networks Canada (British Columbia) Ltd. in 2002. During the 1990's the utility's service area peak loads began to exceed its committed resource capacity. At this time the regional electricity market was flush with surplus generation (and transmission) capacity, so it was both economical and reliable to address the growing capacity deficits through market power purchases. The West Coast Energy Crisis of 2000/2001 damaged confidence in the regional electricity market, but following that crisis the regional market again stabilized and energy prices remained relatively low compared to the cost of procuring new supply, with occasional price spikes caused by extreme weather conditions and/or transmission constraints.

FortisBC was created when Fortis Inc. acquired the BC utility assets of Aquila Networks Canada in 2004.

5.2 Present Market Conditions

The regional electricity market now looks much different than it did for most of the previous two decades. Surplus capacity margins are shrinking despite the closure of several major industrial facilities in the US Pacific Northwest (WECC-Northwest) over the past decade. Increasing volumes of capacity must be committed to firming supply from rapidly growing intermittent renewable resources, most notably wind. The transmission system in the WECC-Northwest features chronic congestion on specific transmission paths, especially during peak load periods.

The FortisBC service area capacity deficit has grown to exceed 140 MW[16] and now represents a substantial component of the peak load demand. FortisBC can still purchase energy directly from the US electricity market, assuming no impeding transmission constraints. Alternatively, FortisBC can purchase

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[16] Based on the Dec 2011 peak load forecast and pre-Waneta Expansion Capacity Purchase Agreement (WAX CAPA) resource stack. The interim capacity purchase from Powerex arranged as part of the WAX CAPA has now addressed most of this gap.

both capacity and energy products from BC Hydro's trading subsidiary Powerex. Due to the robust transmission interconnections between the FortisBC and BC Hydro systems, transmission risks are negligible for such transactions. These transactions are typically cost comparable with prevailing Mid-C prices plus the cost of wheeling to FortisBC's service area.

The WAX CAPA acquisition, by addressing FortisBC's capacity deficit (including an appropriate PRM) for several years, will dramatically reduce FortisBC's need and hence exposure to market risk. FortisBC will ultimately have to determine whether or not it is prudent to again become dependent upon the market as an incremental source of PRM.

5.3 Regional Factors Driving Market Risk

Several factors are presently aligned to potentially increase the market cost of capacity resources by reducing supply in the WECC-Northwest and WECC-Canada regions. These are all credible risk factors which should not be ignored when determining whether looking to the market to secure future capacity requirements (including PRM) is a prudent option.

5.3.1 Intermittent Generation

The nameplate capacity of intermittent renewable generation sources across North America is projected to increase rapidly over the next decade, as detailed in Table 5.3.1-A.

Table 5.3.1-A: Current and Future Wind and Solar: Installed Nameplate Capacities[17]

Area	Wind (MW)			Solar (MW)		
	2010	2019 Planned	2019 Conceptual[18]	2010	2019 Planned	2019 Conceptual
FRCC	0	0	0	33	20	0
MRO	7,540	1,770	41,010	0	0	0
NPCC	3,631	2,228	12,355	1	0	162
RFC	4,093	16,687	19,016	0	6	567
SERC	102	68	1,199	0	0	5
SPP	2,699	796	19,232	16	0	41
TRE	9,116	1,326	30,093	0	0	549
WECC	9,635	18,192	1,610	534	12,367	0
TOTAL	36,816	41,067	124,515	584	12,393	1,324
% of NERC Total[19]	3.6%	4.0%	12.0%	0.052%	1.107%	0.118%

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[17] NERC 2010 Long Term Reliability Assessment, Page 13

[18] From the NERC 2010 Long Term Reliability Assessment, Page 356, this includes resources that "have been identified and/or announced on a resource planning basis" but are not considered sure enough to class as "Future" resources, which themselves are defined as "generation resources the reporting entity has a reasonable expectation of coming online during the period of the assessment".

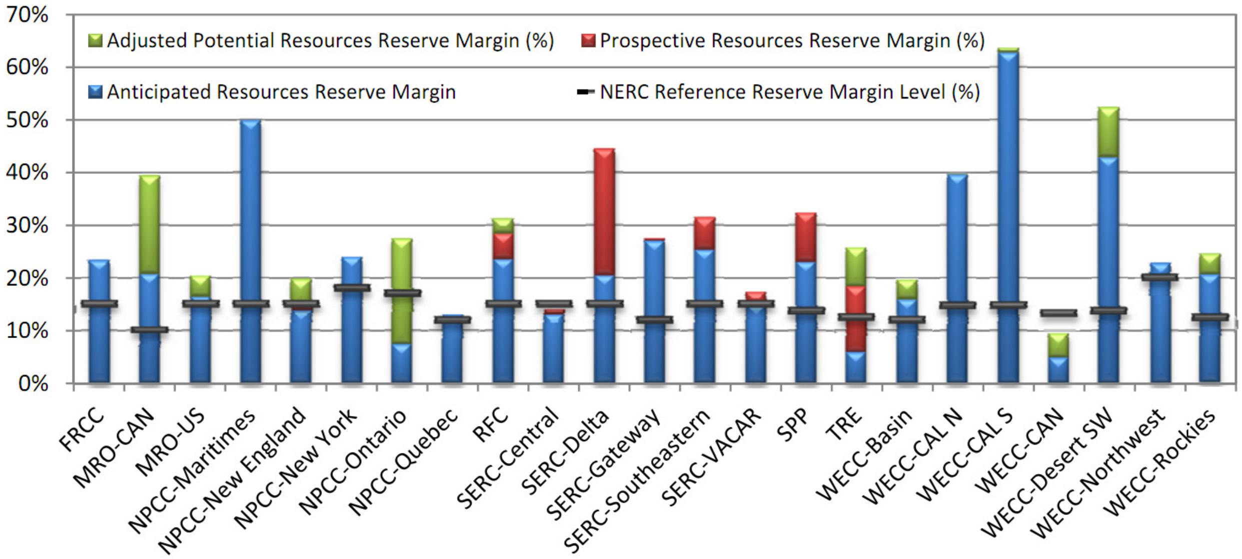
[19] Compared to summer "Anticipated Capacity Resources", found in NERC 2010 Long Term Reliability Assessment, Pages 30-35

Wind generation is becoming an increasingly predominant source of new generation, especially in the WECC region; it is expected to account for anywhere from 4% to 12% of NERC's total resource stack, compared to 3.6% in 2010. This increase in intermittent wind generation will force responsible balancing authorities to reserve a growing amount of dispatchable capacity to firm the highly variable wind power production. The effect of decreasing the amount of surplus capacity in the wholesale electricity market will be increased prices, price volatility and reduced availability of capacity for purchase.

5.3.2 Shrinking Regional Capacity Margins

Compounding the regional impacts of intermittent supply resources, NERC is also projecting that by 2019 the Canadian sub-region (i.e. British Columbia and Alberta) of the WECC will be below its reference reserve margin level, as illustrated in Figure 5.3.2-A. At that time, WECC-CAN will have the distinction of being the most capacity-constrained sub-region in NERC. Making matters worse, Alberta's projected 2010-2011 winter reserve margin is equal to or below the prescribed target reserve margin of 13.2%[20].

Figure 5.3.2-A: NERC Projected On-Peak Planning Reserve Margins in 2019[21]



As regional planning margins continue to shrink, surplus capacity will become less available during extreme conditions when PRM is most likely to be called upon, thus increasing market price volatility.

5.3.3 Direct Service Industry Loads

The closure of a number of large Direct Service Industry ("**DSI**") loads (mostly aluminum smelters) in the US Pacific Northwest during the previous decade created a one-time regional capacity surplus. Since there are effectively no remaining DSI loads to close, the energy and capacity reductions associated with

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[20] North American Electric Reliability Corporation, 2010 Long-Term Reliability Assessment, October 2010, page 284

[21] NERC 2010 Long Term Reliability Assessment, Page 3

DSI load closures is non-repeatable and the surplus resulting from their previous closures will be consumed by normal load growth. Economic recovery in the US over the next decade will lead to increased electrical consumption across all sectors and will contribute to a further erosion of any residual capacity surplus that currently exists. As with the other risk factors, any reduction in surplus capacity will potentially cause increased market prices, greater price volatility and the danger of not actually always being able to secure the desired capacity requirements.

5.3.4 Demand Side Management Saturation

Utilities throughout the WECC region have been given regulatory mandates to mitigate an increasing quantity of their load growth via ambitious Demand Side Management ("**DSM**") targets. The objective in many WECC jurisdictions (including British Columbia) is to sharply reduce electricity demand growth by means of various DSM programs. For example, BC Hydro is required under the Clean Energy Act to achieve DSM savings of 66% of forecast load growth.

Reliance upon aggressive DSM targets to control load growth is untested in the WECC region. It has not yet been demonstrated on a long term basis that regional utilities can successfully achieve the required annual compounding levels of DSM savings once the “low hanging fruit” of easy to achieve DSM savings have been obtained. As economic conditions improve there is therefore a risk that some (or even many) DSM programs will prove less effective than planned and regional loads may resume or even exceed their pre-recession growth trajectories.

Given that utilities are presently implementing DSM programs combined with increasing proportions of intermittent supply resources instead of adding traditional generation resources, this situation increases the risk of regional capacity shortfalls, especially if failure to meet DSM targets becomes widespread. In this case utilities without adequate planning reserve margins will be forced into an increasingly tight marketplace for both capacity and energy, leading to an increased risk of volatile market prices and reduced supply availability.

5.3.5 Variable Regional Hydrology

The heavy reliance on hydroelectric generation in the WECC-Northwest means that the reliability of the regional capacity market is highly dependent upon regional precipitation. An especially cold winter following one (1) to three (3) years of drought would affect most of the utilities in the WECC-Northwest sub-region, creating volatile market prices and potentially a regional supply deficiency.

Fortunately, FortisBC’s long-term firm supply resources are effectively free from hydrology risk due to the nature of the CPA and 3808 PPA. However, any capacity requirement above FortisBC’s existing firm resource stack would expose them to market risk. (This regional reliance on hydroelectric assets would tend to argue for the consideration of fuel source diversity for any future FortisBC capacity additions.)

5.3.6 Transmission Congestion

The regional transmission system is becoming increasingly constrained, especially during extreme weather periods, due to long-distance power transfers between remote interior generation and primarily coastal load centers. The addition of new transmission capacity has been actively resisted in most jurisdictions, so it is unlikely that many of these constraints will be relieved in the near future as loads continue to grow. Transmission constraints effectively break up a regional market into a series of discrete load and generation pools with limited interchange. This balkanization drives up market prices in generation deficient areas because access to lower cost generation resources cannot be obtained via transmission connections, and this is especially true for parties such as FortisBC that do not own firm transmission rights in the US transmission system.

5.3.7 Summary

Increasing proportions of intermittent generation (e.g. wind), shrinking regional capacity margins, the potential for failing to meet aggressive long term DSM targets, regional hydrological variations and transmission congestion are all factors that create risk to the cost and availability of capacity resources in the WECC. Many of these factors can independently cause regional market volatility under extreme weather or other stressed conditions. However taken as a group they represent a high probability that the regional market will begin to display increased price volatility and periods of supply unavailability. In the worst case, the market impacts could reach beyond the local region into the broader WECC.

6 Planning Reserve Margin Methodology

The WECC recommends but does not require that utilities plan for positive capacity margins on a long-term basis. Based upon the risk factors presented in Section 5, Midgard believes it is prudent for FortisBC to carry an appropriate level of PRM tailored to FortisBC's situation.

FortisBC's system is relatively small and its resource stack consists of a limited portfolio of primarily contractual generation assets. FortisBC has recently acquired a large amount of capacity through WAX CAPA. The two (2) WAX units expected to be commissioned in 2015 will account for up to 38% of the FortisBC resource stack during key months of the year. For the purposes of long-term PRM planning, it is prudent for FortisBC to adopt a methodology that considers these unique aspects of the FortisBC system.

The Power Supply Design Criteria established by the Western Systems Coordinating Council (now known as the **"WECC"**) provides three (3) alternative recommended minimum performance approaches for establishing PRM (see Appendix A). This criteria document has been a guideline for utility planning for many years, and has been referenced in several of WECC's annual Power Supply Assessments. The criteria document recommends that at least one of the three (3) provided criteria be met (or exceeded) for the purposes of establishing adequate PRM. Table 6-A displays the three (3) criteria and associated minimum design performance.

Table 6-A: WECC Recommended Minimum Performance Table

Criterion	Criteria	Minimum Design Performance
1	Monthly reserve capacity after deducting scheduled maintenance responsibility	Greater of R, or the largest risk plus 5% of load where R = (0.05H + 0.15T)*L/H+T H = Monthly hydro capability T = Monthly non-hydro capability L = Load responsibility[22]
2	Monthly reserve capacity after deducting scheduled maintenance responsibility	Two (2) largest risks
3	Annual reliability criterion based on probability of loss of load	90% probability of meeting all load in a year

6.1 Criterion One

This criterion recommends using the greater of R or the single largest contingency plus 5% of load responsibility. The value of R can be calculated using the following formula:

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[22] Definition: System or area monthly firm peak load demand plus those firm sales minus those firm purchases for which reserve capacity must be provided by the supplier

$$R = \frac{(0.05H + 0.15T)}{H + T} \times L$$

Given that FortisBC presently has no non-hydro generation assets, T is assumed to be zero. Therefore the formula can be simplified to:

$$R = \frac{(0.05H + 0.15 \times 0)}{H + 0} \times L = \frac{0.05H}{H} \times L = 0.05L$$

With this simplification the following statement becomes true:

$$0.05L < 0.05L + Single\ Largest\ Contingency$$

Therefore, in the FortisBC context Criterion One establishes a monthly PRM sized at 5% of load responsibility plus the single largest contingency. Considering the unique nature of FortisBC's system, this criterion provides a method for calculating a PRM that specifically addresses the large unit contingencies created by WAX CAPA.

6.2 Criterion Two

Criterion Two suggests that PRM be sized to meet or exceed the capacity available from the two (2) largest contingencies found in the system. Although a valid calculation methodology, this criterion will lead to an overly conservative approach to system planning in the FortisBC context. WAX CAPA represents up to 162 MW per unit, or 324 MW total of generation capacity. Meeting Criterion Two would result in carrying 324 MW of reserve, and assuming an average load year this would result in a PRM approaching 45%.

Midgard recommends that this PRM criterion is unnecessarily conservative in the FortisBC context and the resulting impact to ratepayers is unjustified.

6.3 Criterion Three

A loss of load expectation ("**LOLE**") study is a probabilistic method for calculating a sufficient level of reserve and is especially effective for larger, distributed power systems. As stated in the Power Supply Design Criteria document from the WECC, "*it is recommended that Member Systems with a significant percentage of independent power producer owned generation utilize probability methods for reserve planning and reporting.*"

Comprehensive LOLE studies are significant undertakings, requiring detailed system modeling and meaningful performance records for individual generating facilities. Midgard does not believe that a comprehensive LOLE study is either necessary or even practical for FortisBC at the present time for a number of reasons:

- FortisBC has a relatively small power system
- FortisBC does not have a meaningful amount of independent power producer owned generation.
- The largest generating facility that will impact FortisBC's PRM requirements (WAX) has only recently entered the construction phase and does not have an operating track record.
- Most of the other generating units in the FortisBC system have recently been upgraded and have not established the extended performance records that are required for LOLE studies.

6.4 Establishing the Final Recommended PRM Calculation Criterion

Midgard recommends that FortisBC utilize WECC Minimum Design Performance Criterion One as the initial basis for its PRM design:

PRM = 5% of Load Responsibility + the Single Largest Contingency

Where "Load Responsibility" is defined as the monthly system firm peak load demand plus firm sales minus firm purchases for which reserve capacity must be provided by the supplier. The BC Hydro 3808 PPA's 200 MW is currently considered a firm purchase. Although the agreement is set to expire in 2013, the agreement in its renewed form is expected to include the same 200 MW capacity allowance and aggregate energy draws at least up to 2013 levels. As such, the 200 MW of generation capacity included in the 3808 agreement is considered a firm resource and is not included in PRM calculations.

FortisBC entered into WAX CAPA to acquire a variable monthly block of capacity from the WAX project. Since WAX CAPA is based upon the output of the two (2) WAX generators, ½ of WAX CAPA, the output from one unit, becomes the single largest contingency in the FortisBC system for most months of the year. The exceptions are the months of May and June, during which period a single Brilliant unit becomes the largest contingency because the monthly capacity of WAX CAPA is small. Table 6.4-A shows the WAX CAPA and Brilliant contingencies on a month-by-month basis, and calculates the governing N-1 generator contingency for determining PRM.

Table 6.4-A: Determination of Monthly Single Largest Contingency

	WAX CAPA Capacity (MW)	½ WAX CAPA (MW)	Brilliant Single Unit (MW)	Governing Single Contingency	Single Largest Contingency (MW)
January	304.4	152.20	37.33	½ WAX CAPA	152.20
February	303.6	151.80	37.33	½ WAX CAPA	151.80
March	289.1	144.55	37.33	½ WAX CAPA	144.55
April	133.3	66.65	37.33	½ WAX CAPA	66.65
May	69.7	34.85	37.33	Single Brilliant Unit	37.33
June	54.0	27.00	37.33	Single Brilliant Unit	37.33
July	168.7	84.35	37.33	½ WAX CAPA	84.35
August	318.5	159.25	37.33	½ WAX CAPA	159.25
September	323.7	161.85	37.33	½ WAX CAPA	161.85
October	211.3	105.65	37.33	½ WAX CAPA	105.65
November	320.1	160.05	37.33	½ WAX CAPA	160.05
December	312.1	156.05	37.33	½ WAX CAPA	156.05

With the selection of WECC Criterion One, Midgard recommends modifying the calculation methodology to be more operationally realistic. FortisBC forecasts that there will be a number of months of each year (predominantly during freshet) during which WAX CAPA will not be required to serve load and can remain idle. During those months, it is unreasonable to consider WAX CAPA the single largest unit.

To avoid the situation where PRM is calculated based upon an unutilized unit, Midgard recommends modifying the PRM calculation methodology as follows:

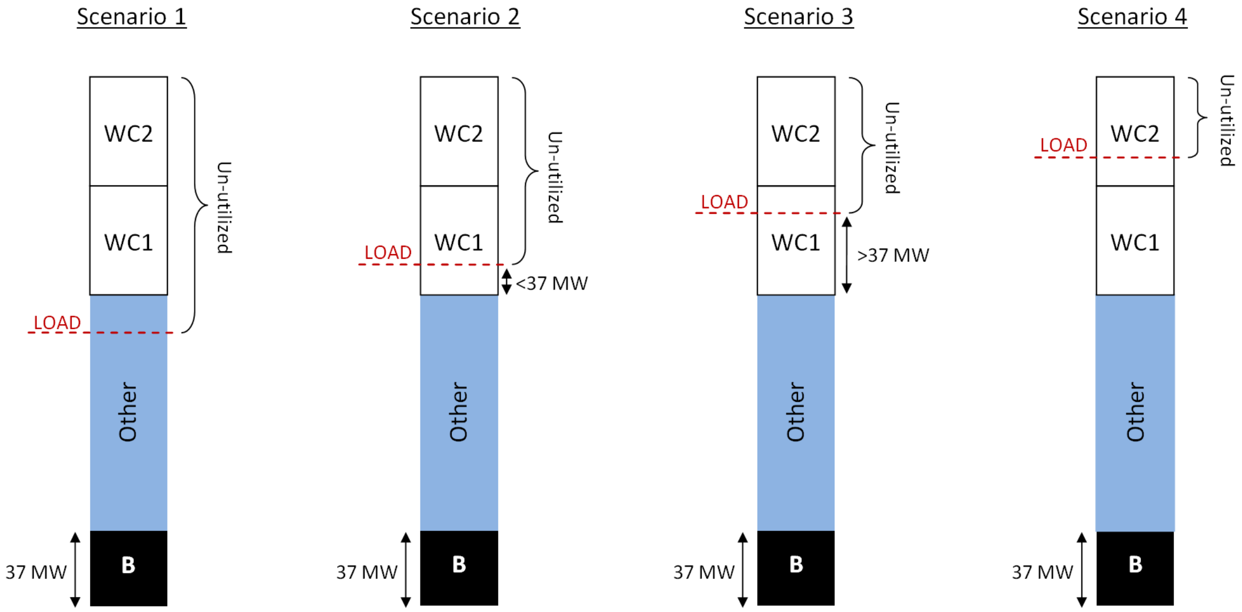
PRM = 5% of Load Responsibility + the Single Largest <u>Utilized</u> Contingency

This calculation produces a less conservative reserve margin and reduces the amount of PRM required in the less critical non-peak months. The following simplified examples demonstrate how the modified calculation will function and are illustrated in Figure 6.4-A.

- **Scenario 1:** Load is being met without utilizing WAX CAPA
  - Since WAX CAPA is not required to generate and therefore not applicable in the calculation, the largest utilized contingency becomes a Brilliant unit at 37.33 MW.
  - In this scenario, the WAX CAPA assets represent sufficient reserves to meet PRM.
- **Scenario 2:** Load is being met by using a small amount of WAX CAPA (<37.33MW Brilliant Unit)
  - WAX CAPA is now part of the utilized resource stack.
  - WAX CAPA's commitment to the supply stack still represents a smaller contingency than a single Brilliant unit of 37.33 MW.

  - If a WAX unit fails to operate, a significant portion of available un-used capacity is lost (greater than what is being utilized). However, there is still a second WAX unit capable of providing all required reserve margin.
  - In this scenario, the second WAX CAPA asset represents sufficient reserves to meet PRM.
- **Scenario 3:** Load is being met by using a larger portion of WAX CAPA (>37.33 MW, but less than one unit's full monthly entitlement)
  - The utilized portion of WAX CAPA now governs as the single largest contingency
  - Again, if a WAX unit fails to operate, a significant portion of available capacity is lost (greater than what is being utilized). However, there is still a second WAX unit capable of providing reserve margin.
  - Depending on the level of load, the second WAX CAPA asset may represent sufficient reserves to meet PRM, but under higher loads additional PRM may have to be otherwise acquired.
- **Scenario 4:** Load is being met by using more than half of the WAX CAPA entitlement (greater than one unit's full entitlement)
  - Since at least one of the two (2) WAX units is being fully utilized, the single largest contingency is now governed by one full wax unit (or ½ of WAX CAPA entitlement).
  - In this scenario, the unused portion of the second WAX CAPA asset can be used to meet part of PRM, but additional PRM would have to be acquired.

Figure 6.4-A: Illustration of PRM Scenarios



Notes: B = Single Brilliant Unit (37.33 MW); WC1 = First WAX CAPA Unit; WC2 = Second WAX CAPA Unit

Note that since the capacity attributable to the individual WAX units is smaller than individual Brilliant unit capacity during the months of May and June, a Brilliant unit will always govern as the single largest unit contingency during the months of May and June regardless of WAX CAPA utilization.

7 Calculation of FortisBC's PRM Requirements

Figure 7-A and Figure 7-B show the monthly PRM requirements for the years 2020, 2030 and 2040 in MW and as a percentage of load served, respectively, based upon the recommended PRM design criterion:

PRM = 5% of Load Responsibility + the Single Largest Utilized Contingency

Table 7-A and Table 7-B present the same data in tabular form.

Figure 7-A: Monthly PRM (MW)

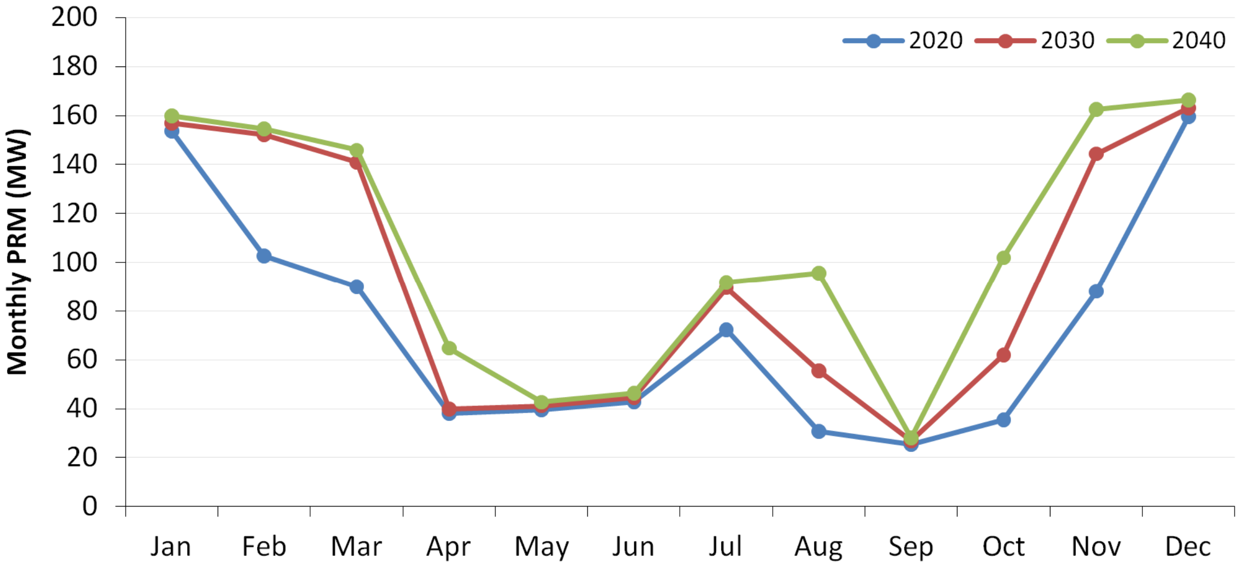


Table 7-A - Monthly PRM (MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Mean
2020	154	103	90	38	40	43	72	31	25	35	88	160	73
2030	157	152	141	40	41	45	90	56	27	62	144	163	93
2040	160	154	146	65	43	46	92	96	28	102	163	166	105

Figure 7-B: Monthly PRM (%)

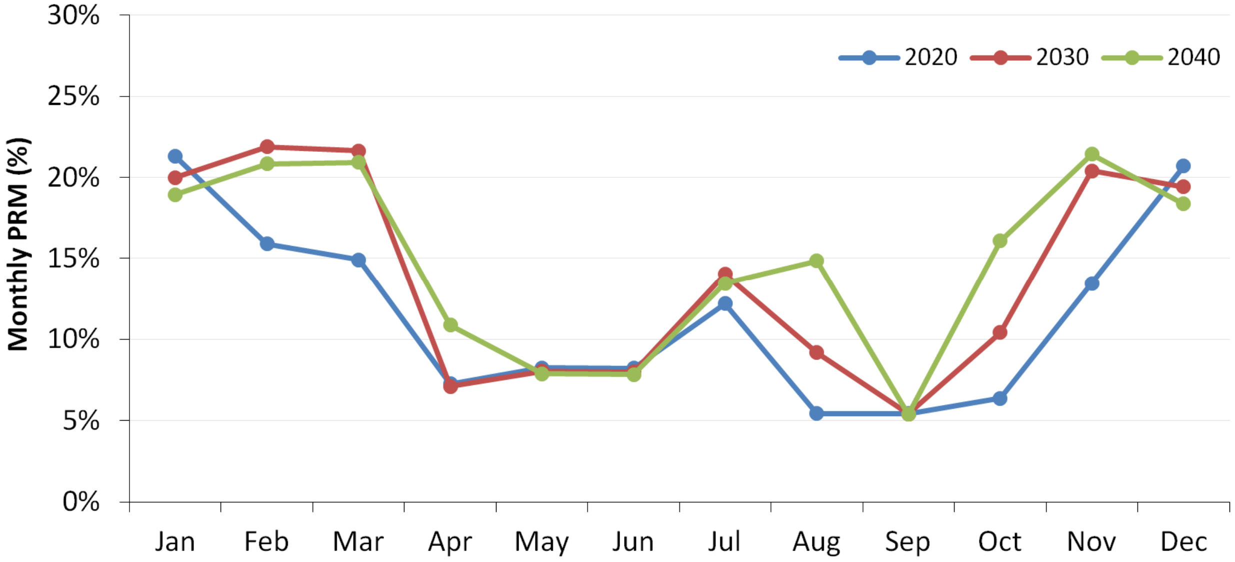


Table 7-B - Monthly PRM (%)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Mean
2020	21	16	15	7	8	8	12	5	5	6	13	21	12
2030	20	22	22	7	8	8	14	9	5	10	20	19	14
2040	19	21	21	11	8	8	13	15	5	16	21	18	15

Although, it is uncommon to show PRM changing on a monthly basis, the majority of FortisBC's supply resources vary by month and require that FortisBC adapt its PRM requirements to match. FortisBC carries more PRM in critical winter months when peak loads require additional PRM coverage and FortisBC carries less PRM in less critical months, thus resulting in a lower overall cost to FortisBC ratepayers and less exposure to long term market risks.

The PRM held by nearby utilities is listed in Table 7-C (a replicate of Table 3.3-A). This table demonstrates that the recommended PRM for FortisBC is comparable to the current industry practice in the region[23].

Table 7-C: Nearby Planning Reserve Margins

Utility	PRM (%)
Avista	15
BC Hydro	14
Idaho Power	10
Northwestern Energy	0
PacifiCorp	12
Portland General Electric	12
Puget Sound Energy	15

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[23] Note that due to the use of different calculation methodologies, some of these utilities actually carry greater reserve capacity than is shown in Table 7-C.

8 Summary and Conclusions

Planning Reserve Margin is similar to Operating Reserves, but rather than addressing real-time operations PRM is intended to address load and resource variability over a planning time frame from one year to 20+ years into the future. PRM addresses three main long term risks:

- unavailability of supply due to unplanned generating unit or transmission outages
- unexpectedly high loads, typically due to extreme weather events
- periods of accelerated load growth that outpaces the installation of new power supply resources

All of these risks are present for FortisBC and all operating utilities.

The FortisBC system is a relatively small power system with a very large unit-contingent resource in the form of the WAX CAPA accounting for a significant proportion of its resource portfolio. Given that an outage to a single WAX generating unit has a material impact on the overall resource stack, Midgard recommends that FortisBC uses the following formula to calculate PRM:

PRM = 5% of Load Responsibility + the Single Largest Utilized Contingency

Focusing on the largest utilized contingency yields a recommended PRM for the FortisBC system that changes on a monthly basis as shown in Figure 1-A and listed in Table 1-A. It is uncommon to show PRM changing on a monthly basis, but the material monthly variability of the majority of FortisBC's supply resources (including WAX CAPA) requires that FortisBC adapt its PRM requirements to match the nature of its supply resources. Simply put, FortisBC carries more PRM in the critical winter months when its peak loads require additional PRM coverage and carries less PRM in other less critical months, thus resulting in a lower overall cost to FortisBC ratepayers and less exposure to long term market risks.

In future years as FortisBC’s load demand continues to grow the amount of WAX CAPA required to serve load will increase and the PRM requirement will also expand commensurately.

Appendix A: WECC Power Supply Design Criteria

WESTERN SYSTEMS COORDINATING COUNCIL

POWER SUPPLY DESIGN CRITERIA

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WESTERN SYSTEMS COORDINATING COUNCIL

POWER SUPPLY DESIGN CRITERIA

INTRODUCTION

The Western Systems Coordinating Council was established to promote the reliable operation of the interconnected bulk power system by the coordination of planning and operation of generating and interconnected transmission facilities.

Article V, Section 1, of the Council Agreement reads, "For the guidance of the members and subject to the review of the Executive Committee, the Planning Coordination Committee shall recommend criteria for such elements of system design as affect the reliability of the interconnected bulk power systems, and the Operations Committee shall recommend such operating procedures as affect the reliability of the interconnected bulk power systems."

In order to accomplish its assignment, the Planning Coordination Committee established the Reliability Criteria for System Design Subcommittee (now called Reliability Subcommittee). This document is the result of work by the Subcommittee.

PURPOSE OF CRITERIA

The criteria in this document are intended to provide, for the guidance of members, recommended minimum levels of installed and planned generation for systems and areas within the WSCC in order to permit evaluation, upon a common basis, of the relative reliability of the interconnected bulk power systems. The criteria do not purport to establish any measure of industry design standards as to member systems, nor are they created for such purpose, it being recognized that the systems of members, pools, or other groups of Council members, may be properly and adequately designed to different criteria.

It is recognized that it is impossible to provide 100% reliability of power supply. It is anticipated that each member will, insofar as practical, protect its customers against loss of service. With the development of the complex interconnected systems, it is likely that the design and performance of one system will be reflected in varying degrees on other systems. Subject to the foregoing, it is the purpose of the criteria to provide:

1) Recommended minimum standards and a uniform method for assessing the adequacy of installed and planned generation within the WSCC for the purposes of reporting to the Council, and to outside agencies.
2) A means for evaluating the possible effect of one system or area on other systems or areas.

The WSCC members will assess resource adequacy in accordance with the *North American Electric Reliability Council (NERC) Planning Policies and Principles* or the *WSCC Power Supply Design Criteria*, whichever is more specific or stringent.

CRITERIA FOR SYSTEM DESIGN

The criteria are based on the principle that for the more common contingency outages there should be no loss of load in a system or area nor adverse effect on neighboring systems or areas. The criteria recognize the necessity for load shedding for those outage contingencies that are credible but of such low probability that it is not feasible to protect the systems against loss of load.

Power supply criteria may be defined and measured in terms of generating reserve margins, ability to withstand contingency outages, or minimum reliability index values derived from probabilistic computations based on capacity.

Each member of the Council, and each Pool or other group of Council members, may utilize criteria which differ from the criteria presented in this document. Such differences may be based upon the geography of the area, type of load being served, system configuration, customer expectations based upon past performance, or other reasons considered appropriate by such member, Pool or group, as long as the minimum requirements of the WSCC criteria are met.

It is recommended that the following criteria be utilized in the design of each member system or area.

1) Each member system or area should provide sufficient generating capacity to serve its load and meet its obligation to others without imposing an undue degradation of reliability on any other system or area.
2) If two or more systems form a group or responsible area for the specified purpose of applying WSCC Power Supply Criteria, they should demonstrate that any inter- or intra-area generating capacity support levels utilized are achievable and that sufficient transmission capacity is available to allow delivery at these levels of generating capacity support.

Assessments of future resource adequacy should generally include the following:

- Electricity demand and energy forecasts, including uncertainties
- Existing and planned demand-side management programs (DSM) including in-service dates and life-cycle
- Demand-side management program characteristics should include the following:
- Consistent ratings (demand and energy), including seasonal variations
- Effect on annual system load shape
- Availability, effectiveness, and diversity of DSM programs
- Contractual arrangements
- Expected program duration
- Aggregate effects (demand and energy) of multiple DSM programs

- Existing and planned supply-side resources including in-service dates and life-cycle
- Supply-side resource characteristics should include the following:
- Consistent generator unit ratings, including seasonal variations
- Availability of utility and independent power producer generator units
- Dependability of and contractual obligations, including assignment of system losses, for capacity and energy purchases and sales
- Abnormal or adverse water conditions for hydro and thermal generator units
- “Net” capacity after deduction of electrical supply for station or auxiliary services
- Fuel availability, deliverability, and diversity
- Retirement of resources
- Delays in resource in-service dates
- Availability and performance characteristics of all resources
- Resource type; include energy profile and any environmental or regulatory restrictions
- Availability of emergency assistance from neighboring systems
- Resources not under a system’s control should be addressed in the planning process as to availability, capacity, emergency assistance, scheduling, and deliverability
- Purchasers, transmitters, and sellers of electricity should coordinate and agree with each other on the characteristics and level of dependability of their electricity transactions for reliability assessment purposes, including such factors as:
- Contractual commitments
- Duration of the transaction
- Dependability of the transaction
- Availability of dedicated generator units
- Availability of transmission capacity
- Effect of the transaction on deliverability of emergency assistance

Technical studies should be performed to periodically evaluate these criteria and that the criteria be periodically reviewed and revised as experience indicates.

RECOMMENDED MINIMUM PERFORMANCE LEVELS

The recommended level of installed and planned generating supply reserve is presented in the Recommended Minimum Performance Table. This table defines recommended minimum power supply reserve levels for reporting systems or areas in the WSCC.

Because reliability reserve levels vary between WSCC member systems, three alternative recommended minimum criteria are provided. In planning and installing resources, each member should endeavor to maintain a balanced relationship among resource type, size, capacity, and location. It is recommended that Member Systems with a significant percentage of independent power producer owned generation utilize probability methods for reserve planning and reporting. It is further recommended that all systems ultimately report installed and planned reserve levels using probability methods.

In order to provide a level of performance consistent with the expectations of their customers and with system experience, individual systems or areas may adopt minimum design performance levels which differ from those presented herein.

Prepared and Submitted by the Adequacy of Supply Task Force
Approved by Planning Coordination Committee - March 7, 1974
Approved by Executive Committee - November 21, 1974
Revised August 11, 1987
Approved by Planning Coordination Committee - October 26, 1995
Approved by Board of Trustees - November 30, 1995

WSCC POWER SUPPLY DESIGN CRITERIA
RECOMMENDED MINIMUM PERFORMANCE TABLE

It is recommended that areas or systems defined for analysis should meet or exceed at least one of the following WSCC criteria for installed and planned generating capacity:

	Criteria	Minimum Design Performance
1.	Monthly Reserve Capacity After Deducting Scheduled Maintenance (MW) Responsibility	Greater of R, or the largest Risk plus 5 percent of Load
2.	Monthly Reserve Capacity After Deducting Scheduled Maintenance	2 largest Risks
3.	*Annual reliability criterion based on probability of loss of load, either	
	a. Frequency of loss of load or,	one day in ten years
	b. probability of meeting all loads in a year	0.90

Definitions

$$R = \frac{.05\ H + .15\ T}{H + T} \times L$$

H = Monthly hydro capability after deducting scheduled maintenance.

T = Monthly non-hydro generating capability after deducting scheduled maintenance.

L = Load Responsibility: System or area monthly firm peak load demand plus those firm sales minus those firm purchases for which reserve capacity must be provided by the supplier.

Reserve Capacity After Deducting Scheduled Maintenance = H + T - L

Risk: Capacity reduction caused by outage of a generator (including independent power producer owned) or transmission line.

* Independent power producer owned generation shall be included when assessing adequacy of power supply using this Criterion.

Performance Table Adopted by Executive Committee - September 19, 1974.
Revised August 11, 1987
Revised October 26, 1995

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Appendix E

FORTISBC PLANNING RESERVE MARGIN REPORT

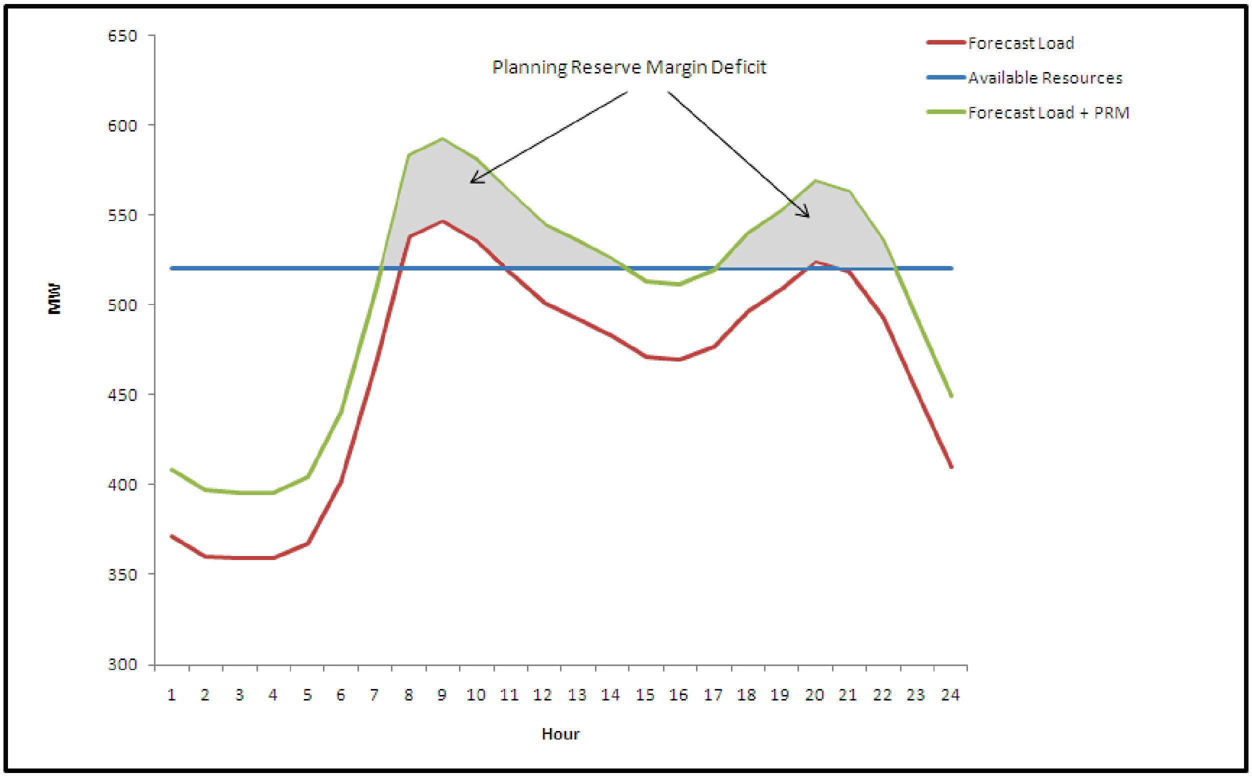
FortisBC Inc. Planning Reserve Margin Study

Introduction

The purpose of this study is to determine what operational requirements must be satisfied by a proposed Planning Reserve Margin (PRM) resource to meet a planning margin requirement. This information is critical in determining whether a proposed planning margin resource is suitable for FortisBC Inc. (FortisBC or the Company) system.

Chart 1 below shows the effect of a PRM on an average daily load curve. For this average day in March, it is clear that FortisBC does not have enough resource in place to meet its load and PRM requirements for many hours of the day. In this study, the Company is attempting to calculate the total PRM requirement, maximum PRM deficit, total hours of PRM deficit per month, percentage of total hours of PRM deficit per month, percentage of super peak hours of PRM deficit per month, maximum consecutive daily hours of a PRM deficit, and the maximum total daily hours of a PRM deficit.

Chart 1: Example of the PRM on an Average Daily Load Curve



FortisBC Resources

In calculating the PRM requirements, the FortisBC resource stack consisting of FortisBC, Brilliant and Brilliant Upgrade Canal Plant Agreement (CPA) entitlement capacity, less

4.45% operating reserves (2.5% spinning reserve), plus Brilliant Tailrace capacity, and BC Hydro capacity is used. FortisBC assumes that the BC Hydro Power Purchase Agreement will be renewed on similar capacity conditions through 2040. FortisBC includes estimated generating unit upgrades in 2011 and 2012, based on FortisBC's Upgrade Life Extension (ULE) projects, and the capacity blocks that FortisBC has under contract from Powerex until the Waneta Expansion (WAX) project comes online in January 2015. One WAX unit is assumed to come online January 1, 2015, and the second unit on April 1, 2015. The Company bases the WAX capacity on the amounts provided in the WAX Capacity Agreement (WAX CAPA), less 7.0% operating reserves (5.0% spinning reserve). The forecast of the Demand Side Management (DSM) capacity savings are included as a resource. A standard maintenance schedule is used to forecast planned outages of FortisBC and Brilliant resources.

Forecasting FortisBC Load Curves

FortisBC bases this analysis on forecast load curves from 2012 to 2040. These load curves are forecast based on the average monthly load curves calculated from actual load data for the FortisBC system from 2007 to 2010, which is then escalated by the difference between the peak average load, and the peak load forecast.

To create the average monthly load curves from 2007 to 2010, each month is analyzed separately. For each month of each year, the daily load curves are sorted in order of the peak day, and then averaged out each similar day. For example, after sorting January's data, there are four peak days, four second peak days, etc., up to and including four 31st peak days for each year from 2007 to 2010. FortisBC then averages each day, to create 31 average daily load curves, which are combined to create the average monthly load curve. This is completed for each month. (For February, leap years are ignored).

From these estimated load curves, FortisBC calculates the PRM using the method detailed below. The estimated load forecast plus PRM margin are compared to the resource stack to calculate the deficit. This study only calculates the deficit of the planning margin, and does not take into account any deficits needed to meet load. This study assumes that the WAX capacity is used to meet reserve requirements even though this may not be the most cost effective method, as it may forgo firm capacity sales. Non-firm or hourly sales from the WAX project would not be affected by this approach.

Calculation of the Planning Reserve Margin

For this study FortisBC has calculated the PRM using 5.0% of its load forecast plus the Single Largest Generating Unit (SLU) that is used to meet load. Currently in the FortisBC system the single largest generating unit is a Brilliant base plant generator, with a capacity of approximately 37.5 MW. There are four of these units in the FortisBC system and they are used as a base load resource. Therefore it is assumed that the Company is always using at least one of these units to meet load and that the SLU is never less than one Brilliant unit, which is calculated as 25% of the total Brilliant entitlement capacity. Once WAX comes online, the SLU becomes one half of the total WAX capacity utilized to serve load. However, if one Brilliant unit is larger than one half of the amount of WAX that is used to meet load, the Company uses the Brilliant unit as the SLU. For example, if 100 MW of WAX CAPA is required to serve load, then the PRM SLU is 50 MW for that month. If we need 70 MW of WAX CAPA to serve load, then one half is only 35 MW, and a 37.5 MW Brilliant unit is used as the SLU.

FortisBC calculates 5.0% of its load based on the load forecast calculated above, less 200 MW of BC Hydro resource that it has under contract, as it is the Company's understanding that BC Hydro will cover the reserve for this resource. As noted above, this study only calculates the deficit of the planning margin, and does not take into account any deficits needed to meet load. The PRM deficit is the grey shaded area below the green line and above the red line or blue line in Chart 1 above.

Operating Margin

In calculating the resource stack, the Company has reduced the FortisBC, Brilliant and Brilliant Upgrade entitlement capacity resources by the 4.45% operating margin that are required to be held on FortisBC and Brilliant resources according to the CPA. On an hourly basis, FortisBC has access to 2.5% of its CPA entitlement that is held as spinning reserve. This amount is subtracted from the potential PRM deficit. FortisBC reduces the WAX capacity by 7.0% of the WAX CAPA for the operating margin, and has subtracted the 5.0% spinning reserve from the potential PRM deficit.

Scheduling Margin

On an hourly operational basis, the FortisBC dispatchers rely on an hourly scheduling margin to ensure that there are enough resources dispatched to meet load, and to ensure that any forecasting error within the hour will not result in a resource deficiency. When planning, the dispatchers attempt to schedule a 10 MW margin. In this study, it is assumed that this is not a factor for a planning margin basis, since hourly market purchases are not a suitable long term resource.

Results

The results through 2040 are summarized below. Table 1 shows the total PRM requirement (MW); Table 2 shows the maximum PRM deficit (MW); Table 3 shows the total hours of PRM deficit per month (Hours); Table 4 shows the percentage of total hours of PRM deficit per month (%);Table 4A shows the percentage of super peak hours of PRM deficit per month (%); Table 5 shows the maximum consecutive daily hours of a PRM deficit (Hours), and Table 6 shows the maximum total daily hours of a PRM deficit (Hours).

In Tables 4 and 4a below, the percentage of total hours of PRM deficit is calculated as well as the percentage of super peak hours in order to give a more accurate representation of the FortisBC risk. It is within these super peak hours that the FortisBC system is the most exposed to uncertainty. Based on a review of FortisBC historical load curves, it is assumed that there are two seasons in which the super peak hours differ. For the winter season (November to March), it is assumed that the super peak hours are between 8:00 to 11:00 and 17:00 to 20:00. For the summer season (April to October), it is assumed that the super peak hours are between 16:00 to 19:00. For both seasons, it is assumed that the peak hours are only on Monday to Saturday.

The results show that the maximum PRM requirement ranges from 54 MW in 2012 to 156 MW in 2040.

FortisBC assumes that December is its peak month, and therefore is the most important month to analyze the PRM deficit. The data suggest that the PRM deficit in December reaches a peak of 156 MW, and last for 245 hours in 2040 (almost 33% of the month). This equals 90% of the super peak hours. It is estimated that the deficit will last for 7 consecutive hours of the day, and will last for a total of 13 hours on the peak day.

Complete results are provided below.

Table 1: Maximum PRM Requirement (MW)

Maximum PRM (MW)													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Maximum**
2012	52	49	47	42	38	38	43	44	40	43	49	54	54
2013	52	49	47	42	38	39	43	44	40	44	49	54	54
2014	53	50	48	42	38	39	44	44	40	44	49	55	55
2015	70	45	38	36	35	37	36	29	24	34	34	94	94
2016	72	47	39	36	35	37	36	29	24	34	34	96	96
2017	74	48	41	36	35	37	38	29	24	34	37	99	99
2018	78	51	43	36	35	37	40	29	24	34	40	103	103
2019	81	54	46	37	35	37	43	29	24	34	42	107	107
2020	84	56	49	37	35	37	45	29	25	35	45	111	111
2021	88	59	51	37	36	38	48	30	25	35	48	115	115
2022	91	62	54	37	36	38	51	30	25	35	51	119	119
2023	95	65	57	37	36	38	53	30	25	35	54	122	122
2024	99	68	60	38	36	38	56	30	25	35	57	126	126
2025	102	71	63	38	36	38	59	31	25	36	61	131	131
2026	106	74	66	38	36	38	62	31	25	36	64	135	135
2027	110	77	69	38	37	39	65	31	26	36	67	139	139
2028	113	80	72	38	37	39	67	31	26	36	70	143	143
2029	117	83	75	39	37	39	70	32	26	37	73	147	147
2030	121	86	78	39	37	39	73	35	26	37	77	151	151
2031	124	89	80	39	37	40	76	37	26	37	79	153	153
2032	128	92	83	39	38	40	78	40	26	40	83	153	153
2033	131	95	86	39	38	40	81	42	26	42	86	154	154
2034	135	98	89	39	38	40	84	44	27	44	89	154	154
2035	138	101	91	40	38	40	86	47	27	47	92	154	154
2036	142	104	94	40	38	40	86	49	27	49	95	155	155
2037	145	106	97	40	38	41	86	51	27	51	98	155	155
2038	149	109	100	40	39	41	86	54	27	53	101	155	155
2039	149	112	102	40	39	41	87	56	27	56	104	156	156
2040	150	115	105	41	39	41	87	58	27	58	107	156	156

Table 2: Maximum PRM Deficit (MW)

Maximum PRM deficit (MW)													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Maximum**
2012	14	47	47	2	0	34	43	41	0	34	48	54	54
2013	24	49	47	9	0	39	43	44	0	42	49	54	54
2014	34	50	48	15	0	39	44	44	0	44	49	55	55
2015	67	0	0	0	0	0	0	0	0	0	0	0	67
2016	0	0	0	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	2	0	0	0	0	0	2	2
2018	0	0	0	0	0	6	0	0	0	0	0	13	13
2019	0	0	0	0	0	10	0	0	0	0	0	23	23
2020	0	0	0	0	0	14	0	0	0	0	0	34	34
2021	0	0	0	0	0	18	0	0	0	0	0	45	45
2022	0	0	0	0	0	22	0	0	0	0	0	56	56
2023	0	0	0	0	0	26	0	0	0	0	0	67	67
2024	6	0	0	0	0	30	3	0	0	0	0	79	79
2025	17	0	0	0	0	35	11	0	0	0	0	90	90
2026	27	0	0	0	0	38	18	0	0	0	0	101	101
2027	37	0	0	0	0	39	26	0	0	0	0	113	113
2028	48	0	0	0	0	39	34	0	0	0	0	125	125
2029	59	0	0	0	0	39	42	0	0	0	0	136	136
2030	69	0	0	0	0	39	50	0	0	0	0	147	147
2031	78	0	0	0	0	40	57	0	0	0	0	153	153
2032	89	0	0	0	0	40	65	0	0	0	0	153	153
2033	99	0	0	0	0	40	72	0	0	0	0	154	154
2034	109	7	0	0	0	40	80	0	0	0	0	154	154
2035	118	15	3	0	0	40	86	0	0	0	0	154	154
2036	128	23	11	0	0	40	86	0	0	0	0	155	155
2037	138	31	19	0	0	41	86	0	0	0	0	155	155
2038	148	39	27	0	0	41	86	0	0	0	0	155	155
2039	149	47	34	0	3	41	87	0	0	0	7	156	156
2040	150	55	42	0	7	41	87	0	0	0	16	156	156

Table 3: Total Hours of PRM Deficit per Month (Hours)

Total Hours of PRM Deficit per Month (Hours)													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Annual**
2012	3	38	153	2	0	14	66	14	0	25	16	63	394
2013	5	55	182	3	0	21	72	17	0	32	24	71	482
2014	7	76	201	5	0	22	73	22	0	41	31	89	567
2015	35	1	0	0	0	0	0	0	0	0	0	0	36
2016	0	0	0	0	0	1	0	0	0	0	0	0	1
2017	0	0	0	0	0	2	0	0	0	0	0	1	3
2018	0	0	0	0	0	4	0	0	0	0	0	1	5
2019	0	0	0	0	0	4	0	0	0	0	0	4	8
2020	0	0	0	0	0	4	0	0	0	0	0	8	12
2021	0	0	0	0	0	6	0	0	0	0	0	14	20
2022	0	0	0	0	0	8	0	0	0	0	0	19	27
2023	0	0	0	0	0	9	0	0	0	0	0	31	40
2024	2	0	0	0	0	11	2	0	0	0	0	41	56
2025	3	0	0	0	0	13	4	0	0	0	0	52	72
2026	5	0	0	0	0	16	6	0	0	0	0	65	92
2027	7	0	0	0	0	18	9	0	0	0	0	76	110
2028	14	0	0	0	0	21	12	0	0	0	0	101	148
2029	21	0	0	0	0	22	15	0	0	0	0	119	177
2030	28	0	0	0	0	25	18	0	0	0	0	134	205
2031	37	0	0	0	0	27	25	0	0	0	0	145	234
2032	42	0	0	0	0	30	30	0	0	0	0	158	260
2033	51	0	0	0	0	36	36	0	0	0	0	170	293
2034	69	4	0	0	0	42	43	0	0	0	0	181	339
2035	81	6	2	0	0	43	50	0	0	0	0	191	373
2036	98	12	3	0	0	48	55	0	0	0	0	200	416
2037	112	14	6	0	0	52	56	0	0	0	0	211	451
2038	130	16	7	0	0	57	59	0	0	0	0	224	493
2039	147	25	12	0	2	61	66	0	0	0	1	238	552
2040	162	32	17	0	2	67	67	0	0	0	1	245	593

Table 4: Percentage of Total Hours of PRM Deficit per Month (%)

Percent of Total Hours of PRM Deficit per Month (%)													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
2012	0.4%	5.7%	20.6%	0.3%	0.0%	1.9%	8.9%	1.9%	0.0%	3.4%	2.2%	8.5%	4.5%
2013	0.7%	8.2%	24.5%	0.4%	0.0%	2.9%	9.7%	2.3%	0.0%	4.3%	3.3%	9.5%	5.5%
2014	0.9%	11.3%	27.0%	0.7%	0.0%	3.1%	9.8%	3.0%	0.0%	5.5%	4.3%	12.0%	6.5%
2015	4.7%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%
2016	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2017	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%
2018	0.0%	0.0%	0.0%	0.0%	0.0%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%
2019	0.0%	0.0%	0.0%	0.0%	0.0%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%	0.1%
2020	0.0%	0.0%	0.0%	0.0%	0.0%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%	0.1%
2021	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	0.0%	0.0%	0.0%	0.0%	0.0%	1.9%	0.2%
2022	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%	0.0%	0.0%	0.0%	0.0%	0.0%	2.6%	0.3%
2023	0.0%	0.0%	0.0%	0.0%	0.0%	1.3%	0.0%	0.0%	0.0%	0.0%	0.0%	4.2%	0.5%
2024	0.3%	0.0%	0.0%	0.0%	0.0%	1.5%	0.3%	0.0%	0.0%	0.0%	0.0%	5.5%	0.6%
2025	0.4%	0.0%	0.0%	0.0%	0.0%	1.8%	0.5%	0.0%	0.0%	0.0%	0.0%	7.0%	0.8%
2026	0.7%	0.0%	0.0%	0.0%	0.0%	2.2%	0.8%	0.0%	0.0%	0.0%	0.0%	8.7%	1.1%
2027	0.9%	0.0%	0.0%	0.0%	0.0%	2.5%	1.2%	0.0%	0.0%	0.0%	0.0%	10.2%	1.3%
2028	1.9%	0.0%	0.0%	0.0%	0.0%	2.9%	1.6%	0.0%	0.0%	0.0%	0.0%	13.6%	1.7%
2029	2.8%	0.0%	0.0%	0.0%	0.0%	3.1%	2.0%	0.0%	0.0%	0.0%	0.0%	16.0%	2.0%
2030	3.8%	0.0%	0.0%	0.0%	0.0%	3.5%	2.4%	0.0%	0.0%	0.0%	0.0%	18.0%	2.3%
2031	5.0%	0.0%	0.0%	0.0%	0.0%	3.8%	3.4%	0.0%	0.0%	0.0%	0.0%	19.5%	2.7%
2032	5.6%	0.0%	0.0%	0.0%	0.0%	4.2%	4.0%	0.0%	0.0%	0.0%	0.0%	21.2%	3.0%
2033	6.9%	0.0%	0.0%	0.0%	0.0%	5.0%	4.8%	0.0%	0.0%	0.0%	0.0%	22.8%	3.3%
2034	9.3%	0.6%	0.0%	0.0%	0.0%	5.8%	5.8%	0.0%	0.0%	0.0%	0.0%	24.3%	3.9%
2035	10.9%	0.9%	0.3%	0.0%	0.0%	6.0%	6.7%	0.0%	0.0%	0.0%	0.0%	25.7%	4.3%
2036	13.2%	1.8%	0.4%	0.0%	0.0%	6.7%	7.4%	0.0%	0.0%	0.0%	0.0%	26.9%	4.7%
2037	15.1%	2.1%	0.8%	0.0%	0.0%	7.2%	7.5%	0.0%	0.0%	0.0%	0.0%	28.4%	5.1%
2038	17.5%	2.4%	0.9%	0.0%	0.0%	7.9%	7.9%	0.0%	0.0%	0.0%	0.0%	30.1%	5.6%
2039	19.8%	3.7%	1.6%	0.0%	0.3%	8.5%	8.9%	0.0%	0.0%	0.0%	0.1%	32.0%	6.3%
2040	21.8%	4.8%	2.3%	0.0%	0.3%	9.3%	9.0%	0.0%	0.0%	0.0%	0.1%	32.9%	6.8%

Table 4A: Percentage of Super Peak Hours of PRM Deficit per Month (%)

Percent of Super Hours of PRM Deficit per Month (%)													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
2012	1.9%	25.0%	57.4%	0.0%	0.0%	11.5%	49.4%	13.6%	0.0%	8.6%	8.3%	27.8%	19.1%
2013	3.1%	32.6%	67.9%	0.0%	0.0%	16.7%	54.3%	17.3%	0.0%	9.9%	12.2%	31.5%	23.1%
2014	4.3%	41.7%	71.0%	0.0%	0.0%	16.7%	55.6%	19.8%	0.0%	12.3%	14.1%	36.4%	25.8%
2015	16.0%	0.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.0%
2016	0.0%	0.0%	0.0%	0.0%	0.0%	1.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
2017	0.0%	0.0%	0.0%	0.0%	0.0%	2.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.6%	0.2%
2018	0.0%	0.0%	0.0%	0.0%	0.0%	3.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.6%	0.3%
2019	0.0%	0.0%	0.0%	0.0%	0.0%	3.8%	0.0%	0.0%	0.0%	0.0%	0.0%	2.5%	0.5%
2020	0.0%	0.0%	0.0%	0.0%	0.0%	3.8%	0.0%	0.0%	0.0%	0.0%	0.0%	4.3%	0.7%
2021	0.0%	0.0%	0.0%	0.0%	0.0%	6.4%	0.0%	0.0%	0.0%	0.0%	0.0%	6.8%	1.2%
2022	0.0%	0.0%	0.0%	0.0%	0.0%	9.0%	0.0%	0.0%	0.0%	0.0%	0.0%	9.3%	1.6%
2023	0.0%	0.0%	0.0%	0.0%	0.0%	9.0%	0.0%	0.0%	0.0%	0.0%	0.0%	14.2%	2.2%
2024	1.2%	0.0%	0.0%	0.0%	0.0%	10.3%	2.5%	0.0%	0.0%	0.0%	0.0%	19.1%	3.2%
2025	1.9%	0.0%	0.0%	0.0%	0.0%	10.3%	3.7%	0.0%	0.0%	0.0%	0.0%	22.8%	3.8%
2026	3.1%	0.0%	0.0%	0.0%	0.0%	12.8%	6.2%	0.0%	0.0%	0.0%	0.0%	29.0%	5.0%
2027	4.3%	0.0%	0.0%	0.0%	0.0%	14.1%	8.6%	0.0%	0.0%	0.0%	0.0%	33.3%	5.9%
2028	7.4%	0.0%	0.0%	0.0%	0.0%	16.7%	11.1%	0.0%	0.0%	0.0%	0.0%	38.9%	7.2%
2029	10.5%	0.0%	0.0%	0.0%	0.0%	16.7%	13.6%	0.0%	0.0%	0.0%	0.0%	46.9%	8.7%
2030	13.6%	0.0%	0.0%	0.0%	0.0%	17.9%	14.8%	0.0%	0.0%	0.0%	0.0%	53.1%	10.0%
2031	16.7%	0.0%	0.0%	0.0%	0.0%	19.2%	19.8%	0.0%	0.0%	0.0%	0.0%	58.6%	11.4%
2032	19.1%	0.0%	0.0%	0.0%	0.0%	20.5%	24.7%	0.0%	0.0%	0.0%	0.0%	61.1%	12.4%
2033	22.8%	0.0%	0.0%	0.0%	0.0%	21.8%	30.9%	0.0%	0.0%	0.0%	0.0%	65.4%	13.8%
2034	30.9%	2.1%	0.0%	0.0%	0.0%	26.9%	33.3%	0.0%	0.0%	0.0%	0.0%	68.5%	15.8%
2035	36.4%	2.8%	0.6%	0.0%	0.0%	28.2%	40.7%	0.0%	0.0%	0.0%	0.0%	71.6%	17.5%
2036	43.2%	6.9%	1.2%	0.0%	0.0%	29.5%	43.2%	0.0%	0.0%	0.0%	0.0%	75.9%	19.6%
2037	46.9%	8.3%	2.5%	0.0%	0.0%	29.5%	43.2%	0.0%	0.0%	0.0%	0.0%	78.4%	20.6%
2038	53.7%	9.7%	3.1%	0.0%	0.0%	30.8%	44.4%	0.0%	0.0%	0.0%	0.0%	82.7%	22.3%
2039	59.9%	16.0%	5.6%	0.0%	0.0%	33.3%	49.4%	0.0%	0.0%	0.0%	0.6%	87.0%	25.1%
2040	66.7%	20.8%	8.0%	0.0%	0.0%	35.9%	50.6%	0.0%	0.0%	0.0%	0.6%	89.5%	27.2%

Table 5: Maximum Consecutive Daily Hours of PRM Deficit (Hours)

Consecutive Daily Hours of PRM Deficit (Hours)													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Annual**
2012	2	4	7	1	0	5	7	5	0	4	4	5	7
2013	2	5	7	2	0	5	7	5	0	6	4	6	7
2014	3	5	7	3	0	6	7	5	0	6	5	6	7
2015	5	1	0	0	0	0	0	0	0	0	0	0	5
2016	0	0	0	0	0	1	0	0	0	0	0	0	1
2017	0	0	0	0	0	2	0	0	0	0	0	1	2
2018	0	0	0	0	0	3	0	0	0	0	0	1	3
2019	0	0	0	0	0	3	0	0	0	0	0	2	3
2020	0	0	0	0	0	3	0	0	0	0	0	3	3
2021	0	0	0	0	0	3	0	0	0	0	0	4	4
2022	0	0	0	0	0	4	0	0	0	0	0	4	4
2023	0	0	0	0	0	4	0	0	0	0	0	5	5
2024	1	0	0	0	0	4	2	0	0	0	0	5	5
2025	2	0	0	0	0	5	3	0	0	0	0	5	5
2026	2	0	0	0	0	5	4	0	0	0	0	5	5
2027	3	0	0	0	0	5	4	0	0	0	0	6	6
2028	4	0	0	0	0	5	4	0	0	0	0	6	6
2029	4	0	0	0	0	6	5	0	0	0	0	6	6
2030	5	0	0	0	0	7	5	0	0	0	0	6	7
2031	5	0	0	0	0	7	5	0	0	0	0	6	7
2032	5	0	0	0	0	7	5	0	0	0	0	6	7
2033	6	0	0	0	0	7	6	0	0	0	0	6	7
2034	6	2	0	0	0	7	6	0	0	0	0	7	7
2035	6	2	2	0	0	7	6	0	0	0	0	7	7
2036	6	3	2	0	0	8	7	0	0	0	0	7	8
2037	6	3	3	0	0	8	7	0	0	0	0	7	8
2038	6	3	3	0	0	8	7	0	0	0	0	7	8
2039	6	4	3	0	2	8	7	0	0	0	1	7	8
2040	6	4	4	0	2	9	7	0	0	0	1	7	9

Table 6: Total Maximum Daily Hours of PRM Deficit (Hours)

Total Maximum Daily Hours of PRM Deficit (Hours)													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Annual**
2012	2	7	13	1	0	6	8	5	0	8	5	10	13
2013	3	9	13	2	0	7	8	5	0	10	8	11	13
2014	4	10	13	3	0	7	8	5	0	10	8	12	13
2015	9	1	0	0	0	0	0	0	0	0	0	0	9
2016	0	0	0	0	0	1	0	0	0	0	0	0	1
2017	0	0	0	0	0	2	0	0	0	0	0	1	2
2018	0	0	0	0	0	3	0	0	0	0	0	1	3
2019	0	0	0	0	0	3	0	0	0	0	0	2	3
2020	0	0	0	0	0	3	0	0	0	0	0	3	3
2021	0	0	0	0	0	3	0	0	0	0	0	4	4
2022	0	0	0	0	0	4	0	0	0	0	0	4	4
2023	0	0	0	0	0	5	0	0	0	0	0	7	7
2024	1	0	0	0	0	5	2	0	0	0	0	9	9
2025	2	0	0	0	0	6	3	0	0	0	0	9	9
2026	3	0	0	0	0	6	4	0	0	0	0	10	10
2027	4	0	0	0	0	7	4	0	0	0	0	11	11
2028	7	0	0	0	0	7	4	0	0	0	0	12	12
2029	7	0	0	0	0	7	5	0	0	0	0	12	12
2030	9	0	0	0	0	7	5	0	0	0	0	12	12
2031	10	0	0	0	0	7	5	0	0	0	0	12	12
2032	10	0	0	0	0	7	5	0	0	0	0	12	12
2033	11	0	0	0	0	8	6	0	0	0	0	12	12
2034	12	3	0	0	0	8	7	0	0	0	0	13	13
2035	12	4	2	0	0	8	7	0	0	0	0	13	13
2036	12	5	2	0	0	10	7	0	0	0	0	13	13
2037	12	6	3	0	0	10	7	0	0	0	0	13	13
2038	12	6	3	0	0	10	7	0	0	0	0	13	13
2039	12	7	5	0	2	10	8	0	0	0	1	13	13
2040	12	7	6	0	2	11	8	0	0	0	1	13	13

Appendix F

CLEAN ENERGY ACT OBJECTIVES

***Clean Energy Act* – British Columbia's Energy Objectives**	**2012 Resource Plan Satisfies Objective**	
(a) to achieve electricity self-sufficiency;	✓	Key input in evaluating capacity and energy alternatives (see Section 6)
(b) to take demand side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66 percent;		Not Applicable
(c) to generate at least 93 percent of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;	✓	Key input in evaluating capacity and energy alternatives (see Section 6)
(d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources;		Not Applicable
(e) to ensure the authority's ratepayers receive the benefits of the heritage assets and to ensure the benefits of the heritage contract under the BC Hydro Public Power Legacy and Heritage Contract Act continue to accrue to the authority's ratepayers;	✓	(see Section 5.1.2.1.1)
(f) to ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America;		Not Applicable

***Clean Energy Act* – British Columbia's Energy Objectives**	**2012 Resource Plan Satisfies Objective**	
(g) to reduce BC greenhouse gas emissions (i) by 2012 and for each subsequent calendar year to at least 6 percent less than the level of those emissions in 2007, (ii) by 2016 and for each subsequent calendar year to at least 18 percent less than the level of those emissions in 2007, (iii) by 2020 and for each subsequent calendar year to at least 33 percent less than the level of those emissions in 2007, (iv) by 2050 and for each subsequent calendar year to at least 80 percent less than the level of those emissions in 2007, and (v) by such other amounts as determined under the Greenhouse Gas Reduction Targets Act;	✓	Key input in evaluating capacity and energy alternatives (see Section 6)
(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;		Not Applicable
(i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;		Not Applicable
(j) to reduce waste by encouraging the use of waste heat, biogas and biomass;	✓	Key input in developing the Clean Energy Call recommendation (see Section 6)
(k) to encourage economic development and the creation and retention of jobs;		Not Applicable
(l) to foster the development of first nation and rural communities through the use and development of clean or renewable resources;		Not Applicable

Clean Energy Act **– British Columbia's Energy Objectives**	**2012 Resource Plan Satisfies Objective**	
(m) to maximize the value, including the incremental value of the resources being clean or renewable resources, of British Columbia's generation and transmission assets for the benefit of British Columbia;	✓	Key input behind future capacity options recommendation (see Section 6)
(n) to be a net exporter of electricity from clean or renewable resources with the intention of benefiting all British Columbians and reducing greenhouse gas emissions in regions in which British Columbia trades electricity while protecting the interests of persons who receive or may receive service in British Columbia;		Not Applicable
(o) to achieve British Columbia's energy objectives without the use of nuclear power;	✓	2012 Resource Plan does not evaluate nuclear power options
(p) to ensure the commission, under the Utilities Commission Act, continues to regulate the authority with respect to domestic rates but not with respect to expenditures for export, except as provided by this Act.		Not Applicable

Appendix G

MONTHLY PEAK DEMAND FORECASTS

Monthly Peak Demand Forecasts (Less DSM)

CAPACITY EXPECTED FORECAST (MW)												
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2011	663	607	564	490	453	497	560	536	444	519	606	710
2012	673	614	571	496	458	503	567	543	449	525	614	721
2013	683	623	579	502	464	509	575	550	454	532	623	731
2014	692	630	587	508	469	515	582	556	458	538	630	741
2015	699	637	593	512	473	519	588	561	461	543	636	747
2016	703	639	595	514	474	521	590	563	462	545	639	751
2017	707	642	598	516	476	523	593	566	464	548	643	758
2018	713	647	603	519	479	527	598	570	466	552	649	764
2019	719	652	608	523	482	530	603	574	469	556	654	771
2020	725	657	613	526	486	534	607	578	472	559	659	778
2021	732	662	618	530	489	538	612	582	475	564	665	785
2022	739	668	623	534	493	542	617	587	478	568	670	792
2023	745	673	628	538	496	546	622	591	480	572	676	799
2024	752	678	633	542	500	550	627	595	484	577	681	807
2025	758	684	639	546	503	554	632	600	487	581	687	814
2026	765	689	644	550	507	558	637	604	490	585	693	821
2027	772	695	649	554	510	562	642	609	493	590	699	829
2028	778	700	655	558	514	566	647	614	496	594	704	836
2029	785	706	660	562	518	570	652	618	499	599	710	844
2030	792	711	665	567	522	574	658	623	502	604	716	851
2031	798	716	670	570	525	578	662	627	505	607	721	858
2032	805	721	675	574	528	582	667	631	508	612	727	865
2033	811	727	680	578	532	586	672	636	511	616	733	872
2034	817	732	685	582	535	590	677	640	514	620	738	879
2035	824	737	690	585	538	593	681	644	516	624	744	887
2036	830	742	695	589	542	597	686	649	519	629	749	894
2037	837	747	700	593	545	601	691	653	522	633	754	901
2038	843	753	705	597	549	605	696	657	525	637	760	908
2039	849	758	710	600	552	609	700	661	528	641	765	914
2040	855	763	715	604	555	612	705	665	531	645	771	921

CAPACITY LOW FORECAST (MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2011	662	605	562	489	452	496	559	535	443	518	604	708
2012	670	612	570	494	457	501	566	541	447	524	612	718
2013	679	620	576	500	462	507	573	547	452	530	619	728
2014	687	626	583	504	466	511	578	552	455	535	626	735
2015	693	631	587	507	469	514	582	556	457	538	631	740
2016	695	632	589	508	469	515	583	556	457	538	632	743
2017	697	632	589	508	469	515	585	557	457	539	634	746
2018	700	635	592	510	471	517	587	559	458	542	637	750
2019	704	638	595	512	472	519	589	561	459	544	640	754
2020	707	640	597	513	473	520	592	563	460	545	642	758
2021	711	643	600	515	475	522	594	565	461	548	646	763
2022	715	646	603	517	477	524	597	568	462	550	649	767
2023	719	649	606	519	479	527	600	570	464	552	652	771
2024	723	652	609	521	480	528	603	572	465	554	655	776
2025	726	654	611	523	482	530	605	574	466	556	658	779
2026	729	657	614	524	483	532	607	576	467	558	661	783
2027	733	659	616	526	485	533	610	578	468	560	663	787
2028	736	662	619	528	486	535	612	580	469	562	666	791
2029	739	664	621	529	487	536	614	582	470	564	668	794
2030	742	666	623	531	489	538	616	584	470	565	671	797
2031	744	668	625	532	489	539	618	585	471	567	673	800
2032	747	670	627	533	490	540	619	586	471	568	675	803
2033	750	672	629	534	491	541	621	587	472	569	677	806
2034	753	674	631	535	493	543	623	589	473	571	680	810
2035	755	676	633	537	494	544	625	591	474	573	682	813
2036	757	677	634	537	494	545	626	592	474	573	683	815
2037	759	678	636	538	495	546	627	593	474	574	685	817
2038	761	680	637	539	496	546	629	594	474	575	686	820
2039	763	681	639	540	496	547	630	594	474	576	688	822
2040	765	683	640	540	497	548	631	595	475	577	689	824

CAPACITY HIGH FORECAST (MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2011	669	612	569	494	457	501	565	541	448	523	611	716
2012	678	620	576	500	462	507	572	547	453	530	619	727
2013	689	629	585	507	469	514	581	555	458	537	629	738
2014	700	638	594	514	475	521	589	563	464	545	638	749
2015	710	646	601	520	480	527	596	569	468	551	646	758
2016	715	650	606	523	482	530	600	572	470	554	650	764
2017	721	654	610	526	485	533	605	576	472	558	656	772
2018	729	662	617	531	490	539	612	583	477	564	663	781
2019	738	668	623	536	495	544	618	588	481	570	670	790
2020	746	676	630	542	500	549	624	594	485	576	678	800
2021	755	683	637	547	505	555	631	601	490	582	686	810
2022	765	691	645	553	510	561	639	607	495	588	694	820
2023	774	699	652	559	515	567	646	614	499	594	702	830
2024	783	707	660	565	521	573	653	620	504	601	710	841
2025	793	715	668	571	526	579	661	627	509	608	718	851
2026	802	722	675	577	531	585	668	634	513	614	727	861
2027	812	731	683	583	537	591	676	641	519	621	735	872
2028	822	739	691	589	543	598	683	648	524	628	744	883
2029	832	748	699	596	549	604	691	655	529	635	753	894
2030	842	756	708	602	555	611	699	662	534	642	762	905
2031	852	764	715	608	560	617	707	669	539	648	770	916
2032	862	773	723	615	566	623	715	676	544	655	779	927
2033	872	781	732	621	572	630	722	684	549	662	788	938
2034	882	790	740	628	578	636	730	691	554	669	797	949
2035	892	798	748	634	583	643	738	698	559	676	805	960
2036	902	807	756	640	589	649	746	705	564	683	814	971
2037	912	815	764	647	595	656	754	712	569	690	823	982
2038	922	824	772	653	600	662	761	719	575	697	832	993
2039	933	832	780	659	606	668	769	726	580	704	840	1004
2040	943	841	789	666	612	675	778	734	585	711	850	1016

Appendix H

MONTHLY CAPACITY GAPS

Monthly Capacity Gaps

CAPACITY GAP (ASSUMING EXPECTED FORECAST) (MW)												
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2011	4	39	101	0	0	34	84	36	0	29	40	74
2012	14	47	108	4	0	40	91	43	0	35	48	85
2013	24	56	117	11	0	47	100	50	0	43	58	96
2014	34	64	125	17	0	53	107	57	0	49	66	106
2015	0	0	1	0	0	4	0	0	0	0	0	0
2016	0	0	0	0	0	6	0	0	0	0	0	0
2017	0	0	0	0	0	9	0	0	0	0	0	2
2018	0	0	0	0	0	12	0	0	0	0	0	13
2019	0	0	0	0	0	16	0	0	0	0	0	23
2020	0	0	0	0	0	20	0	0	0	0	0	34
2021	0	0	0	0	0	24	0	0	0	0	0	45
2022	0	0	0	0	0	28	0	0	0	0	0	56
2023	0	0	0	0	0	32	0	0	0	0	0	67
2024	6	0	0	0	0	36	3	0	0	0	0	79
2025	17	0	0	0	0	41	11	0	0	0	0	90
2026	27	0	0	0	0	45	18	0	0	0	0	101
2027	37	0	0	0	0	49	26	0	0	0	0	113
2028	48	0	0	0	0	54	34	0	0	0	0	125
2029	59	0	0	0	0	58	42	0	0	0	0	136
2030	69	0	0	0	0	62	50	0	0	0	0	147
2031	78	0	0	0	0	66	57	0	0	0	0	156
2032	89	0	0	0	0	70	65	0	0	0	0	164
2033	99	0	0	0	0	74	72	0	0	0	0	171
2034	109	7	0	0	0	78	80	0	0	0	0	179
2035	118	15	3	0	0	82	87	0	0	0	0	186
2036	128	23	11	0	0	86	92	0	0	0	0	194
2037	138	31	19	0	1	90	97	0	0	0	0	201
2038	148	39	27	0	4	94	102	0	0	0	0	208
2039	155	47	34	0	8	98	107	0	0	0	7	216
2040	161	55	42	0	11	102	112	0	0	0	16	223

CAPACITY GAP (ASSUMING LOW FORECAST) (MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2011	2	38	99	0	0	33	82	34	0	27	38	72
2012	11	45	107	2	0	38	90	41	0	34	46	83
2013	21	53	114	8	0	44	97	47	0	40	55	92
2014	29	60	120	13	0	49	103	53	0	45	61	101
2015	0	0	0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	2	0	0	0	0	0	0
2019	0	0	0	0	0	4	0	0	0	0	0	0
2020	0	0	0	0	0	6	0	0	0	0	0	3
2021	0	0	0	0	0	8	0	0	0	0	0	10
2022	0	0	0	0	0	10	0	0	0	0	0	17
2023	0	0	0	0	0	12	0	0	0	0	0	24
2024	0	0	0	0	0	14	0	0	0	0	0	30
2025	0	0	0	0	0	16	0	0	0	0	0	36
2026	0	0	0	0	0	18	0	0	0	0	0	42
2027	0	0	0	0	0	19	0	0	0	0	0	48
2028	0	0	0	0	0	21	0	0	0	0	0	54
2029	0	0	0	0	0	23	0	0	0	0	0	59
2030	0	0	0	0	0	24	0	0	0	0	0	64
2031	0	0	0	0	0	25	0	0	0	0	0	69
2032	0	0	0	0	0	26	0	0	0	0	0	73
2033	3	0	0	0	0	28	0	0	0	0	0	78
2034	8	0	0	0	0	29	0	0	0	0	0	83
2035	12	0	0	0	0	31	0	0	0	0	0	88
2036	15	0	0	0	0	31	2	0	0	0	0	91
2037	18	0	0	0	0	32	3	0	0	0	0	95
2038	22	0	0	0	0	33	5	0	0	0	0	99
2039	25	0	0	0	0	34	7	0	0	0	0	102
2040	28	0	0	0	0	35	9	0	0	0	0	106

CAPACITY GAP (ASSUMING HIGH FORECAST) (MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2011	10	45	106	2	0	38	89	40	0	33	45	80
2012	20	53	114	8	0	44	97	47	0	40	54	92
2013	31	63	123	16	0	52	106	56	0	48	64	104
2014	43	72	132	23	0	59	114	64	0	56	74	115
2015	0	0	14	0	0	12	0	0	0	0	0	3
2016	0	0	0	0	0	16	0	0	0	0	0	13
2017	0	0	0	0	0	19	0	0	0	0	0	25
2018	0	0	0	0	0	25	0	0	0	0	0	39
2019	0	0	0	0	0	30	0	0	0	0	0	53
2020	0	0	0	0	0	36	0	0	0	0	0	68
2021	12	0	0	0	0	42	10	0	0	0	0	83
2022	27	0	0	0	0	48	21	0	0	0	0	99
2023	40	0	0	0	0	54	32	0	0	0	0	115
2024	55	0	0	0	0	61	44	0	0	0	0	131
2025	70	0	0	0	0	67	55	0	0	0	0	147
2026	85	0	0	0	0	73	66	0	0	0	0	160
2027	100	5	0	0	0	80	79	0	0	0	0	171
2028	115	18	4	0	0	87	89	0	0	0	0	183
2029	131	31	17	0	4	94	97	0	0	0	0	194
2030	147	45	30	0	11	101	106	0	0	0	2	206
2031	158	57	42	0	16	107	113	0	0	0	15	217
2032	168	70	54	1	22	114	122	0	0	0	29	229
2033	179	83	67	11	29	121	130	0	0	0	42	240
2034	190	97	80	21	35	128	138	0	0	10	56	252
2035	200	109	92	30	40	134	146	0	0	21	69	263
2036	211	123	105	40	47	141	154	0	0	31	83	275
2037	221	136	117	50	53	148	163	0	0	42	97	287
2038	232	149	130	60	59	154	171	0	0	53	110	298
2039	243	158	142	70	65	161	179	0	0	64	124	310
2040	254	167	151	77	71	168	188	0	0	75	139	322

Appendix I

DETAILED RESOURCE OPTION RATING

Capacity Resource Options Evaluation

Option	Criteria 1: "Resource Size"	Criteria 2: "Environmental Impacts"	Criteria 3: "Economics"[1]
Simple Cycle Gas Turbine ("**SCGT**")	An SCGT is a flexible and scalable resource option. The resource can be sized to match the need in 42MW increments and therefore receives a rating of "1".	Although an SCGT consumes natural gas and emits GHGs, it has minimal negative physical impacts (e.g. flooding land for a reservoir) and it will be primarily function as a reserve resource with a low utilization rate. An SCGT therefore receives a rating of "2".	SCGTs have a low UCC (relative to other capacity resource options) of $8,481/MW-month and therefore receive a rating of "1".
Combined Cycle Gas Turbine ("**CCGT**")	Economic factors govern the minimum size of a CCGT. FortisBC's 2010 Resource Options Report (see Appendix C) identified a CCGT size of 243MW. The expected peak demand capacity deficit in December 2040 is estimated to be 223MW which less than the CCGT size of 243MW. The resource size is larger than the expected resource need and therefore receives a rating of "3".	A CCGT has minimal physical impacts (e.g. flooding land for a reservoir). A CCGT is unable to ramp generation output up/down quickly and therefore functions as a baseload generation resource. Operating a natural gas resource to supply baseload generation will result in significant GHG production and therefore a CCGT receives a rating of "3".	Similar to an SCGT, a CCGT has a low UCC of $12,708/MW-month and therefore receives a rating of "1".
Potential Pumped Storage Hydro ("**PSH**")	PSH is a capacity-only resource that has the ability to shape demand on the system, providing FortisBC with considerable operational flexibility. FortisBC's 2010 Resource Options Report (see Appendix C) identified a potential PSH facility to be 180 MW in size. This is a relatively large resource in the FortisBC context. However, due to the operational benefits that are provided, PSH receives a rating of "2".	Although requiring two reservoirs (an upper and lower) that will have a physical land impact, a PSH facility would have no direct GHG emissions associated with operations. It therefore receives a rating of "1".	PSH has a UCC of $17,412/MW-month, which is higher than either natural gas option and therefore receives a rating of "2".
Similkameen (Small Hydro with Capacity)	Similkameen is a hydro-electric project that provides both capacity and energy. Due to Similkameen's storage abilities, the resource option could provide approximately 60 MW of dependable capacity. The size and flexibility of the capacity product matches with the FortisBC need and therefore it receives a rating of "1".	Although the Similkameen project will have physical land impacts associated with the reservoir upstream of the dam, there will be no GHG emissions associated with operations. Therefore it receives a rating of "1".	Similkameen has a high UCC of $38,003/MW-month and therefore receives a rating of "3".

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[1] Unit capacity costs ("**UCC**") quoted below are taken from FortisBC's 2010 Resource Options Report and assume an 8% weighted average cost of capital.

Energy Resource Option Evaluation

Resource	Criteria 1: "Resource Size"	Criteria 2: "Environmental Impacts"	Criteria 3: "Economics"[2]	Criteria 4: "Energy Shape"
Combined Cycle Gas Turbine ("**CCGT**")	Economic factors govern the minimum size of a CCGT. FortisBC's 2010 Resource Options Report (see Appendix C) identified a CCGT size of 243MW. The estimated energy output for a 243MW CCGT is 1944GWh in year 1 falling to 1888GWh in year 25 (see Appendix C), and this output larger than the expected energy gap in 2040 of 324GWh. The resource size is larger than the expected resource need. If higher than expected loads occur, this resource will become a more viable option and therefore receives a rating of "2".	A CCGT is unable to ramp capacity output up/down quickly and therefore would be required to function as a baseload resource. Operating a natural gas resource to supply baseload energy will result in significant GHG production and therefore a CCGT receives a rating of "3".	A CCGT has a low UEC (relative to other resource options) of $93/MWh and therefore receives a rating of "1".	Given a secure fuel supply, a CCGT is dispatchable whenever energy is needed and therefore receives a rating of "1".
Run Of River Hydro - Coastal	Given the small, scalable amount of energy available from coastal run of river hydro, it receives a rating of "1".	Physical land impacts for run of river projects are considered small. There are no GHG emissions associated with the operations of a run of river plant. Therefore this resource option receives a rating of "1".	Although having a higher UEC than a CCGT ($108/MWh), this resource option still receives a rating of "1".	Coastal run of river hydro tends to contain less freshet energy as a proportion of total production than BC interior run of river facilities. More energy is produced during the winter season when energy is more valuable to FortisBC and therefore it receives a rating of "2".

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[2] Unit energy costs (**"UEC"**) quoted below are taken from FortisBC's 2010 Resource Options Report and assume an 8% weighted average cost of capital.

Resource	Criteria 1: "Resource Size"	Criteria 2: "Environmental Impacts"	Criteria 3: "Economics"[2]	Criteria 4: "Energy Shape"
Similkameen	Similkameen is a hydro-electric project that provides both capacity and energy. On an annual basis, Similkameen is expected to produce 234 GWh of energy. The size of the energy product matches with the FortisBC need and therefore receives a rating of "1".	Although the Similkameen project will have physical land impacts associated with the reservoir upstream of the dam, there will be no GHG emissions associated with operations. Therefore it receives a rating of "1".	Similkameen's higher UEC of $124/MWh (relative to a CCGT and coastal run of river) receives a rating of "2".	Similkameen will have an energy shape similar to traditional run of river hydro. However, due to intra-day storage capabilities, Similkameen's energy shape can be tailored to the daily peak needs and therefore receives a rating of "1".
Run Of River Hydro - FortisBC Territory	Given the small, scalable amount of energy available from run of river Hydro in the FortisBC territory, it receives a rating of "1".	Physical land impacts for run of river projects are considered small. There are no GHG emissions associated with the operations of a run of river plant. Therefore this resource option receives a rating of "1".	Having the same UEC as Similkameen ($124/MWh), FortisBC area run of river also receives a rating of "2".	Run of river hydro in the FortisBC territory will be freshet heavy (undesirable) and therefore receives a rating of "3".
Biomass (Roadside and Sawmill Woodwaste)	Given the small, scalable amount of energy available from Biomass, it receives a rating of "1".	Biomass facilities have physical land impact and it is considered a green resource. Therefore biomass receives a rating of "1".	Biomass' UEC falls in the range of $108-$159/MWh. Given the uncertainty, a conservative approach is taken and the higher end of the range is considered. Therefore, biomass receives a rating of "3".	Given a secure fuel supply that can be collected and stored, a biomass facility is dispatchable whenever energy is needed and therefore receives a rating of "1".
Wind (Low Cost)	Given the scalable amount of energy available from low cost wind, it receives a rating of "1".	Wind farms have small physical land impacts. There are no GHG emissions associated with the operations of a wind farm. Therefore this resource option receives a rating of "1".	Low construction cost wind projects are projected to achieve a UEC of $127/MWh (similar to Similkameen and run of river in the FortisBC territory) and therefore receive a rating of "2".	Wind resource generation is unpredictable on an hour to hour basis (non-firm energy) and therefore receives a rating of "3".
Wind	Given the scalable amount of energy available from wind, it receives a rating of "1".	Wind farms have small physical land impacts. There are no GHG emissions associated with the operations of a wind farm. Therefore this resource option receives a rating of "1".	High construction cost wind projects are projected to achieve a UEC of $154/MWh (higher than low cost wind projects) and therefore receives a rating of "3".	Wind resource generation is unpredictable on an hour to hour basis (non-firm energy) and therefore receives a rating of "3".

2012 Integrated System Plan

Volume 2

2012 Long Term Demand-Side Management Plan (2012 DSM Plan)

June 30, 2011

FortisBC Inc.

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List of Tables and Figures

1. OVERVIEW

FortisBC's 2012 Long Term Demand-Side Management Plan (the 2012 DSM Plan), part of the 2012 Integrated System Plan, is filed pursuant to section 44.1 (2) of the *Utilities Commission Act* (the Act). The Company is seeking Commission acceptance under section 44.1(6) that the 2012 Integrated System Plan is in the public interest. The Company is not seeking specific approval of DSM expenditures identified in the 2012 DSM Plan. The DSM expenditure schedule for 2012 – 2013 is contained and discussed as part of the 2012-2013 Capital Expenditure Plan (Tab 6 of the 2012 – 2013 Revenue Requirements).

The 2007 BC Energy Plan and the *Clean Energy Act* emphasize the employment of demand side measures to meet growing electricity demand in British Columbia. The 2008 Amendment to the Act and the Demand Side Measures Regulation enacted under the Act set out more specific requirements for a public utility to develop "a plan of how the public utility intends to reduce the demand ... by taking cost-effective demand-side measure" and to include certain programs in the DSM plan.

The Company's objective for DSM is to offer customers in its service territory a range of programs within a cost-effective portfolio of measures that address the majority of end uses within each major customer sector. The overall DSM savings target is to offset 50 percent of load growth over the planning period. The first five years of the 2012 DSM Plan (2012-2016) are an extension of the approved[1] 2011 DSM Plan, thereafter a constant savings target is used as a placeholder for future DSM activities.

The 2012 DSM Plan represents program savings only, and excludes potential savings from price elasticity or conservation effects induced by rate redesign (e.g. Residential Inclined Block) or information (e.g. customer consumption portal). The DSM programs include savings for an IHD (in-home display) measure that is dependent upon approval of the Company's Advanced Metering Infrastructure CPCN application to be filed later in 2011.

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[1] BCUC Order G-195-10 approved Dec 17, 2010.

1.1 The 2007 Energy Plan and *Clean Energy Act*

The 2007 *BC Energy Plan* highlighted the importance of DSM as a key component of future electricity supply, setting a target in Policy Action 1 to acquire 50 percent of BC Hydro's incremental resource needs through conservation by 2020. FortisBC has voluntarily adopted this target in its 2012 DSM Plan.

Other *BC Energy Plan* objectives and policy actions influencing DSM programs for public utilities are to:

(a) ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia (Policy Action 2); and

(b) encourage utilities to pursue cost effective and competitive demand side management opportunities (Policy Action 3).

The *Clean Energy Act* refined the target by requiring BC Hydro to "take demand side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%." The *Clean Energy Act* also sets additional objectives, including

> (a) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources;
>
> (b) to encourage communities to reduce greenhouse gas emissions and use energy efficiently.

The *Clean Energy Act* defines a "demand-side measure" to mean 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;

but does *not* include:

(d) a rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increase greenhouse gas emissions in British Columbia, or

(e) any rate measure, action or program prescribed.

FortisBC has prepared the 2012 DSM Plan taking into consideration "British Columbia's energy objectives" set out in the *Clean Energy Act.* Table 1.1 below lists those objectives set out in *Clean Energy Act* which FortisBC believes are directly relevant to the Company's DSM Plan.

Table 1.1 – Relevant *Clean Energy Act* Objectives

***Clean Energy Act* Objectives**	**2012 DSM Plan Satisfies Objective**	
To take demand-side measures and to conserve electricity…	✓	The 2012-2013 Capital Expenditure Plan seeks BCUC approval for DSM program expenditures
To use and foster the development of innovative technologies that support energy conservation and efficiency…	✓	The 2012 DSM Plan includes a framework under which new and emerging DSM measures can be piloted, and/or incented
To encourage communities to reduce greenhouse gas emissions and use energy efficiency;	✓	The Supporting Initiatives (Section 3.6) include funds for Community Energy Planning

1.2 The Act and DSM Regulation

Section 44.1 (2) of the Act requires that FortisBC file a long-term resource plan which includes the following related to DSM:

(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;

(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; and

(f) an explanation of why the demand for energy to be served by facilities…that the utility intends to construct or extend… are not planned to be replaced by demand-side measures.

FortisBC's 2012 Long Term Resource Plan (included in Volume 2 of the 2012 Integrated System Plan) was filed concurrently with the 2012 DSM Plan on June 30, 2011.

The DSM Regulation, issued under the Act, defines what demand side measure should be included in the public utility's DSM plan to be adequate:

3. A public utility's plan portfolio is adequate for the purposes of section 44.1 (8) (c) of the Act only if the plan portfolio includes all of the following:

(a) a demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption;

(b) if the plan portfolio is submitted on or after June 1, 2009, a demand-side measure intended specifically to improve the energy efficiency of rental accommodations;

(c) an education program for students enrolled in schools in the public utility's service area;

(d) if the plan portfolio is submitted on or after June 1, 2009, an education program for students enrolled in post-secondary institutions in the public utility's service area.

FortisBC has prepared the 2012 DSM Plan taking into consideration the DSM Regulation and believes that its DSM Plan meets the adequacy requirements of the Regulation as demonstrated in Table 1.2 (a) below

Table 1.2 (a) – Adequacy Requirements of *DSM Regulation*

DSM Regulation Section 3	**2012 DSM Plan Satisfies Adequacy Requirements**	
(a) a demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption;	✓	Section 3.4.4 of the 2012 DSM Plan
(b) a demand-side measure intended specifically to improve the energy efficiency of rental accommodations;	✓	Section 3.4.4 of the 2012 DSM Plan
(c) an education program for students enrolled in schools; and	✓	Section 3.8 of the 2012 DSM Plan
(d) an education program for students enrolled in post-secondary institutions in the public utility's service area.	✓	Section 3.8 of the 2012 DSM Plan

The DSM Regulation also provides in section 4 that the Commission, in determining the cost-effectiveness of a DSM measure proposed in a long-term resource plan or an expenditure schedule:

(1) may compare the costs and benefits of the measure individually, or together with other demand-side measures in the portfolio, or of the portfolio as a whole;

(2) must, for measures intended to assist residents of low-income households, also use the total resource cost (TRC) test, and consider the benefit of the measure to be 130 percent of its value;

(3) must consider the benefit of the avoided supply cost to be BC Hydro's long-term marginal cost of acquiring new electricity;

(4) must determine the cost-effectiveness of a demand-side measure by determining whether the portfolio is cost-effective as a whole;

(5) must determine the cost-effectiveness of a public awareness program as defined in the DSM Regulation by determining whether the portfolio is cost-effective as a whole;

(6) may not determine that a proposed measure is not cost effective on the basis of a rate-impact measure (RIM) test; and

(7) may, in the case of a measure related to a regulated item to which a specified standard has not yet commenced, include in the benefit a proportion of the benefit that may result from the application of the specified standard.

The Company believes the 2012 DSM Plan, including the 2012 and 2013 DSM expenditures outlined in the 2012-2013 Capital Expenditure Plan, meet the requirements of Section 4.1 of the DSM Regulation as shown in Table 1.2 (b) below:

Table 1.2 (b) – Cost-effective Test

DSM Regulation Section 4(1)	**2012 DSM Plan Satisfies Cost-effective Requirements**	
..a demand-side measure proposed in an expenditure portfolio or a plan portfolio, may compare the costs and benefits of (a) a demand-side measure individually, (b) the demand-side measure *and* other demand-side measures in the portfolio, *or* (c) the portfolio as a whole.	✓	Section 7 (DSM), 2012-13 Capital Plan Table 7.0 (Overall B/C ratio) Table 7.1 (Residential) Table 7.2 (Commercial) Table 7.3 (Industrial)

1.3 BCUC Directives

The 2011 Capital Expenditure Plan Decision (Order G-195-10) contained several directives and comments from the Commission Panel relevant to the 2012 DSM Plan. The Company believes the 2012 DSM Plan addresses those issues as illustrated in Table 1.3 below:

Table 1.3 – 2011 Capital Expenditure Plan Directives (Order G-195-10)

Directive	Status/ Comments	Reference
The Commission Panel therefore directs FortisBC to include the topics of energy efficiency and incentive opportunities in its consultation with the Irrigation Rate Class (page 58).	FortisBC has developed an Irrigation customer – specific DSM product option program. The Company has also modified its soft-start motor control requirements in response to irrigation customer requests and is working with industry stakeholders in the development of other programs.	Section 3.4.2
The Panel has considered the effort that FortisBC undertook to prepare the 2011 DSM Plan (Section 5.2) and encourages FortisBC to incorporate additional best practices, empirical research, and evaluations and lessons learned from pilot programs and program models in other jurisdictions in the preparation of its long-term plan (page 59).	FortisBC has hired two additional staff (PowerSense engineer, and monitoring and evaluation analyst) to provide greater research and evaluation capacity, and incorporate best practices from other utilities and energy efficiency/conservation consortiums.	Section 3.4
The Commission Panel encourages FortisBC to continue to collaborate with other utilities in the planning and delivery of DSM programs (page 59).	FortisBC has partnered with a variety of public and private entities in delivering energy efficiency programs.	Section 3.5

2. DSM PLAN DEVELOPMENT

2.1 Planning Principles

The 2012 DSM Plan was created using the following guiding principles:

1. The DSM Plan will be customer focused by offering a range of measure choices within programs that address the key end uses of the principal customer rate classes;
2. The DSM Plan will be cost effective by including only those measures, with the exception of prescribed measures, which have a TRC Benefit Cost ratio greater than unity on a portfolio basis;
3. The DSM Plan will be inclusive of best practices in terms of program design, implementation, marketing, outreach, monitoring and evaluation; and
4. The DSM Plan will be compliant with the applicable sections of the Act and the Clean Energy Act, and with the DSM Regulation.

2.2 Planning Steps

The 2012 DSM Plan is an extension of the Company's 2011 DSM Plan, filed as part of the FortisBC 2011 Capital Expenditure Plan and approved by Order G-195-10. The 2011 DSM Plan was developed in the manner described below:

1. Identify the key objectives for DSM at FortisBC (the 2008 Strategic DSM Plan);
2. Understand how FortisBC customers use energy within their homes and businesses (2009 Residential Customer End Use Survey and 2009 Commercial End Use Survey);
3. Quantify potential energy savings available (2010 Conservation and Demand Potential Review);
4. Identify alternative measures for consideration and screen them based on the TRC test;
5. Develop three scenarios or plan options, namely Low, Medium and High, which were the subject of public consultations; and
6. The Medium option was selected as the preferred option in the 2011 DSM Plan filing, and ultimately approved by Commission Order G-195-10.

2.3 End Use Surveys

During 2009, market research was undertaken by FortisBC to understand how customers use energy in their homes and businesses in order to design Demand Side Management and information and communications programs.

The specific objective of the Residential End Use Survey (REUS) and the Commercial End Use Survey (CEUS) was to collect detailed information about the characteristics and features of customers' homes and businesses, as well as different ways in which electricity is used in them.

In addition to collecting the end use information, the surveys also set out to solicit customer opinions, attitudes and behaviours related to electricity and conservation. This information will be beneficial for segmenting the customer base, as well as for further informing program development and communications strategies.

2.4 Conservation and Demand Potential Review (CDPR)

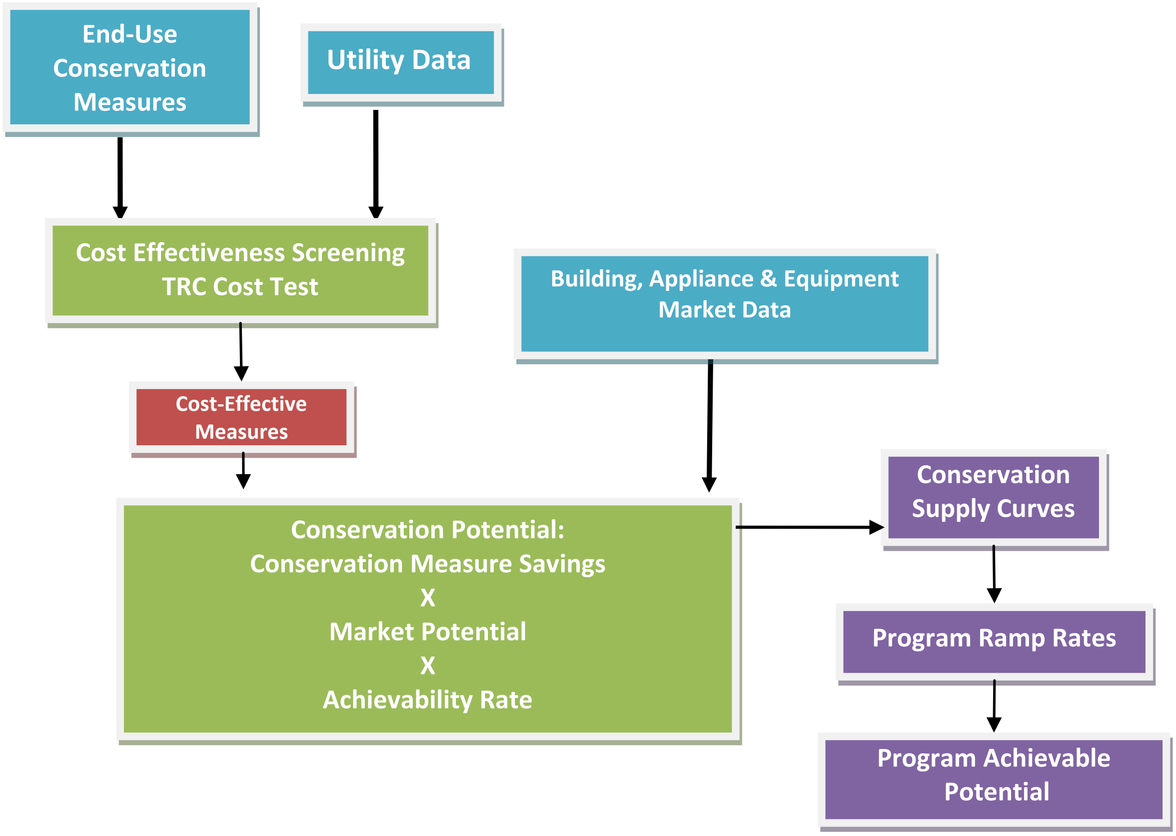
The Conservation and Demand Potential Review (CDPR) was completed in June 2010 by EES Consulting. It provides estimates of potential energy and peak demand savings by sector for the period of 2011 - 2030. The assessment considers a wide range of conservation and demand resources that are reliable, available, and cost-effective. In addition, some emerging technologies, small scale generation, and behavioural measures were considered.

Methodology and Technical Potential

The results of the completed end use surveys were combined with utility specific data to provide a breakdown of how FortisBC's customers use power in their homes and businesses. From this, individual energy efficiency measures were identified along with the number of kWh that could be saved annually from the installation of these measures. The kWh savings from each measure was then multiplied by the total number of measures that could be installed over the life of the program. The resulting figure is the total "technical potential", which is the amount of energy efficiency potential that is available regardless of cost or other constraints such as willingness to adopt measures. It represents the theoretical maximum amount of energy or capacity reduction if these constraints are not considered.

The CDPR was created using multiple inputs and the process deployed is illustrated by Figure 2.4 below:

Figure 2.4 – Overview of 2010 CDPR Inputs and Process



Achievable Economic Potential

All identified measures were then screened to determine their cost-effectiveness potential using the TRC test. The TRC test considers all costs and benefits for each energy efficiency measure regardless of occurrence. Costs and benefits include capital cost, operations and maintenance costs over the life of the measure, program administration costs, distribution and transmission benefits, energy savings benefits and non-energy savings benefits if quantifiable. The aggregate of energy savings, associated with measures that pass the TRC test, are identified as Economic Potential.

To account for customer willingness to adopt measures, achievability rates were then applied to the economic potential. The Northwest Power and Conservation Council uses an 85 percent achievability factor for all measures and has published a white paper describing the basis for using this value[2]. This means that over the course of a 20-year potential study period, 85 percent of all technical potential can be achieved, regardless of how it is achieved.

CDPR Ramp Rates

The final step was to assign "ramp rates" to the achievable potential of each measure. The ramp rate reflects how quickly savings from a particular measure is achieved over the period which depends on various factors, including:

- Availability of technology;
- Capacity of trade allies to install measures;
- Program status (continuing or new);
- Timing of measure implementation; and
- Changes in codes or standards.

The 2010 CDPR provided a table of standardized ramp rates that were applied to the various DSM measures. Many of the ramp rates are linear, acquiring the program or measure savings in equal yearly increments over a 10 to 20 year period. For example a 10-year linear ramp rate equals 10 percent of the achievable potential is expected to be captured each year. A few ramp rates were non-linear, for example emerging technologies, which begins increasing modestly at a 0.5 percent uptake in the first year and accelerates over the over initial decade, then levels off, mimicing the market adoption rate of a new technology. FortisBC modified some ramp rates provided in the CDPR to better reflect local knowledge on market take-up.

The 2012 DSM Plan uses the various types of ramp rates until the economically achievable potential savings, identified in the CDPR, are captured over the 20-year planning horizon.

The final result is the program achievable potential, or the amount of potential a utility could reasonably expect to obtain over the time period given best current knowledge and a defined incentive level.

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[2] "Achievable Savings: A Retrospective Look at the Northwest Power and Conservation Council's Conservation Planning Assumptions." August 2007. http://www.nwcouncil.org/library/2007/2007-13.htm.

Illustrative Example

An illustrative example of determining the DSM target savings for a Building Envelope measure (Energy Star windows) follows. It is based on REUS results indicating that 18 percent of windows are currently single pane, which are to be retrofitted to EnergyStar qualified windows under the program. Based on unit energy savings of 25 kWh/ft^2 of window, times 7,900 detached homes (with forced air electric heat) times 223 ft^2 (average window area per house) times 18 percent single-pane equals 7.9 GWh of Technical Potential. This calculation is repeated for each housing archetype and other types of electric heat (electric baseboard, heat pumps) to yield a total Technical Potential of 47.8 GWh. The applications are screened for a Benefit/Cost ratio greater than one, and multiplied by the 85 percent achievability factor, to yield an economic achievable potential of 33.8 GWh.

Subsequently the Economic Achievable Potential is multiplied by the 20-year ramp rate (5 percent) and the Medium option scaling factor to obtain the 2012 savings target of 1.7 GWh per year.

2.5 Program Options Overview

Three program options were developed from combinations of the measures and incentive levels identified within the CDPR. Each option had different costs and energy offset targets and also varied in the number and kind of energy efficiency programs provided, and in the magnitude of incentives offered. The following table illustrates the three options: Low, Medium and High, which were developed and presented during the stakeholder consultation process undertaken in March 2010.

Table 2.5 – Program Options Overview

	Low Option $5 million	**Medium Option $9 million**	**High Option $20 million**
Percent of new electricity needs offset by DSM	Energy 36% Demand 28%	Energy 51% Demand 41%	Energy 93% Demand 53%
Incentive levels[3]	25%	40%	50%
TRC B/C ratio	> 1.5	> 1.0	> 0.9

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[3] Incentive levels expressed as a percentage of Total Resource Cost (TRC)

Selection of plan option

The public consultation indicated strong support for increased DSM program spending and savings acquisition – 83 percent chose either the Medium or High option. The Medium option was selected as appropriate as a baseline for the 2011 DSM Plan. This decision was based on the strong customer support for this option, the increased demand side benefits it yields and the need to escalate in a prudent fashion from the existing base of established programs.

The High option also received support, but escalating the 2012 DSM Plan to the High option, is not considered prudent because it contains more uneconomic measures (B/C ratio < 1.0), increases spending by paying a larger portion of the TRC cost, and hence increases the magnitude of rate increases due to the decreased load.

FortisBC will continue with a level of expenditure consistent with the 2011 DSM Plan in the 2012 DSM Plan in order to achieve the 50 percent load growth offset target set in the *BC Energy Plan*.

3. THE 2012 LONG TERM DSM PLAN

3.1 Review of 2011 DSM Plan

The selected Medium option was taken, by and large, from the CDPR, and formed the underlying basis for the 2011 DSM Plan.

The CDPR measures unit savings (kWh), unit costs, achievable savings potential and ramp rates were used as the underlying basis of the 2011 DSM Plan. The measure incentives, which were based on 40 percent of TRC for the Medium-option, were modified to either an incentive rate (¢/kWh) or to a unit incentive ($/measure) to make the program offers simpler for customers to understand. The Medium option used a 20 percent of TRC proxy to estimate administrative costs. The 2011 DSM Plan program administration costs were based on the 2010 approved expenditures prudently escalated to administer the higher level of program participation.

The measure benefits were based on unit savings and measure life, sourced from the CDPR report, multiplied by the provincial long-run avoided power purchase costs of $154.15 per MWh.

The CDPR report excludes from program achievable savings all known (provincial and federal) Codes and Standards through the appropriate UEC (unit energy consumption) – for products regulated beforehand, or by modification of the ramp rates for affected measures – for products anticipated to be regulated in future years.

The 2011 DSM Plan, including supporting documentation (End use Surveys, CDPR, Consultation Report), was filed on June 18, 2010 and received approval Dec 17, 2010 by way of Commission Order G-195-10.

3.2 Overview of 2012 Long Term DSM Plan

The 2012-30 DSM Plan is essentially a multi-year extension of the approved 2011 DSM Plan, with a limited number of changes such as updating the avoided power purchase costs used to calculate the DSM benefits, and removing any programs with a Benefit/Cost ratio less than 0.7.

3.2.1 UPDATED AVOIDED POWER PURCHASE COSTS

The blended long-term avoided power purchase costs have been updated, based on the portion of energy procured from BC Hydro. The CDPR determined the levelized BC Hydro avoided energy costs to be $154.15 per MWh, and the 2011 Market Assessment was used to determine the Company's long-term marginal energy costs as $73.80 per MWh. These are firm energy prices, inclusive of capacity benefits. The resulting blended cost of $92.25 per MWh, shown in Table 3.2.1 below, is used to determine the benefits of the programs.

Table 3.2.1 – Long-Term Avoided Power Purchase Costs

Component	Source	Long-term Avoided Cost	Proportion	Blended
Energy ($/MWh)	BC Hydro 2007 CPR 2011 Market report[4]	$154.15 $84.94	28% 72%	$104.32

3.2.2 DSM ECONOMICS

Under the Act and section 4 of the DSM Regulation, the Total Resource Cost test is the primary determinant of cost-effective programs. The Total Resource Cost is the incremental measure cost, which includes the DSM incentive paid to the customer, plus the program administration cost. The benefits are the present value of each measure's energy savings over the effective measure life, valued using the long-term avoided power purchase cost presented in Table 3.2.1 above.

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[4] Midgard FortisBC Energy Market Assessment (Apr 4, 2011) Table 5.1.3.3-A: BC Hydro Mid-C Forward Price Curve (30 Years)

Using the proposed 2012 mix of DSM programs (see 2012-13 Capital Plan DSM Plan filing) the overall Benefit/Cost ratio in 2012-13 is expected to be 1.5, with sector Benefit/Cost ratios as follows:

Table 3.2.2 – Benefit Cost Ratios by Sector

Sector	Benefit/Cost Ratio
Residential	1.6
Commercial	1.7
Industrial	3.9
Sub-total Programs only	**1.6**
Total (including Portfolio costs):	**1.5**

The overall Benefit/Cost ratios presented above, and in the sector tables of section 7 (DSM) of the 2012-13 Capital Plan, have been developed using the 2010 CDPR measure savings and costing data and the avoided costs presented in Section 3.2.1. In this plan, FortisBC has included all programs identified in the Conservation Potential Review reports in which the program TRC ratio is above unity, which supports the objective of pursuing all cost-effective DSM. Over the time span of the 2012 DSM Plan the avoided costs will likely change, as will the measure costs, but the Company will ensure that the Benefit/Cost ratio of the future program mix will be above unity and continue to meet the requirements of the DSM Regulation.

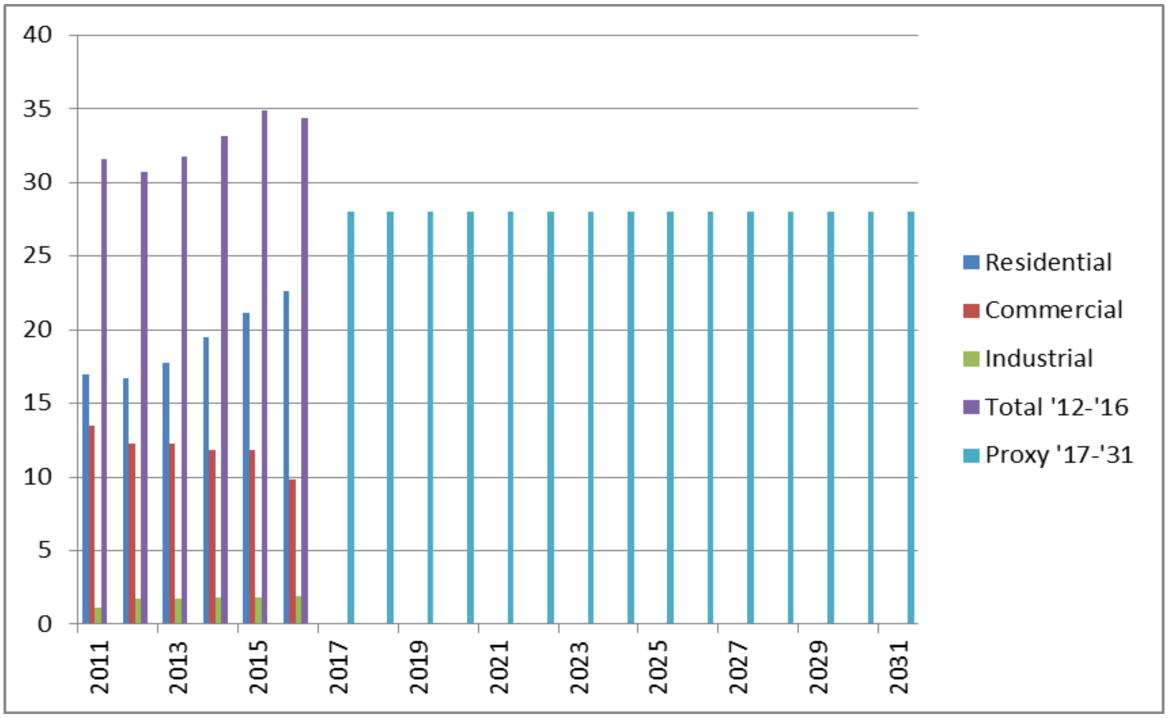
3.2.3 DSM SAVING ESTIMATES BY SECTOR

The 2012 DSM Plan includes programs for the residential, Commercial (which includes commercial, street lighting and irrigation rate classes), and industrial sectors. The programs are described in Section 3.4 of this document. The annual DSM target savings (GWh/year) per sector are shown in Figure 3.2.3 below. The energy savings fluctuate over the time frame as the various measures have different ramp rates which escalate, plateau and then decline or mature, as identified achievable potential is exhausted.

The DSM input into the load forecast is shaped to suit the needs of Resource Planning, by disaggregating the three primary sectors into rate classes, and shaping the annual targets into monthly acquired savings estimates.

The DSM plan figures are used for the period 2012-2016 inclusive, since there is a higher level of certainty over that time period. From 2017 onwards a constant target of 28 GWh/year of DSM savings is used as a proxy for future DSM Program savings. Use of this proxy figure reflects the lesser certainty of DSM Plan figures going farther into the future, while fulfilling the *BC Energy Plan* target of a 50 percent load growth offset.

Figure 3.2.3 – DSM Savings (GWh/year) by Sector



The tabular data of savings targets, in GWh/year, for the above bar graph is as follows:

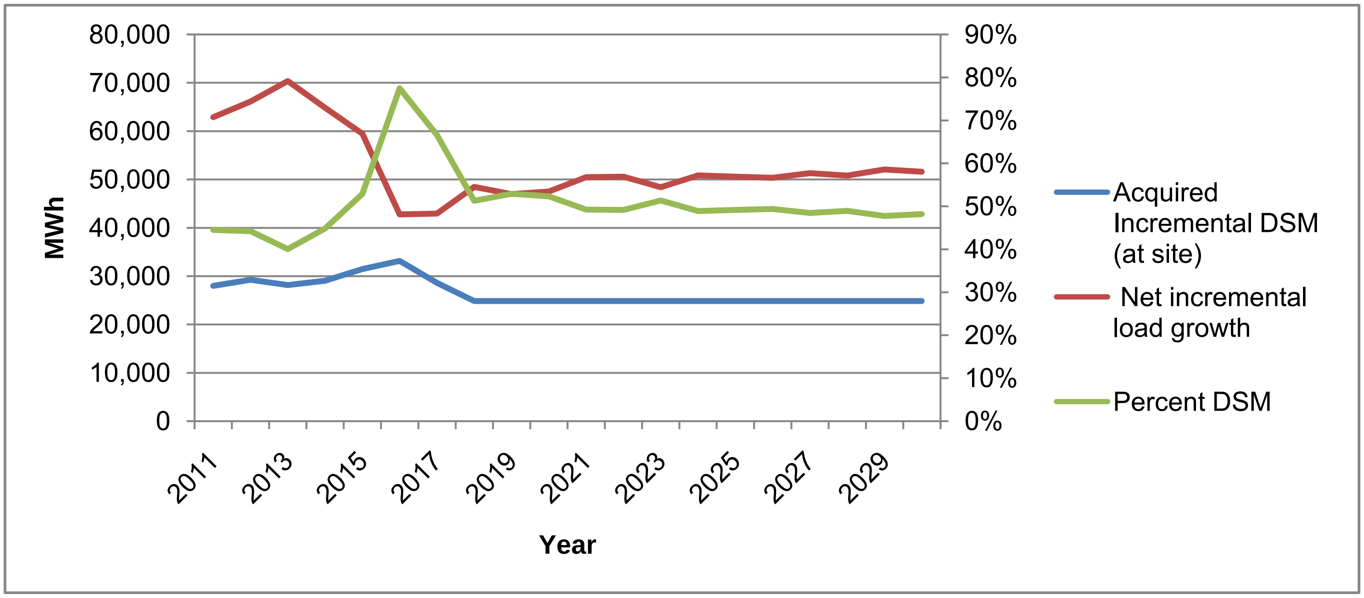
Table 3.2.3 – Savings Targets

Year	Residential	Commercial	Industrial	Proxy '17-31
	GWh			
2011	16.4	13.5	1.1	-
2012	16.1	12.2	1.7	-
2013	16.9	12.3	1.8	-
2014	19.5	11.9	1.8	-
2015	21.1	11.9	1.8	-
2016	22.6	9.9	1.9	-
2017-30	-	-	-	28

3.2.4 DSM SAVINGS AS A PERCENTAGE OF THE LOAD FORECAST

The *BC Energy Plan* set a target of 50 percent of incremental resource requirements to be met by DSM. The 2012 DSM Plan targets, in MWh and percentage of incremental load forecast is shown in Figure 3.2.4 below:

Figure 3.2.4 – Acquired DSM vs. Load Growth Forecast



The individual years' DSM load offset ranges considerably from 40-77 percent, primarily due to a decrease in forecast load growth, before levelling out in 2018. The cumulative impact of DSM, over the 2011-20 period, ending in the milestone year of 2020, is 51 percent which exceeds the *BC Energy Plan* target by a small margin.

3.3 Planning and Evaluation

Planning and evaluation of the DSM initiatives are required to properly plan and control the proposed DSM expenditures and ensure the resource acquisition goals are prudently met. This component includes provisions for the programs manager, technical and reporting staff, as well as external expertise and facilitating meetings of the DSM Advisory Committee (which is comprised of individual customers, organizations representing customers and stakeholders with an interest in DSM).

3.3.1 THE DSM PLANNING CYCLE

The major steps of the DSM planning cycle are anticipated to be repeated at approximately five year intervals, unless circumstances change. The major steps, which are detailed in Section 2.2, include end use studies, and a Conservation Demand Potential Review resulting in an updated Long Term DSM Plan.

Updating the FortisBC DSM Plan at regular intervals ensures that new and emerging commercially available DSM measures are taken into account, avoided cost assumptions are updated and the appropriate program course corrections are made.

3.3.2 MONITORING AND EVALUATION

Appendix D contains the Monitoring and Evaluation Plan (M&E Plan), for the 3-year period 2012-2014 inclusive. This plan is necessary to ensure that the DSM program expenditures will yield the savings expected and that the programs are operating effectively. The M&E Plan recommends that two major program reviews and three mini-reviews be undertaken each calendar year, and that recent behavioural initiatives promoting the use of measures such as clotheslines are also reviewed for effectiveness.

Monitoring and Evaluation of energy efficiency programs provides internal and external accountability by reducing uncertainty in the estimates of energy and demand savings, and by determining the cost effectiveness of these programs compared to other energy resource options. A Monitoring and Evaluation study of a demand-side management or energy efficiency program involves:

- Objective and systematic measurement of program operations and performance;
- Use of social science (behaviour) and engineering data and methods;
- Verifying actual (achieved) energy and demand savings attributable to the program;
- Estimating permanent changes in the market penetration (market transformation) of energy efficient technologies attributable to the program; and
- Providing a basis for future decisions related to a program or portfolio of programs (modifies, expands, or discontinues).

3.4 Programs

Based on the principles and requirements outlined in Section 2, local market knowledge and fiscal prudency, it is expected that program offers will be similar to those of 2011. Several programs will be enhanced and pilot projects will be expanded. This is described in greater detail below.

To help deliver the increased level of DSM programming, FortisBC hired four additional staff in 2011: an additional engineer, a monitoring and evaluation analyst and two program managers. These experts are conducting a DSM best practices literature review and researching best practices developed by other utilities as well as energy efficiency and conservation consortiums and associations. The applicable best practices are being included into new and existing programs as appropriate.

Pilot projects are being developed for a multi-faceted irrigation rebate program, a small commercial product option program, a low-income lighting direct installation program, heat pump water heaters and an industrial process EMIS (Energy Management Information System) program. The results of these pilot projects will be evaluated and incorporated into further program development and application.

3.4.1 RESIDENTIAL SECTOR PROGRAMS

Although the number of new homes being built has decreased within the service area since 2008, the renovation and energy retrofit market remains strong. It is expected that the residential sector will continue to provide the greatest amount of savings over the 2012 DSM Plan timeline. The following briefly describes each incentive program and the primary delivery mechanisms.

Home Improvement Program

The major component of the Home Improvement Program (HIP) is building envelope improvements (insulation, air sealing and Energy Star windows and doors). The HIP program will maintain incentive levels from 2011. Program delivery will be primarily through partnerships with LiveSmart BC and will focus on a “whole house” approach. Individual components of the program like heat pumps and Energy Star appliances and lighting will also be marketed separately, as described below.

Heating and Cooling Program

With its temperate winters and hot summers, the FortisBC service area is an ideal climate for energy-efficient heat pumps. The program will continue with the current rate of incentives for owners to upgrade electric heating systems to either air source heat pumps, ductless (mini) heat pumps or geo-exchange systems. As an alternative to a direct financial incentives, FortisBC will also provide low-interest loans for qualifying customers at a below market interest rate (4.9 percent).

To ensure more customers attain the maximum efficiencies available with heat pump technology, a heat pump maintenance program will be introduced, and on a pilot basis, a duct sealing program for homes with electric heat will be introduced.

A programmable thermostat rebate program will continue.

Residential Lighting Program

It is estimated that 21 percent of all electrical use within the FortisBC service area is attributed to lighting. To help build market transformation and improve customer participation in lighting incentive programs, FortisBC will continue to partner with large and small retailers to provide “instant rebates” at the point of purchase. Rebates will be provided for speciality Energy Star rated CFL and LED lamps and hard-wired luminaires.

Energy Star Appliances and Electronics

The existing rebate program for the highest tier Energy Star clothes washers, refrigerators and freezers, dishwashers, bathroom fans and televisions will continue. Appliance retailers will provide the rebates at the point of purchase or assist customers to fill out the application forms to provide a high level of customer service. A fridge and freezer pick-up program, operated in conjunction with appliance dealers, will facilitate the permanent removal of the old, inefficient appliances.

Water Heating

Approximately 50 percent of FortisBC customers’ water is heated with electricity. To encourage efficient water heating, FortisBC will continue to offer rebates for the installation of solar hot water systems and heat pump water heaters for customers with electrically heated water. Low flow showerheads will be distributed via ESK (Energy Saving Kits) and trade show product samples.

New Home Program

To encourage whole home energy efficiency via non-prescriptive performance paths, two levels of incentives to achieve an EnerGuide rating of 84 or 90 will be offered. To further promote home ratings, FortisBC will offer incentives for energy evaluations. However, if homeowners or builders do not chose to rate their homes, incentives for the efficient insulation and heating/cooling technologies will continue to be offered as a prescriptive option. New home builders and customers will also be eligible for the Energy Star appliance and lighting rebates.

Funding for engineering studies and other assessments will also be provided to encourage energy efficient technologies for larger single-family developments and multi-family buildings.

Residential Behavioural Program

Behavioural programs seek to achieve long-term change in existing patterns of customer energy usage through the use of specific measures (products) along with CBSM messaging to establish Conservation Culture norms. For example PowerSense has given away thousands of clotheslines since 2009, enabling customers to avoid using their electric clothes dryer. Along with the clotheslines, clothespins are provided so the alternative of hanging laundry can be put to immediate use. The recipient signs a pledge sheet to use the clotheslines, and concurrent marketing messages promote usage of clotheslines as a desirable social norm.

Subject to approval of the Company’s Advanced Metering Infrastructure (AMI) project, an incentive will be offered to customers to purchase an IHD, which extracts information from the AMI meter to better inform users of their energy usage and costs. The IHDs will provide near real-time information regarding customers’ energy usage, encouraging them to conserve and/or shift loads.

Again, this measure will be accompanied with education materials to suggest alternatives and substitutions to the electrical loads encountered. Examples include: hanging laundry; delaying the need to switch on central air conditioning by maximizing the use of natural ventilation and shading first; and unplugging the numerous phantom power consuming devices when not in use.

3.4.2 COMMERCIAL SECTOR PROGRAMS

Program offers for the Commercial sector will remain consistent in 2012 other than the Building Optimization Program, which will move from the pilot project phase to full implementation. The Commercial program offers include the following:

Lighting

Incentives for lighting measures are varied, with the rebate limited to achieving a two-year payback on incremental cost. Most incentives will be applied at point-of-purchase through product rebates provided through the authorized lighting wholesalers in the FortisBC service area. For specialty lighting and complex retrofits, customers will be encouraged to contact PowerSense directly for a customized rebate.

FortisBC will also promote and incent adaptive street light technologies (street lights capable of dimming), and LED lighting products, for municipalities and customers with large parking lots.

Building Improvements Program (BIP)

Program assistance and financial incentives include a free assessment of the building and where a more detailed assessment is required, 50 percent of the cost of an approved study. FortisBC also will provide rebates towards the incremental cost of efficiency measures compared to standard "baseline" construction. The rebate entitlement is based on estimated annual kWh savings, with the maximum rebate calculated to achieve a two-year payback on incremental cost.

In addition, FortisBC will offer a suite of standardized fixed rebates (product option) for the most common heating, ventilation and air conditioning (HVAC) measures, pumps and motors, compressed air and refrigeration technologies.

Computers – Data Centre and Server Program

To encourage the use of the most efficient technologies and measures, FortisBC will provide financial incentives and tools to help commercial customers identify and implement server consolidation solutions in their data centres. The program would include data centre assessment studies to identify consolidation (virtualization software and hardware consolidation) opportunities and best approaches to improving energy efficiency in data centres.

Lighting Direct Installation Program

In partnership with LiveSmart BC (Ministry of Energy and Mines), in 2012 FortisBC will continue to deliver a lighting direct installation program for small businesses that use less than $20,000 of electricity per year. FortisBC's portion of the incentive for the program is based on an estimate of the kWh saved.

Municipal Programs

FortisBC will continue to offer a "Partners in Efficiency" Program for local governments. In addition to the incentives offered in the form of rebates and financial incentives, PowerSense representatives will work closely with the municipalities' staff to help determine the economics for energy efficiency upgrades to new and existing facilities, and street lighting.

In addition, municipalities are continuing to work to reduce carbon emissions and are investigating innovative energy efficient technologies, which FortisBC will support if electrical savings are anticipated.

Building Optimization Program (BoP)

The Building Optimization Program targets large Commercial customers with multiple facilities, providing them with a dashboard tool with which to continuously monitor and track their energy usage. FortisBC provides the metering data tie-in and funds the BoP software cost and in exchange the customer agrees to implement all measures identified in a comprehensive audit.

Irrigation Programs

Energy efficiency product rebates will be made available for irrigation components, pump rebuilds or replacements and low-medium pressure pivots. Rebates are offered for replacing a standard efficiency pump motor to a premium efficiency pump motor and variable speed digital controls. In response to requests from irrigation customers, FortisBC has increased the minimum motor size at which "soft-start" pump motor controls are required and simplified the process for approving larger pump motors without "soft-start" controls. Soft-start controls help ensure that electric motors do not affect power quality, but add to the cost of switching to high-efficiency motors.

Product incentives will be offered with Point-of-Sale "instant" rebates through participating irrigation retailers/wholesalers to ensure energy-efficient options are chosen. Irrigation case studies will be profiled in the Powerlines newsletter to raise awareness and attract more participants from this rate class.

FortisBC has started a customer segmentation project that will classify the major groups of irrigation customers (for example, farms, irrigation districts and wineries). This segmentation will form the basis for studying the load characteristics of the irrigation customers. The load study will help inform future PowerSense programs in addition to ensuring that future cost allocation studies have better data available for irrigation customers.

FortisBC has committed to engaging the Irrigation Ratepayers Group that was active in the COSA and RDA Application, and those industrial umbrella groups contacted previously (collectively, the Irrigators), in meaningful consultation regarding new or modified irrigation DSM programs once the necessary data has been collected to allow for proper consideration of the matter.

3.4.3 INDUSTRIAL PROGRAMS

Energy Management Information Systems (EMIS)

This is a process optimization program for which FortisBC will provide financial incentives based on calculated energy savings and operational assistance for the purchase of process optimization technology. EMIS will help customers optimize energy efficiency by monitoring and tracking their energy usage on a production basis (kWh/unit). Recommended strategies are identified through an investigation process with additional focus on documentation and training to realize persistence of savings. The customer also agrees to implement all measures identified.

Industrial Efficiency

FortisBC will offer customized assistance and financial incentives for industrial customers to achieve increased efficiency. This will include free initial assessment of energy use, and where a more detailed assessment is required, 50 percent of an approved study's costs. FortisBC also will provide rebates towards the incremental cost of efficiency measures compared to standard "baseline" construction (the rebate entitlement is based on estimated annual kWh savings, with the maximum rebate calculated to achieve a two-year payback on incremental cost).

3.4.4 OTHER PROGRAMS

Residential Low-Income Households Program

FortisBC will continue to provide low income households with energy saving kits (ESKs) and distribute them directly to qualified customers, primarily through low-income service providers like food banks and low-income housing groups.

In collaboration with the provincial government and other public utilities, FortisBC will provide a direct installation program which includes the basic and some more extended energy conservation measures. The program will employ screening tools to determine which measures are appropriate and cost effective for each application. (It is expected the measures will primarily be insulation of ceilings and attics and draft-proofing, as well as Compact Fluorescent lighting products. Energy Star bathroom fan(s) will be installed to address ventilation concerns. Other types of measures, for example window replacement, would only be considered in situations where the home had very poor windows or for individual replacement of broken or damaged units.)

A direct-install lighting program, similar in execution to the LiveSmart Small Business lighting program, will be instituted for area lighting of common areas such as corridors, stairwells, and lobbies.

Rental Accommodation Programs – Single- and Multi-Family

Beginning in 2012-13, in collaboration with other public utilities, FortisBC will direct-market financial incentive offers to landlords, property managers and rental agencies to upgrade rental properties. Similar to the LiveSmart collaborative program, a suite of “whole home” rebates and incentives for energy building evaluations will be offered. Additional information collateral that target renters directly will also be provided to help inform landlords and renters.

The Multi-Family program will have the same components as the Single-Family program but will also include: a social marketing tactic using tenant-based energy saving teams to encourage behavioural changes; and energy audits and financial incentives to encourage landlords to invest in “whole building” retrofits (insulation, draft-proofing and windows and doors) and energy efficient lighting.

First Nations Residential Households Program

In partnership with FEI and the First Nation communities, PowerSense will continue to provide energy savings kits as needed and create a specific component of the low-income program (ECAP) for First Nations. It will also support First Nation energy efficiency initiatives on reserves: i.e., Okanagan Bands and Ktunaxa Nation energy managers, and provide incentives for energy efficient housing measures.

3.5 Collaborative Programs

During 2012, FortisBC will explore, initiate or continue partnerships in the following collaborative programs which directly support Policy Action 2 of the *BC Energy Plan*:

- LiveSmart BC: partnership with BC Hydro, FortisBC Energy Inc. and the BC Ministry of Energy and Mines. LiveSmart BC is a residential retrofit program that encourages customers to upgrade building envelopes (insulation, windows, doors, draft proofing) and upgrade home space and water heating systems;
- Appliance Take-Back (refrigerators and freezers): partnership with retailers to co-promote the program and collect and safely dispose of (recycle) older, inefficient appliances;
- Appliance and Electronic Rebate Programs: collaboration with major electric utilities to work with manufacturers to provide substantial rebates for specific high level Energy Star appliances and electronics. FortisBC will work closely with local retailers to promote the rebate programs;
- Energy Efficient Lighting: arrange contracts with large retailers to provide instant point-of-sale rebates for specialty CFL and LED lighting;
- Low-Income Program: partnership with BC Hydro and FortisBC Energy Inc. to provide energy saving kits and installation of additional energy efficiency upgrades to income qualified customers (ECAP);
- First Nations: expand partnerships with First Nations bands to support band energy managers, provide additional training for energy efficiency installations and financially support the direct installation of energy efficiency measures in qualified homes. Also support via educational initiatives;
- Wholesale Program: continue partnerships with local electrical wholesalers to provide instant point-of-purchase rebates for specific lighting and other identified energy efficient measures;

- Product Option Program: partnerships with local electrical, refrigeration, HVAC, and pump supply wholesalers to provide point-of-purchase rebates for specific identified energy efficient measures;
- Green Motors: partnership with non-profit organization, Green Motors Practices Group, to provide rebates for "green" motor rewinds; and
- Training and Education: partnerships with many organizations and BC Hydro and FortisBC Energy Inc. to provide trades training and school educational programming.

3.6 Supporting Initiatives

Supporting initiatives are vital to the success of the 2012 DSM Plan because they provide the program support, education and technology required to enable the potential savings that have been identified.

Supporting initiatives complement the incentive-based programs identified in Section 3.5. These are characterized as portfolio-level spending, since they do not result in direct DSM savings, however are necessary to develop greater public awareness, create conservation culture norms and in the education component, including trades training, partially fulfill the adequacy requirements of the DSM Regulation.

The DSM Plan's supporting initiatives include Education and Awareness, Community Energy Planning, and support for energy efficient Codes and Standards.

3.7 Public Awareness

This component seeks to increase public awareness of energy efficiency and conservation matters, and educates customers in regard to the availability of DSM programs. To promote the Company's incentive programs, collateral such as brochures, posters, point-of-sale materials, business case reports and promotional items is required. Collateral and promotional items will be distributed to residential customers at trade shows and community events. It will also be provided to trade allies (electrical contractors, appliance retailers, heat pump contractors) for distribution to customers. The point-of-sale materials highlighting energy efficiency and conservation will be provided to wholesale and retail partners who sell energy efficiency equipment. Targeted information campaigns with specific messaging about programs and energy efficiency will be purchased for trade magazines, newsletters and other industry focused information pieces.

In addition, FortisBC will use a Community-Based Social Marketing (CBSM) approach to help achieve the behaviour changes needed to support a "conservation culture". Research shows that behaviour change programs can achieve measurable savings by influencing customer behaviour to conserve energy or invest in more energy efficient technologies. The CBSM tactics to be used for message delivery include: public relations, community outreach, strategic partnerships, behaviour pledges/commitments, product sampling, promotional contests and media educational campaigns. Some social networking tools will also be used. The following describes the specific educational programs to be implemented.

- PowerSense Month: an educational campaign during October which includes an interactive contest for customers and a multi-media information campaign focusing on energy efficient heating and winterizing homes. FortisBC will also host the annual PowerSense Awards to honour the businesses and individuals that achieve the greatest energy conservation results in their communities.
- Lighting awareness campaigns: to encourage customers to make use of day-lighting, turn off all unnecessary lights and switch to energy efficient lighting. Earth Hour and the energy efficient lighting program will be the "event drivers" for this messaging.
- Cooling and heating awareness: educational campaigns to be run in early summer and fall to encourage customers to set back/up thermostats, heat only occupied areas of a home, maintain weatherproofing, close windows and blinds, etc. In conjunction with an advertising campaign, consumer intercept activities are planned at building supply stores and trade shows to encourage people to draft-proof and insulate their homes appropriately.
- Electronics and phantom power awareness: in combination with the electronics rebate program, phantom power messaging will be promoted during the fall and winter seasons.
- Laundry program: to promote the purchase of Energy Star Tier 3 clothes washers, the use of cold water wash and drying clothes on clotheslines. Promotion will include clothesline product sample give-aways, behaviour pledges and community outreach in partnership with municipal governments and FortisBC Energy Inc.
- Appliance program: in conjunction with the appliance rebate programs, an intensive information campaign will be conducted to build awareness and encourage behaviour change regarding appliance use: i.e., maintain proper refrigeration

temperatures, minimize use of hot water, etc. Hot water and refrigerator/freezer temperature gauge give-aways will help enforce the messaging.

- Subject to approval of the Company's AMI Project, the IHD rebate program will be accompanied by an extensive education program to ensure customers understand how they reduce use.

3.8 Education Programs

Public Schools

FortisBC has long supported elementary, middle and high school energy conservation education initiatives through financial sponsorship of educational events (such as science fairs and tours) and programs (Environmental Mind Grind, Climate Change Showdown) and delivery of curriculum approved longer-term educational programs through non-profit organizations like the Pacific Resource Conservation Society's Destination Conservation program. In 2009, FortisBC, in collaboration with FortisBC Energy Inc. (then Terasen Gas), BC Hydro and the Ministry of Energy and Mines, contracted the services of a consulting company to design a curriculum-based Grade 11 course on energy and energy conservation.

FortisBC will continue to build on existing partnerships and seek additional opportunities in 2012 and 2013.

Post-Secondary

FortisBC continues to support energy efficiency training opportunities such as the Okanagan College "Home for Learning", and providing guest lecturers upon request (for example, Selkirk College's Environmental program).

PowerSense is in discussions with FortisBC Energy Inc. to develop more fulsome offerings for this education segment, including the possibility of student intern positions, and instructing building energy software modelling at UBCO's Engineering faculty.

Trades Training

FortisBC provides sponsorships for training and support for a number of initiatives from the building trades and electrical non-profit trade organizations[5], as well as support for energy

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[5] TECA (Thermal Environmental Comfort Association), SICA (Southern Interior Construction Association), CHBC (Canadian Home builders Association), BCSEA (BC Sustainable Energy Association), GeoExchangeBC, etc.

management planning training like Natural Resources Canada's "Spot the Savings" workshops. Committed to growing the energy efficiency knowledge amongst the trades, FortisBC will continue to provide this support.

FortisBC will work closely with FortisBC Energy Inc. and BC Hydro to provide leadership to help develop new training opportunities that support energy efficiency, as well as provide greater financial support for programming.

3.9 Community Energy Planning

Provincial legislation requires all local governments to identify Greenhouse Gas reduction targets, policies, and actions in their Official Community Plans and Regional Growth Strategies. As a result, BC local governments are completing energy and greenhouse gas emissions plans for their communities and are seeking support from public utilities. As the community energy plans directly impact future electrical use and may include significant energy savings attributed to good planning, it is appropriate to support communities in their efforts. To assist communities and help strategize to achieve greater energy efficiencies, FortisBC will support community energy studies and planning sessions.

3.10 Codes and Standards

A number of international and national organizations like the Consortium for Energy Efficiency, the Canadian Standards Association, and Natural Resources Canada are working to set new efficiency standards for many consumer electronics, appliances, and lighting products amongst other equipment and technologies. Similarly local, provincial and federal governments are setting policy and regulations to increase as-built energy efficiency performance or raise awareness (e.g. EnerGuide building ratings). FortisBC will support codes and standards policy development and research, through in-kind and financial co-funding arrangements.

Appendix A

RESIDENTIAL CUSTOMER END USE SURVEY

2009 Customer End-Use Study

Prepared For: **FortisBC**

Prepared By: **Discovery Research**

Date: **August 2009**

Table of Contents:

1. Background and objectives

FortisBC is an integrated electric utility in British Columbia. FortisBC electric utility business serves about 157,000 customers in more than 30 communities in south central BC. The customers are in two major categories:

Direct - FortisBC delivers power directly to 110,000 customers.
Indirect - FortisBC delivers power indirectly through municipal wholesaler utilities to 48,000 customers .

Research was undertaken to help FortisBC understand how customers use energy in their homes for the purposes of forecasting future electrical demand and also to design Demand Side Management and Marketing and Communications programs. Discovery Research was contracted by FortisBC to complete the study. The specific objective of this study is to collect and track over time, detailed information about the characteristics and features of customers homes, as well as different ways in which electricity is used in them. Areas of interest include, but are not limited to:

- Home characteristics and features such as housing type, age of home, size of home, etc;
- Insulation;
- Windows;
- Doors and door frames;
- Space heating;
- Space cooling;
- Water heating;
- Lighting;
- Kitchen and Laundry appliances;
- Home electronics.

In addition to collecting the end-use information, the study also set out to solicit customer opinions, attitudes and behaviors related to electricity and conservation. This information will be beneficial for segmenting the customer base as well as for further informing program development and communications strategies.

2. Methodology

Given the amount and detail of the information to be collected, the methodology utilized for this research was a self-administered mail survey coupled with an equivalent online version of the survey.

Mailed Survey:

On July 2, 2009 a total of 5000 surveys were mailed to a random sample of FortisBC customers. The total sample of 5000 consisted of 3500 Direct FortisBC customers and 1500 Indirect customers serviced through city wholesalers. The 3500 Direct customers were randomly selected from the entire FortisBC direct residential customer base. The 1500 Indirect customers were randomly selected from the regions serviced by City wholesalers according to the below distribution:

Municipal Wholesaler	Total Customers	Ratio	Indirect sample
Kelowna	13770	29%	**432**
Penticton	16613	35%	**521**
Grand Forks	2105	4%	**66**
Summerland	5436	11%	**171**
Nelson Hydro	9885	21%	**310**
	47,809	100%	**1500**

Each potential respondent was mailed a survey package which included a survey with cover letter and a postage paid return envelope. Respondents were offered two ways to participate in this study:

- Complete the survey and return it in the postage paid envelope via regular mail -OR-
- Complete the online version of the survey and submit it electronically

As an incentive for completion, respondents were entered into a draw for one of three $500 gift certificates to a home improvement retailer of their choice. Respondents were offered an additional entry into the prize draw as an added incentive to complete the survey on-line.

Emailed Survey:

On July 27 2009, 4000 Direct FortisBC customers were randomly chosen from the database of customers that FortisBC has email addresses for. These 4000 email addresses were a mixture of residential and commercial customers who have chosen to receive their monthly bills via email. The customers were sent an email inviting them to participate in the survey and the email included a link to the online residential and online commercial surveys.

Prior to emailing the survey invitations, it was not possible to determine how many of the 4000 email addresses were residential customers and how many were commercial customers. Based on response rates of the respective surveys, we will assume that 3840 email addresses were residential email addresses and 160 were commercial email addresses. Responses to the commercial surveys received are presented in another report (2009 Fortis Commercial End Use Report).

Response Rate

Mailed Survey:

Although 5000 surveys were mailed, 104 were returned to FortisBC as undeliverable – in most cases, likely due to closed accounts and other changes since the time the billing information was last updated. Of the 4896 surveys that were effectively delivered, a total of 1066 were returned: 824 via Canada Post and 242 via the Online version; yielding a response rate of **21.8%** for the Mail survey methodology.

Emailed Survey:

Of the 3840 email invitations sent out, 983 online surveys were received back, giving a response rate of **25.6%** for the Email survey methodology.

Total Response Rate:

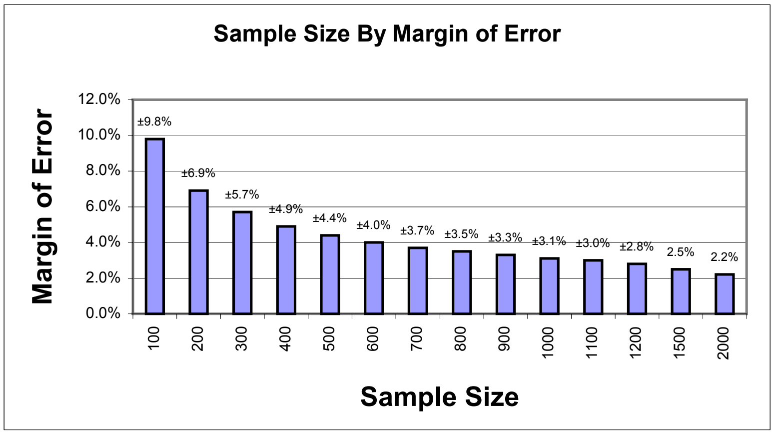
Of the 8736 Residential Customers that were approached, 2049 surveys were completed, giving a total response rate of **23.5%.**

Direct versus Indirect Residential Customer Response Rate:

Of the 1458 surveys that reached Indirect FortisBC residential customers, 230 returned a completed survey, giving a response rate among Indirect customers of **15.8%**.

Of the 7278 surveys that reached Direct FortisBC residential customers, 1819 returned a completed survey, giving a response rate for Direct customers of **25.0%**.

Margin of error



This bar graph displays the margin of error associated with various sample sizes.

Statistics generated from sample size of 2049 will be accurate within ±2.2%, at the 95% confidence interval (19 times out of 20).

Weighting the Data

The sample was weighted by region to ensure the collected sample matched the true composition of FortisBC's total customer base.

	Residential Customer Population				Unweighted Sample		Weighted Sample	
	Direct	Indirect	Total	%	Total	%	Total	%
Central Okanagan (Kelowna) including Big White	42276	12424	54700	**39.74%**	840	41.46%	805	**39.73%**
South Okanagan including Similakameen	20365	19783	40148	**29.17%**	549	27.10%	591	**29.17%**
West Kootenay/Boundary	32641	10166	42807	**31.10%**	637	31.44%	630	**31.10%**
Total	95282	42373	137655	**100.00%**	2026	100.00%	2026	**100.00%**

After applying the weights, the regional proportions in weighted sample match the regional proportions in the Population of FortisBC Customers.

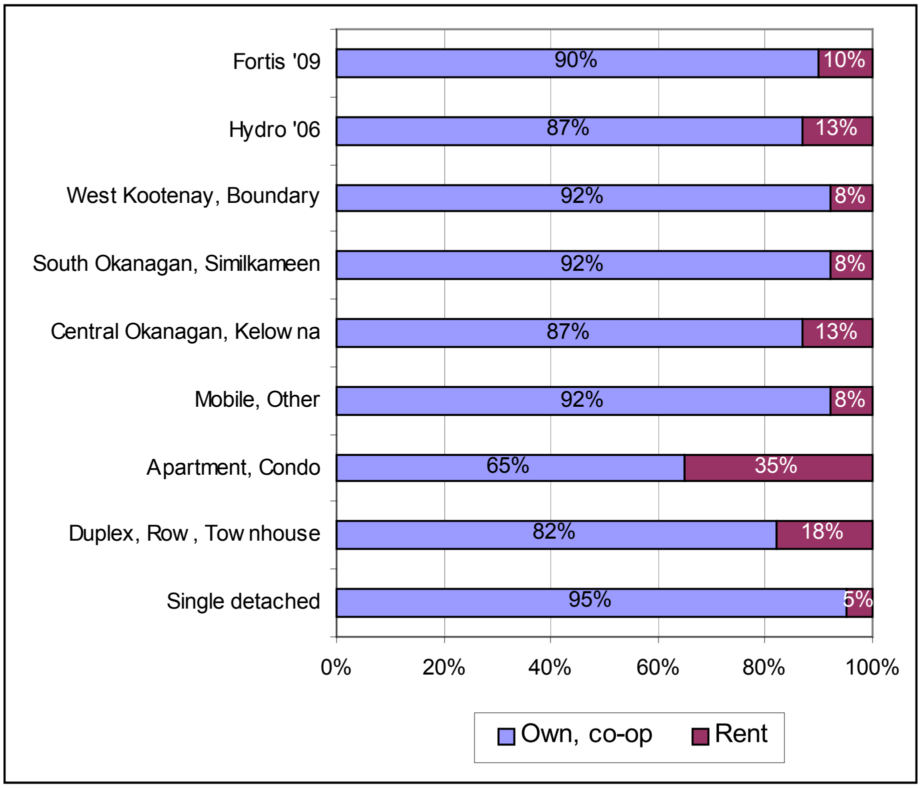
Comparison with BC Hydro 2006 Residential End Use Survey (REUS)

In 2006, BC Hydro completed a comprehensive mail survey (REUS) with their residential customers across BC. Throughout this report, comparisons are made with the response collected from 1144 BC Hydro customers in the Southern Interior of BC. These Southern Interior BC Hydro customers will be referred to as "**Hydro '06"** in comparison graphs and tables.

3. Survey Results

A. About Your Home

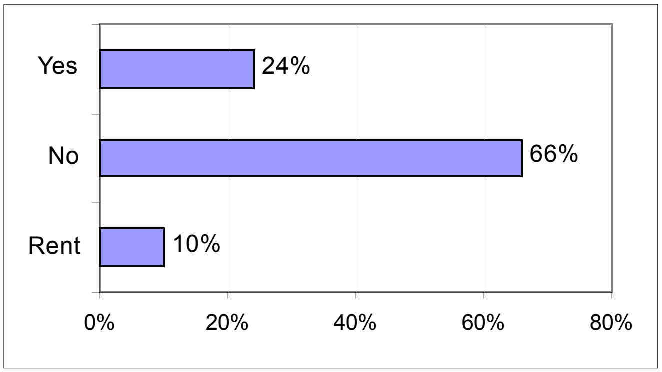
1. Do you own or rent your home?



Ninety percent of FortisBC customers own their home and 10% rent. Among 2006 Hydro customers in the Southern Interior, 87% owned their homes and 13% rented.

Only 65% of respondents who live in Apartments or Condos own their home.

2. Do you pay Maintenance Fees?



Sixty-six percent of FortisBC customers own their home and do not pay maintenance fees, 24% own and pay maintenance fees and 10% rent.

		Type of dwelling			
		Single detached	Duplex, Row, Townhouse	Apartment, Condo	Mobile, Other
Do you pay maintenance fees?	Yes	10%	61%	62%	33%
	No	85%	21%	4%	58%
	Rent	5%	18%	35%	9%
Total	Base	1326	208	245	150

Sixty-one percent of respondents that live in a Duplex, Row or Townhouse and 62% of Apartment and Condo residents pay maintenance fees.

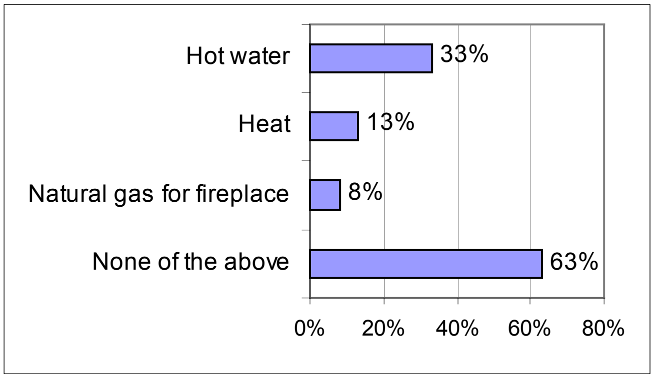
		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
Do you pay maintenance fees?	Yes	36%	21%	10%
	No	50%	71%	81%
	Rent	14%	9%	8%
Total	Base	766	555	592

Residents of the Central Okanagan are the most likely to pay maintenance fees (36%) and residents of the West Kootenay/Boundary are the least likely (10%).

BC Hydro CEUS 2006 Southern Interior Comparison:

Among Hydro customers in the Southern Interior, 31% rent or pay maintenance fees compared to 34% of FortisBC customers.

3. Which of the following are included in your Rent or Maintenance Fees?



Base: Respondents who rent or own and pay maintenance fees.
Column percentages may exceed 100% because multiple responses provided

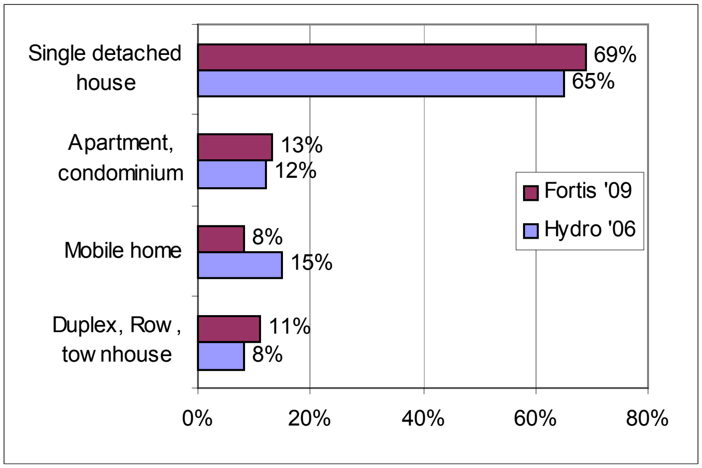
Among respondents that rent or pay maintenance fees, hot water is included for 33% and 13% have heat included. The majority, 63% don't have hot water, heat or gas for a fireplace included in there rent or maintenance fees.

		Type of dwelling			
		Single detached	Duplex, Row, Townhouse	Apartment, Condo	Mobile, Other
Which of the following are included in your rent or maintenance fees?	"None of the above"	76%	88%	28%	86%
	"Hot water"	23%	9%	65%	12%
	"Heat"	19%	4%	14%	9%
	"Natural gas for fireplace"	10%	1%	11%	3%
Total	Responses	250	163	277	76
	Base	194	159	234	68

Base: Respondents who rent or own and pay maintenance fees
Column percentages may exceed 100% because multiple responses provided

Among Apartment or Condo residents, 65% have hot water included in their rent or maintenance fees.

4. What type of dwelling do you live in?

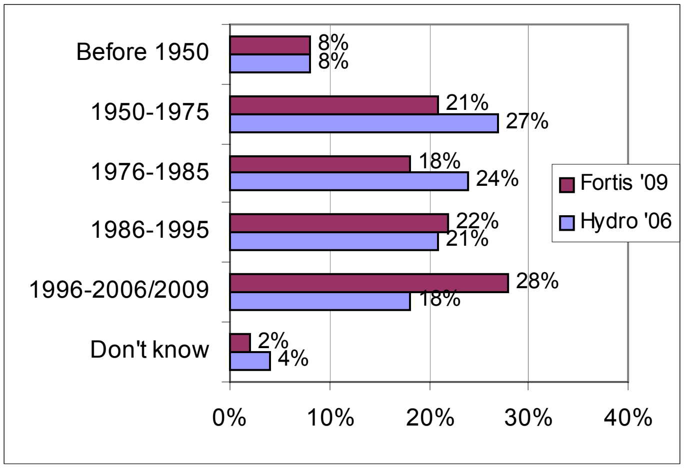


The majority (69%) of FortisBC residential customers live in a single detached house. Thirteen percent live in an apartment or condominium and 8% live in a mobile home. The BC Hydro sample had a higher percentage of residents living in Mobile Homes (15%) compared to 8% of the FortisBC sample.

		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
"What type of dwelling do you live in?"	"Single detached house"	54%	73%	83%
	"Apartment, condominium"	22%	8%	4%
	"Mobile home"	6%	11%	8%
	"Row, townhouse -3+ units attached"	12%	5%	2%
	"Duplex"	5%	3%	2%
Total	Base	776	569	601

Among Central Okanagan residents, 54% live in a single detached house and 22% live in an apartment or condo. West Kootenay/Boundary residents were the most likely (83%) to live in a single detached home.

5a. When was your home built?



Twenty-eight percent of homes were built between 1996 and 2009 and 29% were built before 1975. Compared to the BC Hydro sample, the FortisBC sample had a higher percentage of homes that were built in 1996 or newer because the category includes 3 extra years (2006 to 2009).

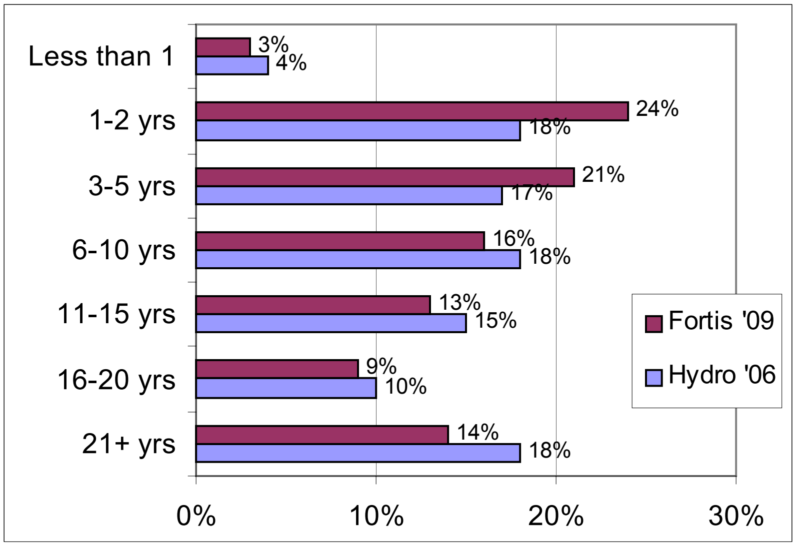
		Type of dwelling			
		Single detached	Duplex, Row, Townhouse	Apartment, Condo	Mobile, Other
"When was your home built?"	"Before 1950"	12%	1%	2%	
	"1950-1975"	25%	14%	5%	25%
	"1976-1985"	18%	19%	10%	31%
	"1986-1995"	21%	28%	23%	21%
	"1996-2009"	24%	32%	53%	22%
	Don't know	1%	5%	7%	1%
Total	Base	1343	208	244	158

Fifty-three percent of Apartments and Condos were built between 1996 and 2009.

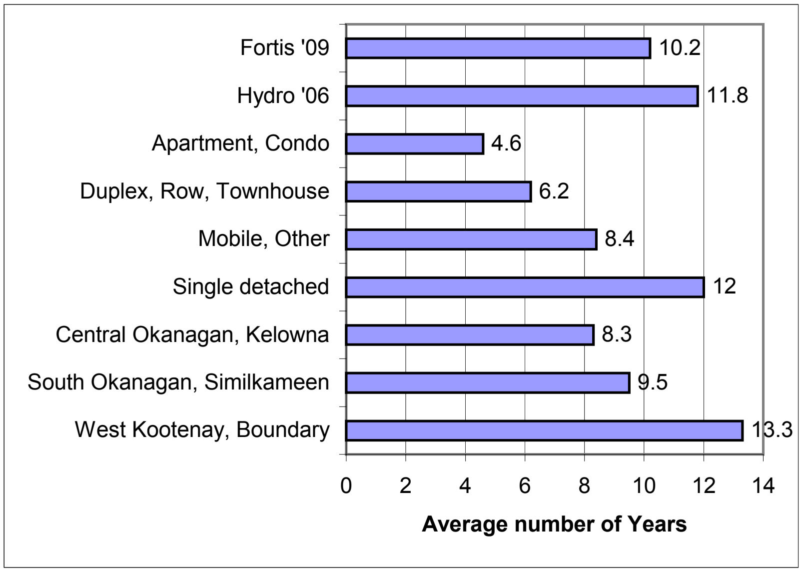
		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
"When was your home built?"	"Before 1950"	2%	7%	17%
	"1950-1975"	14%	21%	31%
	"1976-1985"	16%	17%	21%
	"1986-1995"	26%	24%	13%
	"1996-2009"	39%	28%	16%
	Don't know	2%	3%	2%
Total	Base	775	565	599

Forty-eight percent of homes in the West Kootenay/Boundary were built before 1975 compared to only 16% in the Central Okanagan.

5b. How many years have you lived in this home?



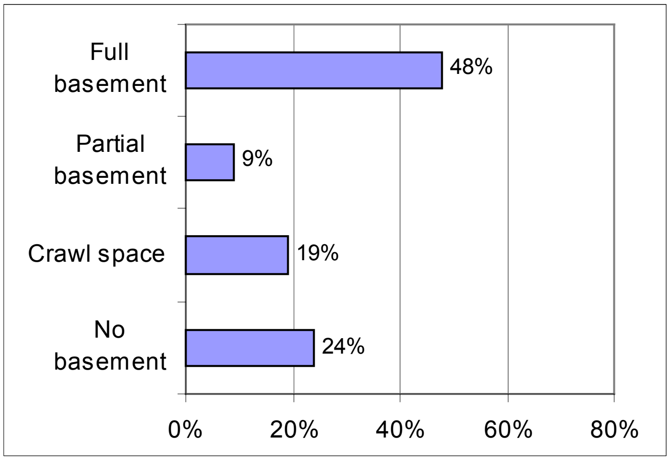
Forty-eight percent of the FortisBC sample had lived in their home for 5 years or less compared to 39% of the BC Hydro Southern Interior sample.



FortisBC customers have lived in their home for an average 10.2 years.

Residents of the West Kootenay/Boundary region have lived in their home on average for 13.3 years.

6. What type of basement does your residence have?



Almost half of residential customers (48%) have a full basement and 9% have a partial basement.

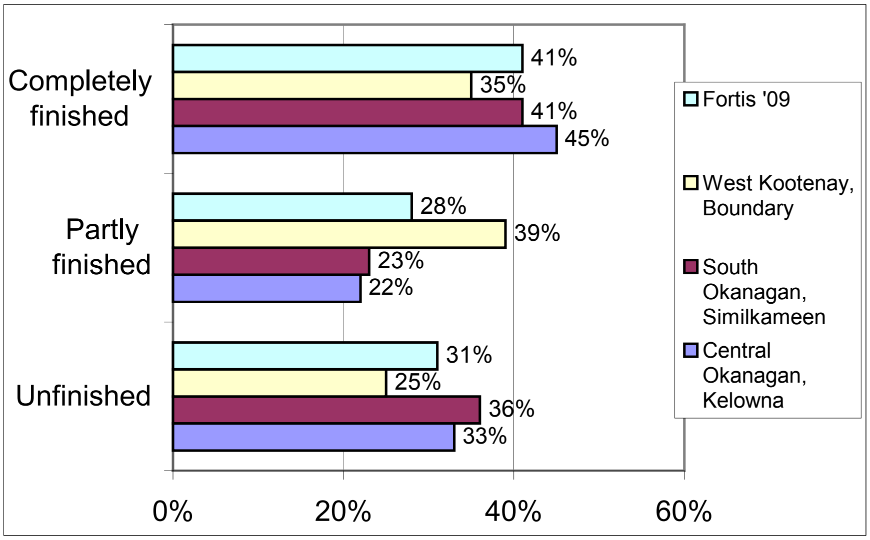
		Type of dwelling			
		Single detached	Duplex, Row, Townhouse	Apartment, Condo	Mobile, Other
"What type of basement does your residence have?"	"Full basement"	60%	46%	11%	2%
	"Partial basement"	12%	8%	2%	1%
	"Crawl space"	20%	27%	3%	26%
	"No basement"	8%	19%	85%	71%
Total	Base	1350	211	234	158

Sixty percent of single detached homes had full basements.

		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
"What type of basement does your residence have?"	"Full basement"	42%	41%	62%
	"Partial basement"	8%	9%	11%
	"Crawl space"	19%	27%	12%
	"No basement"	31%	24%	15%
Total	Base	774	567	599

Sixty-two percent of the West Kootenay/Boundary residents have a full basement compared to 42% of Central Okanagan residents and 41% of South Okanagan residents.

7. Is the basement area of your home finished?

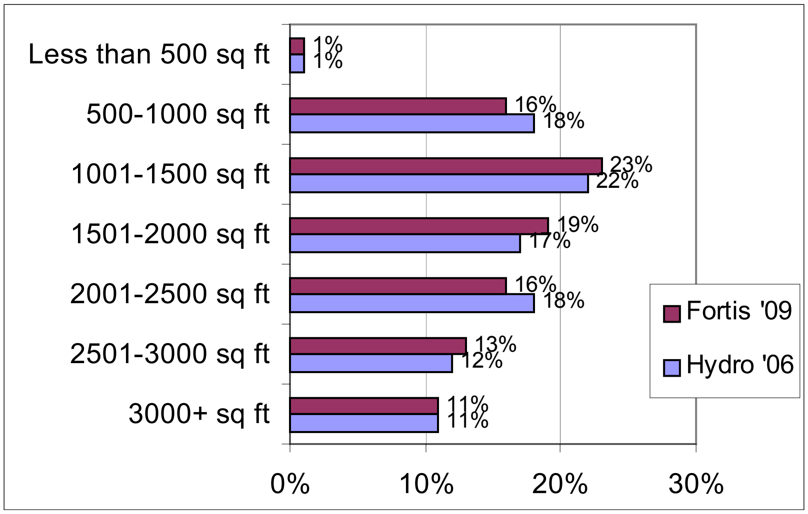


Base: Respondents with basements

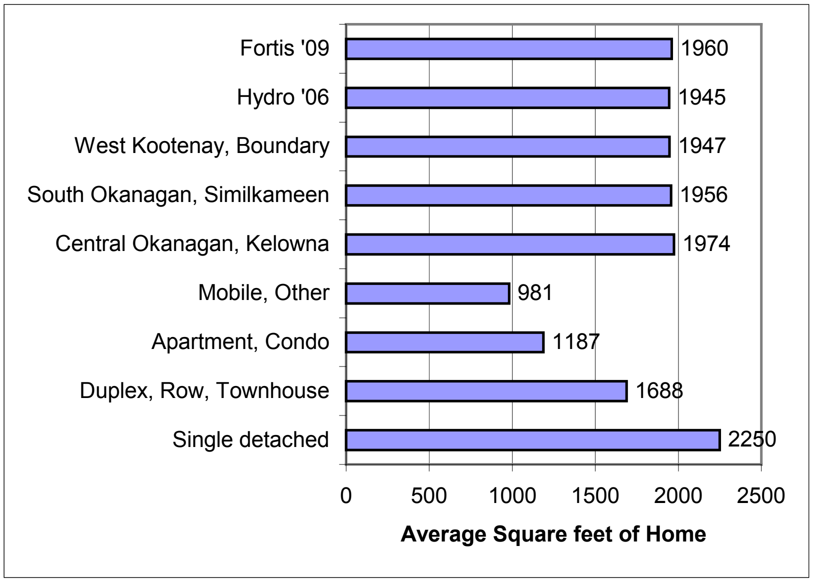
Among all respondents with basements, 41% of basements were completely finished and 28% were partially finished.

Among West Kootenay/ Boundary respondents with basements, 35% were completely finished basements and 39% were partially finished.

8. What is the total floor area of this home?

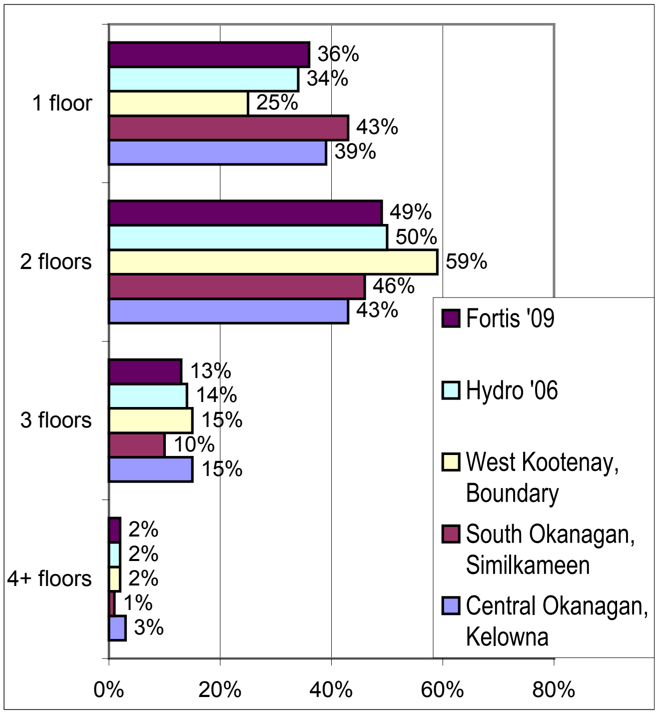


Fifty-eight percent of FortisBC homes were between 1000 and 2500 square feet. The BC Hydro sample had statistically similar home sizes.



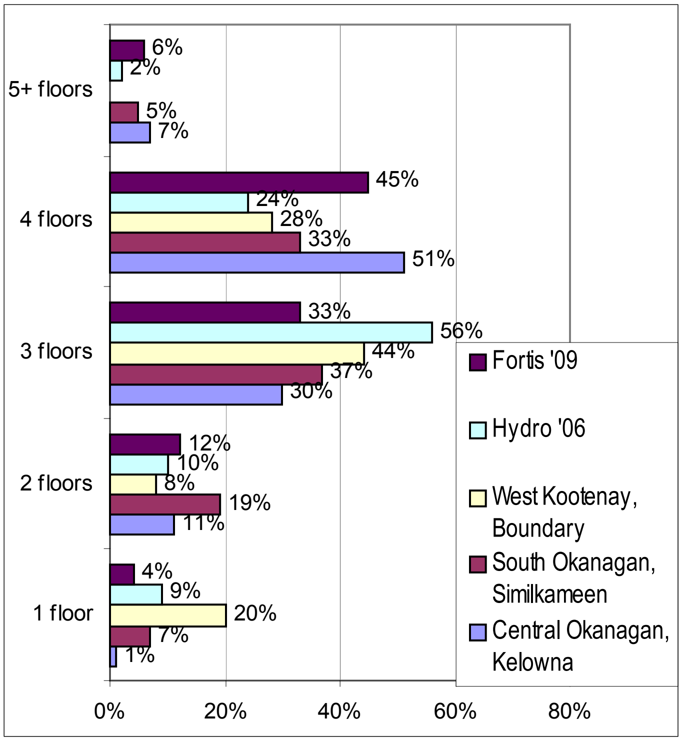
Among FortisBC customers, the average square footage of homes is 1960 square feet. This is similar for all regions.

9. How many floors of heated living space does your home have?



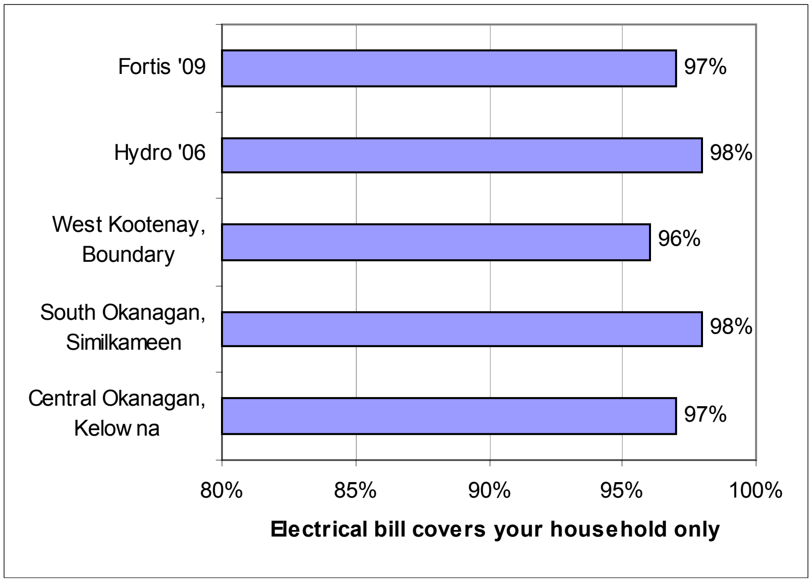
Forty-nine percent of FortisBC customers have 2 floors of heated living space and 36% have 1 floor.

10. If your home is an apartment or condominium, how many stories does your building have (not including underground parking)?



Among FortisBC customers who live in Apartments or Condominiums, 78% have 3-4 floors compared to 80% among BC Hydro southern interior customers.

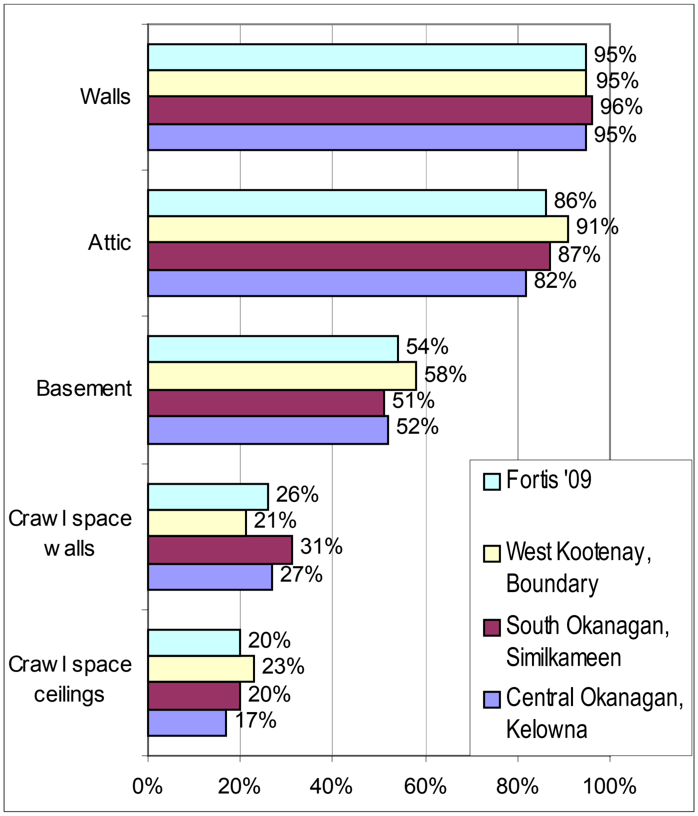
11. Does your electric bill cover only your household or is there an additional suite(s) or household(s) on the same account?



Ninety-seven percent of FortisBC customers have electric bills that cover their household only, and 3% have additional suites.

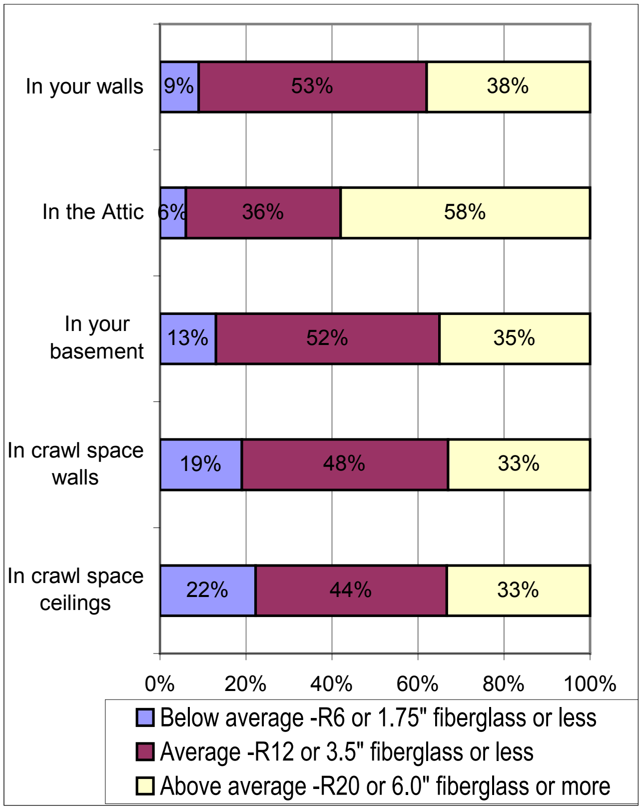
B. Doors, Windows & Insulation

12a. Which areas of your home do you have Insulation?



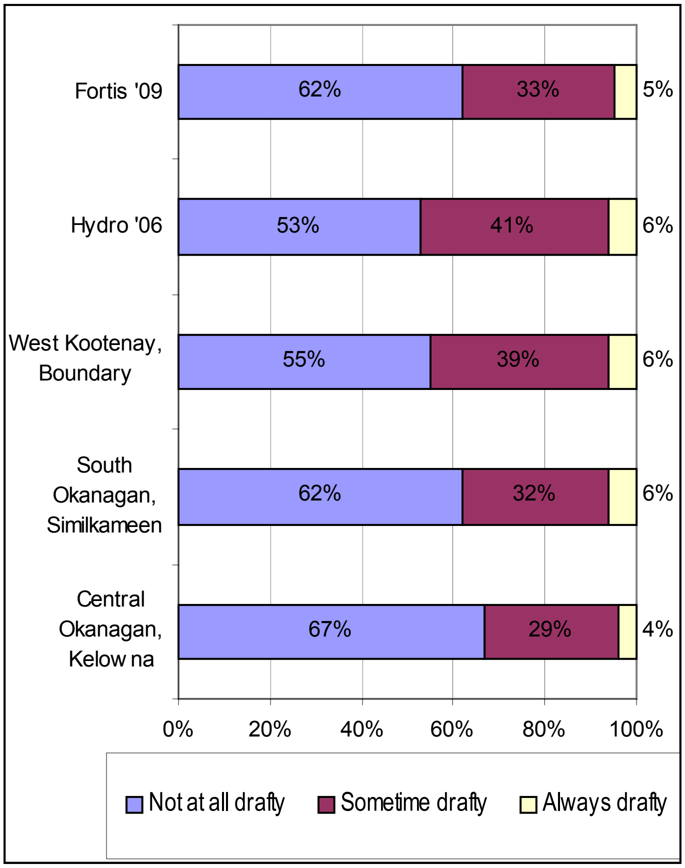
Ninety-five percent of FortisBC customers indicated they had insulation in the walls of their home and 86% said they had insulation in the Attic.

What is the quality of the Insulation?



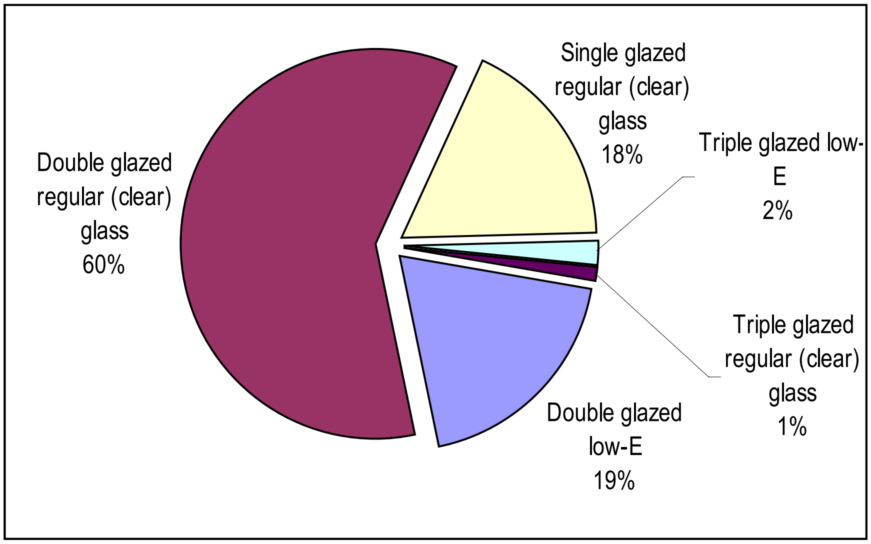
Among the customers that have insulation in their walls, 38% have above average insulation in their walls. Of respondents with insulation in the Attic, 58% have above average insulation in the Attic.

12b. Please indicate how effective the draft proofing in your home is?



Sixty–two percent of FortisBC customers indicated their homes are not drafty at all. Sixty-seven percent of residents of the Central Okanagan indicated their homes are not at all drafty compared to 55% of the West Kootenay/ Boundary area.

12c. What percentage of your windows are:



Sixty percent of the windows in respondents homes are double glazed regular glass and 19% are double glazed low- E glass.

Are the windows Argon filled?

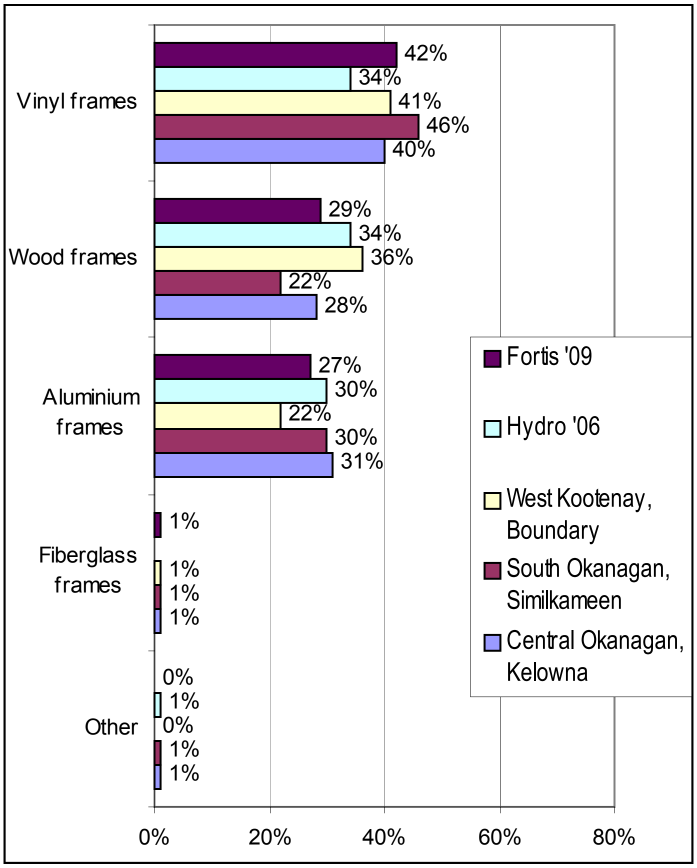
		Total
"Double glazed regular (clear) glass"	"Yes"	28%
Total	Base	714
"Double glazed low-E"	"Yes"	58%
Total	Base	508
"Triple glazed regular (clear) glass"	"Yes"	6%
Total	Base	194
"Triple glazed low-E"	"Yes"	13%
Total	Base	201

Base: Respondents who have this type of window

Among respondents who indicated they have double glazed regular glass, 28% said the windows were argon filled.

Among respondents who indicated they have double glazed low-E glass windows, 58% said the windows were argon filled.

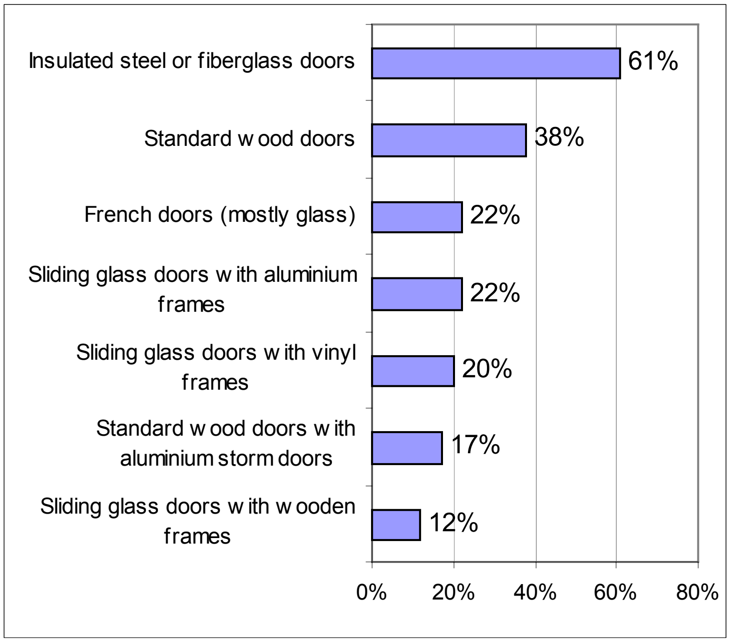
12d. Please estimate what percentage of your windows have the following frames.



On average, forty-two percent of the windows in respondents homes have vinyl frames and 29% have wood frames.

West Kootenay/Boundary homes had an average of 36% of their window frames made of wood, significantly higher than the 22% of window frames in the South Okanagan region.

12e. What type of the following types of doors does your home have?



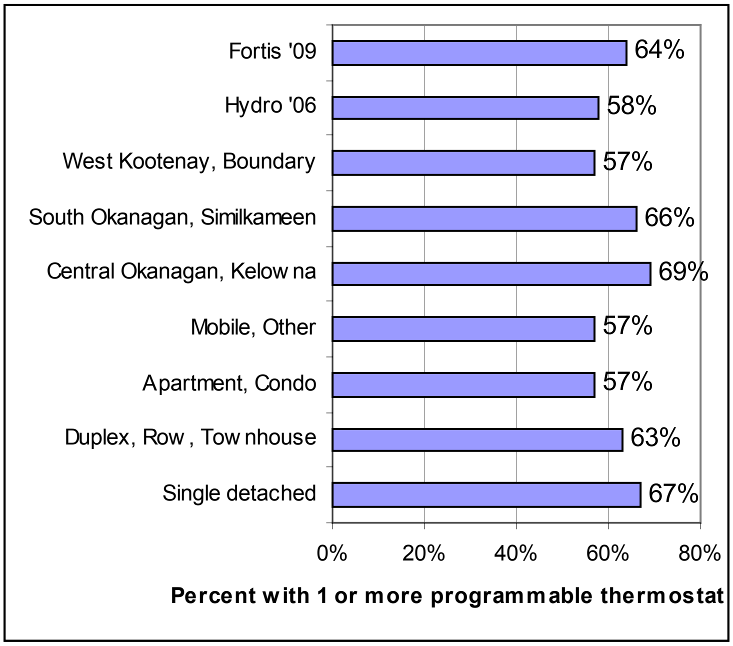
The majority (61%) of homes have one or more insulated steel or fiberglass door. Thirty-eight percent have 1 or more standard wood door.

		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
Which of the following types of doors you have in your home?	Insulated steel or fiberglass doors	60%	64%	60%
	Standard wood doors	33%	36%	**47%**
	Sliding glass doors with aluminium frames	26%	26%	15%
	French doors (mostly glass)	23%	21%	22%
	Sliding glass doors with vinyl frames	21%	23%	16%
	Standard wood doors with aluminium storm doors	14%	18%	22%
	Sliding glass doors with wooden frames	12%	10%	14%
Total	Responses	1434	1138	1187
	Base	761	570	605

Column percentages may exceed 100% because multiple responses provided

Among West Kootenay/Boundary homes, 47% have one or more standard wood door compared to 33% of Central Okanagan customers.

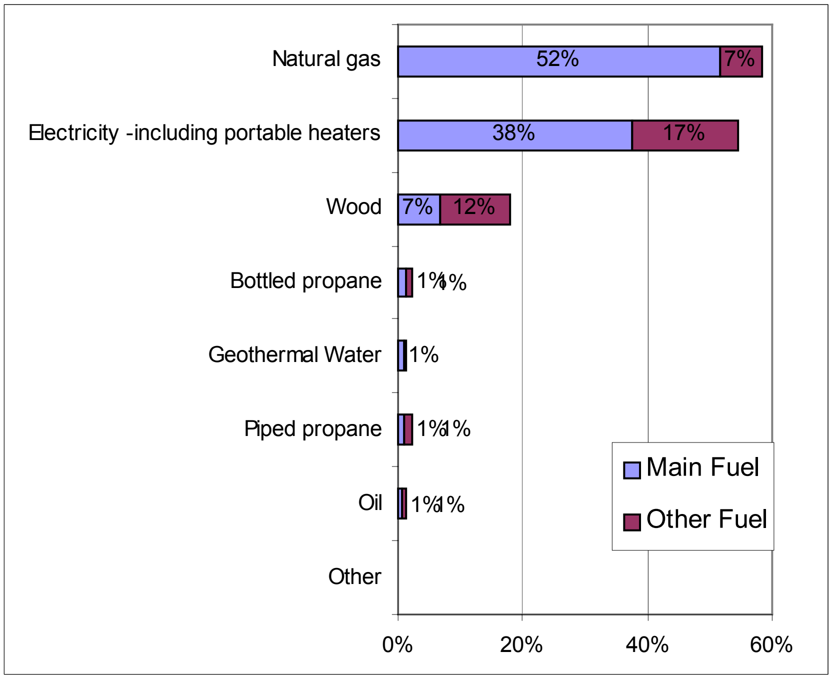
12f. How many programmable thermostats do you have in your home?



Sixty-four percent of FortisBC homes have one or more programmable thermostats. Central Okanagan homes were the most likely (69%) to have programmable thermostats.

C. Space Heating

13. Please indicate the fuels used to heat your home.



Natural gas is the main fuel used to heat 52% of homes, followed by electricity used by 38% of homes. Electricity was also used as a secondary source in 17% of homes. Seven percent of homes used wood as their primary source of heat.

		Type of dwelling			
		Single detached	Duplex, Row, Townhouse	Apartment, Condo	Mobile, Other
"Please indicate the fuels used to heat your home (main fuel)"	"Natural gas"	57%	57%	18%	47%
	"Electricity -including portable heaters"	31%	42%	**80%**	27%
	"Wood"	9%			8%
	"Bottled propane"	0%			11%
	Geothermal Water	1%	0%	0%	
	"Piped propane"	1%	0%	0%	4%
	"Oil"	0%		1%	3%
	"Don't know"	0%		0%	
Total	Base	1333	209	241	157

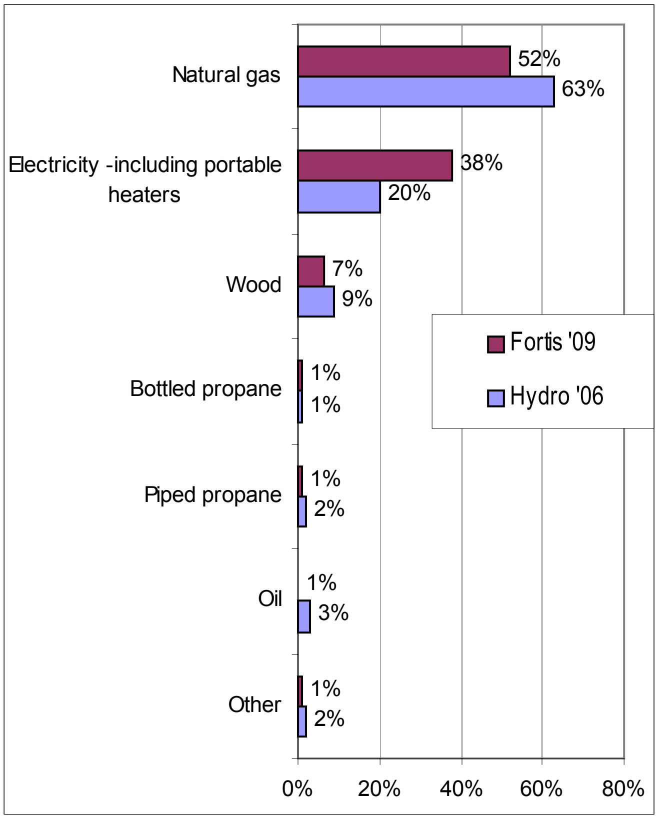
Among apartments and condos, 80% use electricity as the main fuel to heat their homes.

		Customer type	
		Direct	Indirect
"Please indicate the fuels used to heat your home (main fuel)"	"Natural gas"	51%	59%
	"Electricity -including portable heaters"	38%	33%
	"Wood"	7%	5%
	"Bottled propane"	1%	0%
	Geothermal Water	1%	0%
	"Piped propane"	1%	0%
	"Oil"	0%	1%
	"Don't know"	0%	
Total	Base	1613	225

Customers serviced by wholesalers were slightly more likely to have their homes heated by natural gas (59%) compared to 51% of direct Fortis Customers.

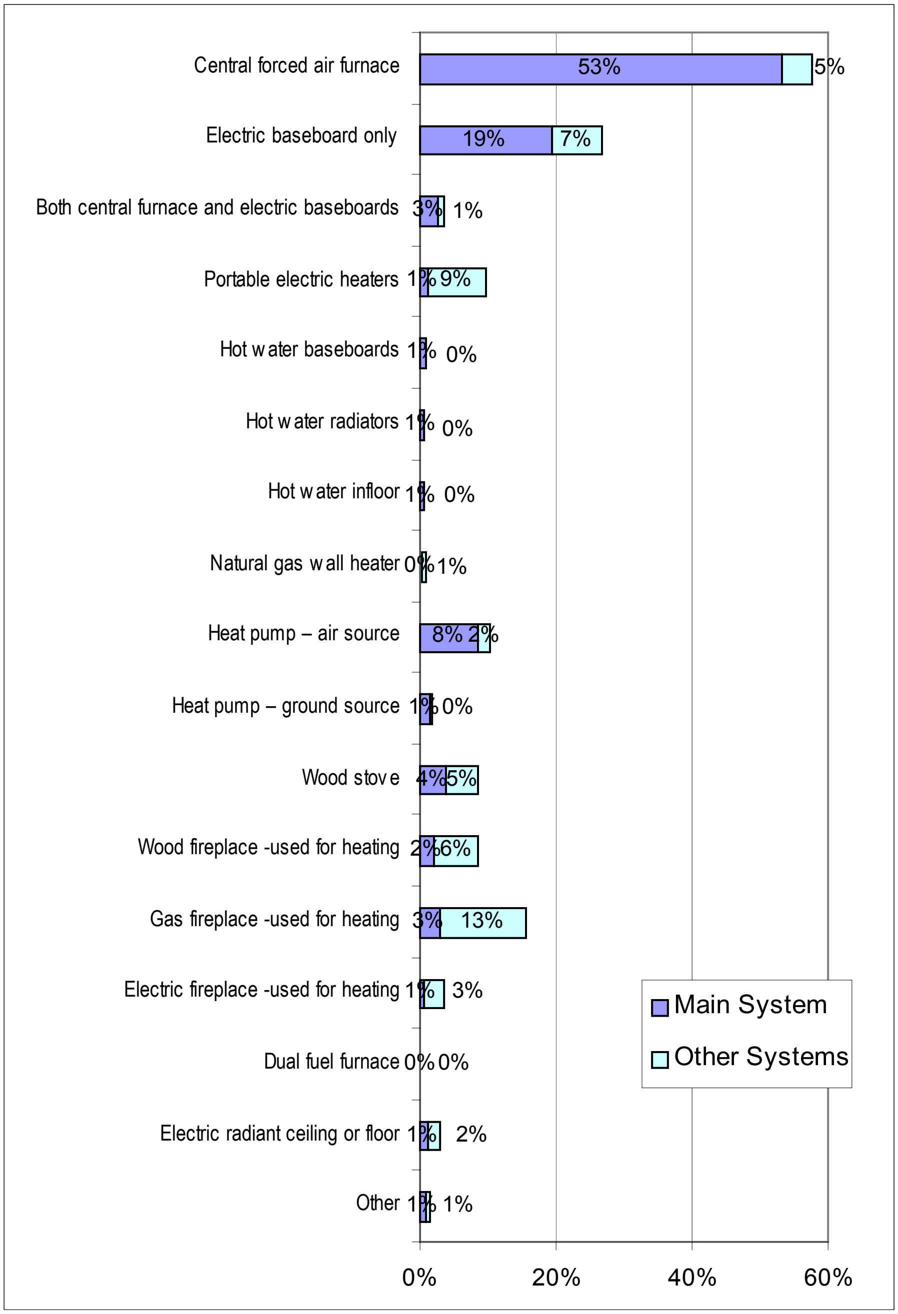
		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
“Please indicate the fuels used to heat your home (main fuel)”	“Natural gas"	60%	47%	46%
	“Electricity -including portable heaters"	34%	42%	38%
	“Wood"	1%	7%	13%
	“Bottled propane"	2%	1%	0%
	Geothermal Water	1%	1%	0%
	“Piped propane"	1%	1%	1%
	“Oil"	0%	1%	1%
	“Don't know"	0%	0%	0%
Total	Base	774	572	601

Among South Okanagan residents, 42% used electricity as their main source of heat. Thirteen percent of West Kootenay/ Boundary homes have wood as the main fuel to heat their home.



Electricity is used as a main fuel source for 38% of FortisBC homes compared to 20% of BC Hydro Southern Interior homes.

14. Please indicate the main heating system you use to heat your home.



The main heating system used to heat the 53% of homes is a Central forced air furnace.

Nineteen percent use electric baseboard heating as the main heating system.

Gas fireplaces are a secondary heating system in 13% of homes.

Main Heating System used to heat your home:

		Type of dwelling				Region		
		Single detached	Duplex, Row, Townhouse	Apartment, Condo	Mobile, Other	Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
"Please indicate the main heating system you use to heat your home (main system)"	"Central forced air furnace"	58.0%	54.7%	16.6%	63.9%	58.4%	50.8%	48.3%
	"Electric baseboard only"	11.3%	30.1%	**65.0%**	3.9%	23.4%	17.4%	16.3%
	"Heat pump – air source"	9.8%	6.3%	2.9%	8.7%	6.2%	**13.1%**	7.1%
	"Wood stove"	5.0%			5.9%	.2%	4.4%	7.7%
	"Gas fireplace -used for heating"	3.0%	3.3%	2.9%	1.3%	3.6%	2.5%	2.3%
	"Both central furnace and electric baseboards"	2.5%	1.5%	3.2%	2.6%	1.7%	1.9%	4.1%
	"Wood fireplace -used for heating"	2.9%	.5%		2.6%	.7%	2.5%	3.9%
	"Heat pump – ground source"	1.6%	.9%	1.2%	.6%	2.1%	1.1%	.7%
	"Electric radiant ceiling or floor"	1.4%	.5%	2.1%		.5%	1.7%	1.8%
	"Portable electric heaters"	.7%		1.6%	5.1%	.9%	.8%	1.6%
	"Other"	.9%	.5%	.8%	.7%	.6%	.8%	1.1%
	"Hot water baseboards"	.9%		.8%	.7%	.1%	.9%	1.5%
	Hot water infloor	.7%	.5%	.4%		.2%	.8%	1.0%
	"Electric fireplace -used for heating"	.3%	.5%	1.6%	1.2%	.9%	.8%	
	"Hot water radiators"	.6%	.5%	.4%			.4%	1.1%
	"Natural gas wall heater"	.2%	.5%	.4%	2.0%	.2%	.4%	.7%
	"Dual fuel furnace"	.4%			.6%	.1%		.8%
Total	Base	1332	208	242	155	773	568	602

Sixty-five percent of apartments or condo's have electric baseboard only for their main heating system. Thirteen percent of South Okanagan residents have an air source heat pump as their main heating system.

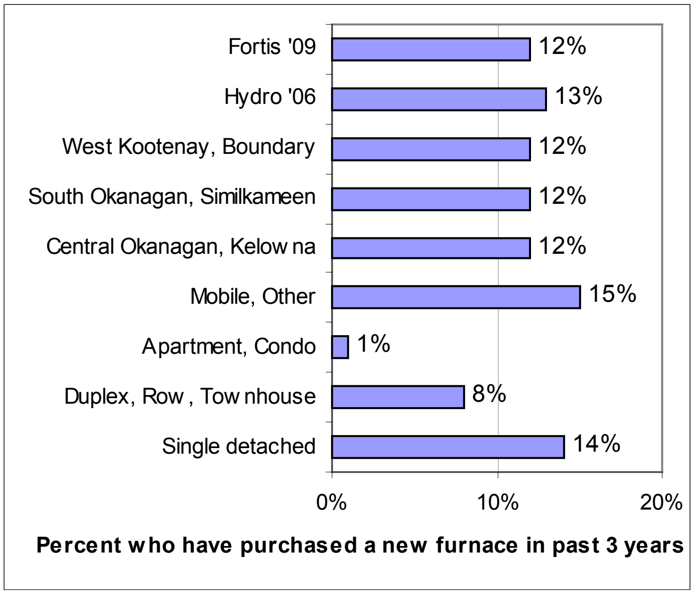
15. How many rooms do you heat in your home altogether?

		Total	Type of dwelling				Region		
			Single detached	Duplex, Row, Townhouse	Apartment, Condo	Mobile, Other	Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
Always heated	0 rooms	**8%**	5%	8%	28%	8%	11%	6%	8%
	1-3 rooms	**18%**	11%	27%	42%	27%	21%	17%	16%
	4-6 rooms	**42%**	42%	49%	28%	60%	37%	49%	43%
	7-9 rooms	**23%**	31%	14%	2%	4%	23%	20%	26%
	10+ rooms	**8%**	11%	2%			9%	8%	7%
Total	Mean	**5.4**	**6.3**	**4.5**	**2.4**	**4.3**	**5.4**	**5.3**	**5.6**
	Base	**1969**	**1331**	**206**	**244**	**158**	**776**	**573**	**600**
Sometimes heated	0 rooms	**64%**	64%	67%	57%	73%	65%	66%	62%
	1-3 rooms	**29%**	29%	27%	39%	23%	29%	29%	30%
	4-6 rooms	**5%**	6%	5%	4%	5%	6%	4%	6%
	7-9 rooms	**1%**	1%	1%			1%	1%	1%
	10+ rooms	**0%**	0%				0%	0%	0%
Total	Mean	**.9**	**1.0**	**.8**	**.9**	**.6**	**.9**	**.8**	**1.0**
	Base	**1969**	**1331**	**206**	**244**	**158**	**776**	**573**	**600**
Rarely or never heated	0 rooms	**80%**	79%	79%	80%	83%	79%	82%	77%
	1-3 rooms	**19%**	19%	20%	18%	15%	19%	16%	21%
	4-6 rooms	**2%**	2%	1%	2%	2%	2%	2%	2%
	7-9 rooms	**0%**	0%		0%		0%		
Total	Mean	**.4**	**.4**	**.4**	**.3**	**.3**	**.4**	**.3**	**.4**
	Base	**1969**	**1331**	**206**	**244**	**158**	**776**	**573**	**600**

Missing values treated as zero. Base sizes include only cases where with at least 1 heated room given.
Average percent of heated rooms includes zeros.

Among the total FortisBC sample, on average 5.4 rooms in the house are always heated; 0.9 rooms are sometimes heated and 0.4 rooms are rarely or never heated. This is statically consistent across all regions.

16a. In the past three years, have you purchased a furnace?



Twelve percent had purchased a new furnace in the past 3 years. This was consistent in all regions.

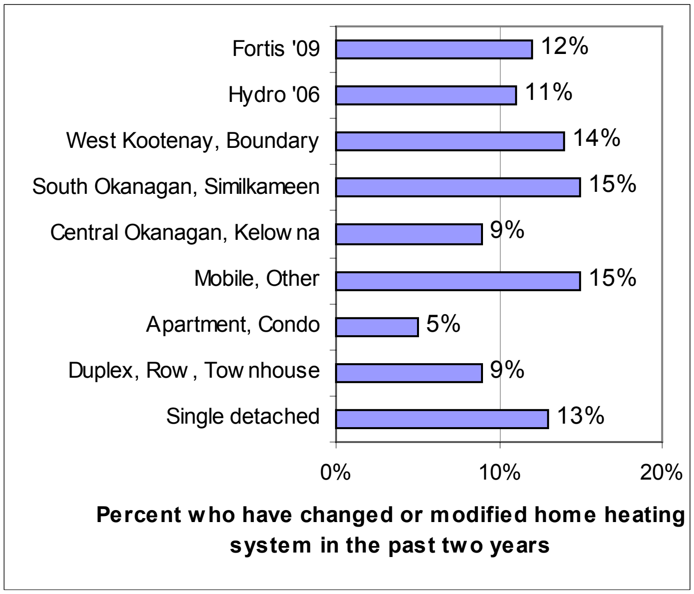
16b. Does your new furnace have a high efficiency blower motor?

		Total	Region		
			Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
"Does your new furnace have a high efficiency blower motor (often called a variable speed motor or electronically controlled motor (ECM)?"	"Yes"	**69%**	65%	71%	71%
	"No"	**14%**	9%	17%	18%
	"Don't know"	**17%**	26%	12%	11%
Total	Base	**240**	**95**	**71**	**71**

Base: Respondents who have purchased a furnace in the past 3 years

Among respondents who have purchased a new furnace in the past 3 years, 69% purchased a a furnace with high efficiency blower motor, 14% did not purchase this type and 17% did not know if their new furnace had a high efficiency blower motor.

16c. Have you changed or modified your home heating system in the last 2 years?



Twelve percent had changed or modified their home heating system in the last 2 years.

What have you changed in the last 2 years?

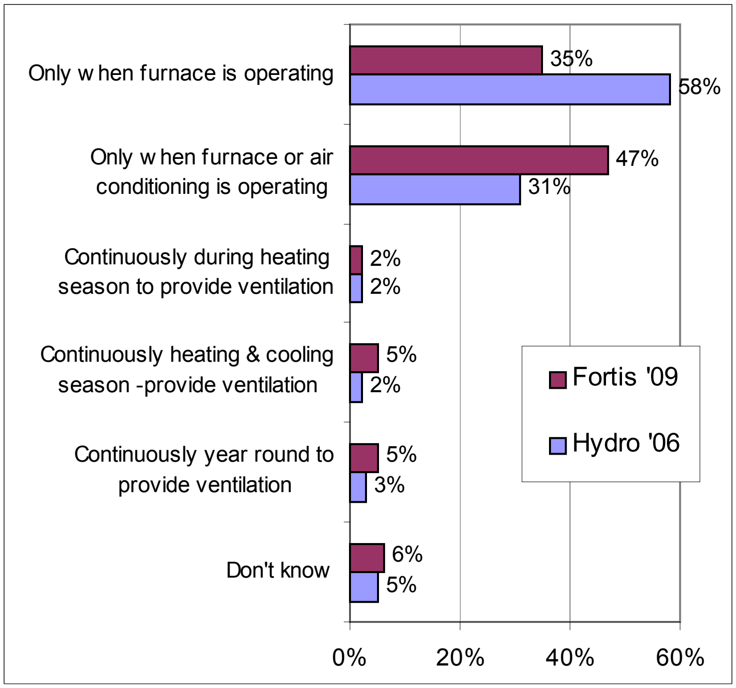
	Electric baseboard heaters	Natural gas furnace or boiler	Portable electric heater(s)	Electric fireplace	Radiant baseboard heaters	Natural gas, propane fireplace	Other
Added	1.0%	0.8%	0.8%	0.5%	0.1%	0.9%	2.8%
Upgraded	1.2%	**2.5%**	0.1%	0.0%	0.0%	0.3%	1.0%
Removed	0.5%	0.3%	0.2%	0.0%	0.1%	0.1%	0.4%
No response	97.3%	96.3%	99.0%	99.5%	99.8%	98.7%	95.7%

Among those who indicated they made some changes to their heating system in the past 2 years, 2.5% stated they upgraded their natural gas furnace or boiler; 1% added electric baseboard heaters and 3.8% said they added or upgraded some other type of heating equipment. A listing of these "other" answers appears below.

		"Other"			
		"Added"	"Upgraded"	"Removed"	No response
"Other changes or modifications to heating system"	Heat pump	29	9		11
	Wood stove	6	5	1	2
	Electric radiant floor	6			1
	Pellet	5			1
	Wood fireplace	3	2		1
	Propane furnace	1		2	
	Oil furnace			3	
	Geothermal	3			
	Gas fireplace		1		1
	Wood airtight	1			
	Propane stove			1	
	Chimney liner	1			
	Inslab water heating				1
	Space heater	1			
	Electric furnace		1		
	Central air unit	1			
	Filter system				1
Total	Base	57	18	7	19

29 respondents indicated they added a heat pump and 9 respondents said they upgraded a heat pump in the past 2 years. A further 11 respondents added (6) or upgraded (5) a woodstove.

17a. How often does your furnace fan blower operate?



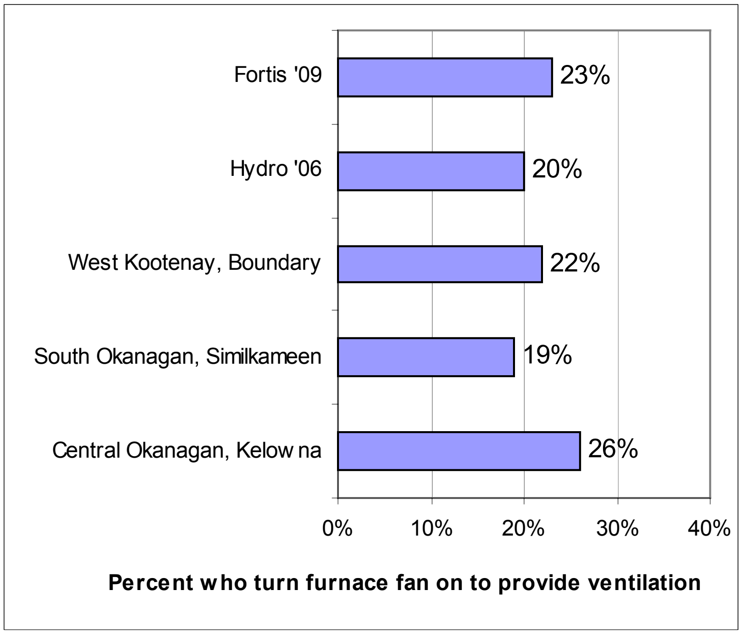
Base: Households with a furnace

Among households with a furnace, 35% of FortisBC customers indicated the furnace fan only blows when the furnace is running and 47% said it only runs when furnace or air conditioning is running.

		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
"How often does your furnace fan blower operate?"	"Only when furnace is operating"	23%	28%	59%
	"Only when furnace or air conditioning is operating"	55%	58%	26%
	"Continuously during heating season to provide ventilation"	2%	1%	2%
	"Continuously heating & cooling season -provide ventilation"	5%	6%	4%
	"Continuously year round to provide ventilation"	6%	5%	4%
	"Don't know"	9%	3%	6%
Total	Base	588	424	421

Fifty-nine percent of West Kootenay/Boundary residents have their furnace fan blower operating only when the furnace is running compared to 23% of Central Okanagan residents.
This difference is most likely the result of West Kootenay/Boundary residents being less likely to have air conditioning.

17b. Do you also turn the furnace fan on to provide ventilation for part of the year?

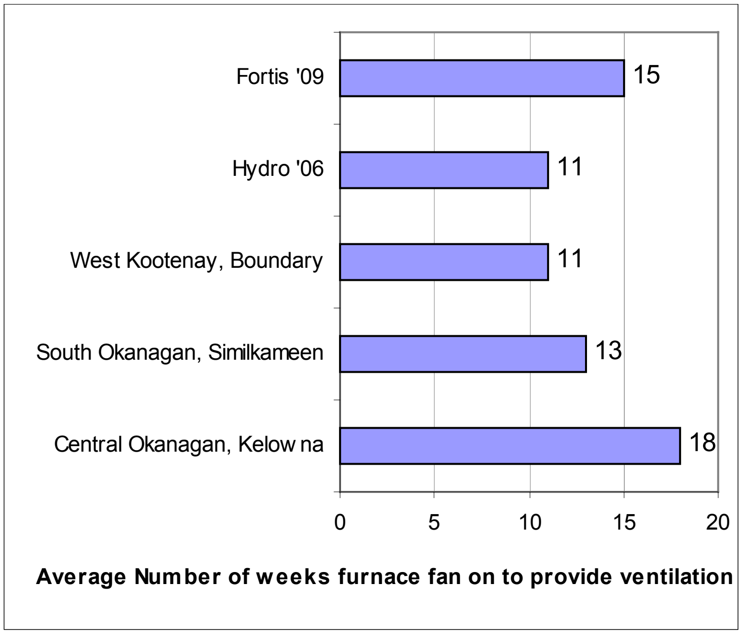


Base: Households with a furnace

Among households with a furnace, 23% of FortisBC households turn the furnace fan on for part of the year to provide ventilation.

Twenty-six percent of Central Okanagan residents turn their furnace fan on for ventilation.

Average Number of weeks the furnace fan is turned on to provide ventilation:

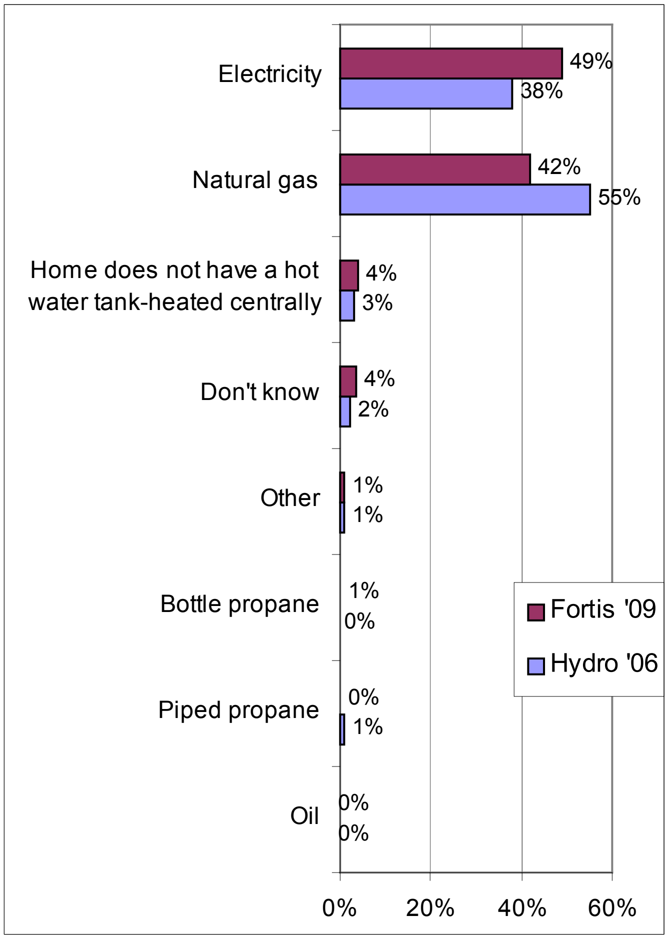


Base: Households with a furnace who turn fan on to provide ventilation

Among FortisBC households that turn on the furnace fan for ventilation, the fan runs, on average for 15 weeks per year.

D. Water Heating

18. What is the main fuel used to heat the (main) hot water tank in your home?



Forty-nine percent of FortisBC customers compared to 38% of BC Hydro customers in the Southern Interior utilize electricity to heat their main hot water tank. Forty-two percent of FortisBC customers heat their hot water tank with natural gas.

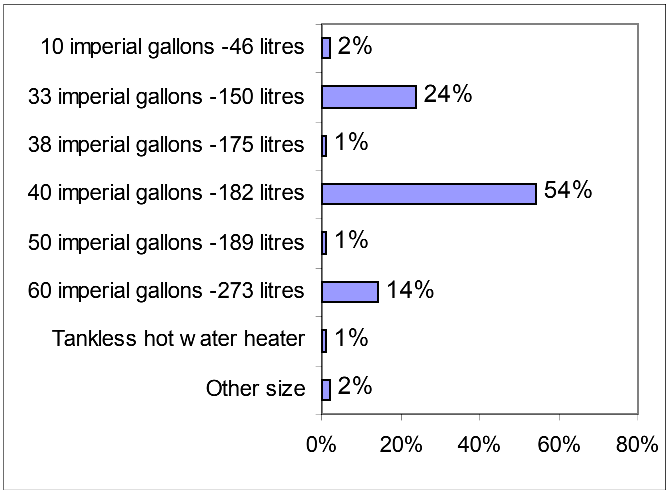
		Type of dwelling			
		Single detached	Duplex, Row, Townhouse	Apartment, Condo	Mobile, Other
"What is the main fuel used to heat the (main) hot water tank in your home?"	"Electricity"	50.3%	42.7%	28.7%	78.1%
	"Natural gas"	47.2%	54.5%	17.7%	13.1%
	"Home does not have a hot water tank-heated centrally"	.5%	.5%	29.4%	1.3%
	"Don't know"	.7%	2.3%	22.2%	1.3%
	"Other"	.8%		1.6%	
	"Bottle propane"	.2%			4.4%
	"Piped propane"	.3%		.4%	1.8%
	"Oil"	.1%			
Total	Base	1335	206	244	158

Fifty percent of single detached homes and 78% of mobile homes utilize electricity to heat their hot water tank.

		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
"What is the main fuel used to heat the (main) hot water tank in your home?"	"Electricity"	30.8%	56.9%	65.5%
	"Natural gas"	53.3%	37.6%	29.9%
	"Home does not have a hot water tank-heated centrally"	6.9%	2.6%	1.8%
	"Don't know"	7.3%	.7%	1.6%
	"Other"	.7%	.9%	.5%
	"Bottle propane"	.6%	.6%	.2%
	"Piped propane"	.4%	.4%	.5%
	"Oil"		.2%	
Total	Base	777	575	602

Sixty-six percent of West Kootenay/Boundary homes utilize electricity to heat their main hot water tank compared to only 31% of Central Okanagan Homes.

19a. What size is the largest hot water tank in your home?



The majority (54%) of households have a hot water tank that holds 40 imperial gallons (182 litres). Twenty-four percent have the second most common size – 33 gallons (150 litres).

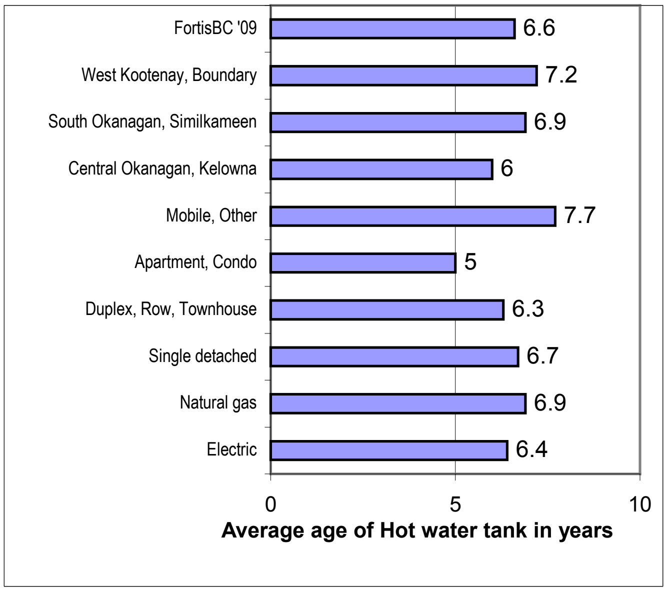
		Main fuel used to heat the hot water tank?	
		"Electricity"	"Natural gas"
"What size is the largest hot water tank in your home?"	"Tankless hot water heater"	1%	2%
	"10 imperial gallons -46 litres"	3%	1%
	"33 imperial gallons -150 litres"	18%	31%
	38 imperial gallons -175 litres	2%	
	"40 imperial gallons -182 litres"	56%	53%
	50 imperial gallons -189 litres	1%	1%
	"60 imperial gallons -273 litres"	18%	10%
	"Other"	2%	2%
Total	Base	783	678

Base: Respondent with Hot water tank

Eighteen percent of electric hot water heaters were 33 gallon tanks compared to 31% of natural gas hot water tanks.

Eighteen percent of electric hot water heaters were 60 gallon tanks compared to 10% of natural gas hot water tanks.

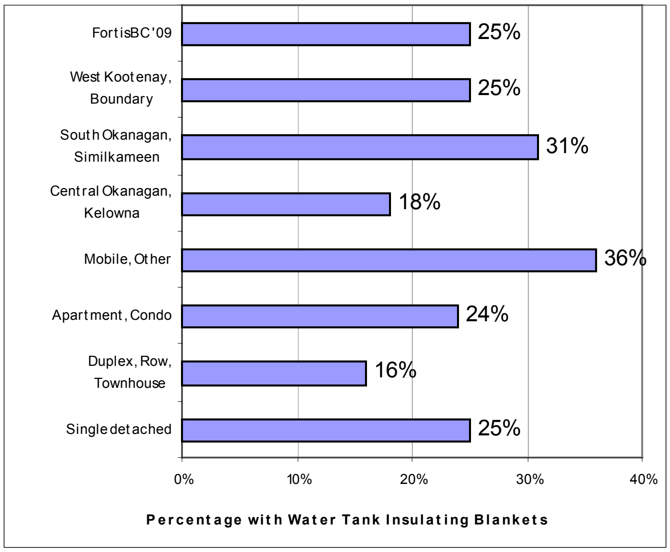
19b. How old is the largest hot water tank in your home?



The average age of hot water tanks is 6.6 years. The oldest hot water tanks are in Mobile homes with an average age of 7.7 years.

Natural gas hot water tanks are slightly older (6.9 years) than electric hot water tanks (6.4 years).

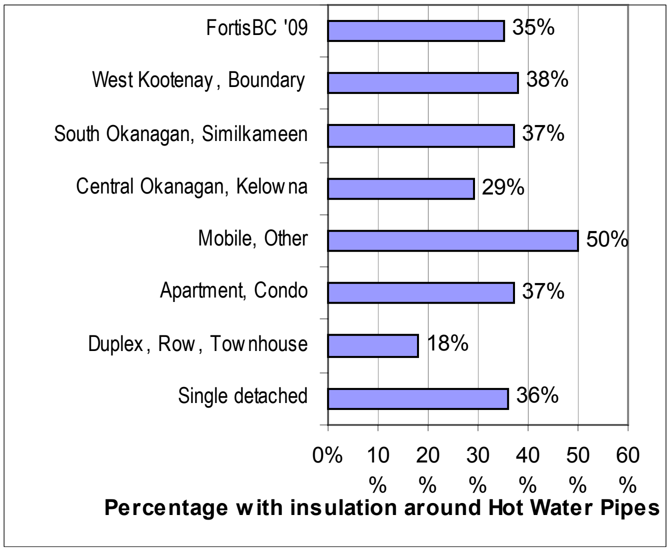
19c. Do you have water tank insulating blankets?



Base: Households with a hot water tank. Don't know responses not included.

One-in-four homes (25%) have hot water tank insulating blankets. Thirty-six percent of mobile homes have hot water tank insulating blankets.

Do you have insulation around hot water pipes?



Base: Households with a hot water tank. Don't know responses not included.

Thirty- five percent of homes have insulation around their hot water pipes. Only twenty-nine percent of homes in the Central Okanagan had insulation around their hot water pipes. Mobile homes were the most likely to have insulation around their hot water pipes (50%).

20. Have you changed your hot water heating fuel in the last two years?

		Total	Region		
			Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
"Have you changed your hot water heating fuel in the last two years?"	"No"	**98.8%**	99.3%	99.2%	97.8%
	"Yes, from natural gas to electricity"	**.5%**	.3%		1.2%
	"Yes, from electricity to natural gas"	**.3%**	.3%	.2%	.5%
	"Yes, from propane to electricity"	**.2%**		.4%	.2%
	"Yes, from oil to electricity"	**.2%**	.1%	.2%	.2%
	"Other"	**.1%**			.2%
Total	Base	**1868**	**716**	**546**	**588**

98.8% of FortisBC customers had not changed their hot water heating fuel in the last two years. 1.2% of West Kootenay/Boundary respondents changed their hot water tank from natural gas to electric.

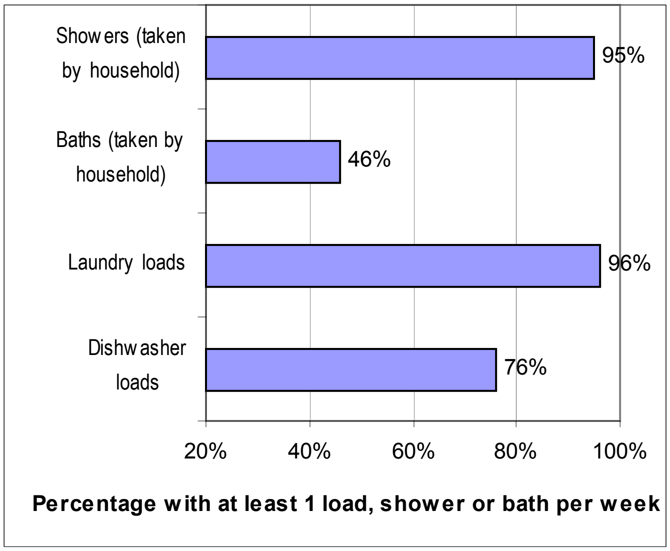
The 2006 BC Hydro results were similar with only 1% changing their hot water heating fuel.

21a. How many of the following do you have in your home? (Showerheads, Low flow shower heads and Instant hot water dispensers)

		Total	Type of dwelling				Region		
			Single detached	Duplex, Row, Townhouse	Apartment, Condo	Mobile, Other	Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
Total number of showerheads	None	**1%**	1%		1%	1%		1%	2%
	1	**32%**	26%	37%	42%	71%	25%	34%	41%
	2	**46%**	49%	46%	50%	26%	51%	46%	40%
	3+	**17%**	22%	14%	3%		20%	16%	12%
	Don't know	**0%**	0%		1%		0%		0%
	No response	**4%**	1%	2%	3%	3%	4%	4%	5%
Total	Base	**2049**	**1353**	**211**	**248**	**159**	**805**	**591**	**630**
Of these, how many are low flow shower heads?	None	**27%**	27%	30%	27%	33%	26%	26%	30%
	1	**24%**	22%	27%	28%	32%	23%	22%	27%
	2	**26%**	29%	23%	26%	15%	28%	29%	21%
	3+	**7%**	9%	7%	2%		9%	6%	5%
	Don't know	**8%**	8%	7%	10%	8%	7%	8%	9%
	No response	**8%**	5%	6%	7%	12%	6%	8%	9%
Total	Base	**2049**	**1353**	**211**	**248**	**159**	**805**	**591**	**630**
Number of instant hot water dispensers	None	**73%**	77%	71%	69%	62%	74%	71%	73%
	1	**2%**	2%	2%	1%	4%	2%	2%	2%
	2	**1%**	0%	1%	2%	1%	1%	0%	0%
	3+	**3%**	3%	4%	4%	6%	2%	4%	3%
	Don't know	**4%**	3%	4%	6%	7%	5%	3%	3%
	No response	**18%**	14%	17%	17%	20%	15%	19%	18%
Total	Base	**2049**	**1353**	**211**	**248**	**159**	**805**	**591**	**630**

Ninety-five percent of households have at least one showerhead. Fifty-seven percent of households have one or more low flow showerhead and 6% of household have at least one instant hot water dispenser.

21b. Household uses for hot water:



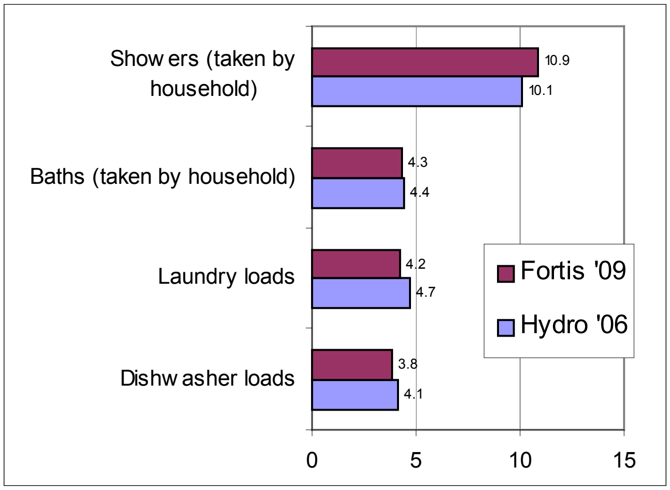
Ninety-five percent of households take at least one shower per week.

Forty-six percent of households take at least one bath per week.

Ninety-six percent of households do at least one laundry load per week.

Seventy-six percent of households complete at least one dishwasher load per week.

Average Number of loads, showers or baths per week:



Note: Zero's not included in calculation of average

Among households that take at least one shower in a week, the mean number of showers taken was 10.9. FortisBC averages were very similar to BC Hydro averages.

E. Lighting

22-30. Number and type of bulbs in house

Percent of Households with at least one bulb type in household

		Fortis '09	Hydro '06	Region		
				Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
Incandescent	1 or more bulbs	89%	97%	90%	89%	87%
Fluorescent	1 or more bulbs	59%	64%	56%	63%	59%
CFL	1 or more bulbs	68%	60%	67%	66%	72%
Halogen	1 or more bulbs	50%	42%	52%	52%	48%
Other types	1 or more bulbs	30%	22%	33%	29%	28%
Total	Base	1972	1124	777	566	612

Missing values treated as zero.

Base sizes include only cases where at least one answer was given for any bulb type

In the 2006 BC Hydro survey, 97% of respondents in the Southern Interior had at least one incandescent bulb in their home compared to 89% of the 2009 FortisBC Households. Moreover, 68% of FortisBC Households had CFL bulbs compared to 60% of BC Hydro Households.

Average number of bulbs used by bulb type:

		Fortis '09	Hydro '06	Region		
				Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
Incandescent Total	Mean	17.7	21.3	18.8	17.4	16.4
Fluorescent Total	Mean	5.4	6.0	5.1	5.3	6.0
CFL Total	Mean	11.3	7.5	11.3	10.9	11.7
Halogen Total	Mean	8.4	5.5	8.1	10.3	6.9
Other types Total	Mean	7.1	6.4	7.1	7.2	7.1

Missing values treated as zero.

Each average is based only on cases having at least 1 or more bulbs. (‘zero’ bulbs removed)

Among Households that had at least one CFL bulb, 2009 FortisBC Households had 11.3 CFL bulbs and 2006 BC Hydro customers had 7.5 CFL bulbs.

Average number of bulbs used by bulb type and room :

		Incandescent		Fluorescent		CFL		Halogen		Other	
		Fortis '09	**Hydro '06**	**Fortis '09**	**Hydro '06**	**Fortis '09**	**Hydro '06**	**Fortis '09**	**Hydro '06**	**Fortis '09**	**Hydro '06**
Bedrooms(s)	Mean	**3.0**	**3.6**	0.2	0.2	**2.3**	**1.4**	0.6	0.5	0.7	0.4
Bathroom(s)	Mean	**3.8**	**4.8**	0.2	0.2	**1.8**	**0.8**	1.1	0.7	1.0	1.8
Kitchen, eating area, including under and over cabinet lighting	Mean	**1.7**	**2.0**	2.1	1.9	**1.4**	**1.0**	3.2	1.8	1.0	0.6
Dining Room	Mean	**1.8**	**2.3**	0.1	0.1	**0.7**	**0.4**	0.3	0.3	2.0	1.0
Living Room	Mean	**1.6**	**1.9**	0.1	0.2	**1.3**	**1.0**	0.8	0.7	0.6	0.5
Den, Study, Office, Family & Game Room(s)	Mean	**1.2**	**1.2**	0.5	0.5	**0.8**	**0.6**	0.8	0.7	0.2	0.3
Hallway(s), Laundry & Utility room(s), Garage(s), Workshop(s)	Mean	**2.4**	**2.9**	1.8	1.8	**1.7**	**1.2**	0.6	0.4	0.4	0.4
Outdoor, Security, Porch & Landscape	Mean	**1.6**	**1.8**	0.1	0.0	**1.0**	**0.6**	1.0	0.9	1.2	1.6
Unfinished Basement	Mean	**0.7**	**0.4**	0.4	0.3	**0.4**	**0.2**	0.0	0.0	0.1	0.1
	Base	1751	4117	1160	2575	1352	2362	994	1865	593	877

Missing values treated as zero. Count of ' zero' are included in mean calculation. Average do not include cases for which no bulb count was given for that ***section****.*

2009 FortisBC customers have an average of 3.8 Incandescent bulbs in their bathrooms and 3.0 bulbs in their bedrooms. In general, the amount of CFL bulbs in all rooms of the house has increased since the 2006 BC Hydro survey.

Fluorescent lighting is most common in the Kitchen (2.1 bulbs). Halogen lighting is also most comment in the kitchen (3.2 bulbs).

Average Hours per day light used by bulb type and room :

		Incandescent		Fluorescent		CFL		Halogen		Other	
		Fortis '09	**Hydro '06**	**Fortis '09**	**Hydro '06**	**Fortis '09**	**Hydro '06**	**Fortis '09**	**Hydro '06**	**Fortis '09**	**Hydro '06**
Bedrooms(s)	Mean	1.7	2.1	1.7	2.6	1.9	2.7	1.7	1.8	2.4	3.1
Bathroom(s)	Mean	1.6	1.9	1.7	2.1	1.9	2.2	1.7	1.7	2.3	2.0
Kitchen, eating area, including under and over cabinet lighting	Mean	2.8	3.4	3.4	4.2	3.3	4.2	2.5	3.0	2.8	2.7
Dining Room	Mean	1.8	1.8	1.5	3.5	2.0	2.9	1.6	1.9	1.7	1.8
Living Room	Mean	2.7	3.1	3.1	3.2	3.0	3.8	2.4	2.8	2.2	3.3
Den, Study, Office, Family & Game Room(s)	Mean	2.5	3.0	2.7	2.6	2.9	3.6	2.5	2.8	2.5	2.5
Hallway(s), Laundry & Utility room(s), Garage(s), Workshop(s)	Mean	1.5	1.8	1.6	1.8	2.0	2.4	1.6	1.5	3.1	3.2
Outdoor, Security, Porch & Landscape	Mean	2.1	3.0	2.3	8.9	3.5	5.7	2.0	2.2	4.5	6.7
Unfinished Basement	Mean	1.1	1.2	1.1	1.8	1.4	2.2	0.9	2.8	1.0	11.6

Each average is based only on cases having at least one bulb type in the specific room.

Incandescent lights are on an average of 2.8 hours per day in the Kitchen compared to CFL lights which are on an average of 3.3 hours per day in the Kitchen. In general, in all rooms of the house, CFL lights are kept on longer than Incandescent lights.

31. Number of Light bulbs controlled by dimmers and timers

Percent of Households light switches with a dimmer

		Total	Region		
			Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
Incandescent	1 or more dimmer	39%	43%	37%	34%
Fluorescent	1 or more dimmer	1%	2%	2%	
CFL	1 or more dimmer	8%	7%	9%	8%
Halogen	1 or more dimmer	16%	17%	17%	14%
Other types	1 or more dimmer	14%	15%	18%	11%

Missing values treated as zero.

Base sizes include only cases where at least one answer was given for specific bulb type.

Among households with at least one incandescent light bulb in their house, 39% had at least one dimmer switch controlling an incandescent bulb.

Among households with at least one Halogen light bulb in their house, 16% had at least one dimmer switch.

Average number of bulbs with a dimmer

		Total	Region		
			Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
Incandescent	Mean	4.0	4.4	3.7	3.8
Fluorescent	Mean	2.9	3.6	2.4	.1
CFL	Mean	3.4	3.3	3.9	3.0
Halogen	Mean	6.5	4.4	9.6	6.5
Other	Mean	4.3	4.0	4.5	4.4

Zero's not included in mean calculation.

Each average is based only on cases having 1 or more dimmer switch

Base sizes are small, interpret results with caution

Among Households with dimmer switches on incandescent bulbs, the average number of switches was 4.

Percent of Households light switches with a timer

		Total	Region		
			Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
Incandescent	1 or more timer	10%	9%	12%	8%
Fluorescent	1 or more timer	0%	0%	0%	0%
CFL	1 or more timer	8%	10%	7%	6%
Halogen	1 or more timer	5%	6%	4%	4%
Other types	1 or more timer	6%	3%	11%	4%

Missing values treated as zero.

Base sizes include only cases where at least one answer was given for specific bulb type.

Among households with at least one incandescent light bulb in their house, 10% had at least one timer. Among households with at least one CFL light bulb in their house, 8% had at least one timer.

Average number of bulbs with a Timer

		Total	Region		
			Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
Incandescent	Mean	2.6	2.9	2.3	2.8
Fluorescent	Mean	5.9	9.5	3.0	2.0
CFL	Mean	2.4	2.7	2.1	2.2
Halogen	Mean	3.2	4.3	2.2	2.2
Other types	Mean	7.0	7.4	4.4	13.6

Zero's not included in mean calculation.

Each average is based only on cases having at least 1 or more timer

Base sizes are small, interpret results with caution

Among households with timers on incandescent bulbs, the average number of timers was 2.6.

32. Torchieres

Percent of Households with a Torchiere with the following bulb type:

			Region		
		Total	Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
Incandescent	1 or more	17%	18%	18%	15%
Fluorescent	1 or more	13%	13%	15%	11%
CFL	1 or more	4%	5%	3%	4%

Missing values treated as zero.

Base sizes include only cases where at least one bulb was given of any type.

Seventeen percent of households had at least one incandescent bulb torchiere. Thirteen percent of households had at least 1 fluorescent bulb torchiere and 4% had 1 or more CFL bulb torchieres.

Average number of torchieres by bulb type

			Region		
		Total	Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
Incandescent	Mean	1.7	1.8	1.6	1.5
Halogen	Mean	1.5	1.4	1.4	1.8
CFL	Mean	2.0	2.3	1.8	1.7

Zero's not included in mean calculation.

Each average is based only on cases having at least 1 or more torchiere

Base sizes are small, interpret results with caution

Among Households with incandescent bulb torchieres, the average number of torchieres was 1.7.

Average hours per day torchieres are on by bulb type:

			Region		
		Total	Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
Incandescent	Mean	2.2	2.2	2.3	1.9
Halogen	Mean	2.0	2.4	1.6	1.7
CFL	Mean	2.9	2.7	2.3	3.6

Zero's not included in mean calculation.

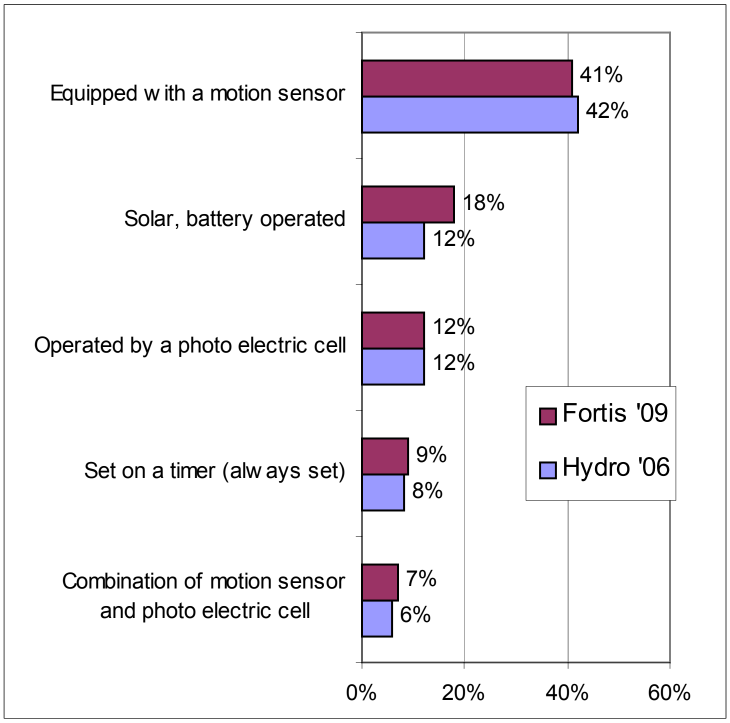
Each average is based only on cases having at least 1 or more torchiere

Base sizes are small, interpret results with caution

Incandescent torchieres are on an average of 2.2 hours per day and CFL torchieres are on an average of 2.9 hours per day.

33. Outdoor Lighting fixtures

Percent of Households with outdoor light fixtures equipped with the following:



Forty-one percent of households have outdoor lights equipped with motion sensors and eighteen percent have solar/battery operated outdoor lights.

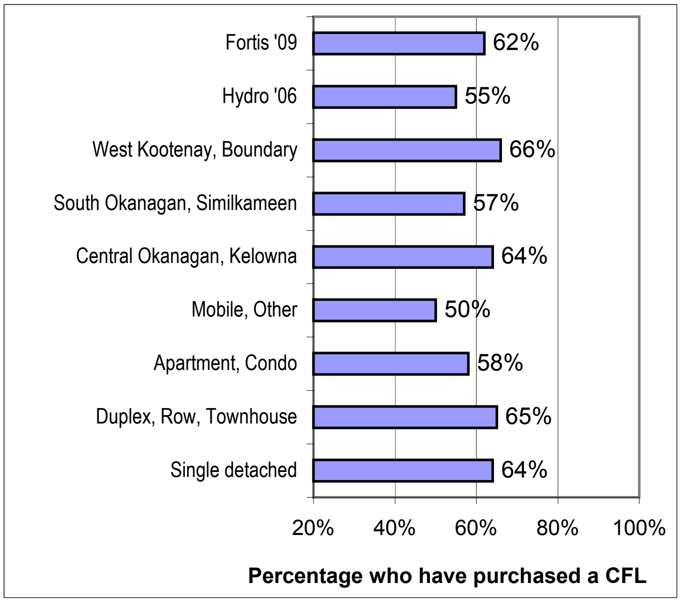
Do you have outdoor light fixtures equipped with the following?

		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
Equipped with a motion sensor (turns on when movement is detected)	Yes	34%	46%	47%
Solar, battery operated	Yes	15%	21%	20%
Operated by a photo electric cell	Yes	12%	14%	12%
Set on a timer (always set)	Yes	10%	11%	6%
Combination of motion sensor and photo electric cell	Yes	5%	8%	8%

Forty-seven percent of West Kootenay/Boundary households are equipped with a motion sensor compared to 34% of Central Okanagan households.

34. Compact Fluorescent Light bulbs (CFL's)

In the past 12 months, have you purchased a CFL?



Sixty-two percent of FortisBC respondents had purchased a CFL bulb in the past 12 months compared to 55% of BC Hydro respondents.

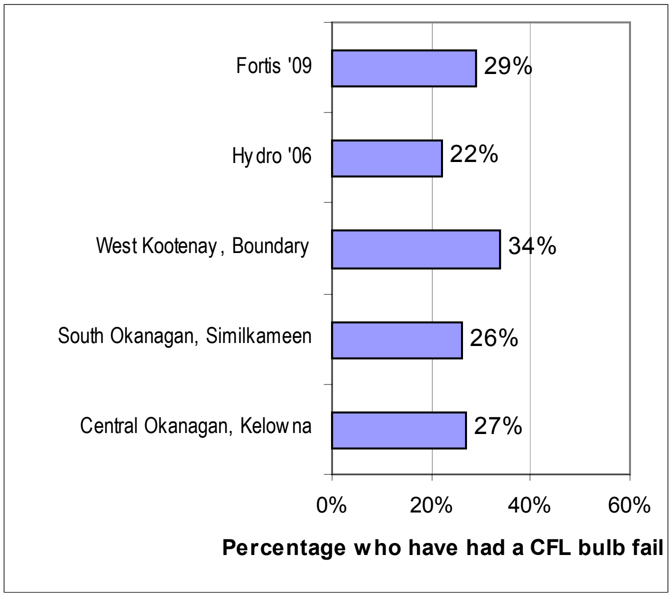
Average number of CFL bulbs:

		Fortis '09	Hydro '06
"How many in total have you purchased?"	Mean	9.2	7.3
"Of these, how many have you installed?"	Mean	6.5	4.5
"How many were rebated by FortisBC?"	Mean	.6	n/a

Base: Respondents who have purchased CFL's in past 12 months.

Not surprisingly, CFL bulbs are more commonly used in 2009 then in 2006.

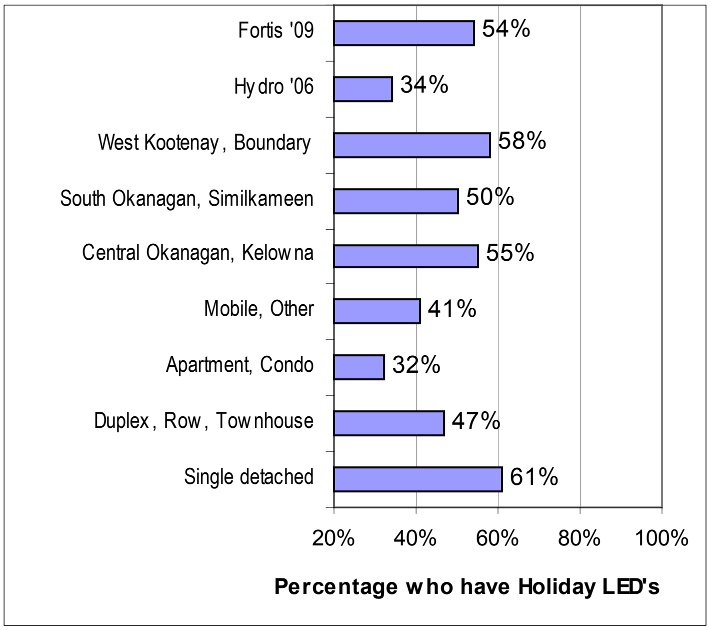
In the past 12 months, have any CFL bulbs failed?



Twenty-nine percent had a CFL bulb fail in the past 12 months. Among households that had a failed CFL bulb, the average number of failed bulbs was 2.2. Among the failed CFL bulbs, the average number that were replaced with another CFL bulb was 1.7.

35. LED Holiday Lights

Do you have Holiday LED's?



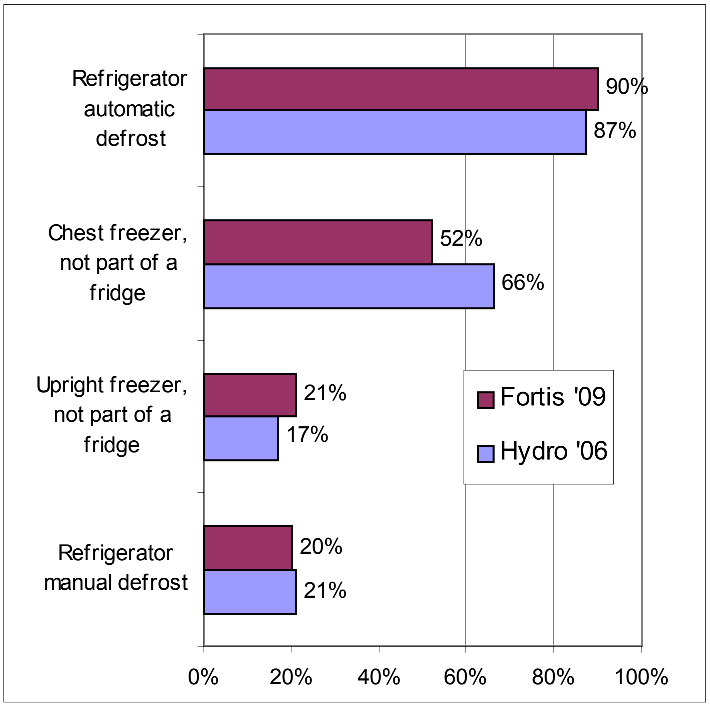
Fifty-four percent of FortisBC households have holiday LED's compared to only 34% of BC Hydro 2006 households.

Single detached homes were the most likely to have holiday LED's.

The average number of LED strings per household was 5.5 among FortisBC customers compared to 4.8 amount BC Hydro customers.

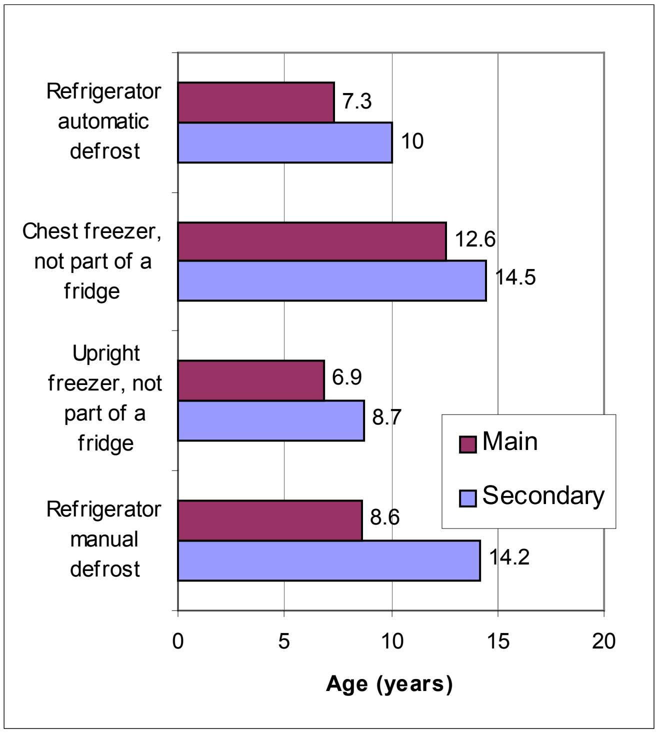
F. Appliances

36. Do you have the following Refrigerator/Freezer appliances in your home?



Ninety percent of FortisBC households have a refrigerator with automatic defrost and 52% have a chest freezer. BC Hydro households were more likely to have a chest freezer (66%).

Average age of appliances:

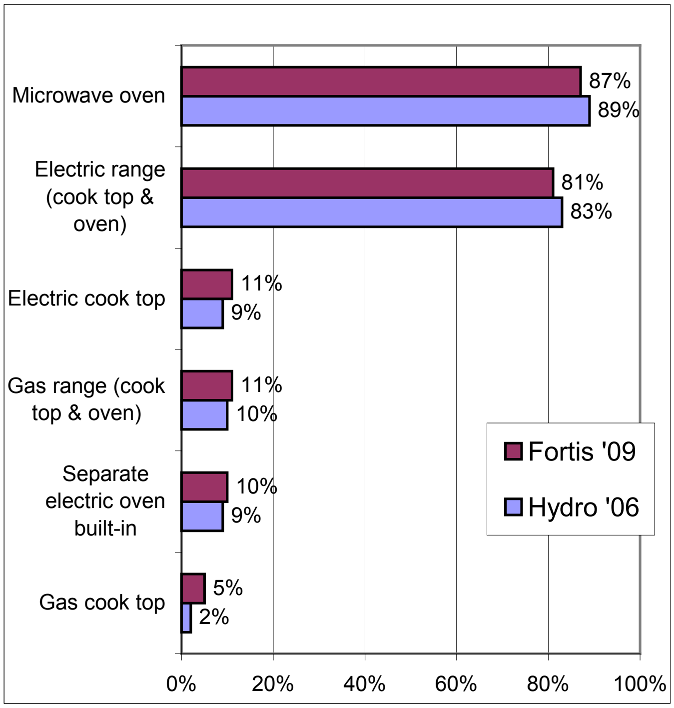


Each average is based only on cases having appliance (main or secondary)

The average age of main automatic defrost refrigerator was 7.3 years and if the refrigerator was secondary, the average age was 10 years.

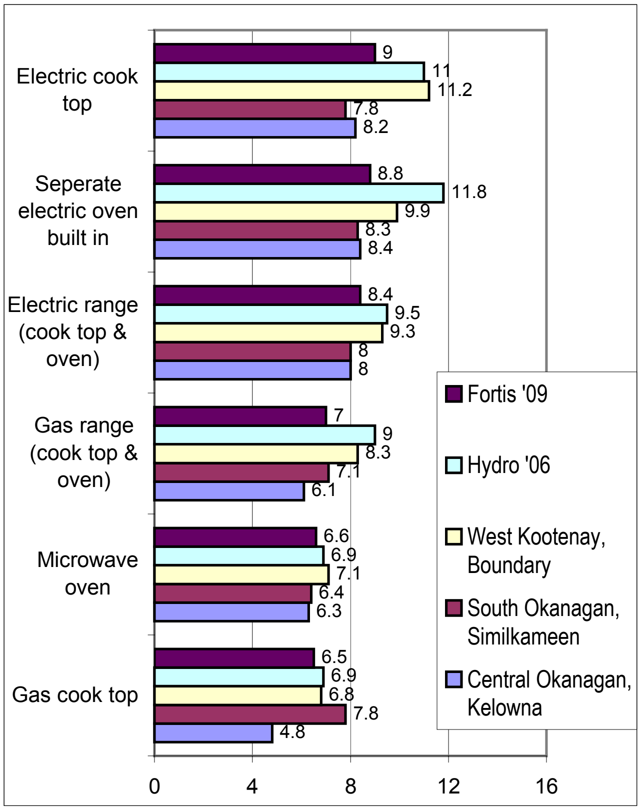
The average age of the main chest freezer was 12.6 years and the average age of upright freezers was 6.9 years.

37. Do you have the following Cooking appliances in your home?



Eighty-seven percent of FortisBC Households have a microwave oven and 81% have an electric range (cook top & oven).

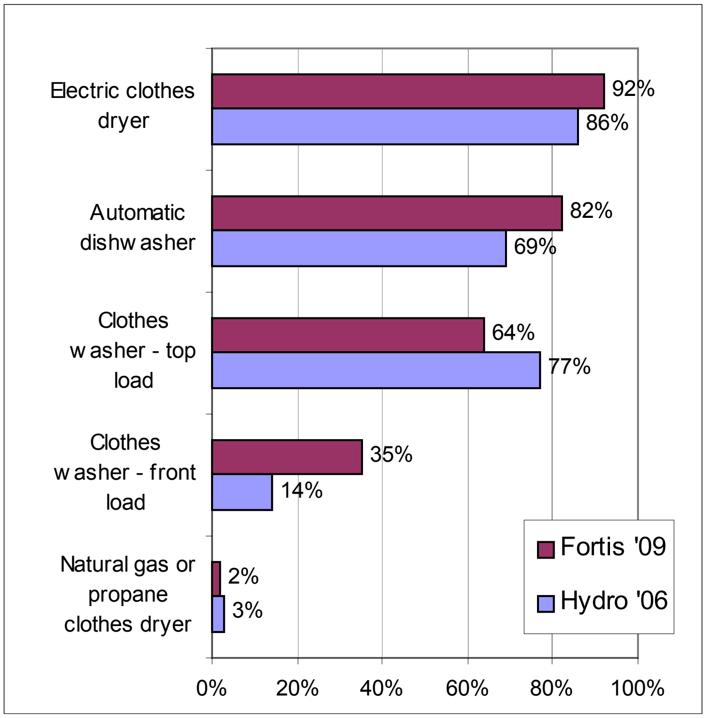
Average age of appliances:



Each average is based only on cases having appliance

The average age of Electric cook tops was 9.0 years among all FortisBC Households and 11.2 years among West Kootenay/Boundary households. Cooking appliances were on average slightly older in the West Kootenay/Boundary area.

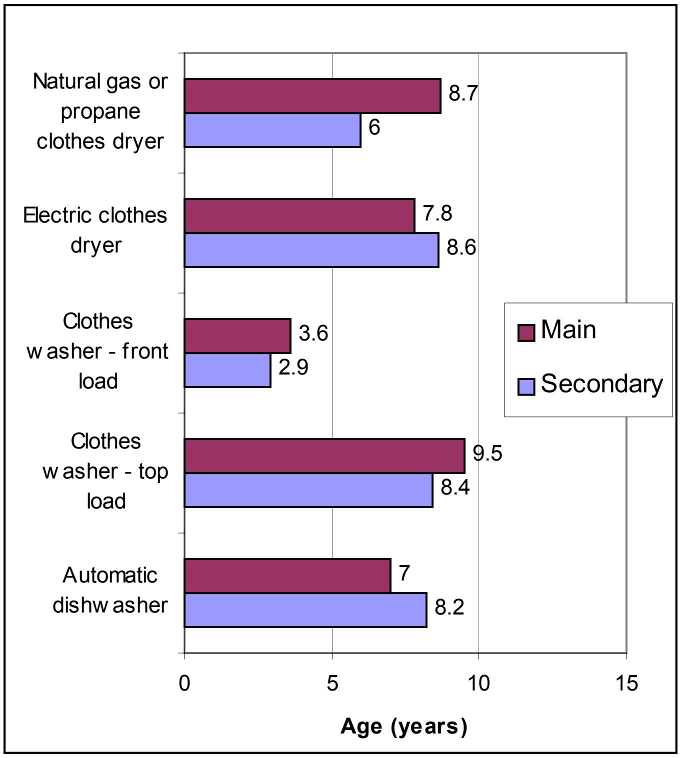
38. Do you have the following Laundry/Dryer appliances in your home?



Ninety-two percent of FortisBC Households have an electric clothes dryer and 82% have an automatic dishwasher.

Front load washing machines are more prevalent in 2009 among FortisBC Households (35%) than the were in 2006 Hydro households (14%).

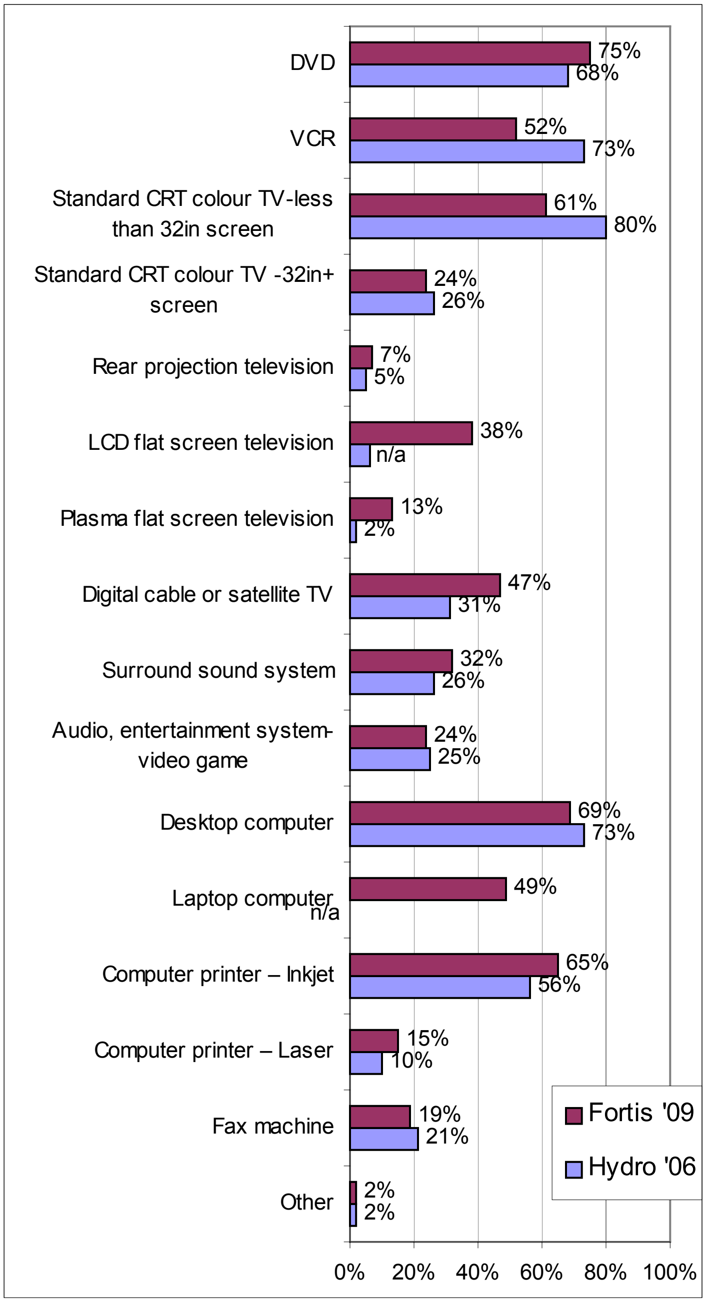
Average age of appliances:



Each average is based only on cases having appliance (main or secondary)

The average age of the main front loading washing machine is 3.6 years and the average age of top load washing machines is 9.5 years.

39. Do you have the following home electronics in your home?



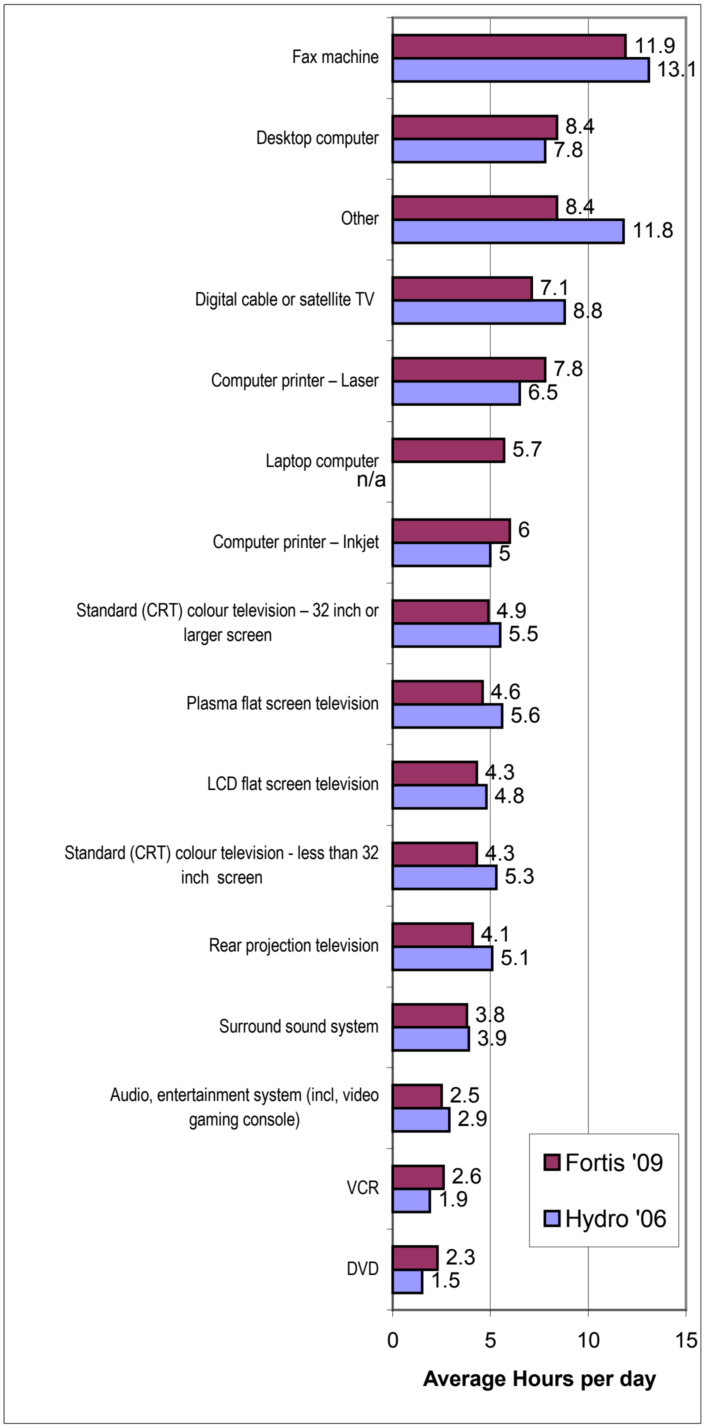
Seventy-five percent of FortisBC households have a DVD.

Only 52% of household had a VCR in 2009 compared to 73% in 2006.

In 2006, 80% of BC Hydro households had a standard TV with a 32 inch or less screen compared to 61% of FortisBC households.

Forty-seven percent have digital cable or satellite TV and 38% have an LCD flat screen TV. The percentage of households with LCD and Plasma TV's has increased significantly since 2006.

Average number of hours left on per day:



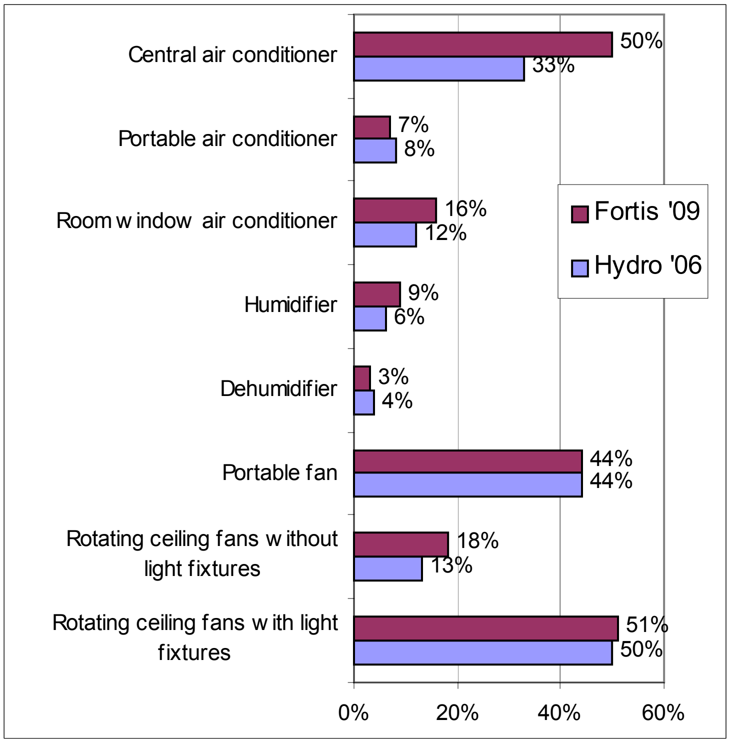
Fax machines are left on an average of 11.9 hours per day and desktop computers are left on 8.4 hours per day.

"Other" electrical items are left on an average of 8.4 hours per day. The specific other items provided by respondents are shown in the below chart:

"Other appliance"	Radio	8
	LCD projector	5
	Scanner	5
	Photocopier	5
	Fax\printer (all in 1)	4
	Cordless phone	2
	Home theatre	2
	Battery charger	2
	UPC	2
	Modem\pvr	2
	Water pumps domestic supplies	1
	Dot matrix	1
	Adding machine	1
	CD recorder	1
	Well pumps	1
	Sewing machine	1
	TV (small)	1
	Protable A\C	1
	Notebook computers	1
	Toaster oven	1
	Router\switch	1
	Hot tub	1
	Server	1
Total		50

G. Space Cooling

40a. Do you have the following Air Conditioning appliances in your home?



The majority of FortisBC homes (50%) have a central air conditioner. Only 33% of BC Hydro homes in the Southern interior have central air conditioners.

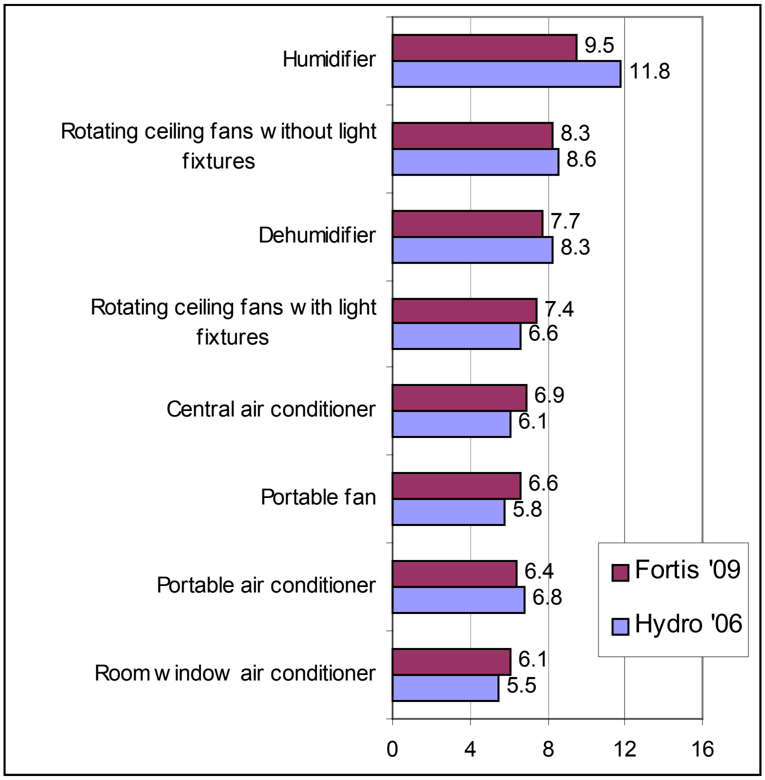
Air conditioners by region:

		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
Do you have the following appliances in your home?	Central air conditioner	**63%**	**57%**	**23%**
	Portable air conditioner	7%	6%	9%
	Room window air conditioner	17%	16%	14%
	Humidifier	11%	8%	5%
	Dehumidifier	2%	3%	6%
	Portable fan	43%	39%	50%
	Rotating ceiling fans without light fixtures	16%	24%	15%
	Rotating ceiling fans with light fixtures	46%	55%	55%
Total	Responses	1551	1141	954
	Base	755	548	540

Column percentages may exceed 100% because multiple responses provided

Sixty-three percent of Central Okanagan households have a central air conditioner compared to 23% of West Kootenay/Boundary households.

Average hours per day the air conditioners are in use: (when used)

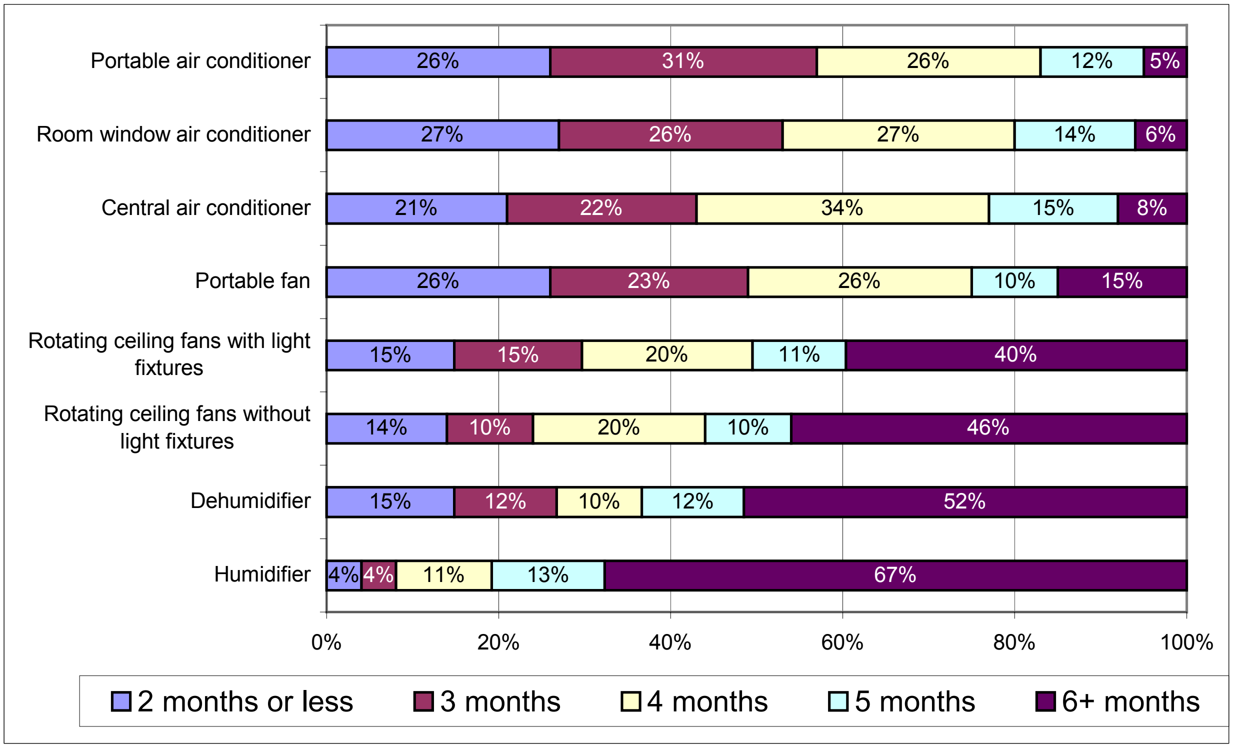


Each average is based only on cases having appliance. Zero's included.

When Humidifiers are in use, FortisBC homes will keep their humidifier on for an average of 9.5 hours per day.

When central air conditioners are in use, FortisBC homes will keep their central air conditioner on for an average of 6.9 hours per day.

Number of months air conditioners in use per year:



The majority of households utilize portable air conditioners (83%), room window air conditioners (80%), central air conditioners (77%) and portable fans (75%) for 4 months or less each year. The majority of these households utilize these air conditioners from June or July to September each year.

Dehumidifiers are utilized over 6 months per year by 52% and humidifiers are used over 6 months per year by 67%.

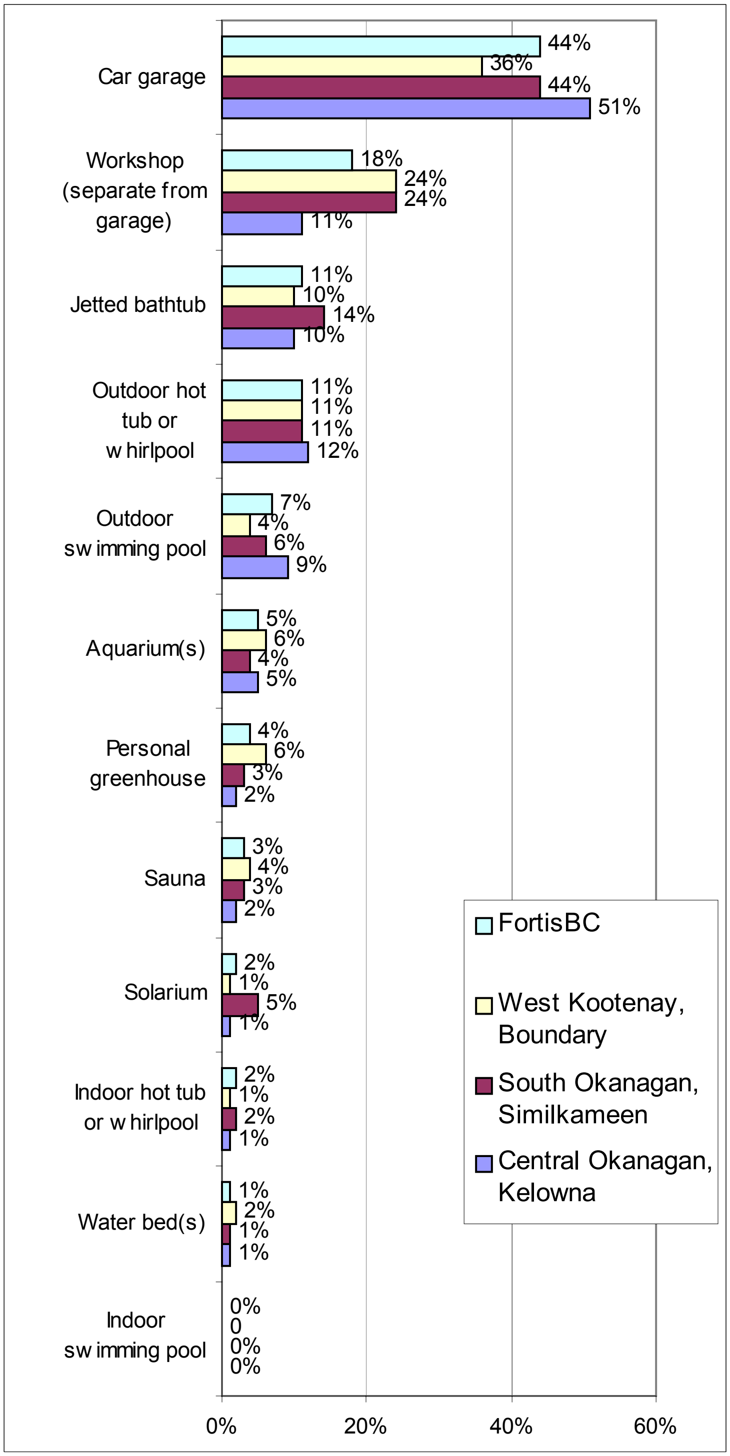
40b. Are you planning to buy the following types of air conditioners in the next 12 months?

			Region		
		Total	Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
"Portable"	"Yes"	2%	2%	1%	2%
"Room"	"Yes"	2%	2%	1%	2%
"Central"	"Yes"	2%	2%	1%	4%

Only 6% of FortisBC households are planning purchasing an air conditioner in the next 12 months. This is split evenly between portable, room and central air conditioners.

H. Other End Uses

41a. Do you have the following items at your home? (Pools, hot tubs, car garage, etc).



Forty-four percent of households have a car garage, with the highest percentage in the Central Okanagan (51%).

Eleven percent have an outdoor hot tub or whirlpool. Among outdoor hot tub or whirlpool owners, 97% cover their hot tubs when not in use to save energy.

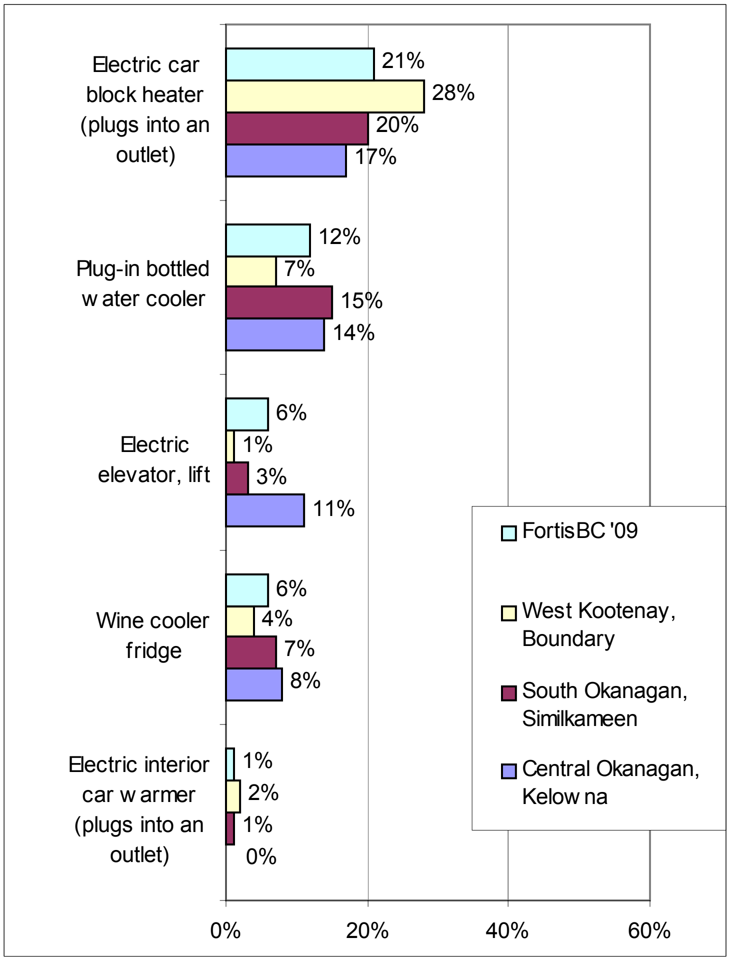
Seven percent have an outdoor swimming pool. Among swimming pool owners, 70% cover the outdoor pool when not in use to save money.

How is it heated?

	Indoor swimming pool	Outdoor swimming pool	Indoor hot tub or whirlpool	Outdoor hot tub or whirlpool	Sauna	Water bed(s)	Aquarium (s)	Car garage	Workshop (separate from garage)	Personal greenhouse	Solarium
Electric	10%	6%	57%	92%	93%	56%	63%	18%	36%	32%	15%
Gas	28%	27%	11%	4%	2%	30%	15%	28%	26%	37%	40%
Don't know	26%	7%	9%	3%	4%	0%		1%	1%	0%	0%
Not heated	36%	60%	23%	1%	2%	14%	22%	53%	38%	31%	45%
Base	11	124	56	213	54	30	107	840	357	39	67

The majority of outdoor swimming pools are not heated (60%). Ninety-two percent of outdoor hot tubs or whirlpools are electric and 93% of Saunas are electric. The majority of car garages (53%) are not heated.

41b. Do you have the following items at your home?

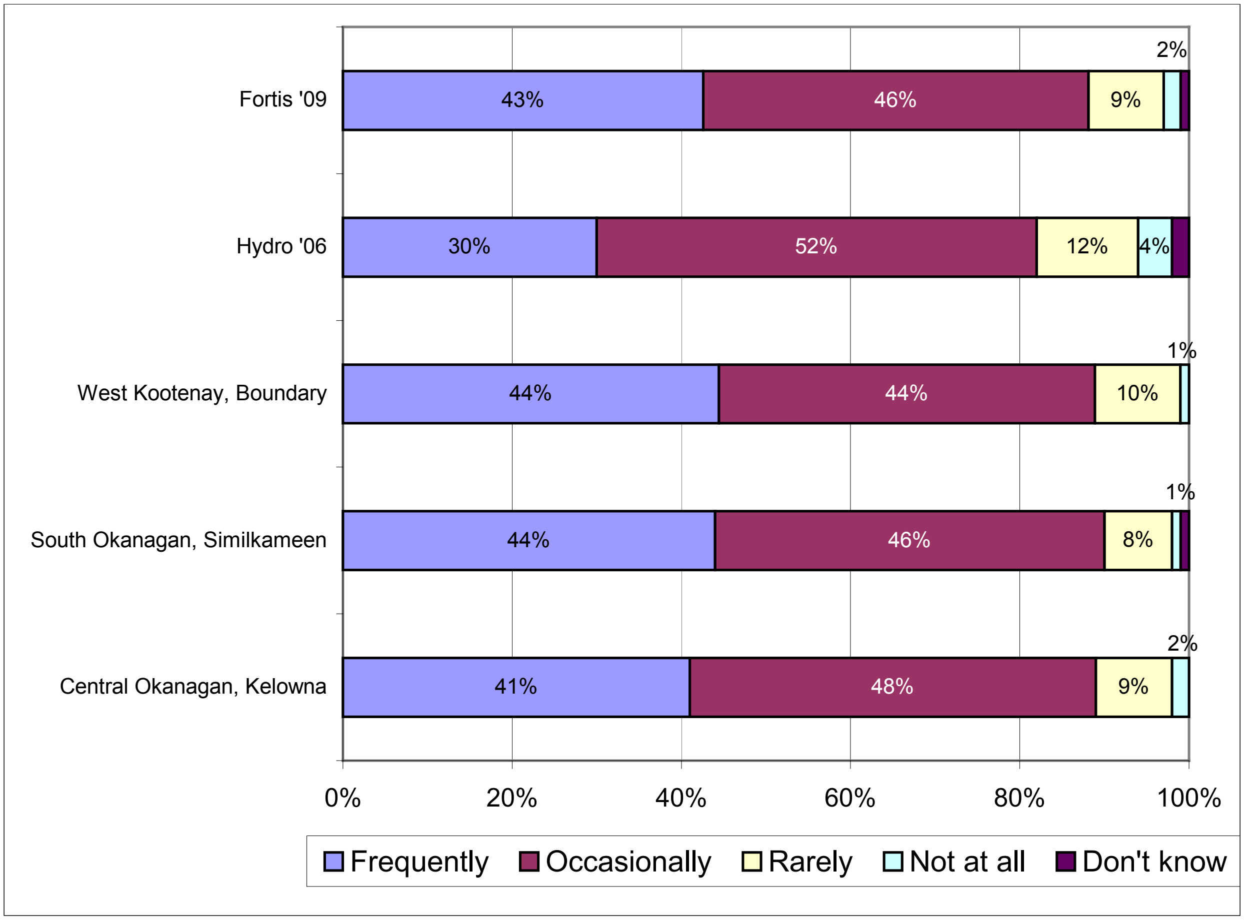


Twenty-eight percent of West Kootenay/Boundary households have an electric block heater for their car compared to 17% of Central Okanagan households.

Plug-in water coolers are more popular in the Southern and Central Okanagan than in West Kootenay/ Boundary.

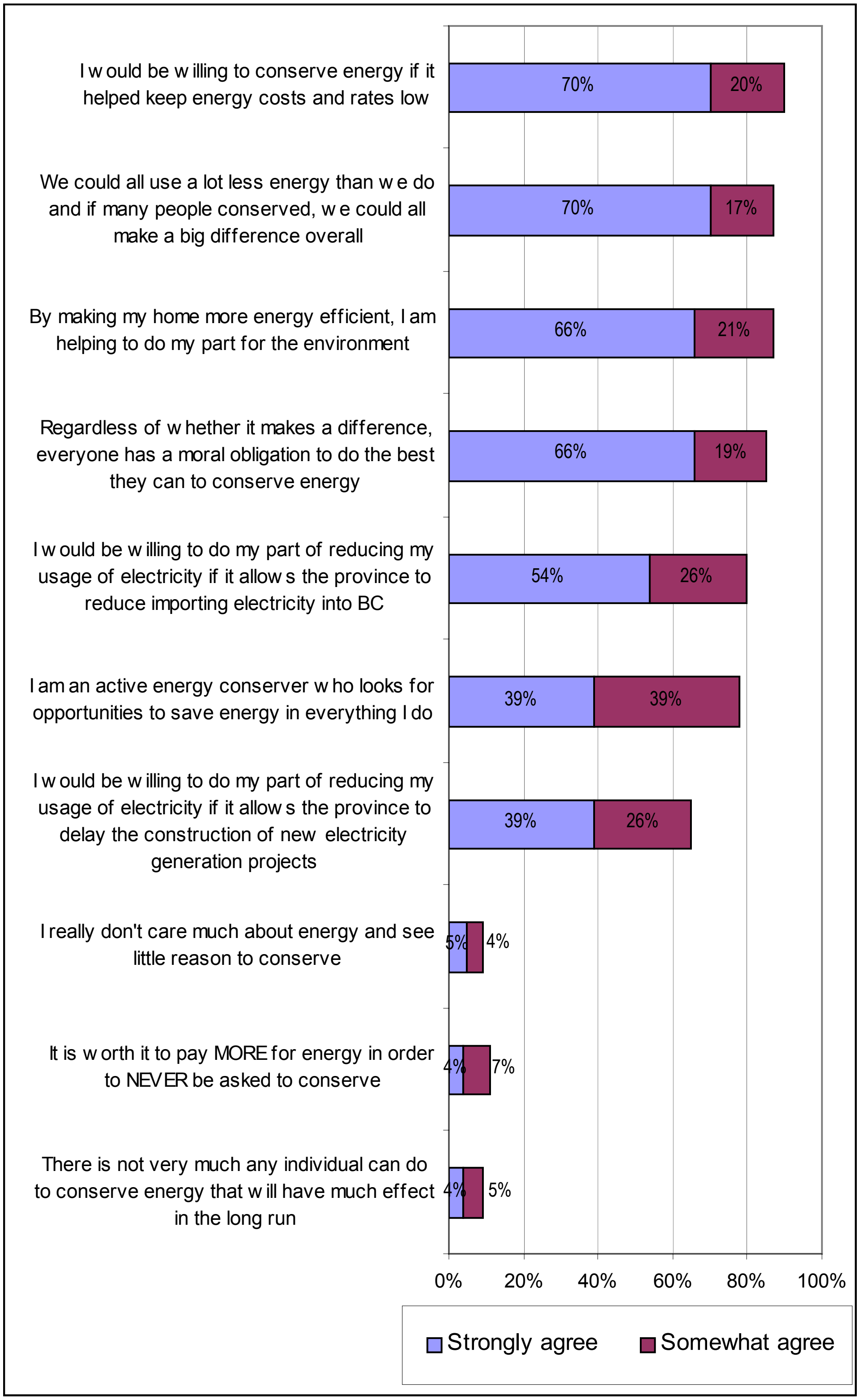
I. Electricity and the Environment

42. How much have you been thinking about energy issues in BC and how they affect you and your family and friends?



The majority of FortisBC respondents (89%) have been thinking about energy issues in BC frequently (43%) or occasionally (46%). Energy issues are more on peoples minds than they were during the 2006 Hydro survey in which 30% thought of energy issues frequently and 52% occasionally.

43. Please rate your agreement with the following: Energy conservation



Ninety percent feel they would be willing to conserve energy if it helps keep energy costs and rates low.

Eighty percent agree (strongly-54%; somewhat-26%) they would be willing to reduce usage of electricity if it allows the province to reduce importing electricity into BC.

44a. What encourages you to use less energy in your household?

	Fortis '09	Hydro '06
To reduce costs\lower bills	73%	81%
Environmental reasons\power conservation	37%	21%
It's my philosophy\habit\common sense	10%	8%
Other family members	4%	1%
Cost\availability of energy efficient appliances\technology	3%	2%
To be a good role model	2%	0.5%
Information\tips\education to save energy	1%	0.5%
Incentives\rebates	1%	1%
Advertising\reminders to save energy	1%	1%
Not at home much\don't use much energy	0.9%	0.5%
Other	0.7%	3%
Warm\summer weather	0.5%	1%
Daylight\long days	0.4%	1%
Nothing in particular	0.3%	5%

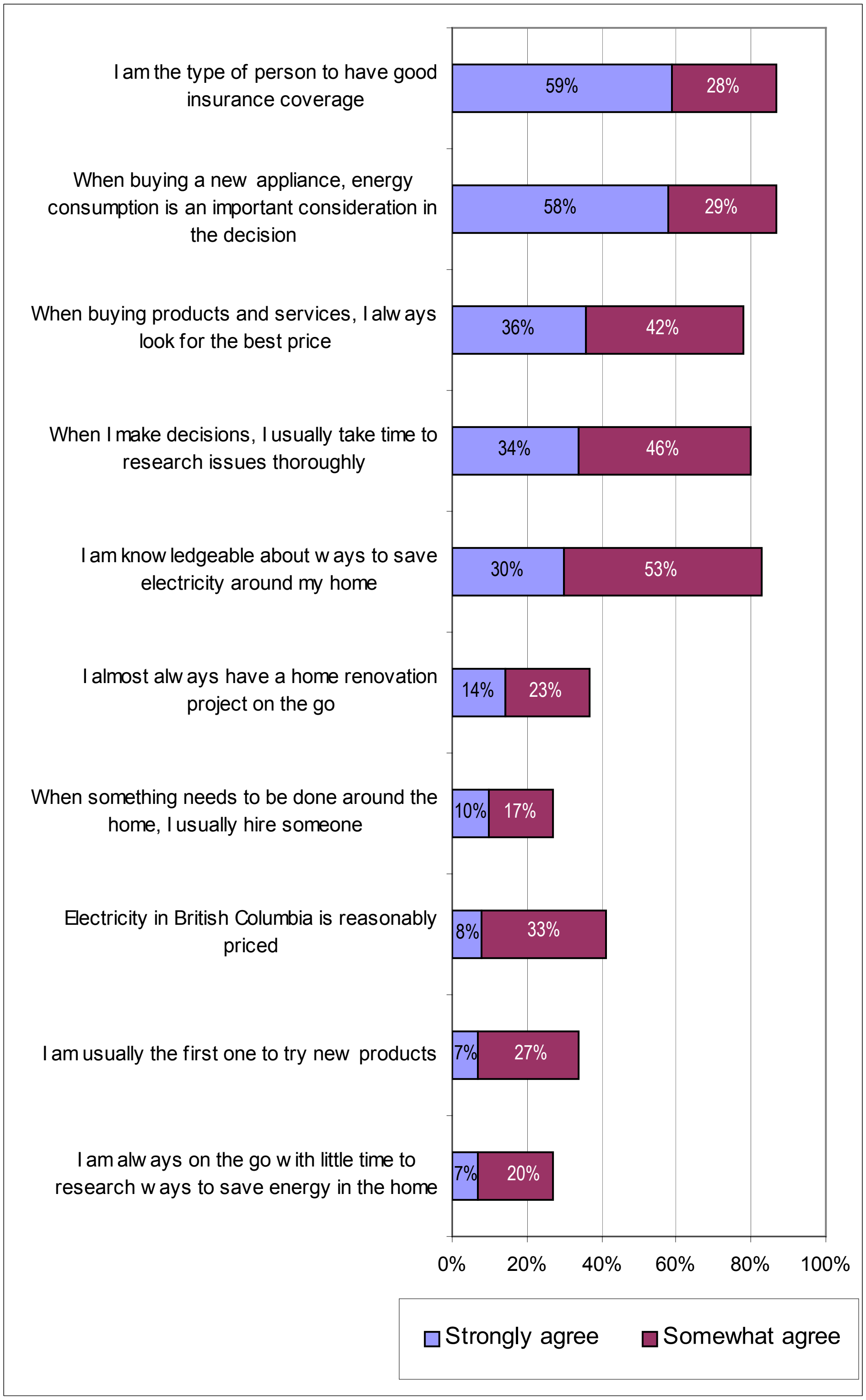
Not surprisingly, 73% of FortisBC respondents said that reducing costs/lowering bills would encourage them to use less energy. Thirty- seven percent of FortisBC customers and only 21% of Hydro customers would be encouraged to use less energy for environmental reasons or power conservation.

44b. What prevents you from using less energy in your household?

	Fortis '09	Hydro '06
Too costly to upgrade current appliances	*9%*	*7%*
Cost of upgrading\renovations\old house	*6%*	*4%*
Too costly to upgrade current windows\insulation	*3%*	*5%*
Cost of energy efficient lights\fixtures	*1%*	*2%*
Cost (general)	*10%*	*9%*
Total cost	***28%***	***27%***
Nothing in particular	15%	18%
Entertainment\lifestyle\household requirements	11%	14%
Too lazy\busy\I forget	10%	7%
Current usage is already at the minimum level	9%	10%
Comfort	9%	3%
Weather (ie. cold winter\hot summer)	9%	10%
Other family members are not participating\children	8%	9%
Convenience	5%	3%
Other	3%	4%
Problems with energy efficient bulbs	3%	1%
Darkness (ie. long winter nights) - need light	2%	5%
Don't know	2%	1%
Don't know how to save energy\lack of information	1%	1%
Rent\rental restrictions	1%	1%
Have an older furnace	1%	1%
Low cost of electricity\hydro bill	1%	1%
Security concerns	0.3%	0.4%
Have a home office	0.2%	1%

Cost prevents 28% of FortisBC customers from using less energy. Eleven percent of customers are prevented from using less energy because of their entertainment, lifestyle and household requirements. Ten percent are simply too lazy, busy or forget to use less energy.

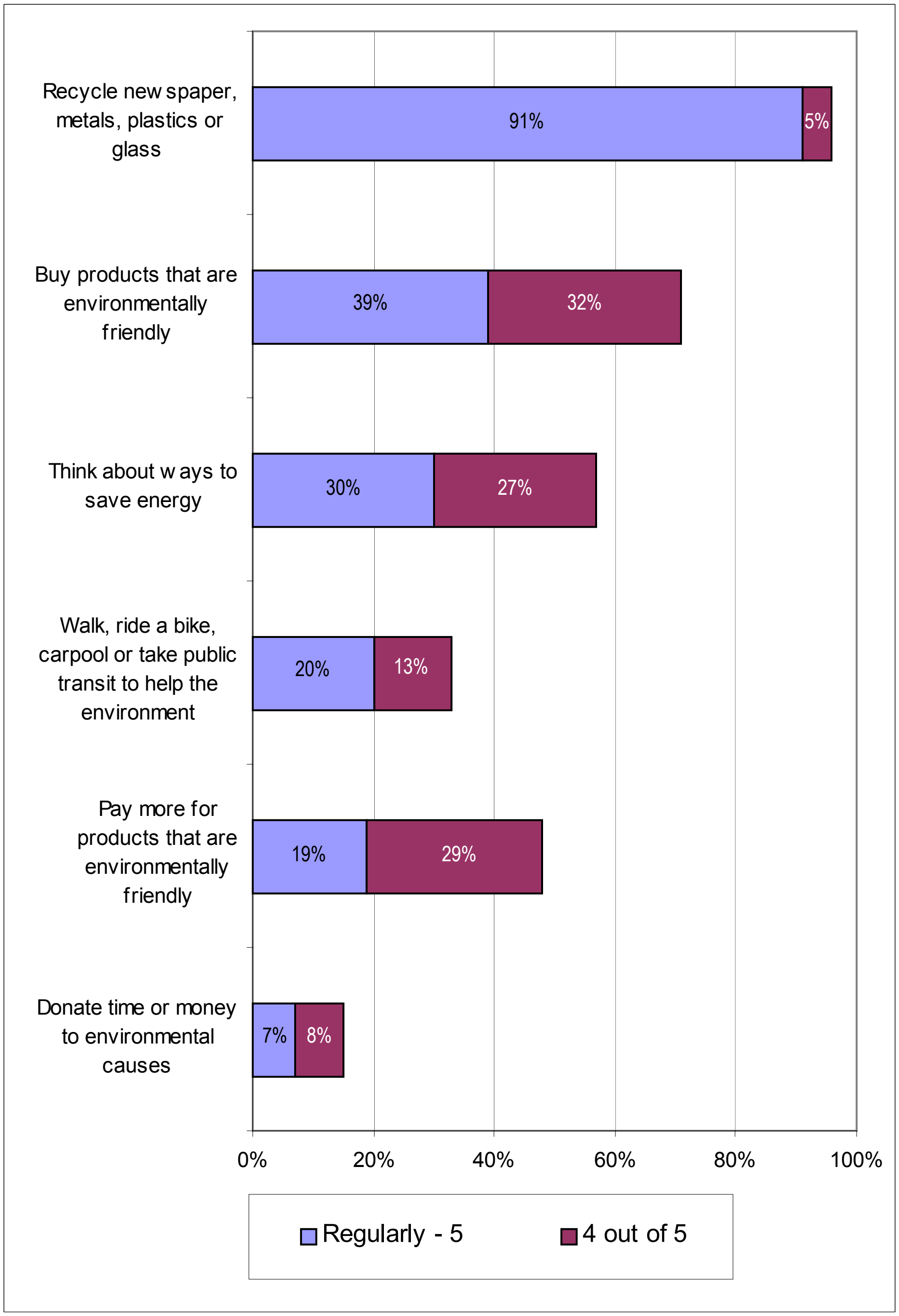
44c. Please rate your agreement with the following: New Products, Services and Electricity



The majority agree (87%) that they are the type of person to have good insurance coverage and when buying a new appliance, energy consumption is an important consideration in the decision.

Eight percent strongly agree and 33% agree that electricity in BC is reasonably priced.

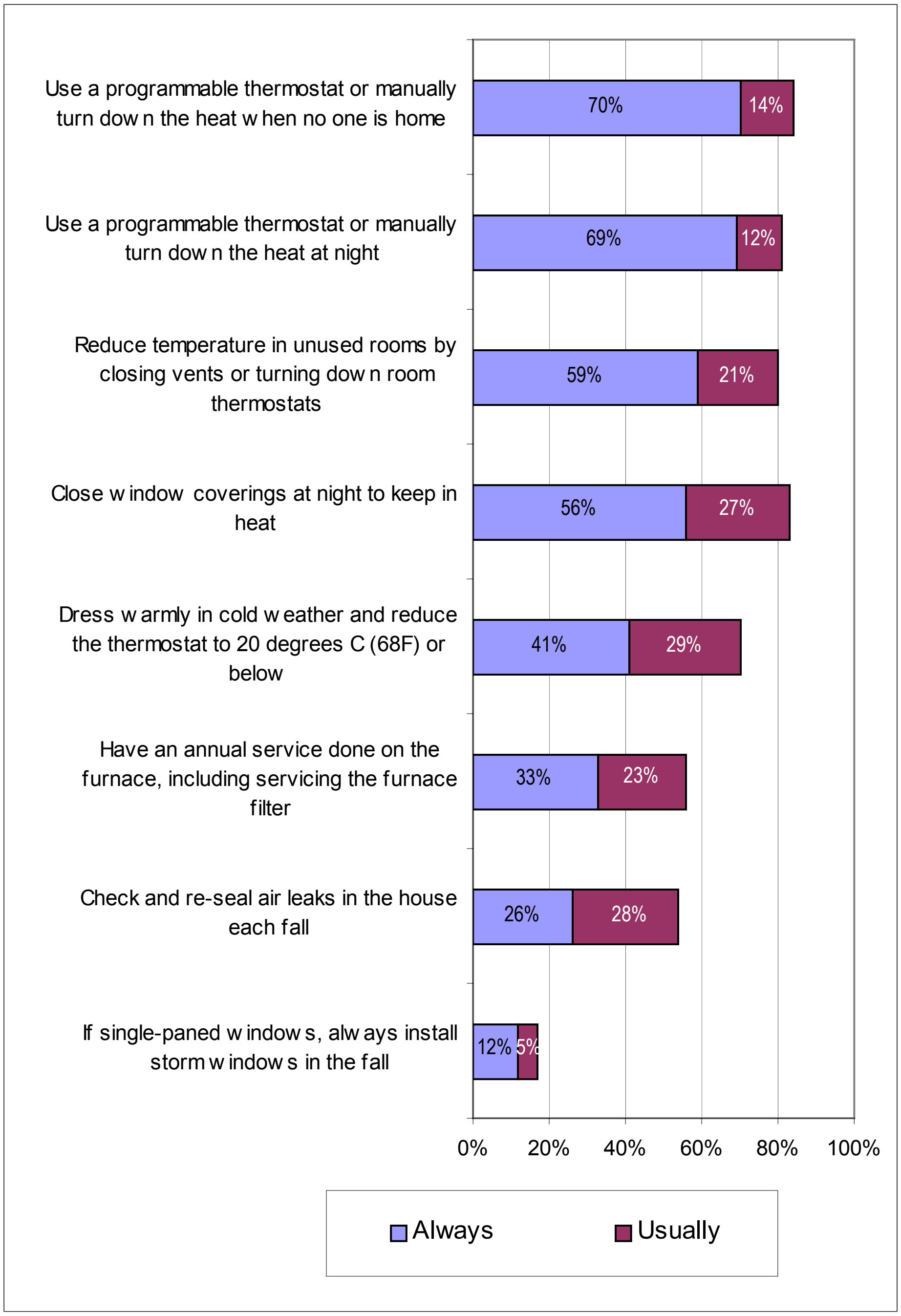
44d. Attitudes towards Environmentally friendly products, causes, and recycling



The majority (96%) recycle newspaper, metals, plastics or glass regularly. Seventy-one percent buy products that are environmentally friendly on a regular basis.

J. Managing Electricity

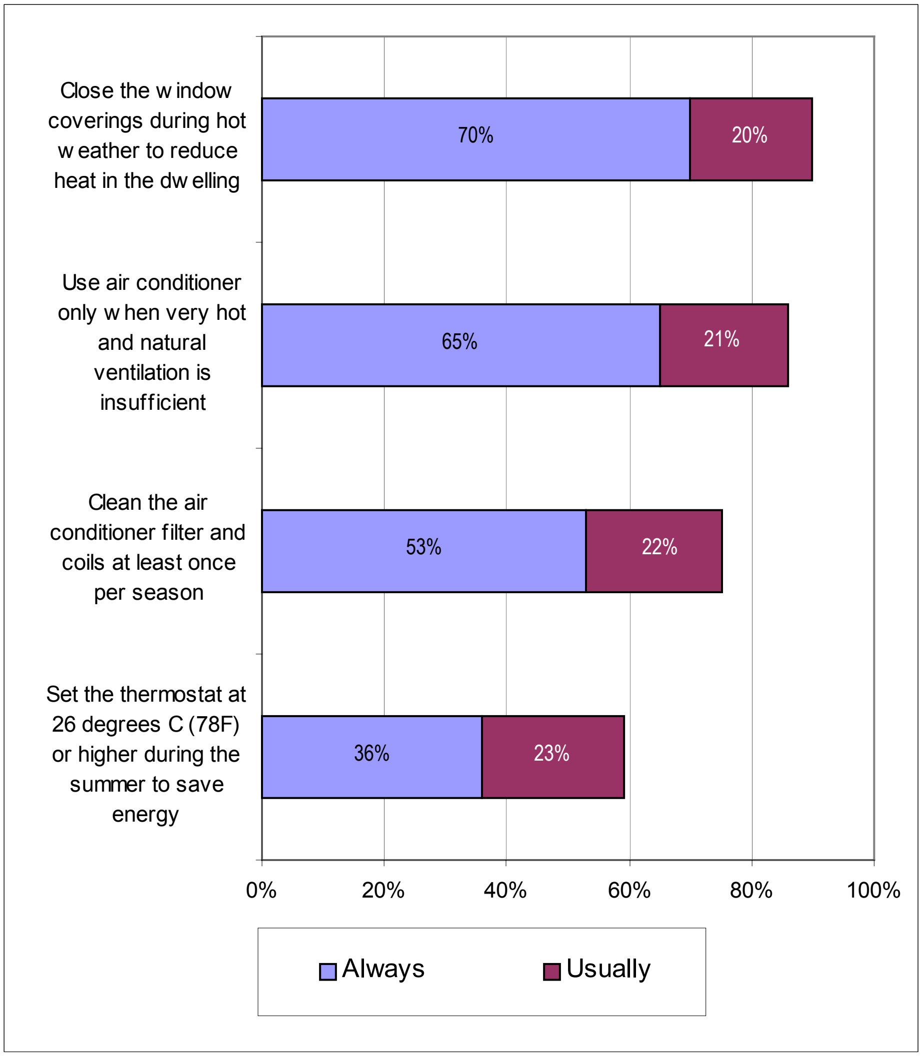
45. Space Heating Habits and Practices



Eighty-four percent turn down the thermostat when no one is home.

Eighty-one percent use a programmable thermostat or manually turn down the heat at night.

46. Space Cooling Habits and Practices



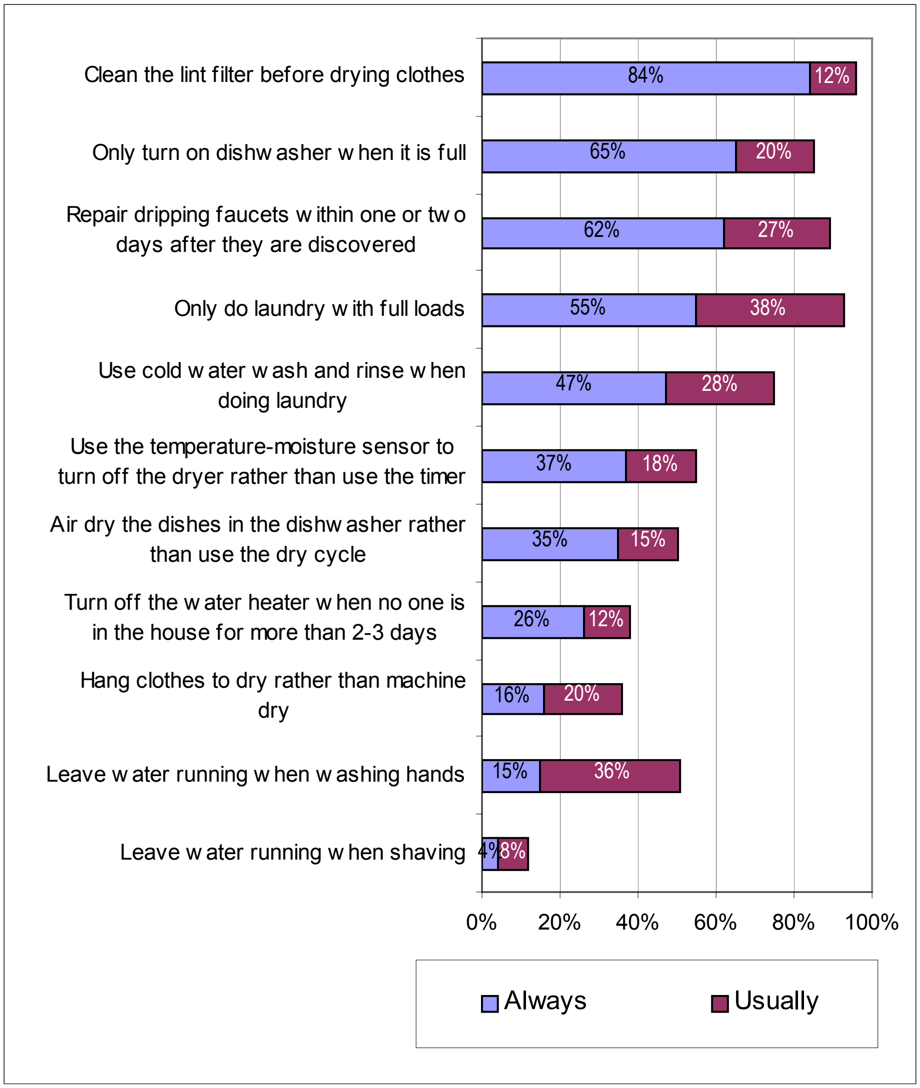
Ninety percent close the window coverings during hot weather to reduce heat in the dwelling.

Fifty-nine percent set the thermostat at 26 degrees C or higher during the summer to save energy.

Planting Vegetation or Installing shade devices to keep home cool:

Fifty percent have planted trees or other vegetation to keep their home cool. Forty-one percent have installed shading devices (i.e. awnings, pergolas) to keep their home cool.

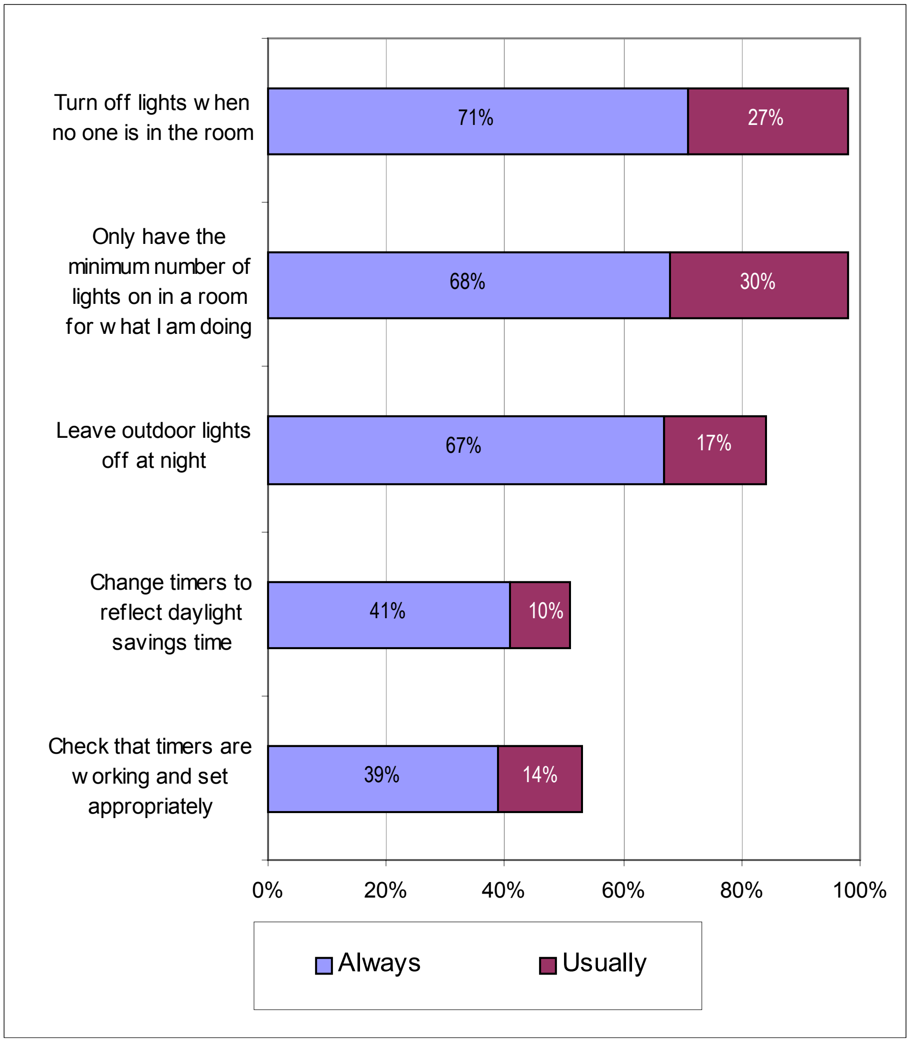
47. Water Usage / Laundry Habits and Practices



Ninety-six percent always (84%) or usually (12%) clean the lint filter before drying clothes.

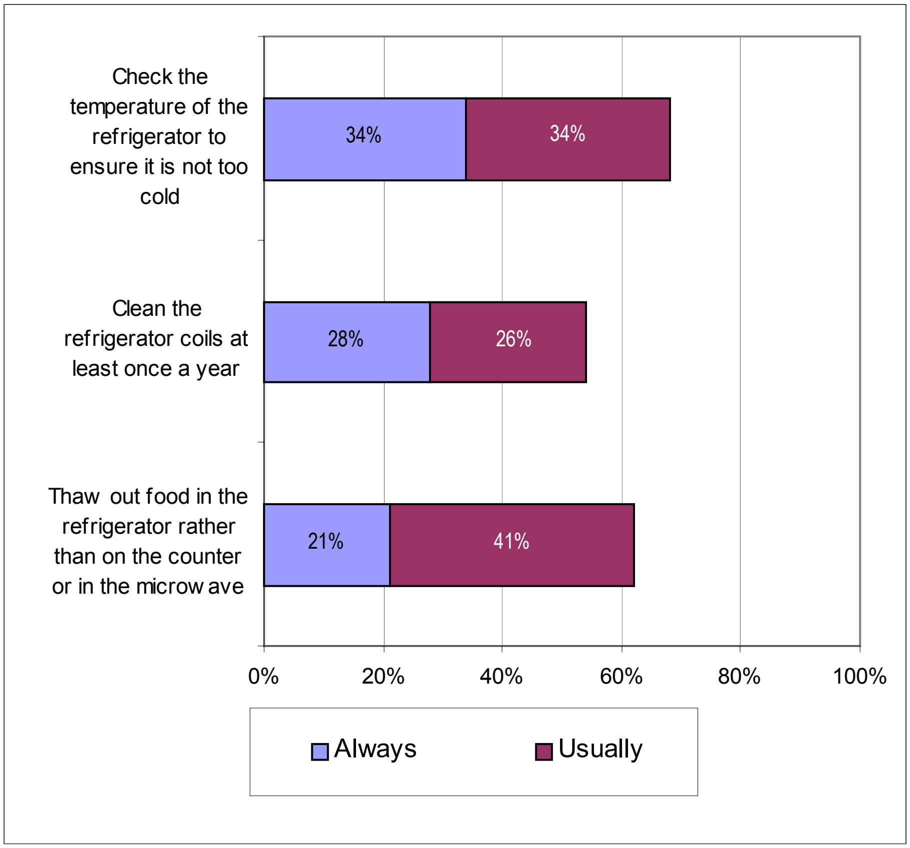
Ninety-three percent always (55%) or usually (38%) do laundry with full loads.

48. *Lighting Habits and Practices*



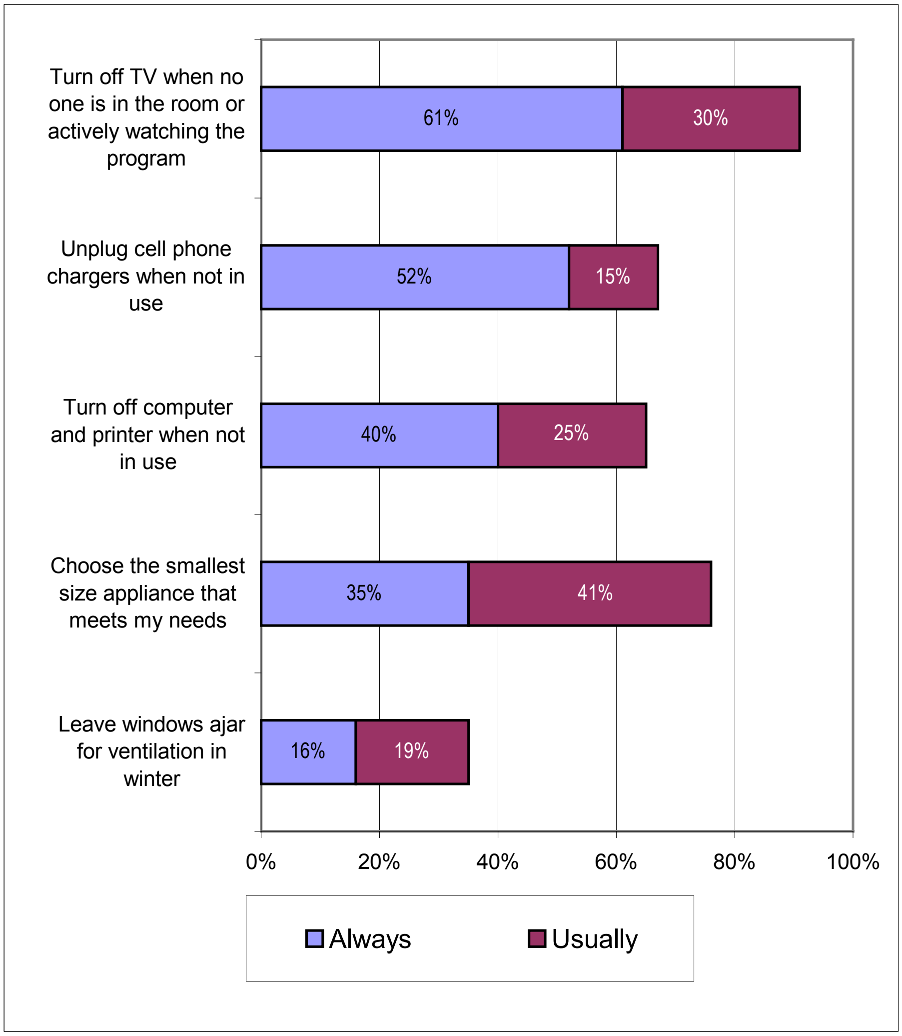
Ninety-eight percent always (71%) or usually (27%) turn off lights when no one is around.

49. Refrigeration Habits and Practices



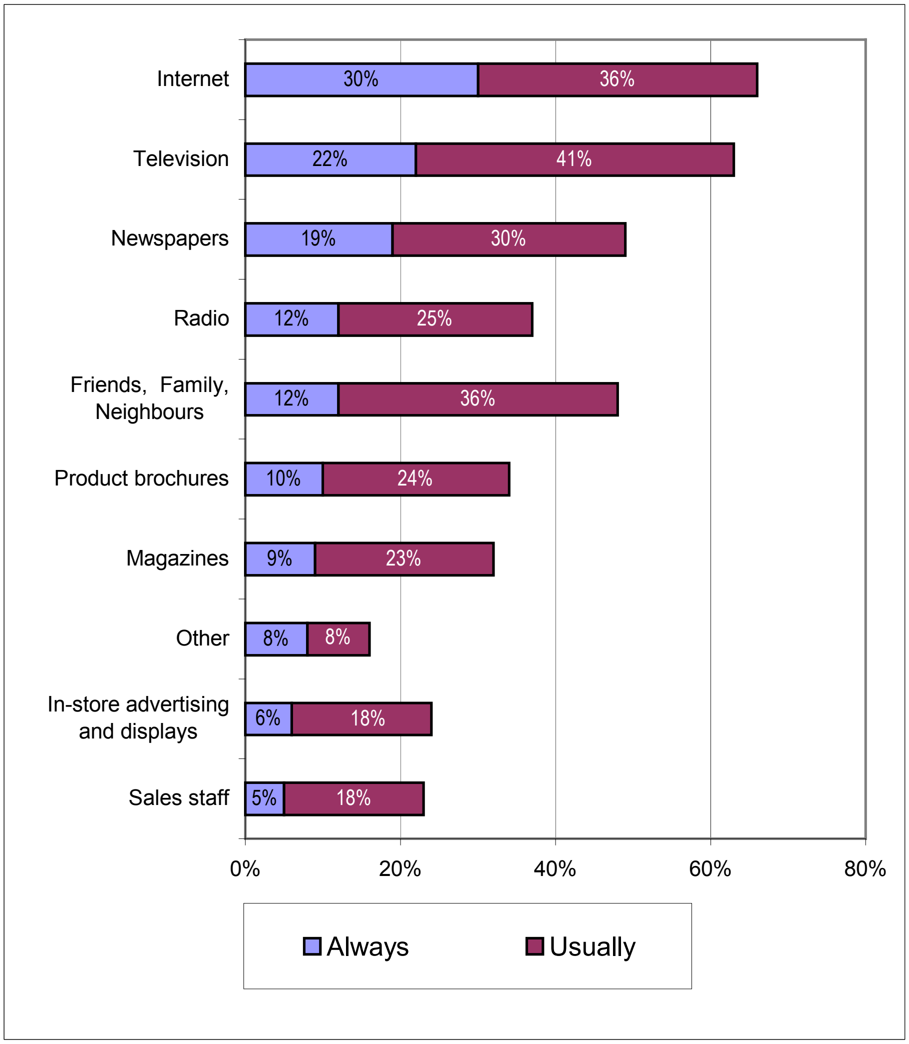
Sixty-four percent always (34%) or usually (34%) check the temperature of the refrigerator to make sure it is not too cold.

50. Other Habits and Practices



Ninety-one percent always (61%) or usually (30%) turn off the TV when no one is in the room or actively watching the program.

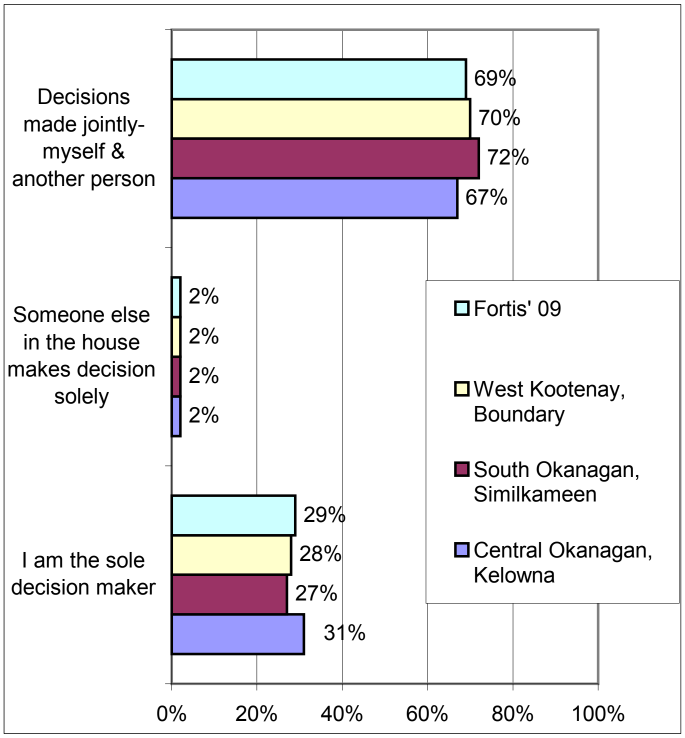
51. Information Sources



Respondents were asked where they obtain information regarding new products and services. Sixty-six percent always (30%) or usually (36%) get information from the Internet and 63% get information from TV.

K. About your Household

52a. Thinking about major appliance purchase decisions in your household, what is your role in the decision making processes?



When making major appliance purchase decisions, 69% make decisions with another person's input.

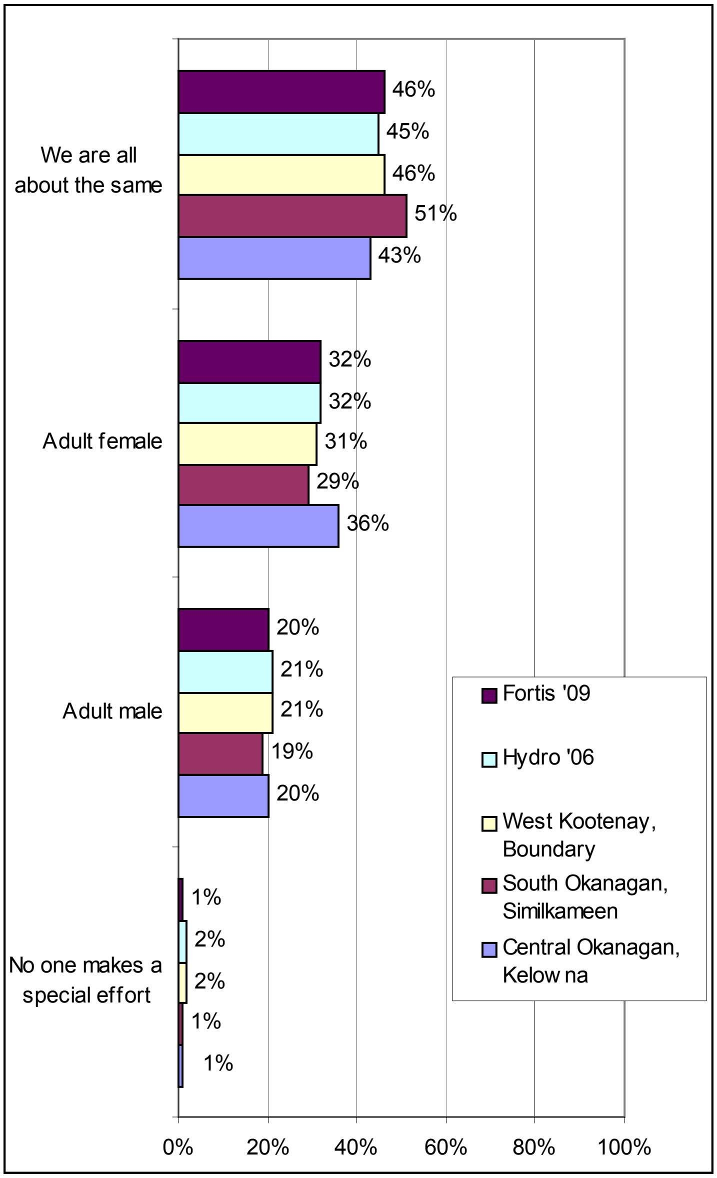
		Type of dwelling			
		Single detached	Duplex, Row, Townhouse	Apartment, Condo	Mobile, Other
"Thinking about major appliance purchase decisions in your household, please indicate your role in the decision making process"	"I am the sole decision maker"	21%	41%	47%	44%
	"Someone else in the house makes decision solely"	2%	2%	3%	5%
	"Decisions made jointly- myself & another person"	77%	57%	50%	51%
Total	Base	1322	204	240	155

Seventy-seven percent of respondents living in Single detached households will make decisions jointly when making major appliance purchases.

			Region		
		Total	Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
Gender of decision maker for major appliance purchases	Female	21%	24%	19%	19%
	Male	10%	9%	10%	11%
	Jointly - Female and someone else in home	33%	32%	34%	32%
	Jointly - Male and someone else in home	37%	35%	37%	38%
Total	Base	1976	781	576	610

Females are the sole decision maker for major appliance purchase in 21% of homes and males are the sole decision maker in 10% of homes. The majority of appliance purchase decisions are made jointly between 2 or more people in the household.

52b. Thinking about making efforts to conserve electricity in your household, please indicate your role in the decision making process:



In 46% of households, all members conserve energy about the same amount.

Adult Females are slightly more likely (32%) to conserve electricity than Male adults (20%).

53. Your age is:

		Total	Region		
			Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
"Age"	"18-24 yrs"	2%	3%	1%	1%
	"25-34 yrs"	7%	11%	3%	7%
	"35-44 yrs"	11%	13%	6%	13%
	"45-54 yrs"	19%	18%	16%	23%
	"55-64 yrs"	27%	24%	32%	27%
	"65+ yrs"	34%	31%	42%	29%
Total	Base	2015	795	587	620

The majority of the respondents (61%) were 55 years or older.

54. Gender

		Total	Region		
			Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
"Gender"	"Female"	53%	56%	53%	51%
	"Male"	47%	44%	47%	49%
Total	Base	2006	796	581	614

The majority of the respondents (53%) were female.

55. Education

		Total	Region		
			Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
"Education"	"Less than Grade 12"	9%	7%	11%	10%
	"High school diploma"	16%	14%	20%	15%
	"Some college, vocational or technical school"	21%	22%	19%	21%
	"College, vocational or technical school graduate"	22%	22%	19%	25%
	"Some university"	7%	7%	8%	6%
	"University, graduate degree"	24%	28%	20%	23%
	"Don't know, refused"	1%	1%	1%	1%
Total	Base	2009	795	586	617

Forty-six percent of respondents had a college (22%) or university (24%) degree.

56. Age of people living in household

		Total	Region		
			Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
Ages of people living in household on full time basis.	0-5 yrs	7%	9%	4%	8%
	6-12	8%	10%	4%	10%
	13-24	15%	17%	10%	16%
	25-64	67%	66%	62%	72%
	65+ yrs	38%	34%	48%	32%
Total	Base	1963	776	574	602

Column percentages may exceed 100% because multiple responses provided

The majority of households have people aged 25-64 years of age.

57. Main Language spoken in household.

		Total	Region		
			Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
"What is the main language spoken in your household?"	"English"	98.0%	97.6%	97.8%	99.0%
	"German"	.7%	.7%	.9%	.3%
	"Other"	.6%	.7%	.4%	.6%
	"French"	.2%	.2%	.4%	
	"Chinese"	.1%	.2%	.2%	
	"Japanese"	.1%	.2%		
	"Dutch"	.1%	.2%		
	"Punjabi"	.1%		.4%	
Total	Base	2013	795	590	617

English is the main language spoken in 98% of households.

58. Total Household income before taxes

		Total	Region		
			Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
"Please indicate the combined total income before taxes for your household in the last year"	"Under $20k"	8%	7%	9%	9%
	"$20k to $40k"	25%	21%	27%	27%
	"$40k to $60k"	23%	21%	27%	21%
	"$60k to $80k"	18%	18%	16%	20%
	"$80k to $120k"	17%	20%	15%	15%
	"$120k or over"	9%	12%	7%	7%
Total	Base	1739	693	494	546

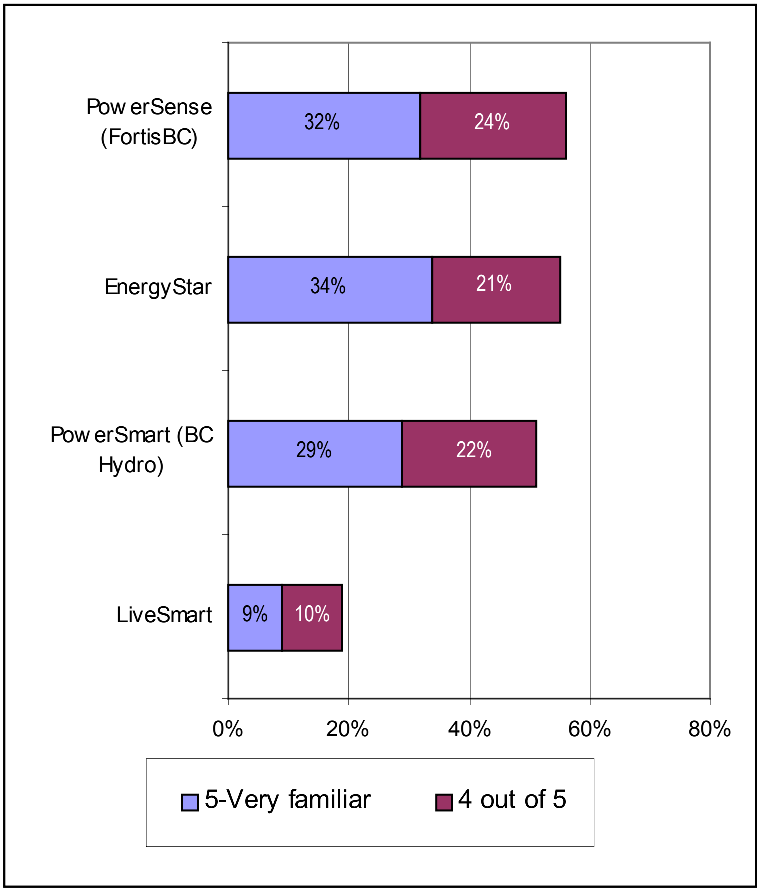
Household incomes are higher in the Central Okanagan than the other regions.

59. Is part of your home used as a full time or part time office?

		Total	Region		
			Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
"Do you or anyone in your household use part of your home as a full-time or part-time office from which they conduct a business?"	"No"	79%	78%	79%	81%
	"Yes, full-time business"	5%	5%	4%	4%
	"Yes, part-time business"	16%	16%	16%	15%
Total	Base	2004	795	581	618

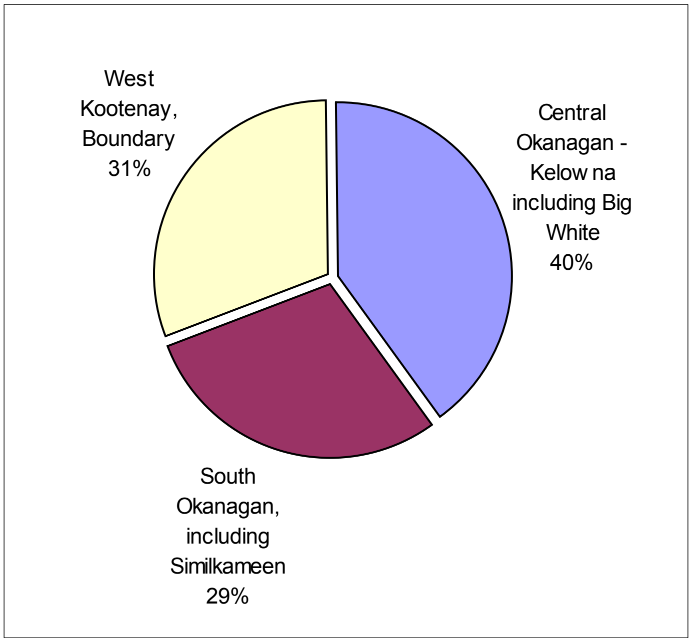
Twenty-one percent of homes are used as part of a business, 5% full time and 16% part time.

60. How familiar are you with the following trademarks?



Fifty-six percent are very (32%) or somewhat (24%) familiar with the PowerSense trademark. An equivalent percentage (55%) were familiar with the EnergyStar trademark.

61. Which region do you reside in?



Forty percent of the sample lived in the Central Okanagan; 31% in the West Kootenay/Boundary and 29% in the South Okanagan.

62. Are you a direct or indirect customer?

		Total	Region		
			Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
"FortisBC provides electricity to customers directly and indirectly through city wholesalers; Local wholesalers supply electricity to some areas of Kelowna, Penticton, Summerland, Grand Forks and Nelson; Are you a direct or indirect customer?"	No response	1%	0%	1%	1%
	"Direct FortisBC customer"	82%	88%	76%	82%
	"Indirect FortisBC customer"	11%	7%	18%	11%
	"Don't know"	5%	5%	5%	7%
Total	Base	2049	805	591	630

The majority of the sample (82%) were direct FortisBC customers. Eleven percent of the sample were indirect customers and 5% did not know.

		Total
"Which wholesaler provides your electric service?"	"City of Penticton"	37%
	"City of Kelowna"	26%
	"Nelson Hydro"	25%
	"District of Summerland"	8%
	"City of Grand Forks"	4%
Total	Base	230

Base: Indirect customers only

Among the 230 indirect customers, 37% were City of Penticton customers, 26% were City of Kelowna customers; and 25% were Nelson Hydro customers.

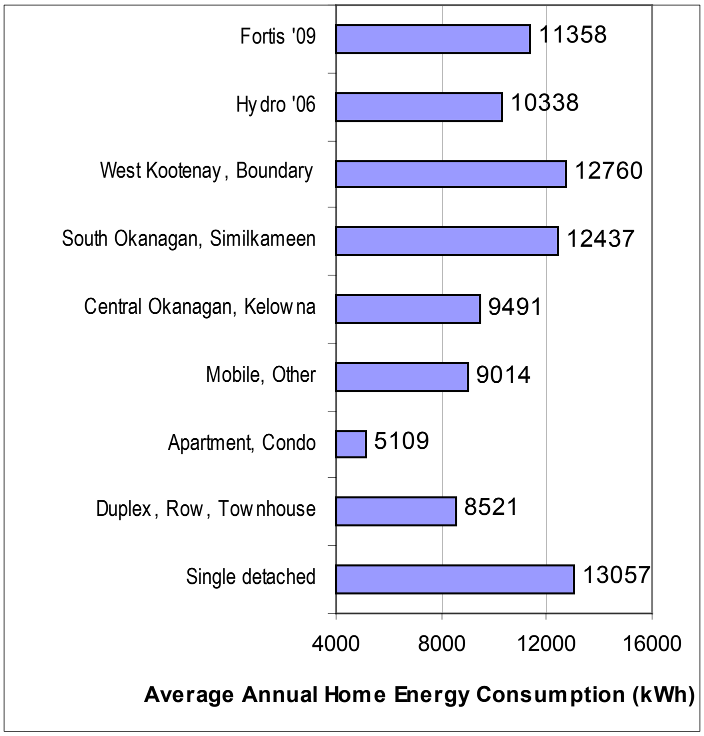
63. May we have your account number?

		Total
"FortisBC would like to access this information from your account history and link it to the responses you've given today, may we please have your permission for FortisBC to do this?"	No response	7%
	"Yes"	76%
	"No"	17%
Total	Base	2049

Seventy-six percent of respondents said it would be alright for FortisBC to use their account number. Sixty two percent actually provided an account number and 43% percent of the total sample (871 cases) provided a valid account number for which usage rates could be determined.

L. Home Energy Consumption

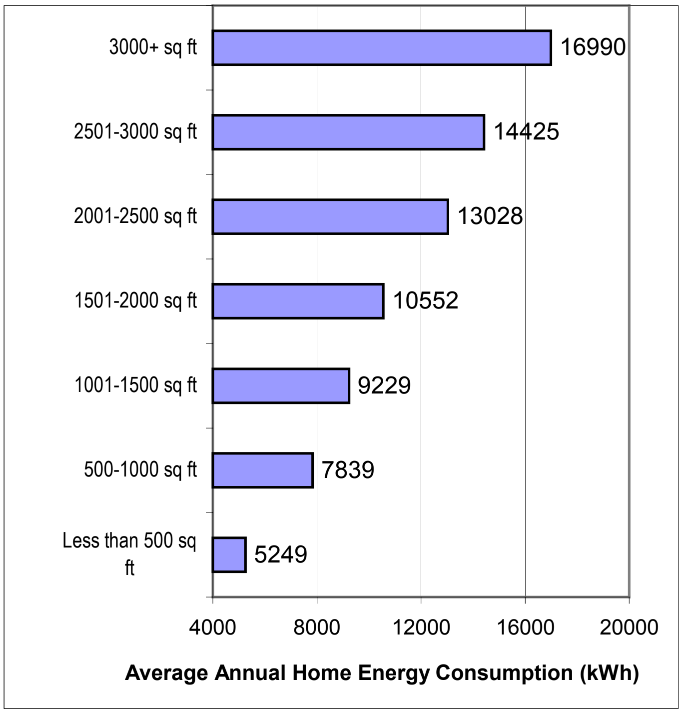
Energy consumption: Total, Region & Housing type



The average annual home energy consumption among FortisBC customers in the sample was 11358 kWh compared to Hydro customers at 10338 kWh. One possible explanation for this difference could be that the Hydro services areas in the Southern Interior with milder temperatures than Fortis.

Homes in West Kootenay/Boundary and the South Okanagan used more energy on average per year than homes in the Central Okanagan. This is most likely the result of a higher percentage of apartments and condos in the Central Okanagan. Single detached homes use the most energy at 13057kWh and apartments or condos use the least at 5109kWh.

Energy consumption: By size of Home



The average annual home energy consumption among homes larger than 3000 square feet was 16990 kWh compared to 5249 kWh for homes less than 500 square feet.

Appendix B

COMMERCIAL END USE SURVEY

2009 Commercial End-Use Study

Prepared For: **FortisBC**

Prepared By: **Discovery Research**

Date: **August 2009**

Table of Contents:

1. Background and objectives

FortisBC is an integrated electric utility in British Columbia. FortisBC electric utility business serves about 157,000 customers in more than 30 communities in south central BC. The customers are in two major categories:

Direct - FortisBC delivers power directly to 110,000 customers.
Indirect - FortisBC delivers power indirectly through municipal wholesaler utilities to 48,000 customers .

Research was undertaken to help FortisBC understand how commercial customers use energy in their businesses for the purposes of forecasting future electrical demand and also to design Demand Side Management and Marketing and Communications programs. Discovery Research was contracted by FortisBC to complete the study. The specific objectives of this study is to collect information about customers businesses, but most importantly, the characteristics and features of the buildings they occupy, as well as the different ways in which electricity and other fuels are used in the buildings. Area of interest include, but are not limited to:

- Business characteristics in the building such as ownership, primary business activities, etc.;
- Building characteristics and the features such as primary building type, age of building, size of building, floors, exterior wall construction, windows, number of occupants, etc.;
- Operating schedule;
- Space heating;
- Space cooling;
- Air distribution system;
- Indoor lighting;
- Outdoor lighting;
- Building Automation systems;
- Service Water Heating Equipment;
- Refrigeration Equipment;
- Cooking Equipment;
- Office and other Commercial Equipment;
- Process Equipment.

In addition to collecting the end-use information, the study also set out to solicit customer opinions, attitudes and behaviors related to electricity and conservation. This information will be beneficial for segmenting the commercial building/customer base as well as for further informing program development and communications strategies.

2. Methodology

Given the amount and detail of the information to be collected, the methodology utilized for this research was a self-administered mail survey coupled with an equivalent online version of the survey.

Mailed Survey:

On July 2, 2009 a total of 4000 surveys were mailed to a random sample of FortisBC customers. The total sample of 4000 consisted of 3000 Direct FortisBC customers and 1000 Indirect customers serviced through city wholesalers. The 3000 Direct customers were randomly selected from the entire FortisBC direct commercial customer base. The 1000 Indirect customers were randomly selected from the regions serviced by City wholesalers according to the below distribution:

Municipal Wholesaler	Total Customers	Ratio	Indirect sample
Kelowna	13770	29%	288
Penticton	16613	35%	347
Grand Forks	2105	4%	44
Summerland	5436	11%	114
Nelson Hydro	9885	21%	207
	47,809	100%	1000

Each potential respondent was mailed a survey package which included a survey with cover letter and a postage paid return envelope. Respondents were offered two ways to participate in this study:

- Complete the survey and return it in the postage paid envelope via regular mail
- Complete the survey on the Internet and submit it electronically

As an incentive for completion, respondents were entered into a draw for one of three $500 gift certificates to a home improvement retailer of their choice. Respondents were offered an additional entry into the prize draw as an added incentive to complete the survey on-line.

Emailed Survey:

On July 27, 4000 Direct FortisBC customers were randomly chosen from the database of customers that FortisBC has email addresses for. These 4000 email addresses were a mixture of residential and commercial customers who have chosen to receive their monthly bills via email. The customers were sent an email inviting them to participate in the survey and the email included a link to the online residential or commercial surveys.

Prior to emailing the survey invitations, it was not possible to determine how many of the 4000 email addresses were residential customers and how many were commercial customers. Based on response rates of the respective surveys, we will assume that 3840 email addresses were residential email addresses and 160 were commercial email addresses.

Response Rate

Mailed Survey

Although 4000 surveys were mailed, 98 were returned to FortisBC as undeliverable – in most cases, likely due to closed accounts and other changes since the time the billing information was last updated. Of the 3902 surveys that were effectively delivered, a total of 367 were returned: 275 via Canada Post and 92 via the Online version; yielding a response rate of **9.4%** for the Mail survey methodology.

Emailed Survey:

Of the 160 email invitations sent out, 16 completed online surveys were received back, giving a response rate of **10.0%** for the Email survey methodology.

Total Response Rate:

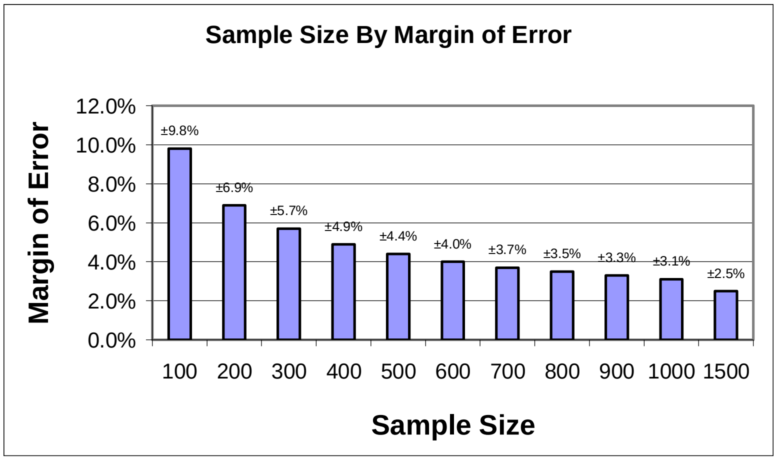
Of the 4062 Commercial Customers that were approached, 383 surveys were completed, giving a total response rate of **9.4%.**

Direct versus Indirect Commercial Customer Response Rate:

Of the 945 surveys that reached Indirect FortisBC commercial customers, 58 returned a completed survey, giving a response rate among Indirect customers of **6.1%**.

Of the 3117 surveys that reached Direct FortisBC commercial customers, 325 returned a completed survey, giving a response rate for Direct customers of **10.4%**.

Margin of error



This bar graph displays the margin of error associated with various sample sizes.

Statistics generated from sample size of 383 will be accurate within ±5.0%, at the 95% confidence interval (19 times out of 20).

Weighting the Data

The sample was weighted by region to ensure the collected sample matched the true composition of FortisBC's commercial customer base.

	Commercial Customer Population				**Unweighted Sample**		**Weighted Sample**	
	Direct	Indirect	Total	%	Total	%	Total	**%**
Central Okanagan (Kelowna) inlcud Big White	4102	1346	5448	**33.18%**	103	27.39%	125	**33.16%**
South Okanagan including Similakameen	4480	2011	6491	**39.53%**	110	29.26%	149	**39.52%**
West Kootenay/Boundary	2656	1824	4480	**27.29%**	163	43.35%	103	**27.32%**
Total	11238	5181	16419	**100.00%**	376	100.00%	377	**100.00%**

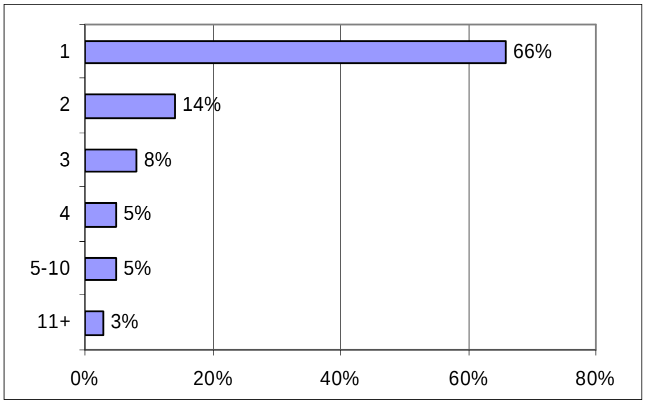
After applying the weights, the regional proportions in the weighted sample match the regional proportions in the Population of FortisBC Commercial Customers.

Comparison with BC Hydro 2006 Commercial End Use Survey (CEUS)

In 2006, BC Hydro completed a comprehensive mail survey (CEUS) with their commercial customers across BC. Throughout this report, comparisons are made with the response collected from 1946 BC Hydro commercial customers across BC. These BC Hydro customers will be referred to as "**Hydro '06**" in comparison graphs and tables. Please note that the Hydro survey results are collected from Hydro commercial customers across the entire province of BC and the Fortis results are from businesses in the Southern Interior of BC. Therefore interpret comparisons between these two surveys cautiously.

A. About the Building

1. How many buildings/structures are at this location?



The majority (66%) of locations have one building.

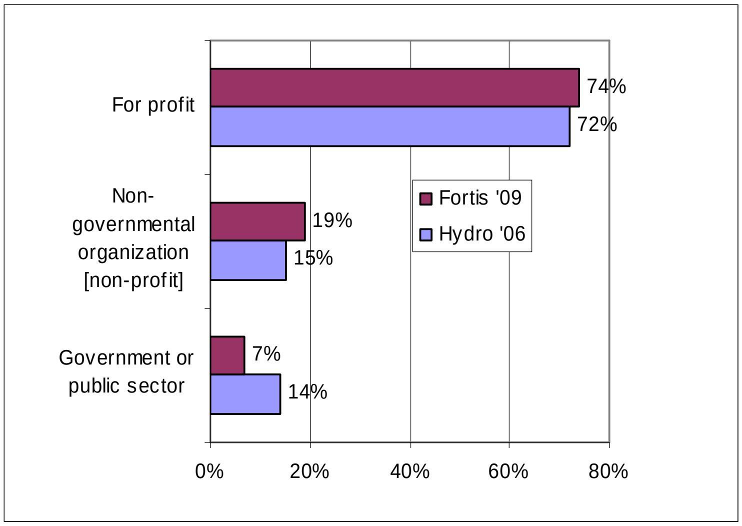
		Type of building					
		Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
"How many buildings, structures are at this location?"	"1"	56%	73%	61%	53%	72%	72%
	"2"	9%	11%	21%	24%	11%	11%
	"3"	8%	6%	7%	12%	5%	8%
	"4"	11%	2%	4%	10%		3%
	"5-10"	9%	5%	8%		5%	5%
	"11+"	8%	2%			7%	3%
Total	Base	43	80	67	48	38	91

Mixed use buildings and industrial/warehouse buildings are twice as likely to have two buildings at a location compared to other building types.

		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
"How many buildings, structures are at this location?"	"1"	71%	58%	71%
	"2"	13%	15%	15%
	"3"	3%	12%	5%
	"4"	4%	6%	4%
	"5-10"	6%	6%	2%
	"11+"	3%	3%	2%
Total	Base	121	146	101

Multiple buildings per location are found more frequently in the South Okanagan, Similkameen.

2. Which of the following best describes the ownership of the buildings/structures at this location?



The large majority of buildings are "for profit" enterprises (74%), whereas non-government/not for profit organizations own 19% of buildings and the government/public sector owns 7%.

2009 FortisBC commercial customers are less likely (7%) to be in buildings owned by the government/public sector than 2006 BC Hydro commercial customers (14%).

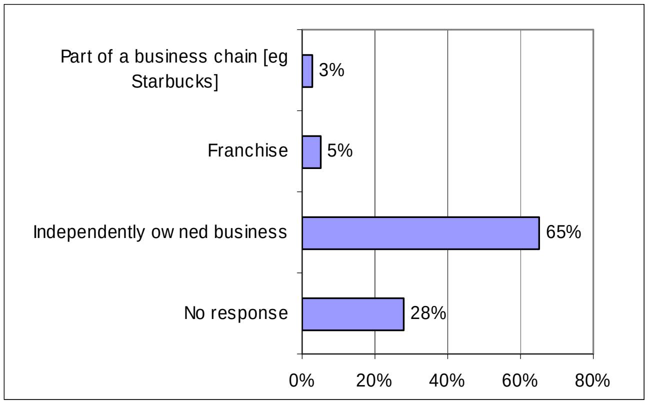
		Type of building					
		Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
"Which of the following best describes the ownership of the buildings, structures at this location?"	"Government or public sector"		8%	4%	5%	25%	3%
	"Non-governmental organization [non-profit]"	14%	57%	9%	6%	10%	7%
	"For profit"	86%	35%	88%	88%	65%	91%
Total	Base	42	81	67	48	38	91

As would be expected, the majority of buildings used for education/healthcare/public assembly purposes are either owned by government or non-government (non-profit) organizations (65%).

		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
"Which of the following best describes the ownership of the buildings, structures at this location?"	"Government or public sector"	7%	7%	6%
	"Non-governmental organization [non-profit]"	8%	22%	27%
	"For profit"	85%	71%	67%
Total	Base	121	145	101

There is higher "for profit" ownership in the Central Okanagan (85%) than in South Okanagan (71%) and West Kootenay/ Boundary (67%).

2b. Which of the following best describes the building owner?



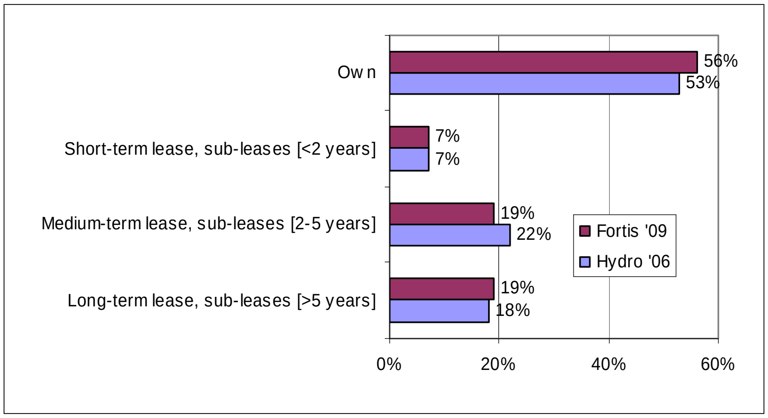
Two-thirds of buildings are owned by independent businesses.

		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
"Which of the following best describes the building owner?"	No response	17%	31%	34%
	"Independently owned business"	73%	61%	61%
	"Franchise"	4%	6%	3%
	"Part of a business chain [eg Starbucks]"	6%	2%	2%
Total	Base	125	149	103

Base: Respondents who's building is used for profit

Buildings in the Central Region are much more likely to be owned by businesses compared to the South Okanagan and West Kootenay/ Boundary.

3. Do the majority of businesses within the buildings/structures at this location own or lease the space they occupy?



Most buildings are owned (56%); however, 38% indicated their buildings are on medium to longer term leases.

Building ownership was very similar between the 2009 FortisBC sample and the 2006 BC Hydro sample.

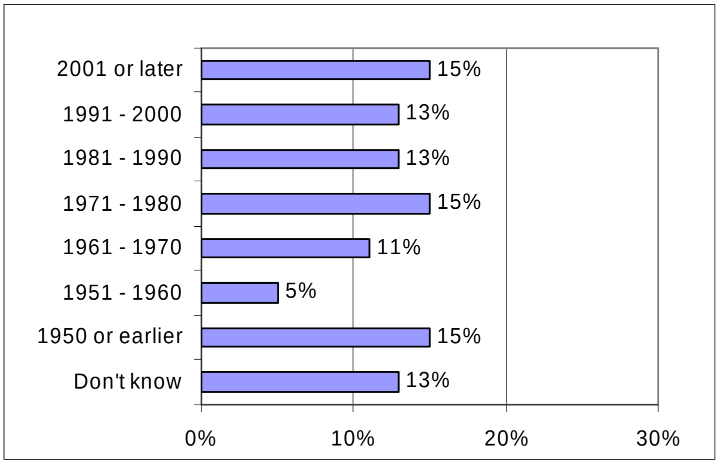
		Type of building					
		Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
"Do the majority of businesses within the buildings, structures at this location own or lease the space they occupy?"	"Own"	67%	64%	50%	68%	66%	39%
	"Short-term lease, sub-leases [<2 years]"	5%	5%	7%	9%	5%	8%
	"Medium-term lease, sub-leases [2-5 years]"	11%	14%	23%	11%	16%	27%
	"Long-term lease, sub-leases [>5 years]"	16%	17%	20%	11%	13%	25%
Total	Base	39	79	66	48	38	91

Retailers are less likely to own their premises than other business types (39%), followed by industrial warehousing facilities (50%). Over 65% of the other building types are owned.

		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
"Do the majority of businesses within the buildings, structures at this location own or lease the space they occupy?"	"Own"	35%	66%	67%
	"Short-term lease, sub-leases [<2 years]"	5%	8%	4%
	"Medium-term lease, sub-leases [2-5 years]"	30%	11%	16%
	"Long-term lease, sub-leases [>5 years]"	29%	14%	13%
Total	Base	120	143	96

Leasing is the predominant method in the Central Okanagan (65%) compared to the other two regions at 33%.

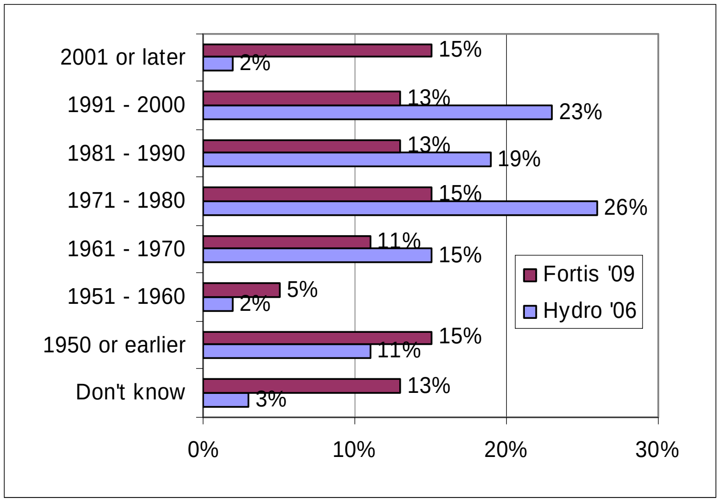
4. When was the building at this address built?



The majority of the buildings in the survey region (46%) were built before 1980.

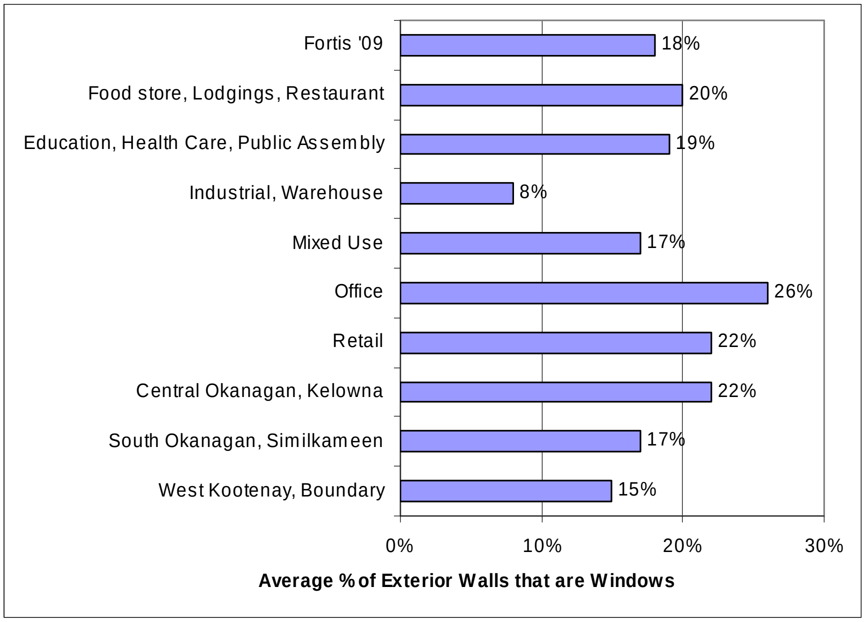
		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
“When was the building at this address built?”	“2001 or later“	19%	15%	11%
	“1991 – 2000”	14%	12%	11%
	“1981 – 1990”	15%	10%	13%
	“1971 – 1980”	19%	16%	10%
	“1961 – 1970”	7%	11%	15%
	“1951 – 1960”	2%	6%	6%
	“1950 or earlier”	2%	18%	27%
	“Don't know”	22%	10%	8%
Total	Base	117	142	99

The buildings in the Central Region are significantly younger than those in the other two regions with those in the West Kootenay/ Boundary being the oldest.



The Fortis ’09 and BC Hydro ’06 results differ significantly with the Fortis survey indicating an older building stock.

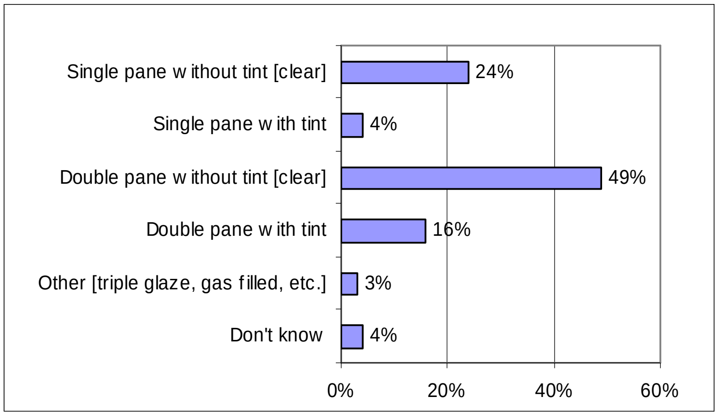
5. Approximately what percentage of the exterior walls of the building are windows?



Eighteen percent of the exterior walls of Fortis commercial customers are windows, with the smallest amount being found in the Industrial, Warehouse buildings (8%) and the highest in Offices (26%).

The newer buildings in the Central Okanagan have more window space than their older counterparts in both the South Okanagan or West Kootenay/ Boundary regions.

6. What is the main type of exterior window in the building?



Clear windows, whether double pane (49%) or single pane (24%), are most popular exterior window type.

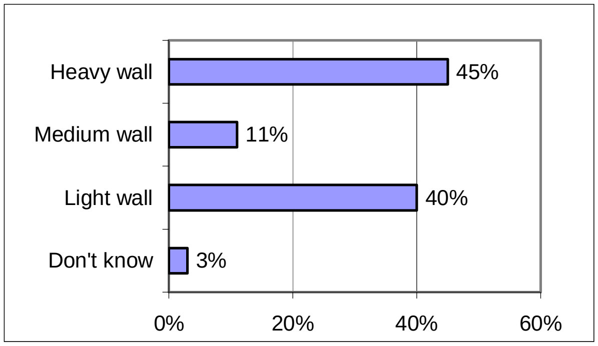
		Type of building					
		Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
“What is the main type of exterior window in the building?”	“Single pane without tint [clear]”	28%	19%	22%	21%	17%	31%
	“Single pane with tint”		7%	5%	5%	6%	3%
	“Double pane without tint [clear]”	53%	55%	53%	39%	56%	41%
	“Double pane with tint”	15%	20%	13%	18%	19%	13%
	“Other [triple glaze, gas filled, etc.]”	3%		2%	14%		2%
	“Don't know”	1%		5%	3%	2%	8%
Total	Base	42	77	53	46	38	89

The retail buildings are most likely to have single clear glass.

		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
“What is the main type of exterior window in the building?”	“Single pane without tint [clear]”	18%	28%	24%
	“Single pane with tint”	9%	2%	2%
	“Double pane without tint [clear]”	39%	53%	56%
	“Double pane with tint”	25%	13%	11%
	“Other [triple glaze, gas filled, etc.]”	2%	3%	5%
	“Don't know”	7%	1%	3%
Total	Base	116	134	96

The newer buildings in the Central Okanagan Region are most likely to have tinted double pane windows.

7. Which of the following best describes the exterior wall construction materials of the building?



Most wall construction material is either Heavy Wall (45%) or Light Wall (40%).

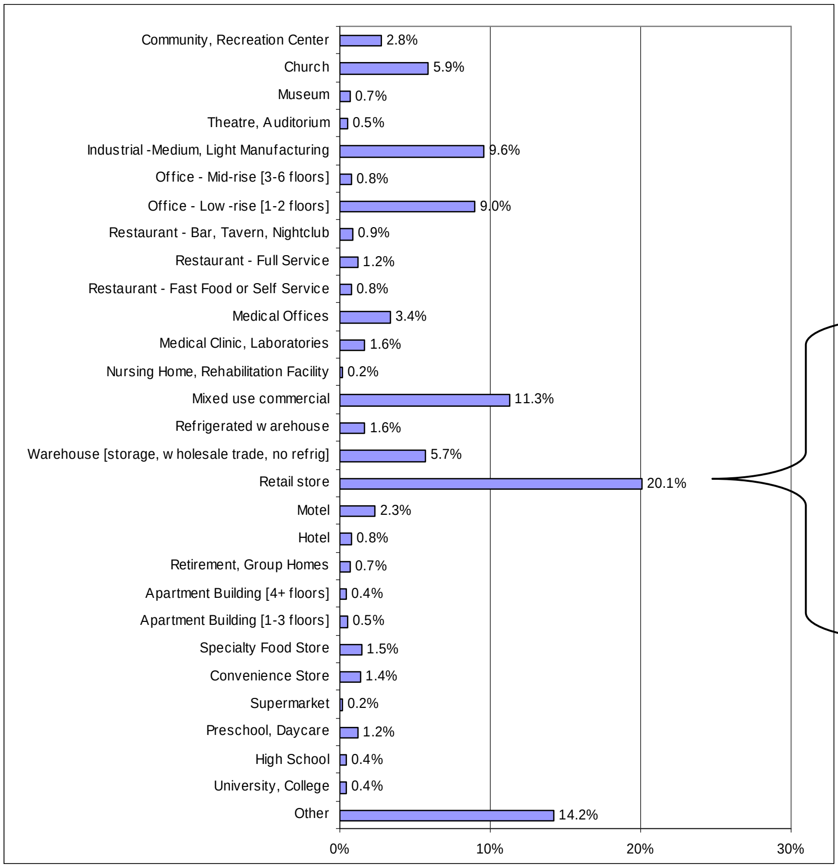
		Type of building					
		Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
"Which of the following best describes the exterior wall construction materials of the building?"	"Heavy wall [concrete block, concrete masonry]"	33%	44%	40%	30%	60%	61%
	"Medium wall [brick or stone veneer on a frame]"	15%	14%	6%	15%	13%	9%
	"Light wall [wood,shingle,aluminium panels,glass,steel]"	46%	39%	54%	55%	24%	25%
	"Don't know"	6%	3%			3%	4%
Total	Base	42	80	66	48	38	90

Heavy wall construction dominates the Office and Retail buildings whereas light wall construction is found more frequently in Industrial, Mixed Use and to a lower extent in Food Stores, Lodgings, and Restaurants.

		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
"Which of the following best describes the exterior wall construction materials of the building?"	"Heavy wall [concrete block, concrete masonry]"	62%	40%	35%
	"Medium wall [brick or stone veneer on a frame]"	14%	9%	12%
	"Light wall [wood,shingle,aluminium panels,glass,steel]"	21%	48%	51%
	"Don't know"	3%	3%	3%
Total	Base	121	143	101

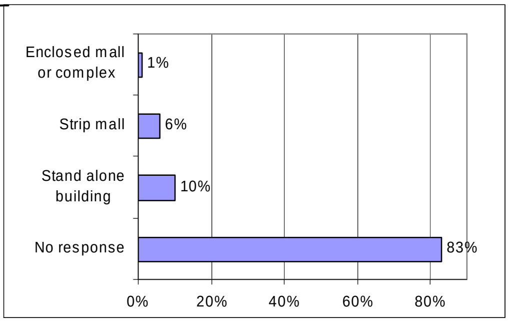
Heavy wall construction is most frequently found in the Central Okanagan (62%) followed by the Southern Region at 40% and the least used in West Kootenay (35%). Light wall construction shows the opposite pattern.

8. Primary type of business at this address.



The major uses for the buildings in the survey are: Retail - 20.1%; Mixed Use Commercial - 11.3%; Industrial Medium/Light Manufacturing - 9.6%; Offices - 9.0%

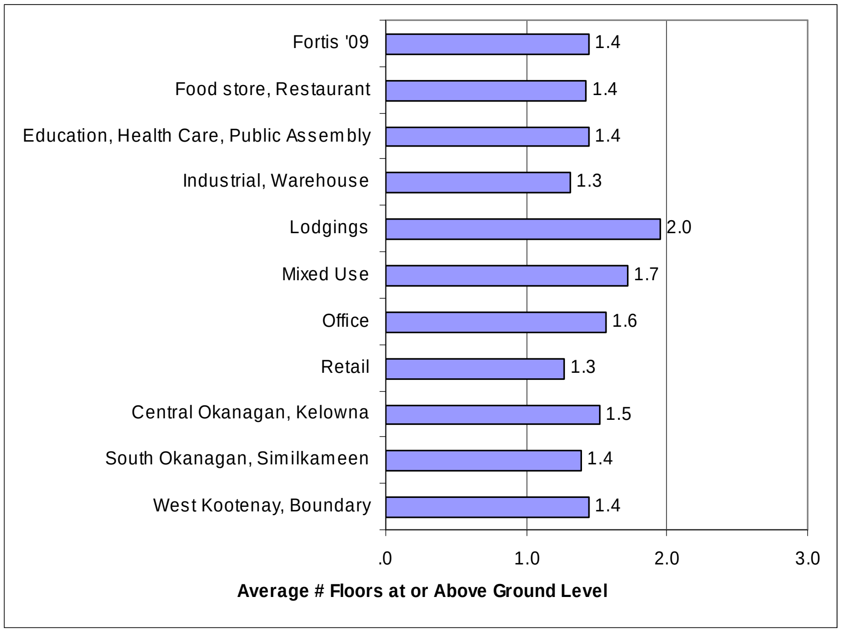
If Retail Store was selected:
Which of the following best describes the Building at this location?



Among the 14.2% that classified their business type as ‘other’, 10 respondents were auto repair/service businesses:

		Total
“Please check the one box that best describes the primary type of building at this address (other responses)”	Auto repair\service	10
	Power and\or water, club house	5
	Farm	4
	Government center\services	3
	Veterinary hospital	3
	Storage facility	2
	Caretaker residence	2
	GYM, fitness center	2
	Camp site, cabins	2
	Art gallery, paint studio	2
	Real estate - construction office	2
	Childrens summer camp	1
	Non-profit	1
	Home based sewing	1
	Flea market	1
	Heritage site	1
	Pump house	1
	Processing, dist. center, admin. For library system	1
	Funeral home and crematorium	1
	Truck crossing dock	1
	Hall for the Slocan Valley region and women's institute	1
	Picnic site kitchen, refreshment, bbq, storage	1
	Bowling center	1
	Welding shop	1
	Laundromat	1
	Airport hanger	1
Total	Base	53

9. How many floors (stories) does the building have at or above ground level?



Lodgings, Mixed Use buildings and Offices have the most above ground stories.

10a. How many floors (stories) does the building have below ground level?

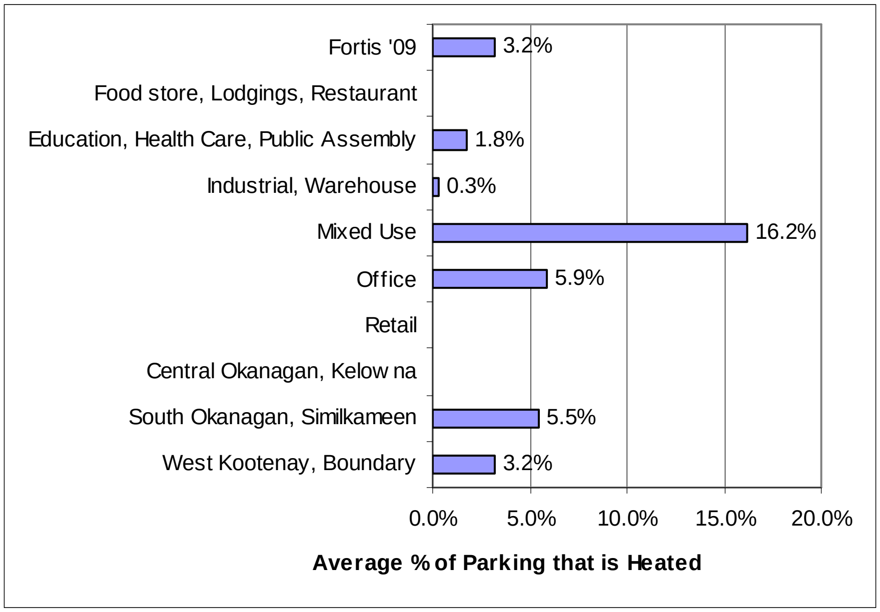
		Total	Type of building					
			Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
"How many floors (stories) does the building have below ground level (including parking levels)?"	"None"	77%	73%	68%	84%	75%	79%	80%
	"1"	23%	27%	30%	16%	24%	21%	20%
	"2"	0%		2%		1%		
Total	Base	369	43	79	66	46	38	93

Twenty-three percent of businesses have 1 floor below ground level.

		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
"How many floors (stories) does the building have below ground level (including parking levels)?"	"None"	86%	77%	63%
	"1"	13%	23%	36%
	"2"	1%		1%
Total	Base	121	143	99

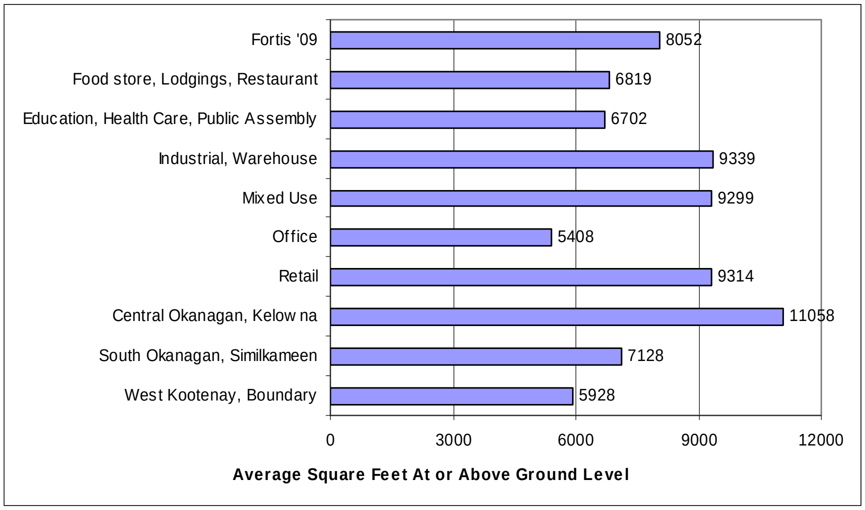
The Central Okanagan building stock is the least likely to have below ground floors (14%) compared to the Southern Region (23%) and West Kootenay/ Boundary (37%).

10b. What percentage of parking is heated?



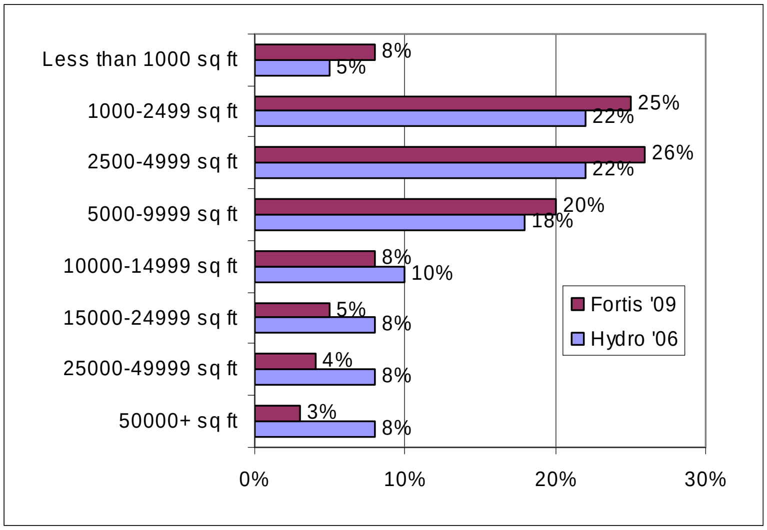
Mixed Use buildings are the most likely to have heated parking followed by Office buildings. All others are not likely to offer this amenity.

11. Please estimate the total (gross) square footage at or above ground level of the (largest) building at this location.



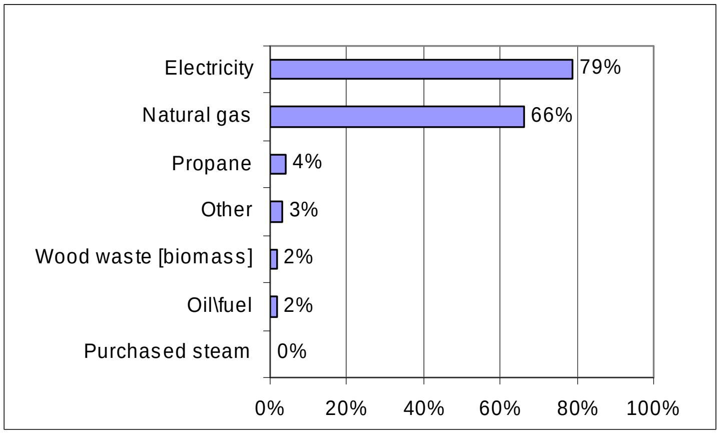
The total gross square footage of the largest building was 8052 square feet.
Mixed Use and Industrial Warehouse buildings were the largest and Offices the smallest.

Central Okanagan buildings are significantly larger than those in the two other regions.



The Fortis ’09 and BC Hydro ’06 results for building size have somewhat similar patterns, however the ’06 sample has 24% of the buildings at 15000 square feet or more compared to 12% of the 09’ sample.

12a. Which fuels provide energy for the building?



Electricity and natural gas in tandem provide the majority of energy for buildings in the sample.

		Type of building					
		Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
Which fuel provides enegy for the building?	Electricity	94%	71%	89%	81%	69%	74%
	Natural gas	38%	65%	62%	58%	79%	81%
	Propane	8%	3%	4%	3%	2%	3%
	Other	5%	3%	3%	4%		3%
	Wood waste [biomass]	3%		3%	7%		
	Oil\fuel		2%		1%		4%
	Purchased steam						1%
Total	Responses	59	113	100	70	49	142
	Base	40	79	62	46	33	86

Column percentages may exceed 100% because multiple responses provided

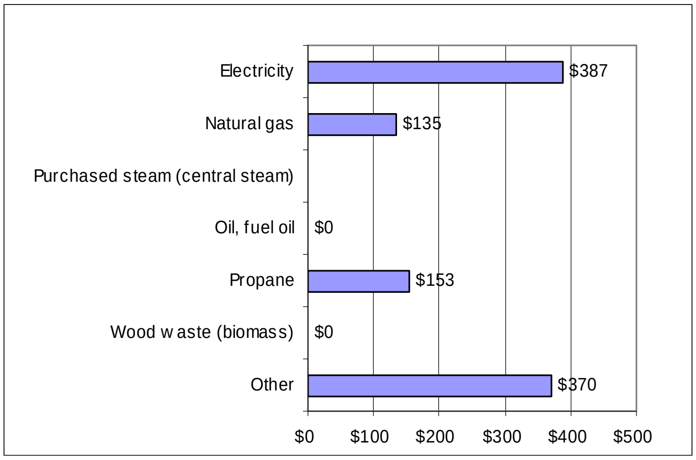
Food Stores and Restaurants are the most likely to use electricity whereas Offices and Retail rely on natural gas.

		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
Which fuel provides enegy for the building?	Electricity	82%	80%	76%
	Natural gas	82%	63%	49%
	Propane	2%	5%	4%
	Other	2%	2%	5%
	Wood waste [biomass]	3%	1%	1%
	Oil\fuel		1%	5%
	Purchased steam			1%
Total	Responses	193	211	130
	Base	113	139	92

Column percentages may exceed 100% because multiple responses provided

Natural gas has the lowest penetration in the West Kootenay (49%) and highest in the Central Okanagan (82%).

12b. Provide an estimate of the average monthly fuel bill - Summer



In summer, electricity expenditures are almost triple those spent on natural gas.

Summer: Average monthly bill

			Type of building					
		Total	Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
Electricity	Mean $	$387	$577	$250	$464	$199	$183	$498
	Base	169	23	29	38	23	16	39
Natural gas	Mean $	$135	$369	$137	$98	$107	$108	$117
	Base	140	11	28	21	18	16	44
Propane	Mean $	$153	$127	$400	$250	.	.	$0
	Base	7	2	1	1	0	0	3
Other	Mean $	$370	.	$400		$478	.	.
	Base	3	0	1	0	2	0	0

Base: Respondents who have this fuel type in building and provided estimate of monthly bill

Food store, Lodgings and Restaurants have the highest average summer bill for electricity at $577/month.

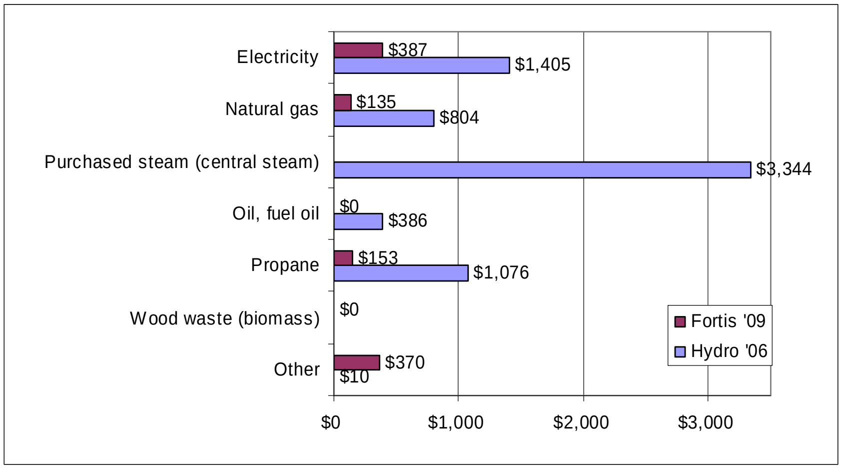
Summer: Average monthly bill

		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
Electricity	Mean $	$531	$334	$261
	Base	62	62	45
Natural gas	Mean $	$130	$94	$215
	Base	59	50	30
Propane	Mean $	.	$130	$400
	Base	0	7	1
Other	Mean $	.	$700	$133
	Base	0	1	2

Base: Respondents who have this fuel type in building and provided estimate of monthly bill

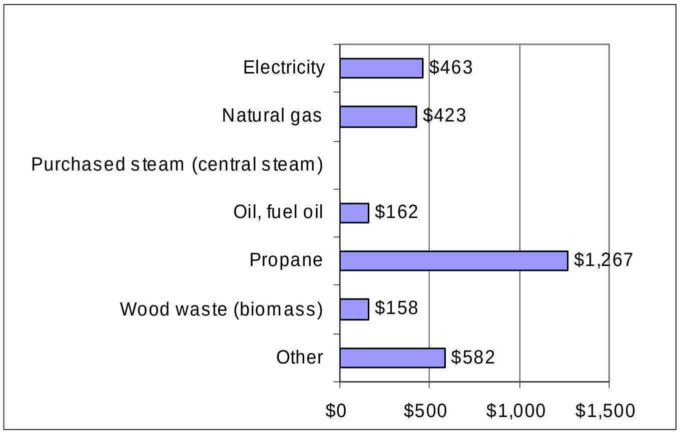
Commercial customers in the Central Region spend the most on electricity whereas West Kootenay/ Boundary customers spend the most on natural gas and propane.

Summer: Average Monthly Bill



Monthly fuel bill estimates in 2009 are significantly lower than for the 2006 Hydro survey.

12c. Provide an estimate of the average monthly fuel bill - Winter



Natural gas expenditures in the winter are almost the same as on electricity.

Winter: Average monthly bill

		Type of building					
		Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
Electricity	Mean $	$751	$358	$512	$294	$226	$532
	Base	21	27	35	23	15	40
Natural gas	Mean $	$800	$371	$303	$358	$321	$480
	Base	12	28	23	17	15	42
Purchased steam (central steam)	Mean $	.	.	.	.	.	.
	Base	0	0	0	0	0	0
Oil, fuel oil	Mean $	.	$93	.	.	.	$300
	Base	0	1	0	0	0	1
Propane	Mean $	$500	.	$2,100	$60	.	$1,310
	Base	1	0	1	1	0	3
Wood waste (biomass)	Mean $	$300	.	.	$0	.	.
	Base	1	0	0	1	0	0
Other	Mean $	.	.	$50	$750	.	.
	Base	0	0	1	2	0	0

Base: Respondents who have this fuel type in building and provided estimate of monthly bill

In winter, Food Stores and Restaurants spend the highest amounts on both electricity and natural gas of all building usage types.

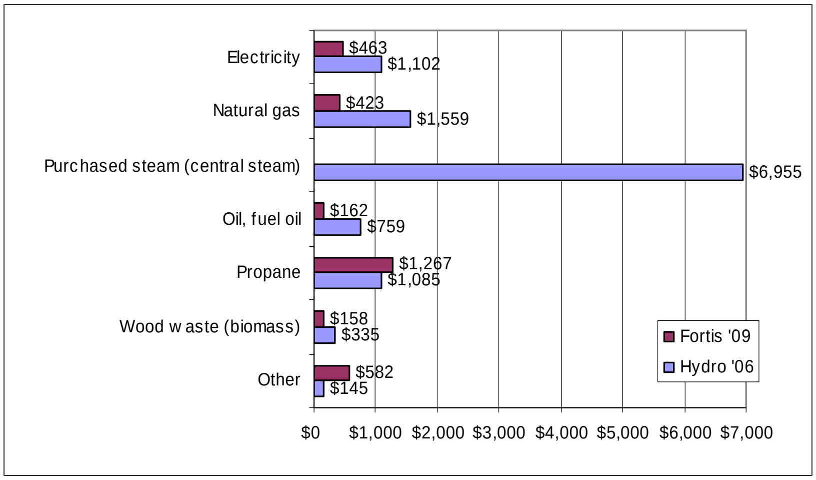
Winter: Average monthly bill

		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
Electricity	Mean $	$634	$387	$341
	Base	57	61	43
Natural gas	Mean $	$483	$359	$424
	Base	56	53	30
Purchased steam (central steam)	Mean $	.	.	.
	Base	0	0	0
Oil, fuel oil	Mean $	.	.	$162
	Base	0	0	2
Propane	Mean $	.	$1,573	$280
	Base	0	4	1
Wood waste (biomass)	Mean $	$0	$300	.
	Base	1	1	0
Other	Mean $	.	$1,100	$25
	Base	0	1	1

Base: Respondents who have this fuel type in building and provided estimate of monthly bill

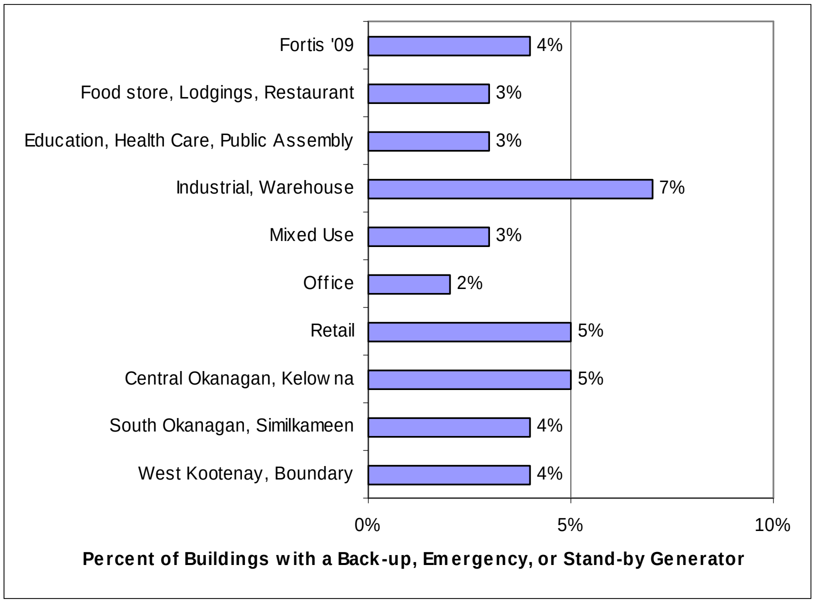
Central Okanagan business customers spend the highest amount on electricity in the winter but South Okanagan businesses spend high amounts on propane.

Winter: Average Monthly Bill



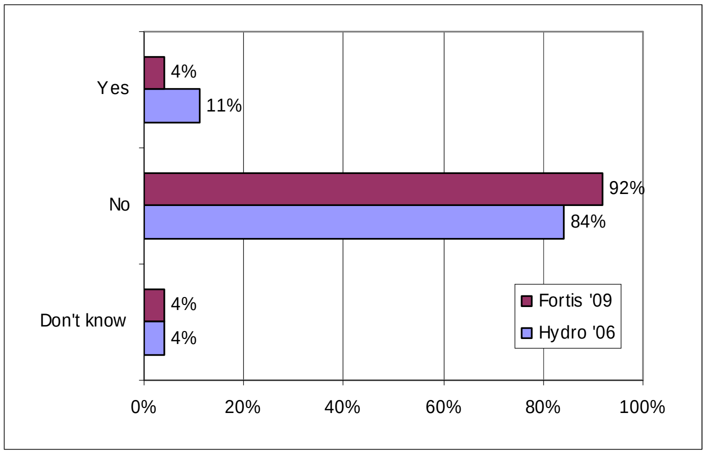
The Hydro ‘06 businesses had considerably higher winter bills for Electricity and Natural gas.

13. Does the building have a back-up, emergency, or stand-by generator?



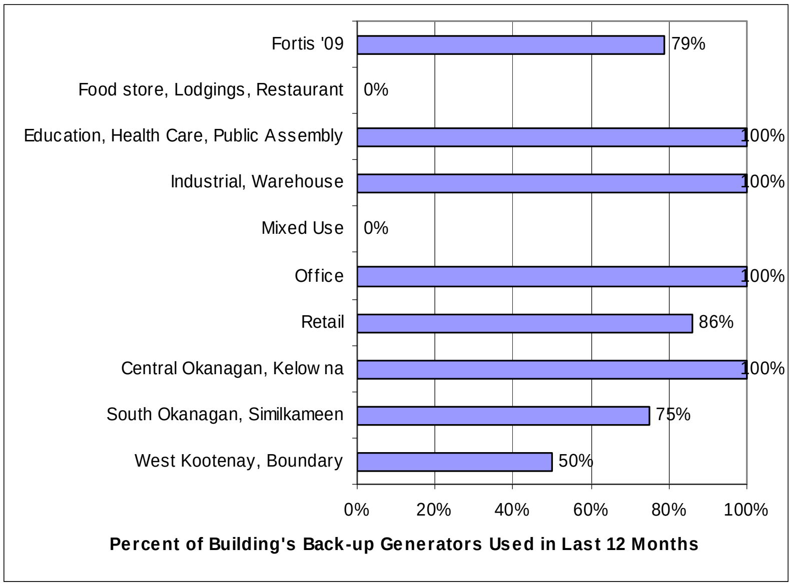
Only 4% of businesses have back-up generators for use in emergencies. The highest penetration being in the Industrial/Warehouse sector (7%).

Does the building have a back-up, emergency, or stand-by generator?

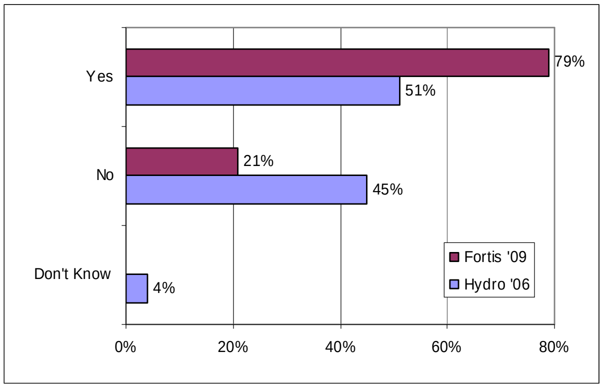


FortisBC commercial customers were less likely (4%) to have a back-up or stand by generator compared to Hydro customers (11%).

14a. Has the building’s back-up generator been used in the last 12 months?



Among businesses with back-up generators, 79% had used their back up generator in the past 12 months.

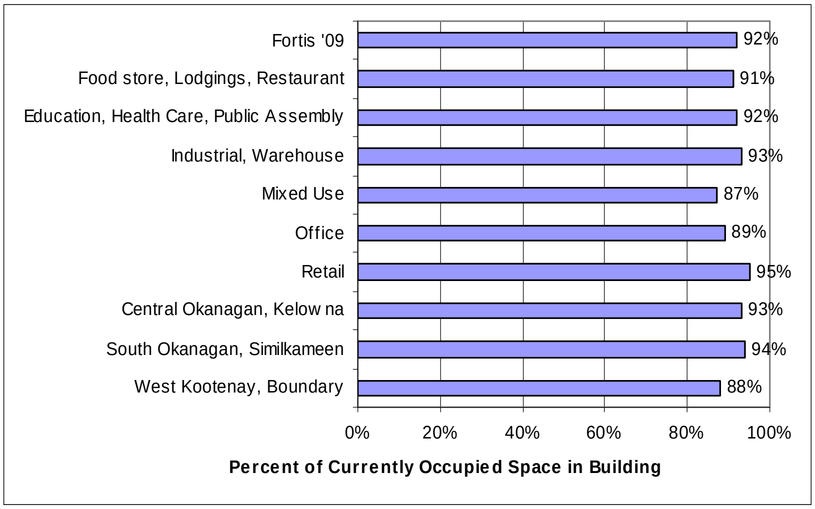


Seventy-nine percent indicated that their back-up generators had been used in the last 12 months compared to 51% in the BC Hydro 2006 survey.

14b. What is the capacity of the back-up generator?

Only 3 respondents were aware of the capacity of their back up generator. The average capacity for these 3 back up generators was 1141 kWh’s.

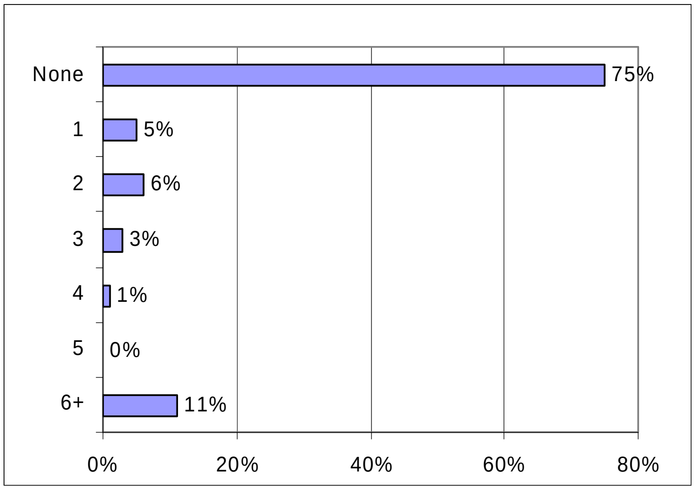
15. What percentage of the space in the building is currently occupied?



On average, 92% of space in the building is currently occupied.

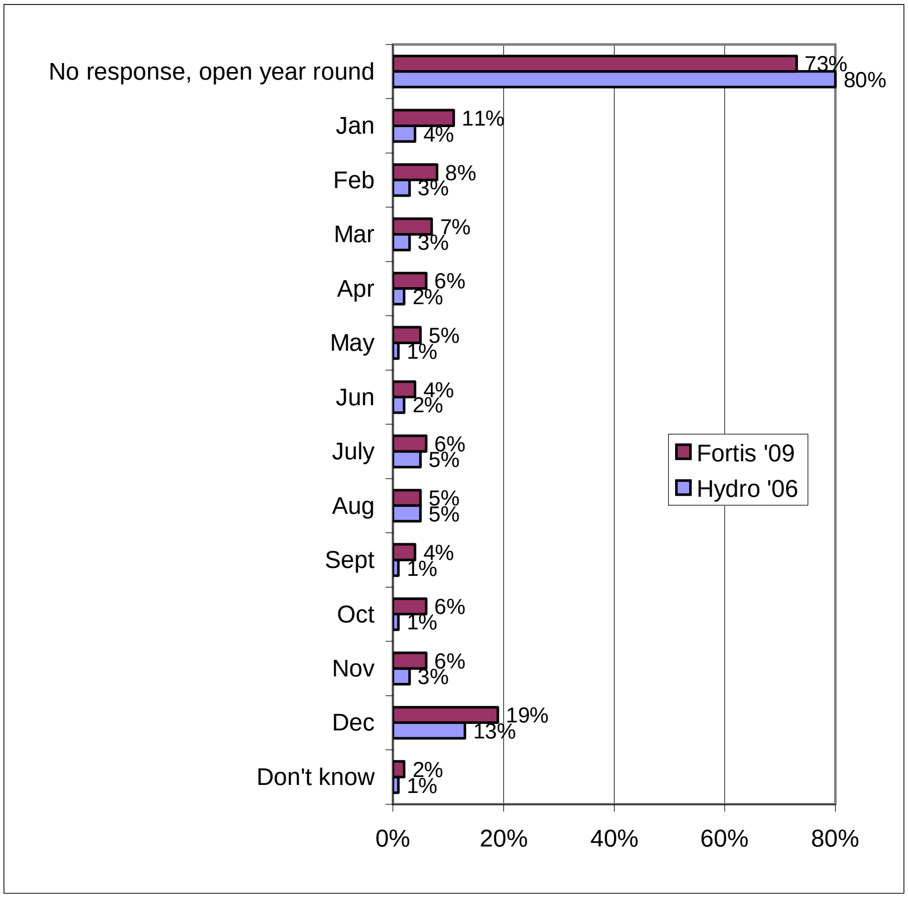
B. The Operating Schedule

16. How many weeks per year is the building closed?



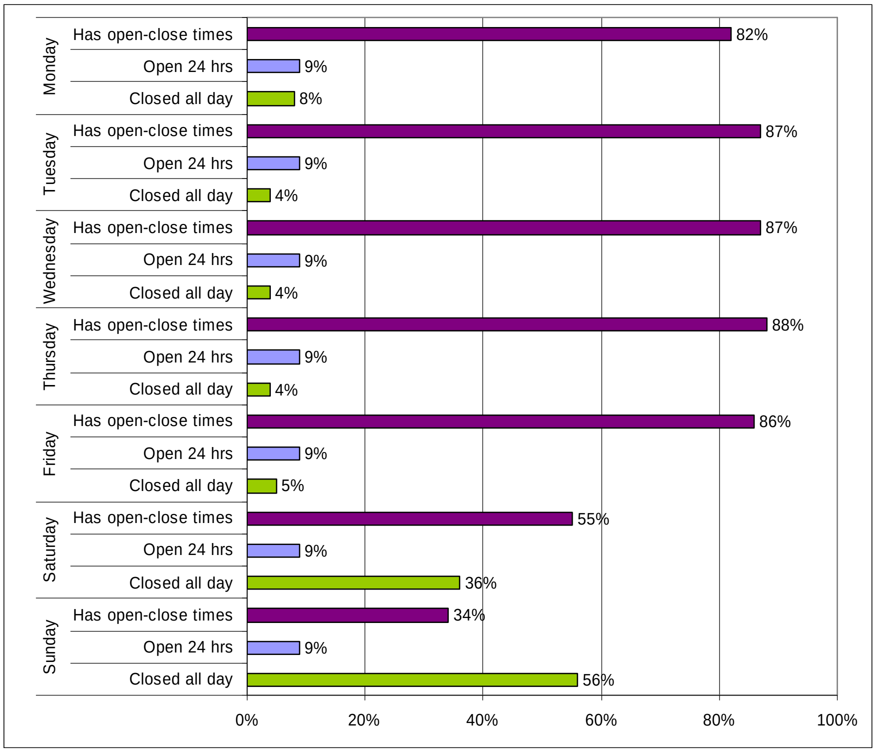
3/4 of the buildings reported in the survey do not close during the year. However, approximately 1/10 of buildings close for six weeks or more.

17. During which months is the building closed for a week or more?



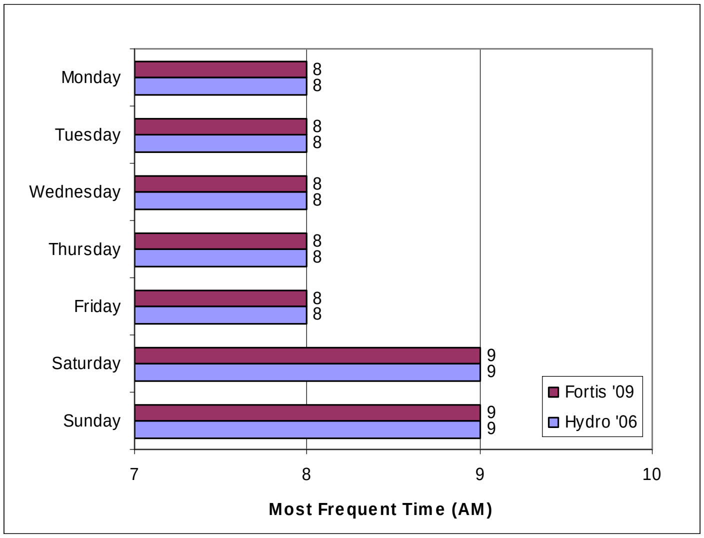
The winter months are the most likely for building closures.

18. Please identify the typical opening and closing times for the building at this location.



During weekdays over 80% of commercial buildings are open from 8am or 9am to 5pm. Nine percent of these buildings are open 24 hours. Sixty-four percent are open on Saturdays and 43% Sundays.

Opening Times



Most businesses open at 8am during the weekdays and 9am on the weekend.

Please identify typical OPENING times for the building at this location

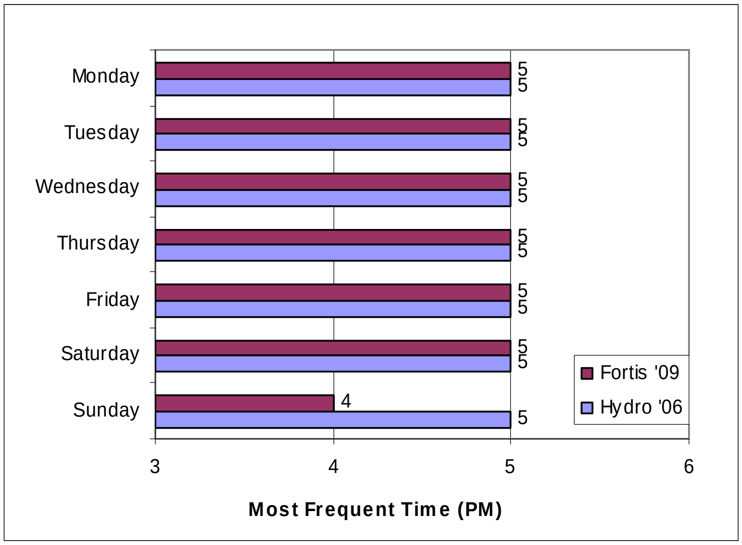
		Type of building					
		Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
Monday	Most frequent AM	8.00	8.00	7.00	8.00	8.00	9.00
	Base	25	55	53	32	36	82
Tuesday	Most frequent AM	8.00	8.00	7.00	9.00	8.00	9.00
	Base	26	65	54	32	36	85
Wednesday	Most frequent AM	8.00	8.00	7.00	9.00	8.00	9.00
	Base	26	63	53	34	36	86
Thursday	Most frequent AM	8.00	8.00	7.00	9.00	8.00	9.00
	Base	26	65	54	34	36	85
Friday	Most frequent AM	8.00	8.00	7.00	9.00	8.00	9.00
	Base	26	57	53	34	36	86
Saturday	Most frequent AM	9.00	9.00	8.00	9.00	9.00	9.00
	Base	24	32	19	21	13	70
Sunday	Most frequent AM	9.00	9.00	9.00	11.00	8.00	11.00
	Base	21	34	7	14	4	26

Base: Buildings with opening times on these days

On weekdays Industrial/ Warehouses open at 7am, Retail and Mixed Use at 9am, and all other buildings at 8am.

On weekends 9am is the norm for most buildings however 11am is the opening time for Mixed Use and Retailers.

Closing Time



Closing time is typically 5pm on most days except for Sunday when most common closing time is 4pm.

Please identify typical CLOSING times for the building at this location

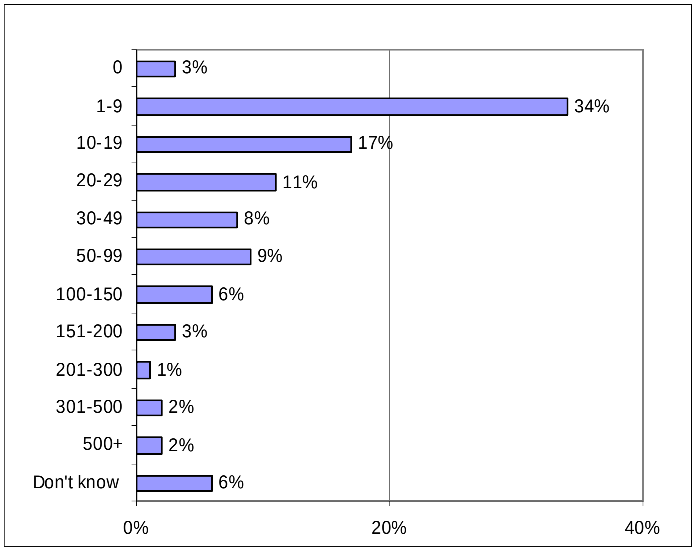
		Type of building					
		Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
Monday	Most frequent PM	9.00	5.00	5.00	5.00	5.00	5.00
	Base	25	55	53	31	36	80
Tuesday	Most frequent PM	9.00	5.00	5.00	5.00	5.00	5.00
	Base	26	65	54	30	36	85
Wednesday	Most frequent PM	9.00	5.00	5.00	5.00	5.00	5.00
	Base	26	63	53	32	36	86
Thursday	Most frequent PM	9.00	5.00	5.00	5.00	5.00	5.00
	Base	26	65	54	32	36	85
Friday	Most frequent PM	9.00	5.00	5.00	5.00	5.00	5.00
	Base	26	57	53	32	36	86
Saturday	Most frequent PM	9.00	4.00	5.00	5.00	4.00	5.00
	Base	24	32	19	21	13	70
Sunday	Most frequent PM	9.00	2.00	4.00	4.00	4.00	5.00
	Base	21	34	7	14	4	26

Base: Buildings with CLOSING times on these days

Food Stores / Lodging / Restaurants stay open until 9pm everyday.

Other buildings close at 5pm on weekdays and earlier on Sundays, except for Retail which closes at 5pm everyday.

19a. On a typical weekday, what is the average number of people present in the building during the day?

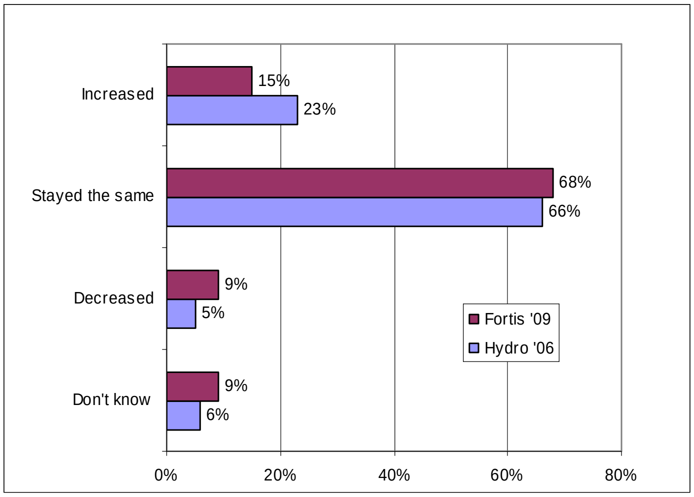


The majority (54%) of buildings have less than 20 people in the buildings at any one time. Fourteen percent have more than 100.

		Type of building					
		Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
“On a typical weekday, what is the average number of people (i.e. employees, customers, students, visitors, patients) present in the building during the day?”	“0”		5%	7%		2%	1%
	“1-9”	16%	22%	53%	51%	43%	26%
	“10-19”	21%	15%	19%	10%	13%	18%
	“20-29”	6%	20%	8%	7%	8%	13%
	“30-49”	8%	12%	6%		7%	12%
	“50-99”	16%	9%	3%	10%	6%	9%
	“100-150”	9%	5%		19%	10%	1%
	“151-200”	3%	8%			4%	2%
	“201-300”	4%					1%
	“301-500”	1%	2%			2%	3%
	“500+”	10%					2%
	“Don't know”	6%	2%	4%	4%	6%	10%
Total	Base	44	79	65	45	38	93

The largest number of people present at any one time occurs in the Food Store / Lodging / Restaurant sector.

19b. During the past 12 months, has the average number of occupants:



Eighty-three percent of respondents indicated that the number of occupants in their building had either remained the same or increased during the last 12 months.

		Type of building					
		Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
"During the past 12 months, has this average number of occupants"	"Increased"	6%	16%	13%	18%	18%	15%
	"Stayed the same"	62%	61%	79%	66%	62%	73%
	"Decreased"	9%	11%	8%	11%	13%	5%
	"Don't know"	23%	11%		6%	6%	8%
Total	Base	42	79	63	46	38	89

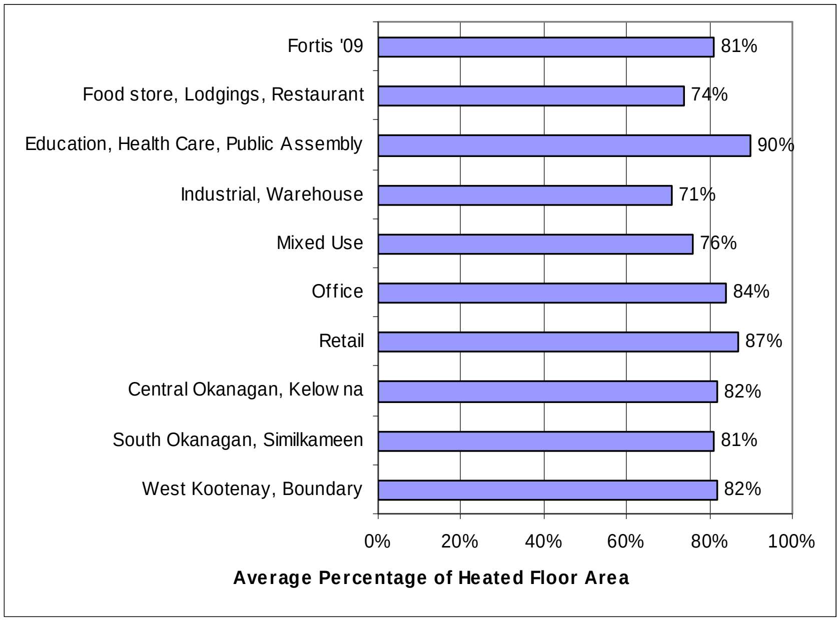
The Food Store / Lodging / Restaurant sector was the only one to indicate a net decrease in occupancy.

		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
"During the past 12 months, has this average number of occupants"	"Increased"	10%	18%	15%
	"Stayed the same"	69%	68%	67%
	"Decreased"	12%	4%	11%
	"Don't know"	8%	10%	7%
Total	Base	117	142	98

The Central Region respondents had noted a slight net decrease in occupancy (-2%), whereas increases in both South Okanagan (+14%) and West Kootenay (+4%) were reported.

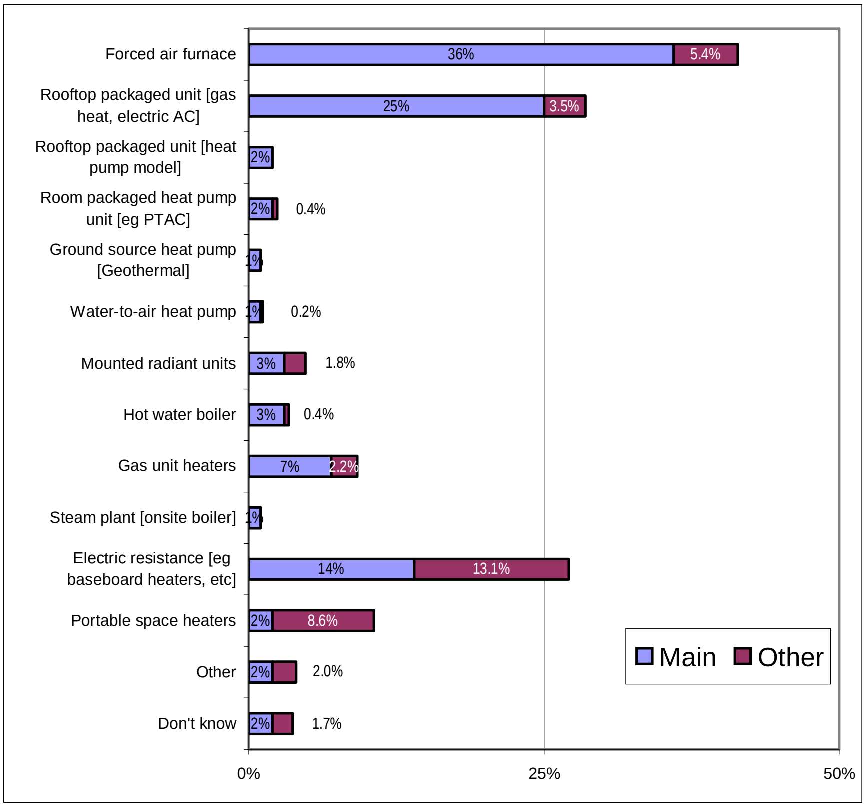
C. Space Heating

20. What percentage of the enclosed floor area in the building is heated?



Over 80% the enclosed floor areas is heated with Industrial / Warehouse buildings being the lowest (71%) and Education / Health Care / Public Assembly, the highest (90%).

21. Please indicate the main type of heating system used to heat the building. If more than one heating system, please indicate other systems.



Forced air furnaces are the primary source of building heat for over 1/3 of the buildings reported by the survey respondents.

Rooftop packaged units are next for 1/4 of the buildings, followed by electric resistance units. Electric resistant units are the main secondary supply with 13% of the buildings using this heat source.

MAIN type of heating system

		Type of building					
		Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
"Please indicate the main type of heating system used to heat the building"	"Forced air furnace"	26%	50%	26%	24%	44%	35%
	"Rooftop packaged unit [gas heat, electric AC]"	22%	18%	17%	30%	33%	33%
	"Rooftop packaged unit [heat pump model]"	2%	4%	2%		4%	1%
	"Room packaged heat pump unit [eg PTAC]"	11%	2%				1%
	"Ground source heat pump [Geothermal]"	2%	2%		3%		1%
	"Water-to-air heat pump"			2%		4%	
	"Mounted radiant units"			9%	8%		3%
	"Hot water boiler"		3%	1%	3%	4%	4%
	"Gas unit heaters"	3%	1%	11%	8%		12%
	"Steam plant [onsite boiler]"		2%	2%		2%	
	"Electric resistance [eg baseboard heaters, etc]"	33%	9%	24%	23%	8%	3%
	"Portable space heaters"		4%	1%		2%	1%
	"Other"	2%	3%	3%			4%
	"Don't know"		3%		1%		3%
Total	Base	35	76	56	42	32	83

1/2 of Education / Health Care and Public Assembly type buildings use forced air furnaces followed by Office buildings at 44% and Retail at 35%.

1/3 of Food Stores / Lodging / Restaurants are most likely to use electric resistance heaters followed by Educational / Warehouse (24%) and Mixed Use buildings (23%).

1/3 of Mixed Use, Office, and Retail have rooftop packaged units for heat.

MAIN type of heating system

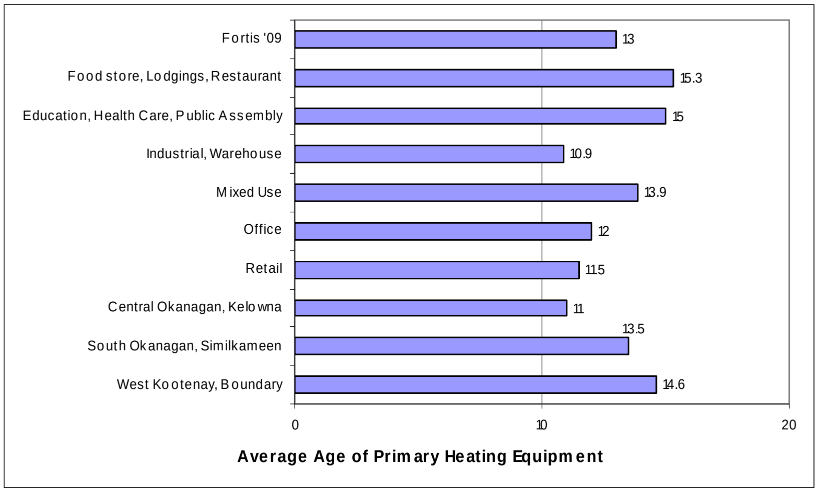
		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
“Please indicate the main type of heating system used to heat the building”	“Forced air furnace”	33%	41%	31%
	“Rooftop packaged unit [gas heat, electric AC]”	39%	20%	16%
	“Rooftop packaged unit [heat pump model]”	2%	2%	1%
	“Room packaged heat pump unit [eg PTAC]”	2%	1%	2%
	“Ground source heat pump [Geothermal]”		1%	3%
	“Water-to-air heat pump”		1%	1%
	“Mounted radiant units”	5%	4%	1%
	“Hot water boiler”		2%	6%
	“Gas unit heaters”	8%	7%	4%
	“Steam plant [onsite boiler]”		2%	1%
	“Electric resistance [eg baseboard heaters, etc]”	8%	13%	24%
	“Portable space heaters”		1%	4%
	“Other”	2%	2%	3%
	“Don't know”	1%	2%	1%
Total	Base	107	128	90

In the Central Region 2/5 of buildings have rooftop packaged units as their heat source (39%) followed by 1/3 of buildings using forced air.

Forced air furnaces is the most popular for 2/5 of properties in the South Okanagan, followed by 1/5 using rooftop packaged units and just over 1/8 using electric resistance units.

Almost 1/3 of buildings in the West Kootenay Region use forced air furnaces, followed by 1/4 using electric resistance units and 1/6 using rooftop packaged units.

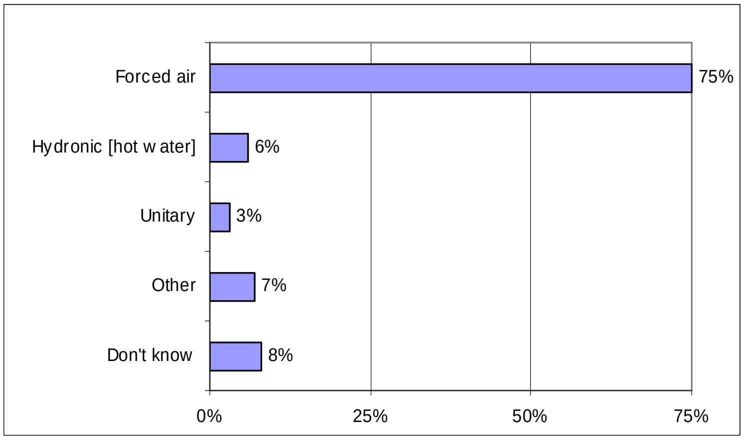
22. What is the age of the primary heating equipment?



Most heating units are in the 13 year old range with the youngest (11 years old) in Industrial, Warehouse premises and Retail.

The oldest heating units (15+ years) are in Food Store / Lodging / Restaurant and Education / Health Care / Public Assembly.

23. What is the main type of heating distribution system?

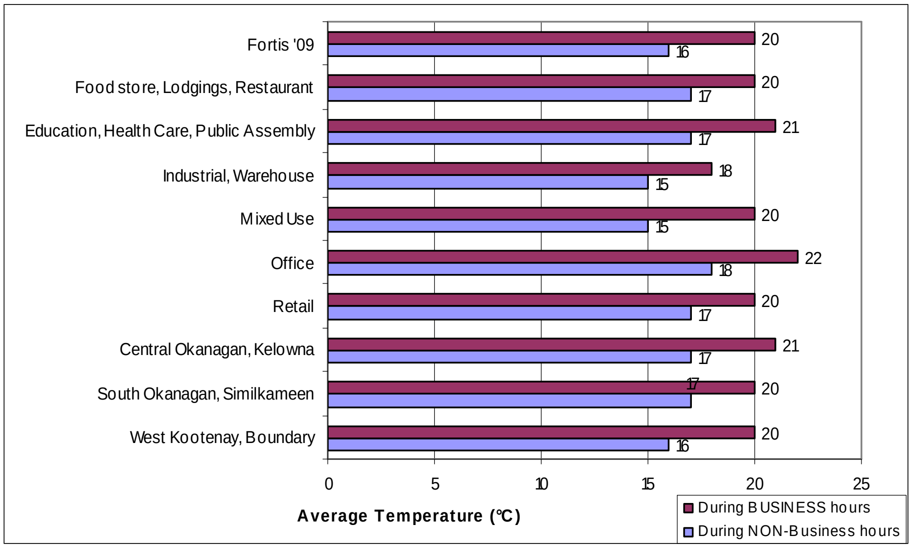


Forced air is the heat distribution system used by the vast majority (over 3/4) of buildings.

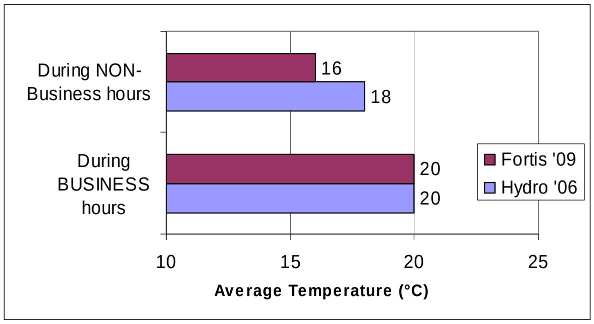
		Type of building					
		Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
"What is the main type of heating distribution system?"	"Forced air"	59%	82%	66%	64%	92%	80%
	"Hydronic [hot water]"	4%	8%	6%	6%	6%	6%
	"Unitary"	9%		6%	9%		1%
	"Other"	17%	7%	11%	10%		4%
	"Don't know"	11%	3%	11%	12%	2%	10%
Total	Base	34	74	52	41	32	82

Ninety-two percent of Office buildings use forced air distribution systems.

24. What are the typical thermostat settings during winter months?

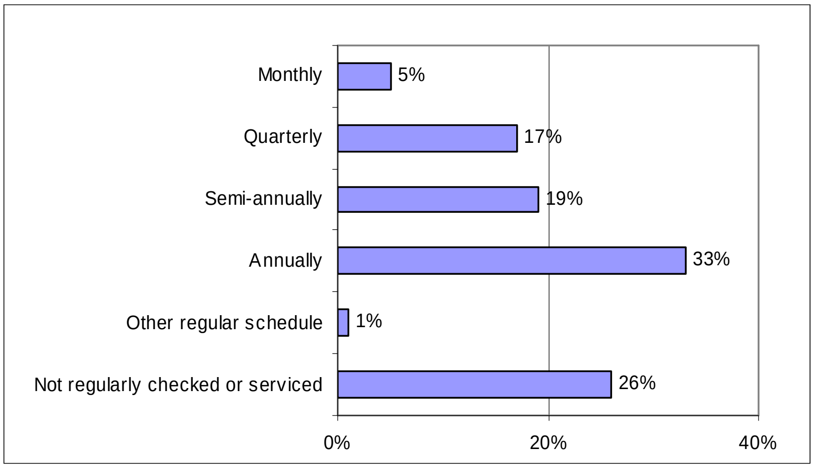


20°C is the predominant thermostat setting for most customer categories for daytime and 17°C during the evening. Industrial / Warehouse keep the temperatures the lowest for both day and night (18°C day / 15°C night).



FortisBC commercial customers keep the thermostat a little lower (16°C) than Hydro customers (18°C) during non business hours.

25. Is the heating equipment checked or serviced:



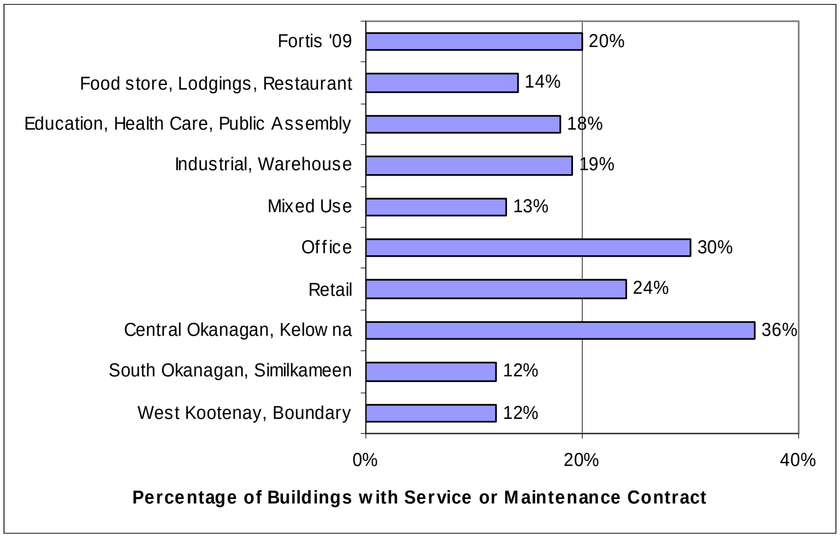
Although 1/3 of heating equipment is checked annually, 41% is checked or serviced more frequently.

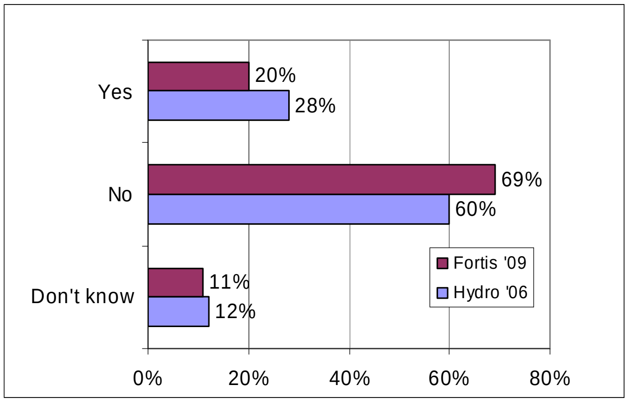
Over 1/4 of the heating equipment is not checked on a regular basis.

		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
"Is the heating equipment checked or serviced:"	"Monthly"	7%	4%	4%
	"Quarterly"	30%	9%	10%
	"Semi-annually"	11%	25%	18%
	"Annually"	29%	36%	36%
	"Other regular schedule"	1%		1%
	"Not regularly checked or serviced"	22%	25%	31%
Total	Base	105	128	86

Heating equipment is checked most frequently in the Central Region (37% quarterly or more frequently) and least in West Kootenay (67% annually or irregularly).

26. Is there a service/maintenance contract in place for the heating equipment?





Only 1/5 of all respondents indicated that a service / maintenance contract is in place for their heating equipment.

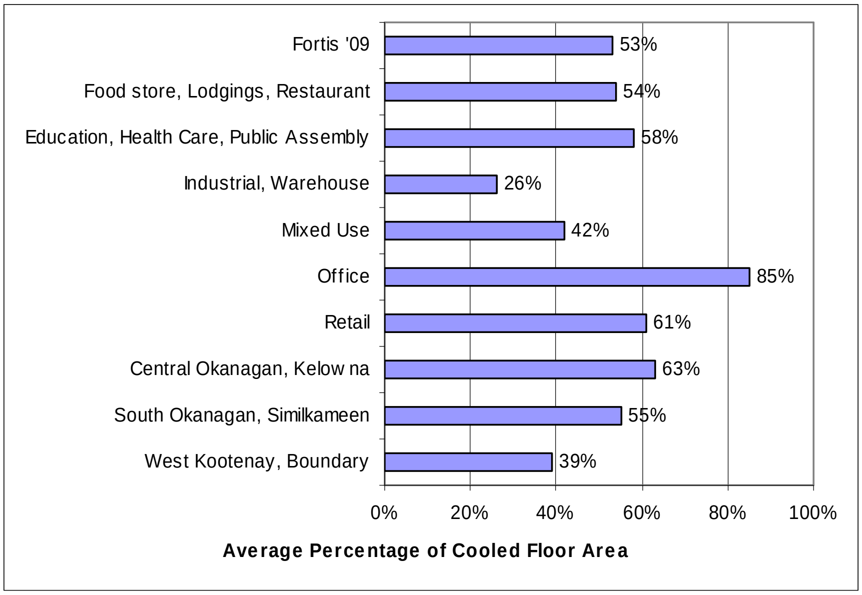
Mixed Use buildings are the least likely (13%) and Office buildings the most likely (36%).

Thirty-six percent of Central Okanagan buildings have a service contract but only 12% of buildings are covered in the other 2 regions.

Twenty-eight percent of Hydro commercial customers have a service maintenance contract in place for the heating equipment.

D. Space Cooling

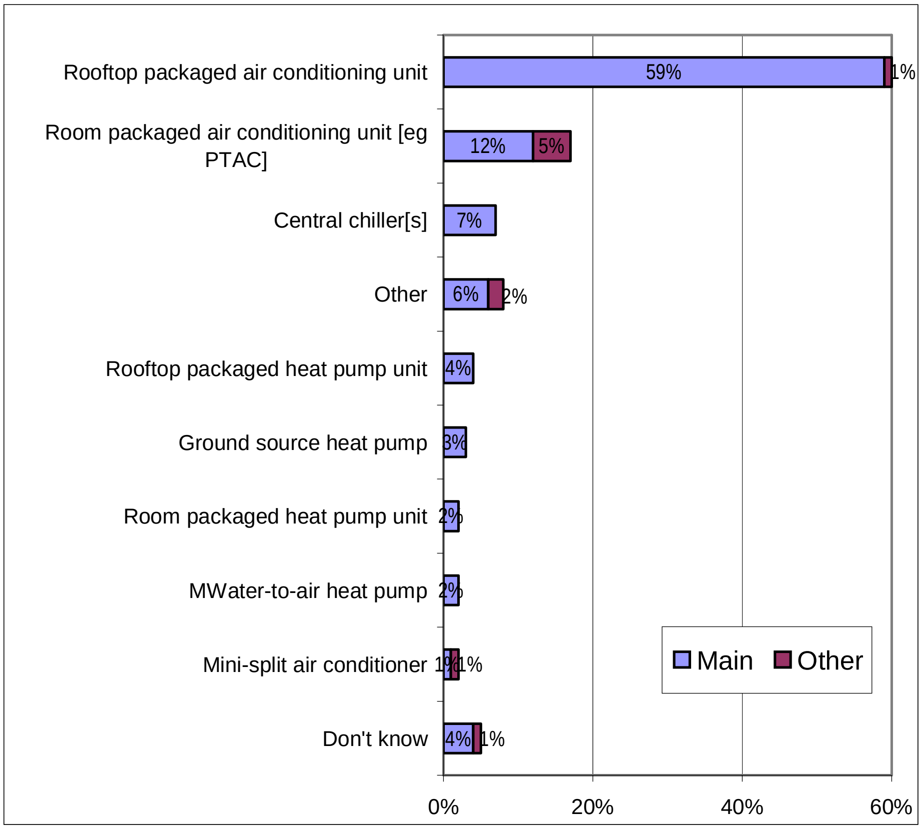
27. What percentage of the enclosed floor area in the building is cooled?



On average, 53% of the enclosed floor area of buildings surveyed are cooled. Only 26% of the enclosed floor are of Industrial / Warehouse properties are cooled and Offices are the most likely to have air conditioned space (85%).

Central Okanagan buildings are much more likely compared to those in the West Kootenay region have cooled space (63% compared to 39%).

28. Please indicate the main type of cooling equipment used to cool the building. If more than one cooling system, please indicate other systems.



Sixty percent of buildings have air conditioning provided by rooftop packaged units, followed by room packaged units (12% primary, 5% secondary).

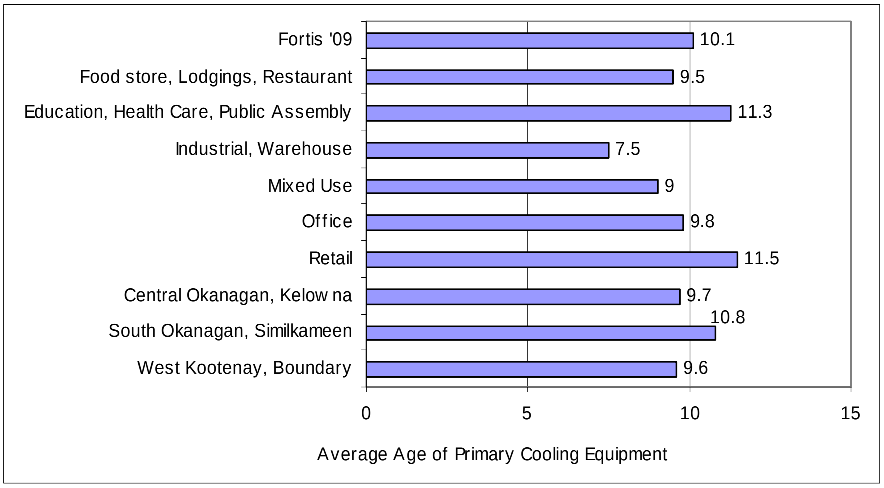
MAIN type of cooling equipment

		Type of building					
		Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
"Please indicate the main type of cooling equipment used to cool the building"	"Rooftop packaged air conditioning unit"	48%	45%	48%	76%	58%	76%
	"Rooftop packaged heat pump unit"	4%	7%	8%		7%	1%
	"Room packaged air conditioning unit [eg PTAC]"	23%	13%	18%	3%	11%	9%
	"Room packaged heat pump unit"	7%					2%
	"Mini-split air conditioner"	4%	1%				1%
	"Central chiller[s]"	4%	16%		6%	8%	5%
	"MWater-to-air heat pump"			4%		10%	
	"Ground source heat pump"	2%	6%		11%		
	"Other"	7%	6%	10%	5%	6%	3%
	"Don't know"		5%	12%			3%
Total	Base	30	51	32	24	33	65

Base: respondents with cooled building

3/4 of Mixed Use and Retail buildings use rooftop packaged units compared to approximately 1/2 of other building categories. Offices and Education / Health Care / Public Assembly buildings are the most likely to have a variety of cooling systems with the latter category the most likely to have "Central Chillers".

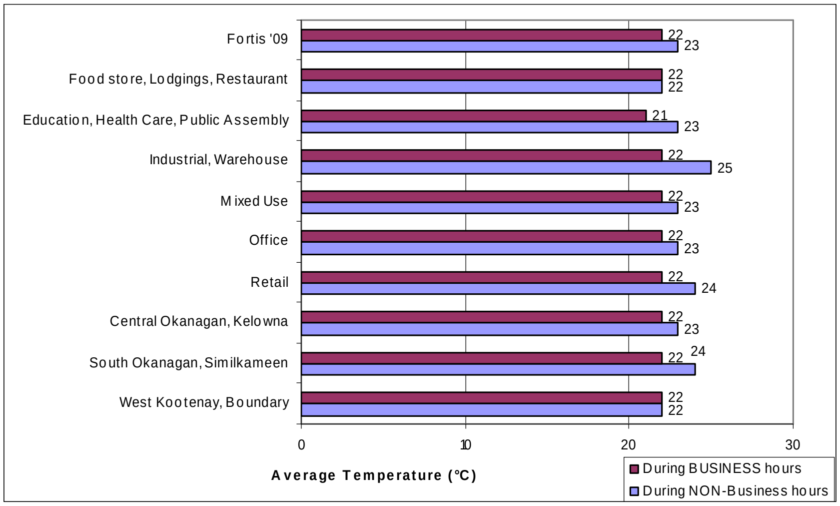
29. What is the age of the primary cooling equipment?



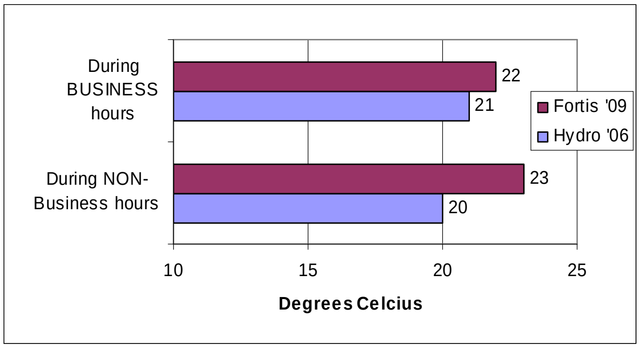
Cooling systems on average are 10 years old, with little variations by building type or by area.

Industrial / Warehouse buildings have installed cooling systems most recently (7.5 years).

30. What are the typical thermostat settings during summer months?

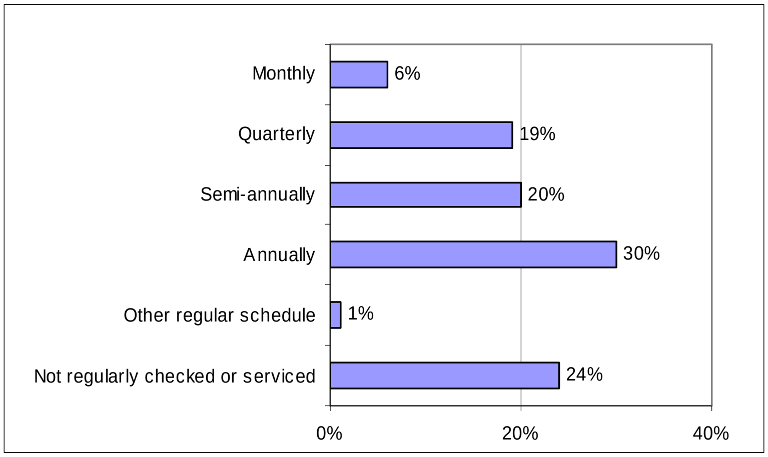


Most building types in all three regions keep their thermostats at 22°C during business hours and 23-24°C when they are not open.



Hydro customers keep the thermostat lower than FortisBC customers during the summer months.

31. Is the cooling equipment checked or serviced:



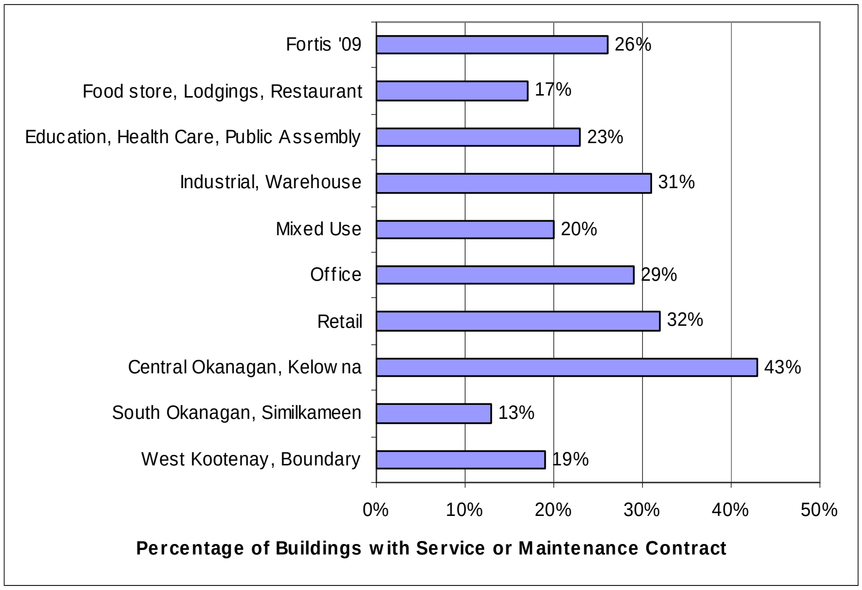
Seventy-five percent have their cooling equipment checked at least annually.

		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
"Is the cooling equipment checked or serviced:"	"Monthly"	6%	4%	10%
	"Quarterly"	29%	10%	16%
	"Semi-annually"	15%	24%	19%
	"Annually"	28%	40%	16%
	"Other regular schedule"		1%	1%
	"Not regularly checked or serviced"	22%	21%	38%
Total	Base	96	97	48

Base: respondents with cooled building

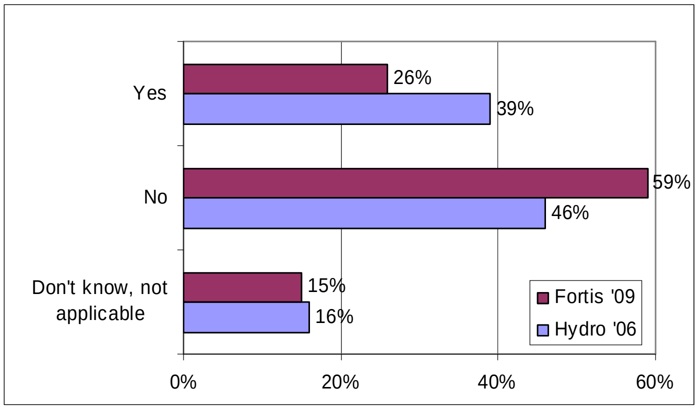
Cooling systems are checked least frequently in the West Kootenay - 2/5 are not checked on a regular basis.

32. Is there a service/maintenance contract in place for the cooling equipment?



Service contracts are in place in 1/4 of the buildings surveyed. Food Stores / Lodgings / Restaurants have the lowest level of servicing the cooling equipment.

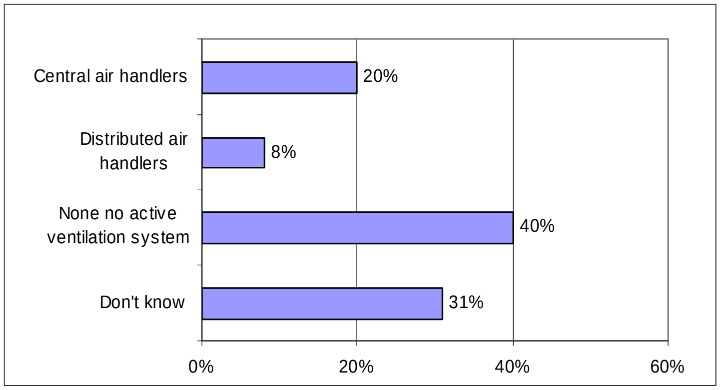
The Central Region buildings are significantly higher than average with 43% having cooling equipment service contracts compared to the South Okanagan at 13% and West Kootenay at 19%.



Hydro commercial respondents were more likely to have an service contract for the cooling equipment (39%) compared to Fortis respondents (26%).

E. Air Distribution

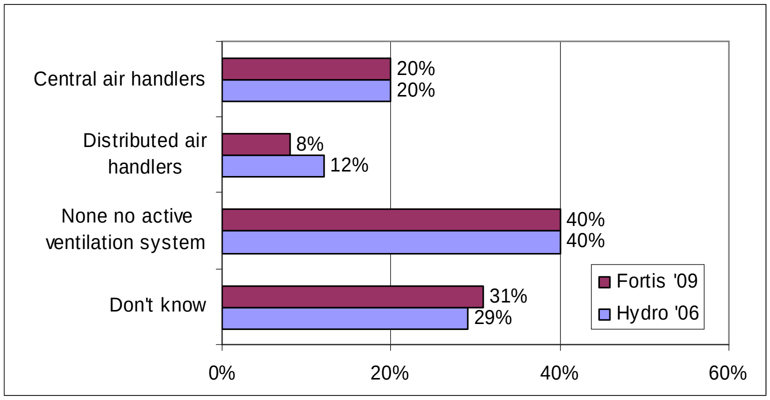
33. What type of equipment is used for the main air supply system for the building?



Central and distributed air handlers were used in 28% of the buildings for which the respondents were able to answer this question. Forty percent reported no active ventilation system and 31% were not sure what type air distribution system was used.

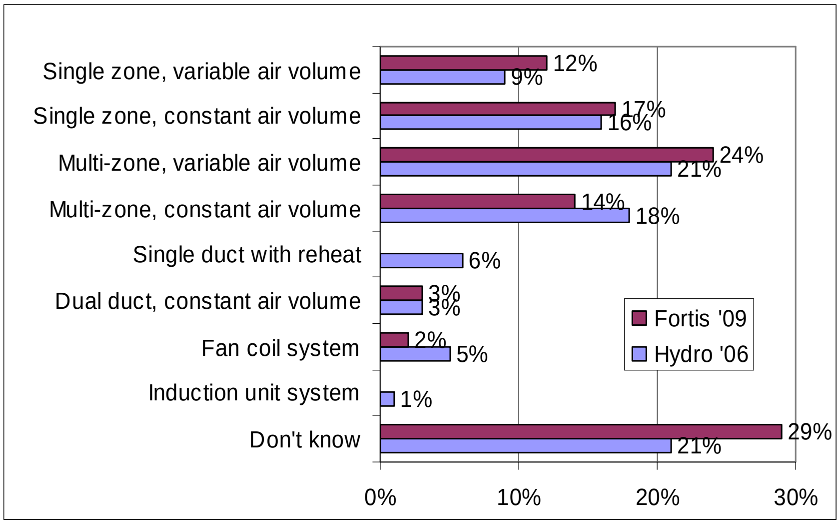
		Type of building					
		Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
“What type of equipment is used for the main air supply system for the building? (check one)”	“Central air handlers”	19%	27%	9%	24%	28%	16%
	“Distributed air handlers”	8%	7%	9%	1%	12%	11%
	“None no active ventilation system”	35%	33%	63%	41%	30%	38%
	“Don't know”	38%	34%	20%	34%	30%	35%
Total	Base	41	76	62	46	38	91

The information from those respondents who were able to answer this question indicates that air supply systems are least likely to be found in Industrial / Warehouse facilities (18%) and most likely in Education / Health Care / Public Assembly and Office buildings; 34% and 40% respectively.



The type of air distribution systems were similar for Fortis and Hydro.

34. What type of system is the main air distribution system?



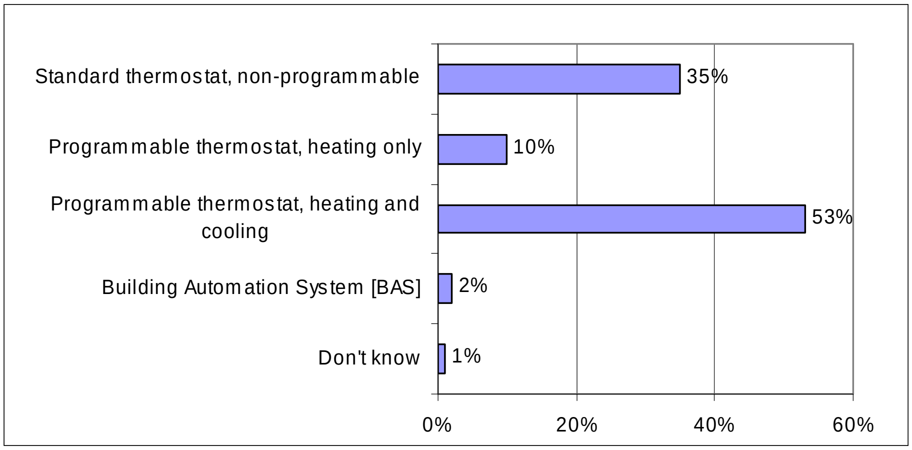
The most frequent methods of air distribution were multi-zone with variable air volume (24%) followed by single zone constant air volume (17%).

		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
"What type of system is the main air distribution system?"	"Single zone, variable air volume"	18%	9%	8%
	"Single zone, constant air volume"	15%	21%	12%
	"Multi-zone, variable air volume"	18%	35%	16%
	"Multi-zone, constant air volume"	21%	9%	12%
	"Dual duct, constant air volume"	3%		8%
	"Fan coil system"		3%	2%
	"Don't know"	26%	24%	41%
Total	Base	47	46	31

Base: buildings with ventilation system

In the South Okanagan, multi-zone variable air volume systems have been installed most frequently, whereas in the Central Okanagan all systems are used fairly equally.

35. What is the main type of equipment used to control temperature?



Programmable thermostats are in use in over 1/2 of buildings and standard non-programmable versions in over 1/3. Building Automation Systems are not installed frequently.

		Type of building					
		Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
"What is the main type of equipment used to control temperature?"	"Standard thermostat, non-programmable"	31%	22%	48%	33%	13%	55%
	"Programmable thermostat, heating only"	6%	17%	8%	20%	6%	4%
	"Programmable thermostat, heating and cooling"	59%	58%	39%	47%	80%	37%
	"Building Automation System [BAS]"		3%				4%
	"Don't know"	3%		4%			
Total	Base	21	35	14	13	19	31

Base: buildings with ventilation system

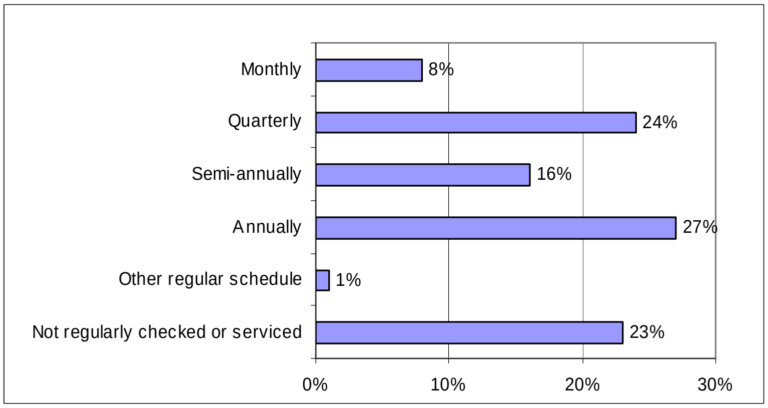
Approximately 1/2 of Retail (55%) and Industrial / Warehouse facilities (48%) have standard thermostats. 80% of Offices have programmable versions.

		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
"What is the main type of equipment used to control temperature?"	"Standard thermostat, non-programmable"	24%	42%	40%
	"Programmable thermostat, heating only"	10%	14%	5%
	"Programmable thermostat, heating and cooling"	63%	42%	52%
	"Building Automation System [BAS]"	2%	3%	
	"Don't know"			3%
Total	Base	50	49	37

Base: buildings with ventilation system

Programmable thermostats are most likely to be found in Central Region buildings and least in the South Okanagan.

36. Is the air distribution equipment checked or serviced?



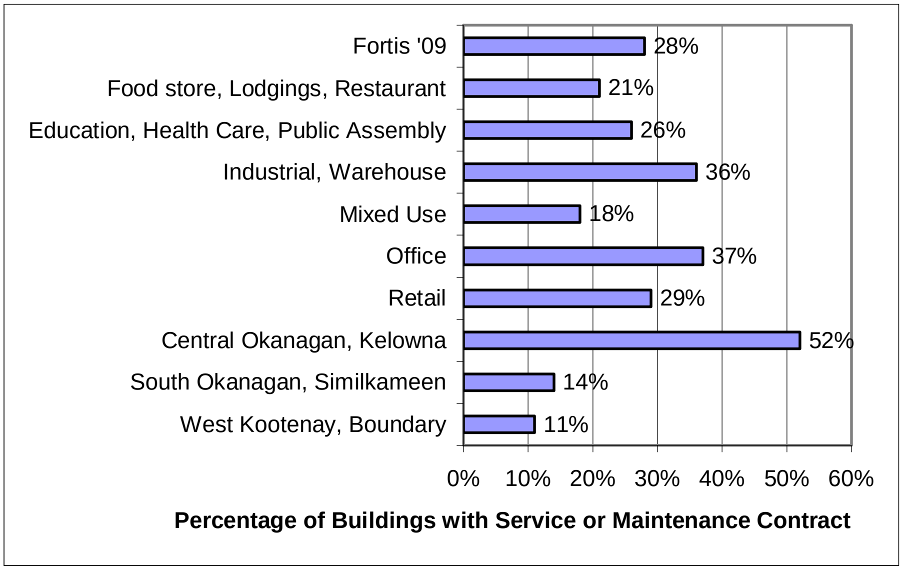
Almost 1/2 of the air distribution equipment (48%) is checked at least twice a year. Just less than 1/4 of these systems are not checked on a regular basis.

		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
"Is the air distribution equipment checked or serviced"	"Monthly"	5%	8%	10%
	"Quarterly"	45%	11%	15%
	"Semi-annually"	13%	19%	17%
	"Annually"	18%	36%	25%
	"Other regular schedule"		3%	
	"Not regularly checked or serviced"	18%	22%	33%
Total	Base	46	49	33

Base: buildings with ventilation system

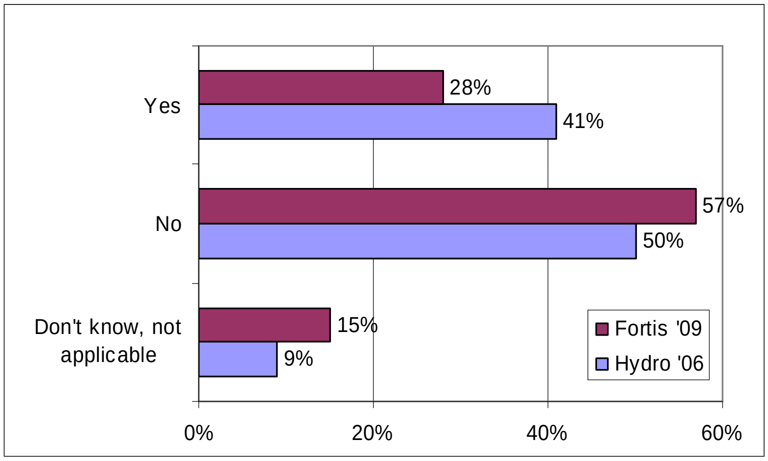
Eighty-two percent of air distribution systems in the Central Okanagan are checked at least once per year compared to 78% in the South Okanagan and 67% in the West Kootenay.

37. *Is there a service or maintenance contract in place for the air distribution equipment?*



Service contracts are most likely to be in place in Industrial / Warehouse (36%) and Offices (37%), and least likely in Mixed Use facilities.

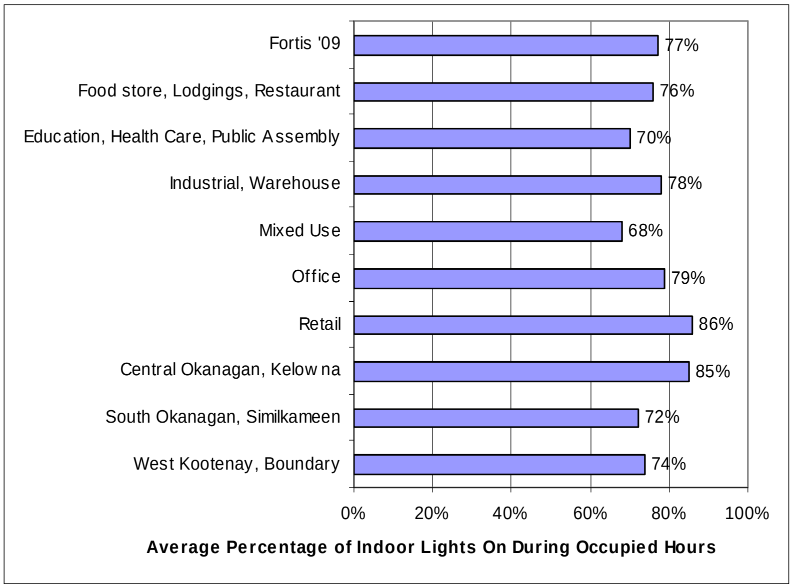
Over 50% of Central Okanagan buildings have service or maintenance contracts compared to 14% in the South Okanagan and 11% in West Kootenay.



Forty-one percent of Hydro business have service contracts in place for their air distribution equipment.

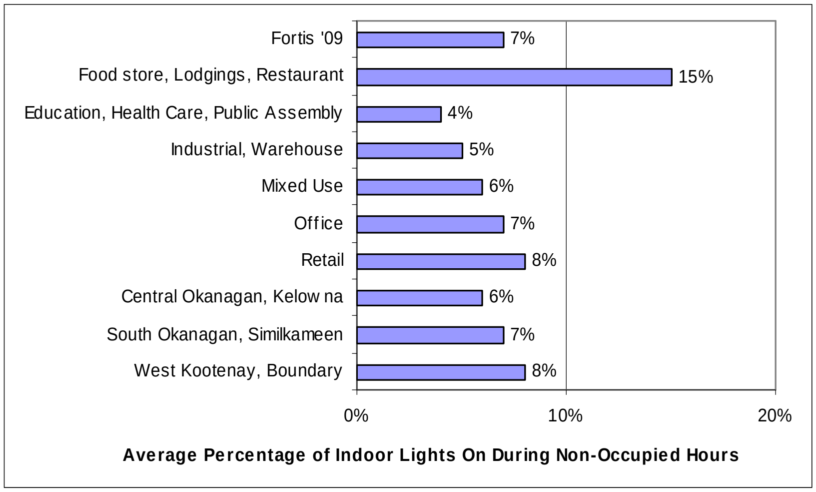
F. Indoor Lighting

38. On average, what percentage of the indoor lights on your electrical account are on during occupied hours?



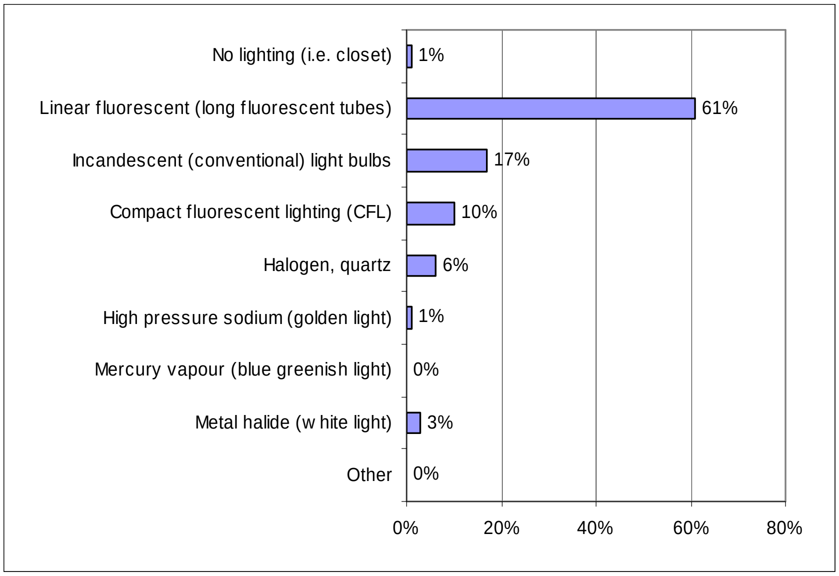
Almost 4/5 of all lights are on during the time Fortis buildings are occupied, with slightly higher amounts in:
- the Retail sector (86%)
- the Central Okanagan (85%).

39. On average, what percentage of the indoor lights on your electrical account are on during non-occupied hours?



Seven percent of all lights are kept on in buildings when they are not occupied.
Among Food Store / Lodgings and Restaurants at 15% of all lights are kept on in buildings when they are not occupied.

40. Please estimate the percentage of the floor space that is lit by each type of lighting.



Linear fluorescent tubes light 61% of the floor space of buildings reported in the survey.

Standard light bulbs are used to light 17% and CFL's are used to light 10% of the floor space.

Please estimate the percentage of floor space that is lit by each type of lighting

		Type of building					
		Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
No lighting (i.e. closet)	Mean %	1%	1%	1%	3%	1%	2%
	Base	30	61	47	31	27	62
Linear fluorescent (long fluorescent tubes)	Mean %	34%	63%	62%	56%	74%	65%
	Base	30	63	48	31	27	64
Incandescent (conventional) light bulbs	Mean %	27%	23%	16%	18%	16%	9%
	Base	30	63	47	31	27	64
Compact fluorescent lighting (CFL)	Mean %	30%	8%	4%	16%	7%	6%
	Base	30	63	47	31	27	64
Halogen, quartz	Mean %	6%	4%	6%	4%	2%	10%
	Base	30	63	47	31	27	64
High pressure sodium (golden light)	Mean %	0%	1%	3%	0%	0%	2%
	Base	30	63	47	31	26	64
Mercury vapour (blue greenish light)	Mean %	0%	0%	1%	0%	0%	0%
	Base	30	63	47	31	27	64
Metal halide (white light)	Mean %	2%	0%	9%	2%	0%	5%
	Base	30	63	48	31	27	64
Other	Mean %	0%	0%	0%	0%	0%	1%
	Base	30	63	47	31	26	64

Missing values treated as zero. Base sizes include only cases where at least one lighting type was given
Average percent of lighting includes zero percent

Food Stores / Lodgings / Restaurants are most likely to use CFL's (30%) and standard bulbs (27%) and least likely to use linear fluorescent tubes (34%).

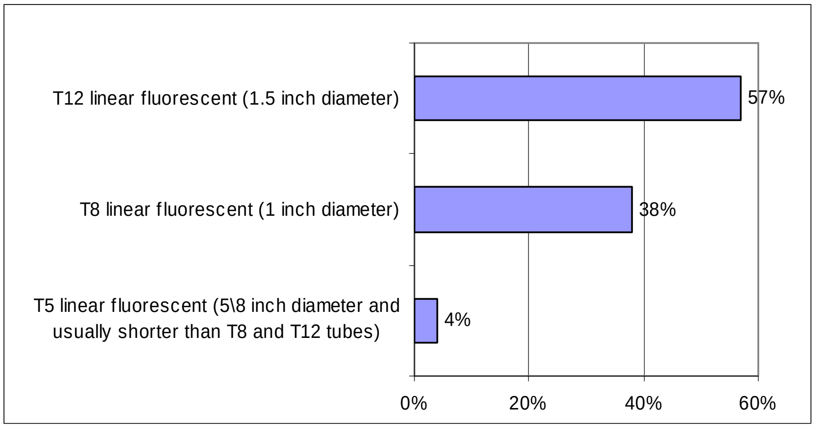
Please estimate the percentage of floor space that is lit by each type of lighting

		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
No lighting (i.e. closet)	Mean %	1%	2%	1%
	Base	86	100	72
Linear fluorescent (long fluorescent tubes)	Mean %	68%	55%	59%
	Base	87	103	74
Incandescent (conventional) light bulbs	Mean %	10%	21%	21%
	Base	86	103	74
Compact fluorescent lighting (CFL)	Mean %	9%	9%	14%
	Base	86	103	74
Halogen, quartz	Mean %	8%	6%	2%
	Base	86	103	74
High pressure sodium (golden light)	Mean %	2%	0%	1%
	Base	86	103	74
Mercury vapour (blue greenish light)	Mean %	1%	0%	0%
	Base	86	103	74
Metal halide (white light)	Mean %	2%	7%	1%
	Base	87	103	74
Other	Mean %	0%	0%	1%
	Base	86	103	74

Missing values treated as zero. Base sizes include only cases where at least one lighting type was given
Average percent of lighting includes zero percent

Buildings in the Central Okanagan are more likely to use linear fluorescent tubes (68% of floor space) than those in the South Okanagan (55%) or West Kootenay (59%), and less likely to use standard bulbs (10% compared to 21% in both other regions).

41. If the building has linear fluorescent lights, please estimate the percentage breakdown of the total linear fluorescent lighting used.



T12 linear fluorescents are used in almost 60% of all buildings using this type of lighting, almost 40% choose the T8 option.

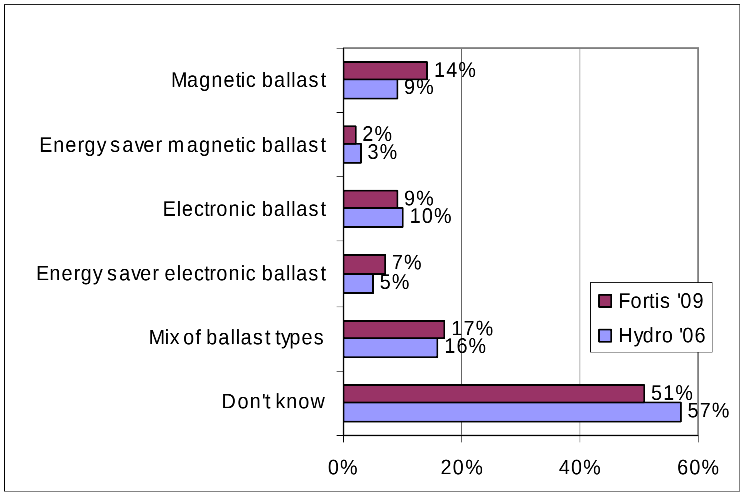
If the building has linear fluorescent lights, please estimate the percentage breakdown of the total linear fluorescent lighting used

		Type of building					
		Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
T12 linear fluorescent (1.5 inch diameter)	Mean %	54%	49%	64%	46%	65%	59%
	Base	17	38	37	16	25	46
T8 linear fluorescent (1 inch diameter)	Mean %	35%	51%	32%	52%	34%	33%
	Base	17	38	37	16	25	46
T5 linear fluorescent (5\8 inch diameter and usually shorter than T8	Mean %	11%	0%	4%	2%	1%	8%
	Base	17	38	37	15	25	46

Missing values treated as zero. Base sizes include only cases where at least one linear fluorescent lighting type was given
Average percent of lighting includes zero percent

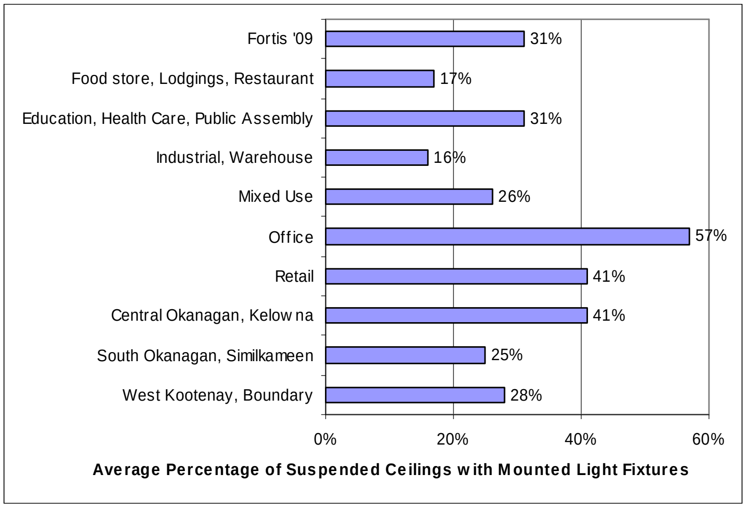
The smaller T8 tubes are used in over 1/2 of the Education / Health Care / Public Assembly and Mixed Use buildings whereas other buildings are more likely to use the larger T12's.

42. What is the main linear fluorescent ballast type in use in the building?



Over 50% of survey respondents were unable to identify the fluorescent ballast type used in their building. Of those who could, 17% reported using a mix of ballast types and 14% magnetic ballasts.

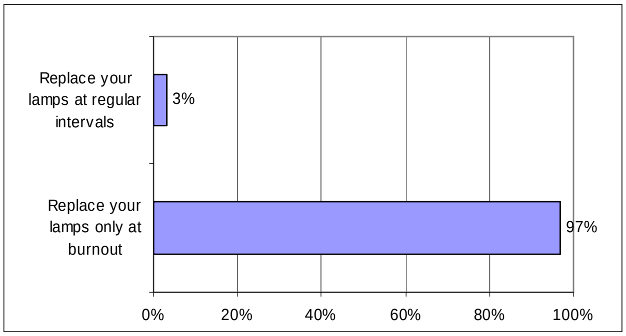
43. Approximately what percentage of the ceiling area in this building consists of suspended ceilings, where light fixtures are mounted in the ceiling?



On average, 31% of ceiling area is covered in suspended ceilings with the highest percentage being in:
- Offices (57%)
- in the Central Region (41%)

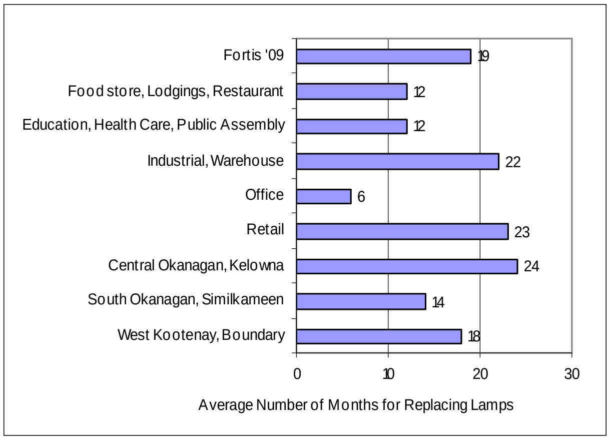
44. Which of the following maintenance methods do you use in each technology?

Lamps

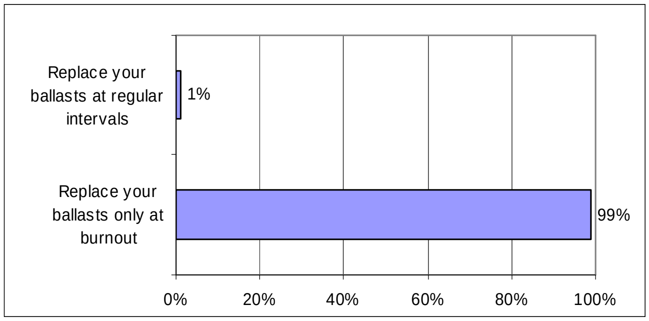


Ninety-seven percent of lamps are only replaced when they burn out. This was similar for the Hydro '06 sample.

Please specify the interval:

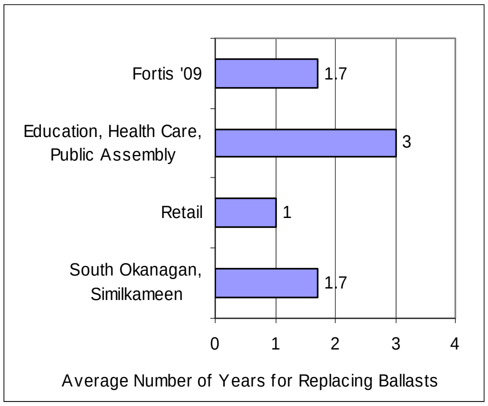


Ballasts

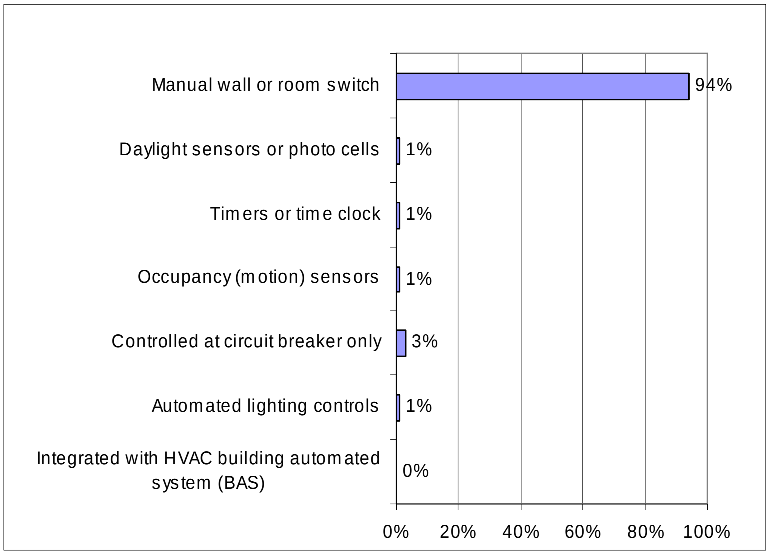


Ninety-nine percent of ballasts are replaced when they burn out.

Please specify the interval:



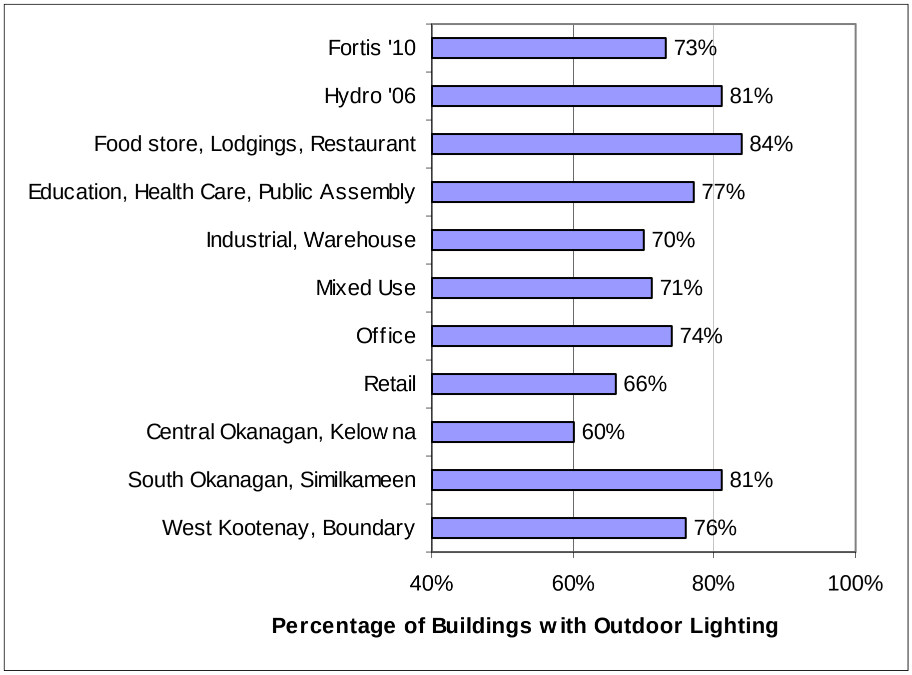
45. What is the percentage breakdown of the indoor lighting controlled by each of the following types of equipment?



The major control mechanism in almost all buildings are manual wall switches.

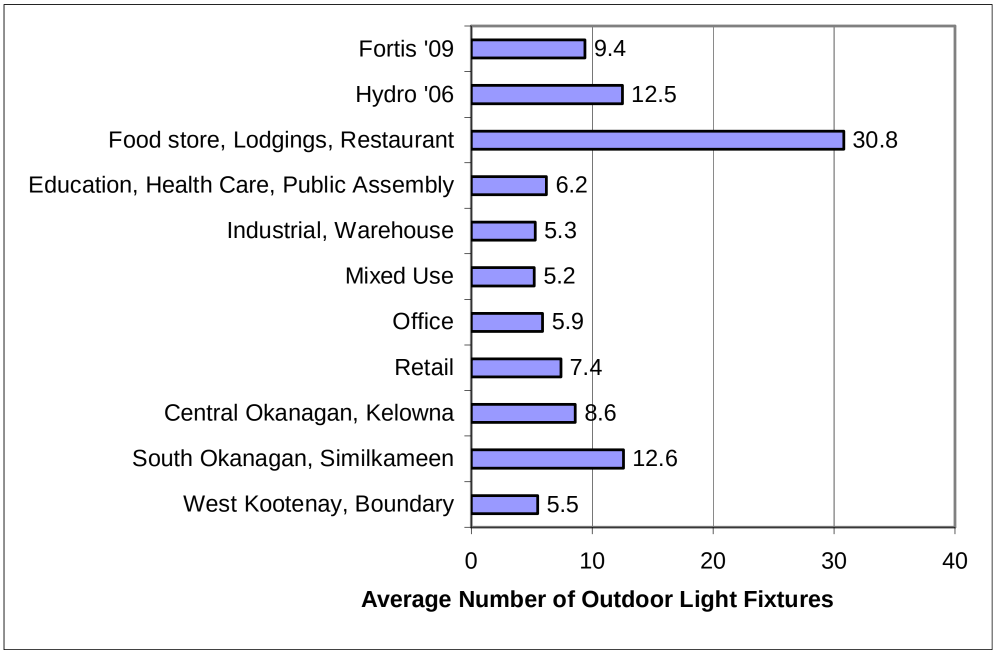
G. Outdoor Lighting

46. Is there outdoor lighting at this building that is associated with your electrical account?



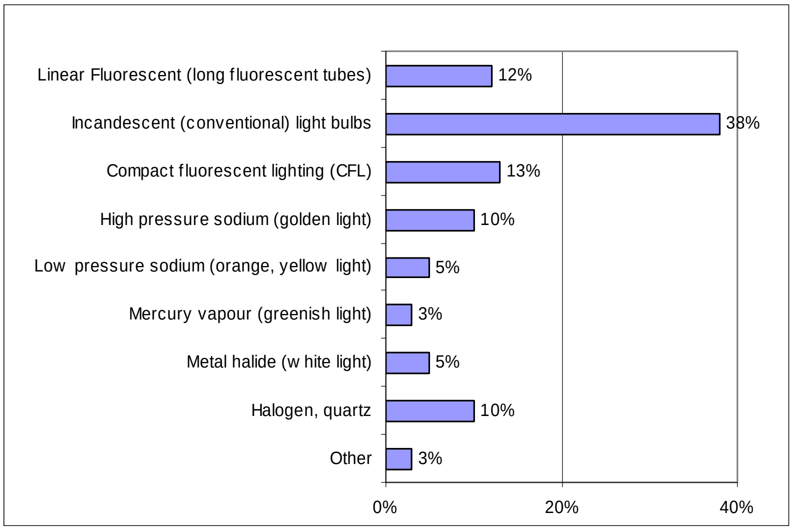
Over 70% of all commercial buildings have outdoor lighting with the highest being Food Stores / Lodgings / Restaurants (84%) and in the South Okanagan region (81%). Retail properties have the lowest incidence of outdoor lighting (60%).

47. Please estimate the total number of outdoor light fixtures (of all types) at this building?



Similar to the previous tables, the Food Store / Lodgings / Restaurant category has the largest number of outdoor lighting fixtures by a factor of 3 to 4 times all other building categories.

48. Please estimate the percentage breakdown of each type of outdoor lighting fixture in use at this building, relative to the total number of outdoor fixtures?



Conventional light bulbs are used three times more frequently for outdoor lighting than any other bulb type.

Please estimate the percentage of each type of outdoor lighting fixture in use at this building

		Type of building					
		Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
Linear Fluorescent (long fluorescent tubes)	Mean %	11%	1%	5%	14%	19%	25%
	Base	30	51	42	32	20	51
Incandescent (conventional) light bulbs	Mean %	27%	53%	25%	45%	55%	29%
	Base	30	51	42	32	20	51
Compact fluorescent lighting (CFL)	Mean %	18%	16%	10%	16%	16%	7%
	Base	30	51	42	32	20	51
High pressure sodium (golden light)	Mean %	7%	9%	17%	8%	10%	10%
	Base	30	51	42	32	20	51
Low pressure sodium (orange, yellow light)	Mean %	1%	8%	5%	6%	0%	4%
	Base	30	51	42	32	20	51
Mercury vapour (greenish light)	Mean %	6%	0%	11%	0%	0%	2%
	Base	30	51	42	32	20	51
Metal halide (white light)	Mean %	5%	2%	10%	3%	1%	9%
	Base	30	51	42	32	20	51
Halogen, quartz	Mean %	21%	6%	17%	2%	0%	10%
	Base	30	51	42	32	20	51
Other	Mean %	5%	5%	0%	5%	0%	4%
	Base	30	51	42	32	20	51

Missing values treated as zero. Base sizes include only cases where at least one outdoor lighting fixture in use
Average percent of lighting fixtures includes zero percent

Over 1/2 of both Education / Health Care / Public Assembly (53%) and Office building (55%) categories use conventional bulbs most frequently for outdoor light.

Retail buildings and Offices are the most likely to use linear fluorescent bulbs (25%).

Food Stores / Lodgings / Restaurant are the most likely to have halogen, quartz bulbs outside (21%), followed by Industrial / Warehouse facilities (17%).

Please estimate the percentage of each type of outdoor lighting fixture in use at this building

		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
Linear Fluorescent (long fluorescent tubes)	Mean %	21%	9%	9%
	Base	62	100	67
Incandescent (conventional) light bulbs	Mean %	23%	45%	42%
	Base	62	100	67
Compact fluorescent lighting (CFL)	Mean %	11%	11%	18%
	Base	62	100	67
High pressure sodium (golden light)	Mean %	19%	8%	7%
	Base	62	100	67
Low pressure sodium (orange, yellow light)	Mean %	3%	5%	6%
	Base	62	100	67
Mercury vapour (greenish light)	Mean %	8%	2%	1%
	Base	62	100	67
Metal halide (white light)	Mean %	5%	7%	3%
	Base	62	100	67
Halogen, quartz	Mean %	9%	11%	9%
	Base	62	100	67
Other	Mean %	2%	3%	6%
	Base	62	100	67

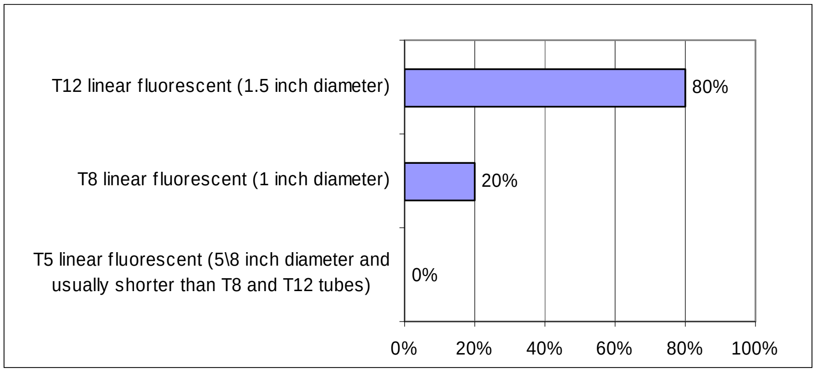
Missing values treated as zero. Base sizes include only cases where at least one outdoor lighting fixture in use
Average percent of lighting fixtures includes zero percent

Buildings in the South Okanagan (45%) and West Kootenay (42%) are twice as likely to use conventional bulbs for outdoor lighting than buildings in the Central Okanagan Region (23%).

In the Central Region, linear fluorescent (21%), high pressure sodium (19%) and mercury vapor bulbs (8%) are comparatively more popular than in the other two regions.

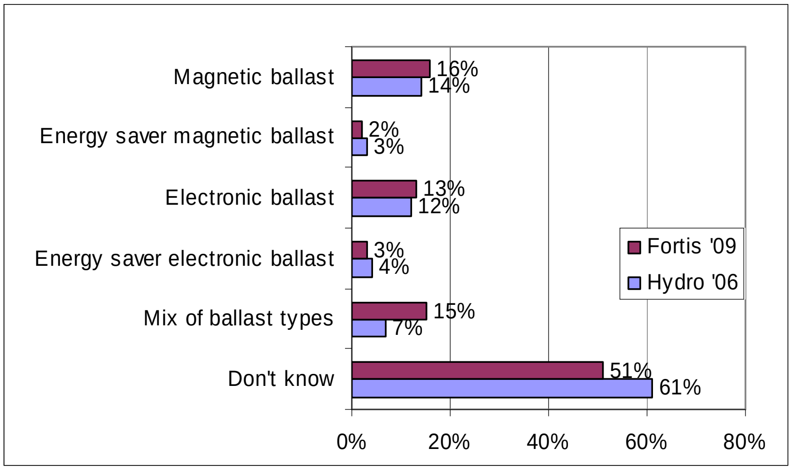
CFL's are more frequently used for outdoor lighting in the West Kootenay (18% versus 11%).

49. If the building has linear fluorescent lights outdoor, please estimate the percentage breakdown of the total linear fluorescent lighting used outdoor?



T12 linear fluorescent bulbs are four times more frequently used for outdoor lighting purposes than T8's.

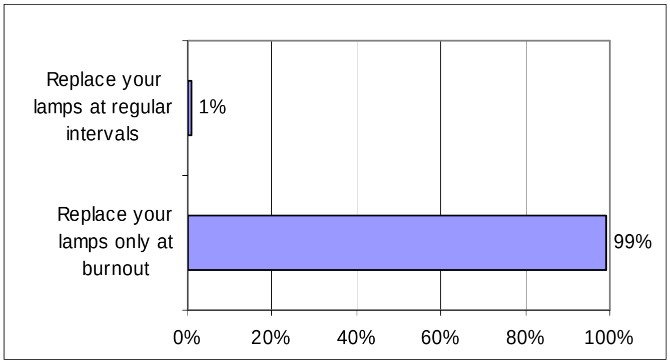
50. Which of the following is the main linear fluorescent ballast type in use?



Similar to the previous questions on ballasts, most respondents were unaware of the type used for their outdoor fluorescent lighting. Of those who could answer, 16% mentioned magnetic ballast, 13% electronic and 15% a mix of various ballast types.

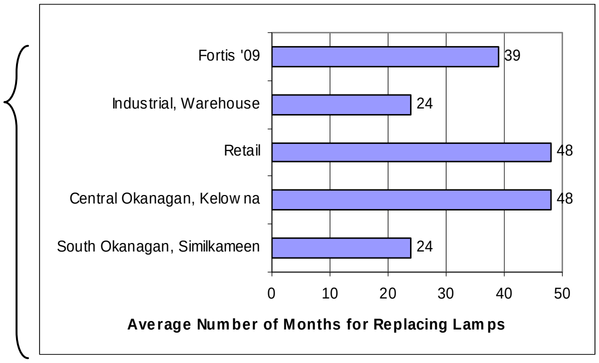
51. Which of the following maintenance methods do you use in each technology?

Lamps



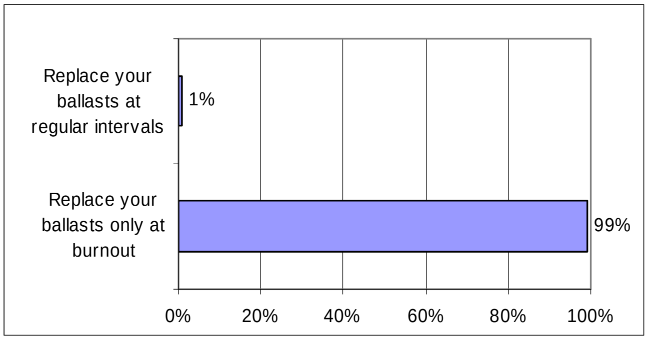
Outdoor lamps are replaced when they burn out in 99% of buildings. This was consistent with the Hydro results.

Please specify the interval:



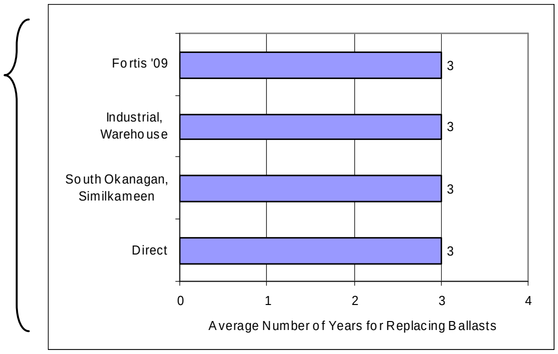
A small percentage of buildings replace their lamps on average every 39 months.

Ballasts



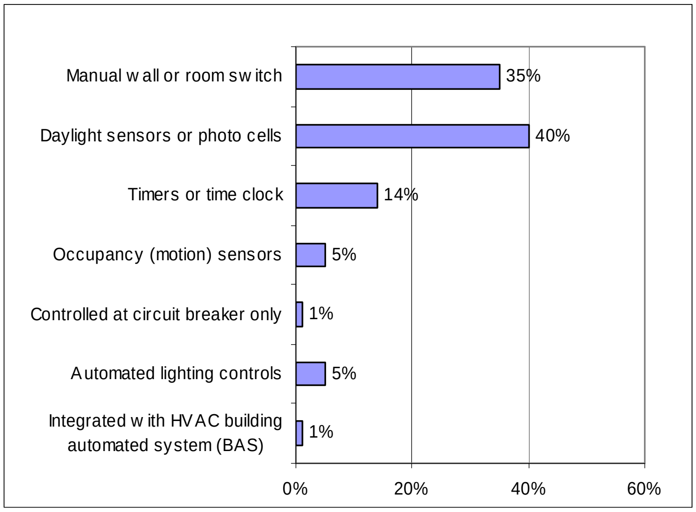
Ninety-nine percent of buildings replace ballasts only when they burn out.

Please specify the interval:



A small percentage of buildings replace their ballasts every 3 years.

52. What is the percentage breakdown of the outdoor lighting controlled by each of the following types of equipment?



Outdoor lighting is much more likely to be controlled by sensors than indoor lighting (45% compared to 1%). Thirty-five percent of outdoor lights are controlled by manual switches compared to 95% for indoor lights.

What percentage of the outdoor lighting is controlled by each of the following types of equipment?

		Type of building					
		Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
Manual wall or room switch	Mean %	32%	39%	24%	34%	29%	41%
	Base	33	54	42	32	23	53
Daylight sensors or photo cells	Mean %	29%	36%	55%	50%	50%	31%
	Base	33	54	43	32	23	53
Timers or time clock	Mean %	26%	10%	9%	6%	11%	18%
	Base	33	54	43	32	23	53
Occupancy (motion) sensors	Mean %	4%	5%	3%	11%	6%	5%
	Base	33	54	43	32	23	53
Controlled at circuit breaker only	Mean %	0%	1%	4%	0%	1%	0%
	Base	33	54	43	32	23	53
Automated lighting controls	Mean %	9%	7%	5%	0%	3%	4%
	Base	33	54	43	32	23	53
Integrated with HVAC building automated system (BAS)	Mean %	0%	2%	0%	0%	0%	0%
	Base	33	54	43	32	23	53

Missing values treated as zero. Base sizes include only cases where at least one lighting control system was given
Average percent of lighting control systems includes zero percent

Industrial / Warehouse (55%), Mixed Use (50%), and Offices (50%) use sensors compared to approximately 30% of other building categories.

Twenty-six percent of Food Stores / Lodgings / Restaurants use timer devices as do 18% of Retailers.

What percentage of the outdoor lighting is controlled by each of the following types of equipment?

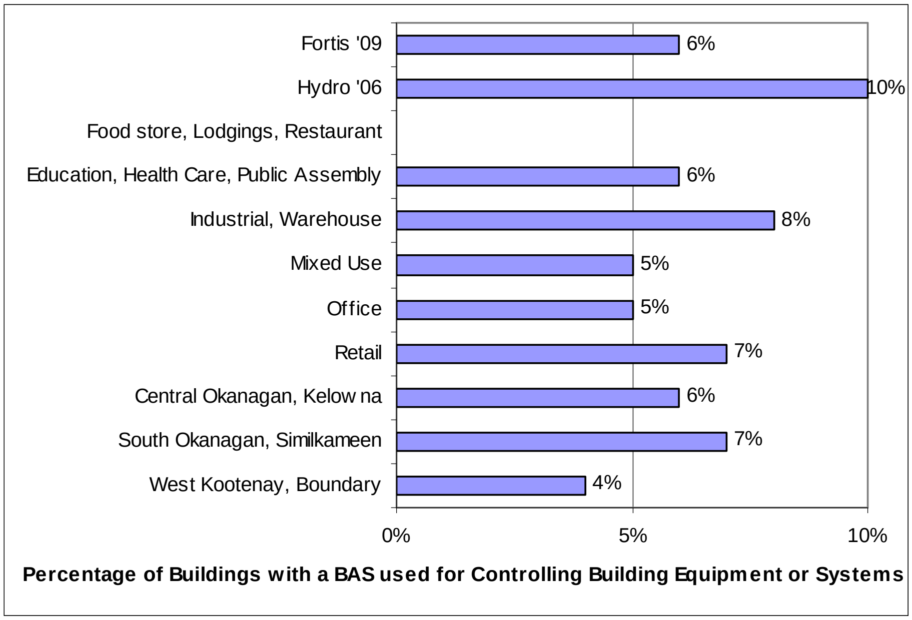
		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
Manual wall or room switch	Mean %	22%	35%	45%
	Base	63	109	69
Daylight sensors or photo cells	Mean %	55%	37%	31%
	Base	63	109	69
Timers or time clock	Mean %	19%	13%	11%
	Base	63	109	69
Occupancy (motion) sensors	Mean %	2%	7%	6%
	Base	63	109	69
Controlled at circuit breaker only	Mean %	2%	0%	2%
	Base	63	109	69
Automated lighting controls	Mean %	0%	7%	6%
	Base	63	109	69
Integrated with HVAC building automated system (BAS)	Mean %	0%	1%	0%
	Base	63	109	69

Missing values treated as zero. Base sizes include only cases where at least one lighting control system was given
Average percent of lighting control systems includes zero percent

Sensors are more frequently found in the majority of Central Okanagan buildings (55%) compared to 37% in the South Okanagan and 31% in West Kootenay.

H. Building Automation Systems

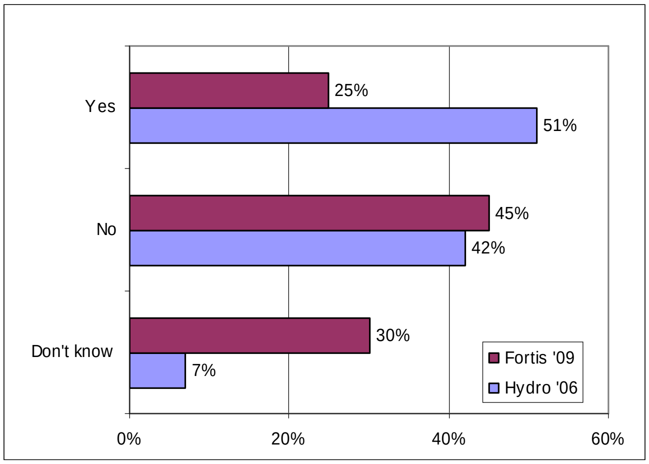
53. Is there a building automation system (BAS) used for controlling building equipment or systems?



Only 6% of the respondents indicated that Building Automation Systems are in place in their buildings. The highest penetration can be found in Industrial / Warehouse facilities (8%) and the lowest in Food Store / Lodgings / Restaurant buildings (0%).

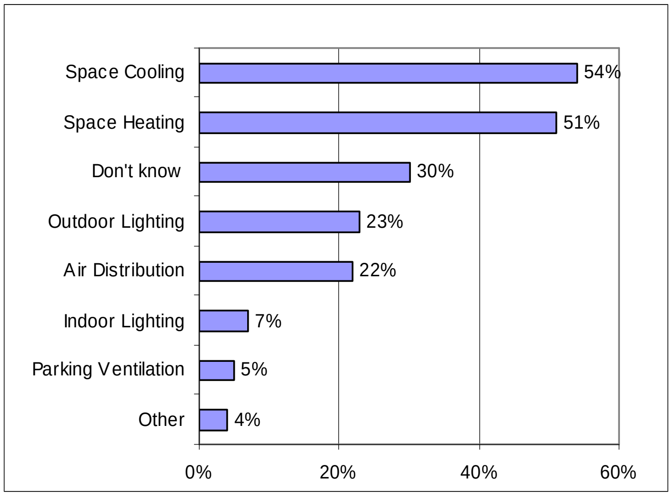
Only 4% of buildings in the West Kootenay has BAS.

54. If your building has a BAS, was it installed as a retrofit (after the building was constructed)?



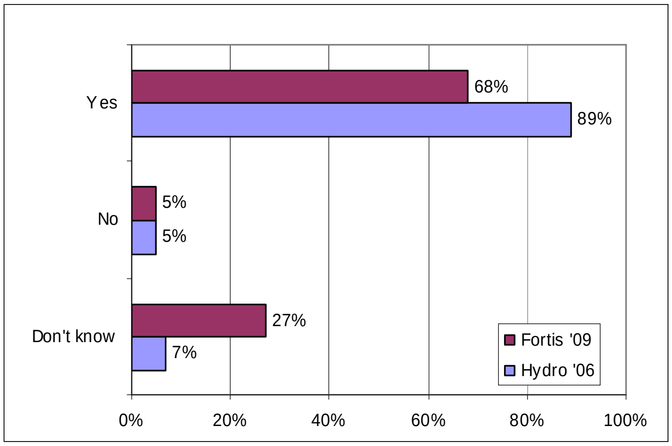
Twenty-five percent said the BAS they had was a retrofit installation and 30% did not know if it was a retrofit instalation.

55. Which equipment is controlled/scheduled by the BAS?



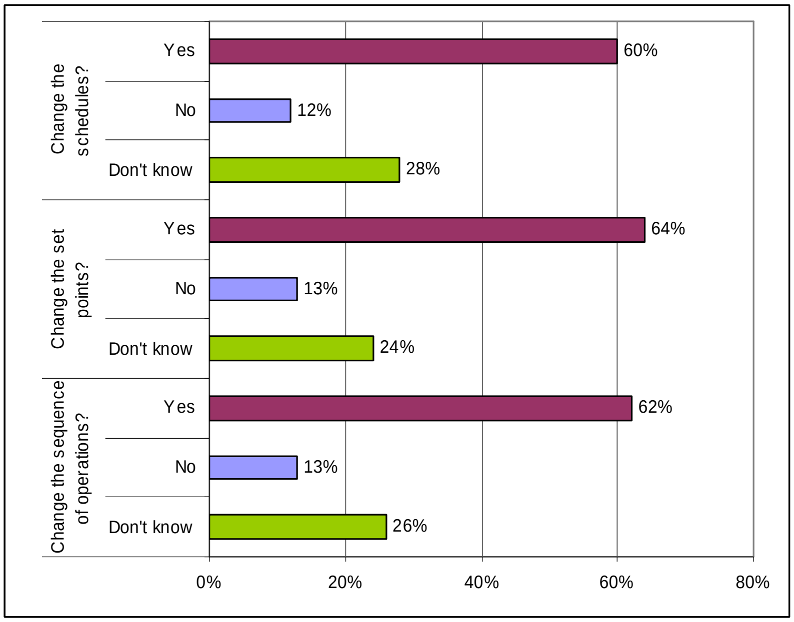
Among respondents with a BAS, 54% control space cooling systems and 51% control space heating systems.

56. Is the BAS functional and operating as designed?



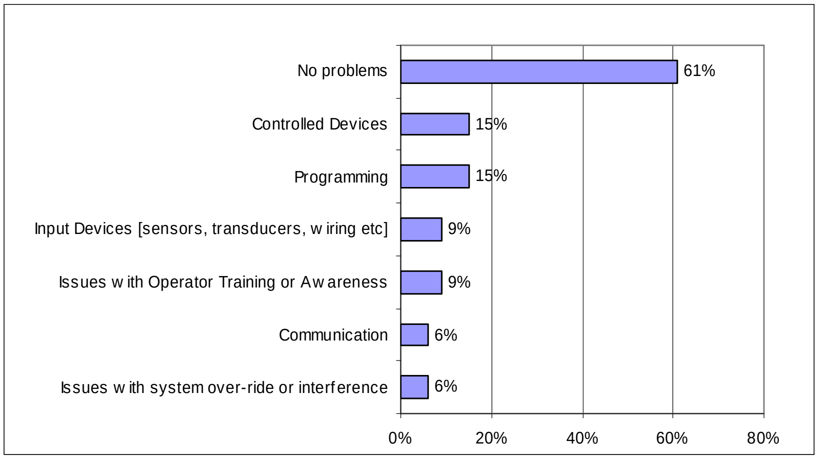
Sixty-eight percent were satisfied with the BAS functionality.

57. Do you or your BAS operator know how to:



Over 60% know how to change the BAS schedule, change the set points and change the sequence of operations.

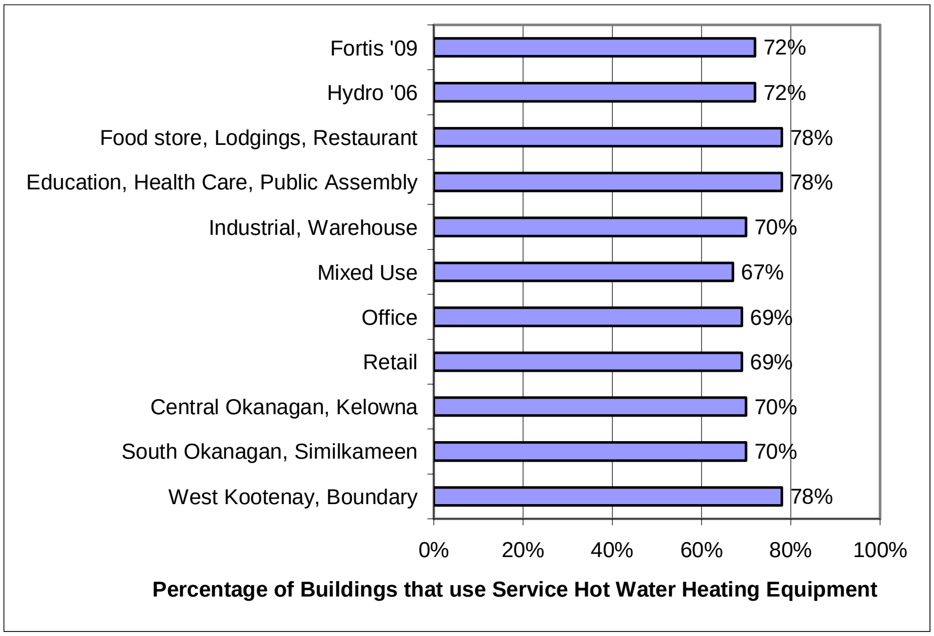
58. Please check up to three selections that represent the most common problems with your BAS.



If there are problems with the BAS, the most common are with:
- controlled devices and
- programming

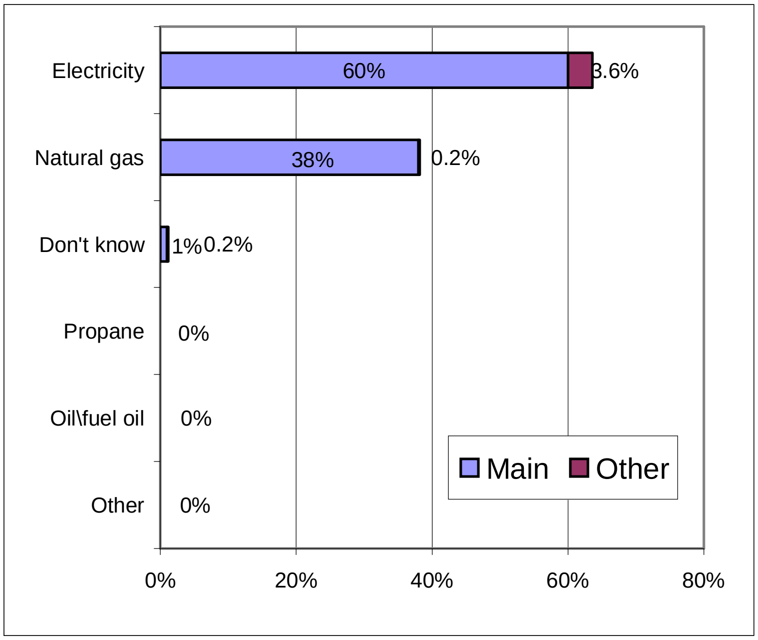
I. Service Water Heating Equipment

59. Is there service hot water heating equipment used in the building?



Seventy-two percent of buildings use service hot water heating equipment.

60. What is the main fuel type or energy source used by the service water heating system(s) for the building? If the building uses more than one fuel type for service hot water system(s), indicate any additional systems as other fuel types.



Sixty-four percent of the hot water equipment is heated by electricity and 38% by natural gas. No other fuels were mentioned.

MAIN fuel type or energy source

		Type of building					
		Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
“What is the main fuel type or energy source used by the service water heating system(s) for the building?”	“Electricity”	61%	52%	60%	61%	61%	70%
	“Natural gas”	39%	45%	38%	37%	39%	30%
	“Don't know”		2%				
	“Propane”			1%	2%		
	“Oil\fuel oil”			1%			
	“Other”		1%				
Total	Base	35	63	47	34	28	63

Base: respondents with service hot water heating equipment

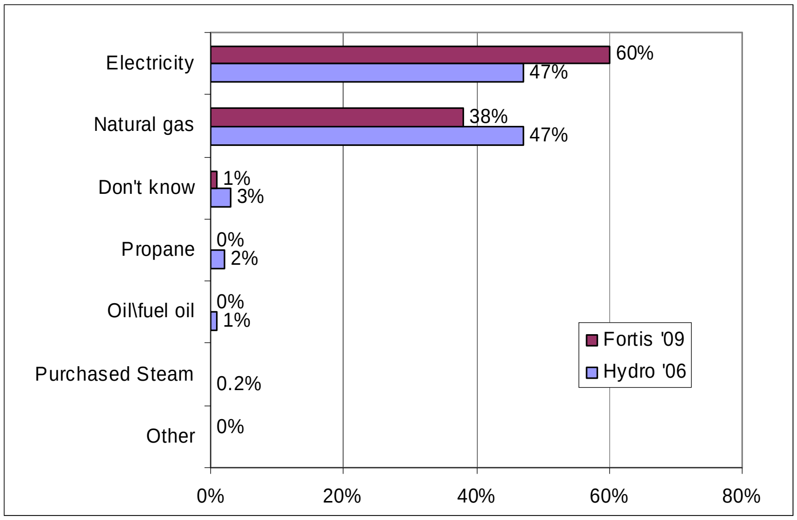
Electricity is used least by Education / Health Care / Public Assembly buildings (52%) and most in Retail establishments (70%) to heat water.

MAIN fuel type or energy source

		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
“What is the main fuel type or energy source used by the service water heating system(s) for the building?”	“Electricity”	54%	56%	72%
	“Natural gas”	46%	43%	24%
	“Don't know”		1%	1%
	“Propane”			2%
	“Oil\fuel oil”			1%
	“Other”			1%
Total	Base	87	107	81

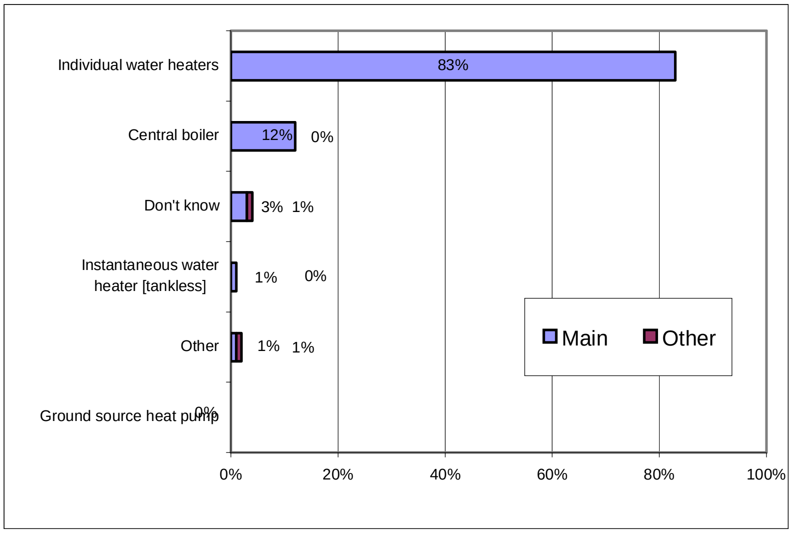
Base: respondents with service hot water heating equipment

Buildings in the West Kootenay are most likely to use electricity to heat water. Buildings in the Central Region (54%) and South Okanagan (56%) are less likely to use electricity.



Electricity is a more common energy source among Fortis customers than Hydro customers for service hot water heating systems.

61. What is the main type of hot water equipment used to produce service hot water in the building? If more than one type of service hot water system is used in the building, indicate any additional systems as other systems.



Individual water heaters are the main source of hot water (83%) with only 12% mentioning central boilers.

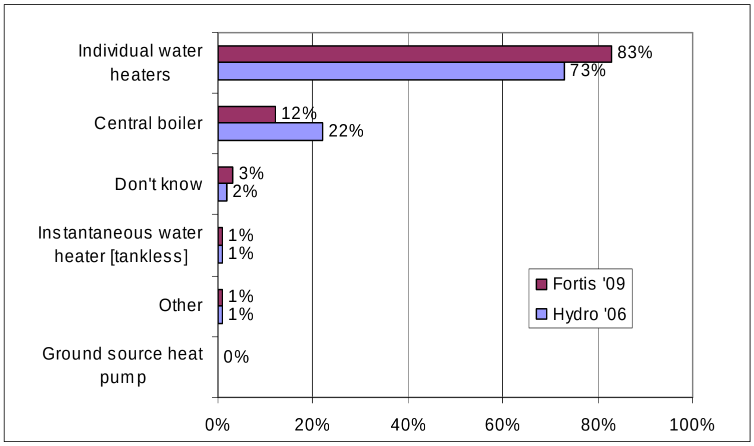
MAIN type of hot water equipment

		Type of building					
		Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
"What is the main type of hot water equipment used to produce service hot water in the building? If more than one type of service hot water system is used in the building?"	"Individual water heaters"	83%	76%	81%	78%	91%	92%
	"Central boiler"	10%	18%	12%	20%	9%	6%
	"Don't know"	6%	4%	3%	2%		
	"Instantaneous water heater [tankless]"			4%			
	"Other"		1%				2%
	"Ground source heat pump"	2%					
Total	Base	33	63	46	34	27	61

Base: respondents with service hot water heating equipment

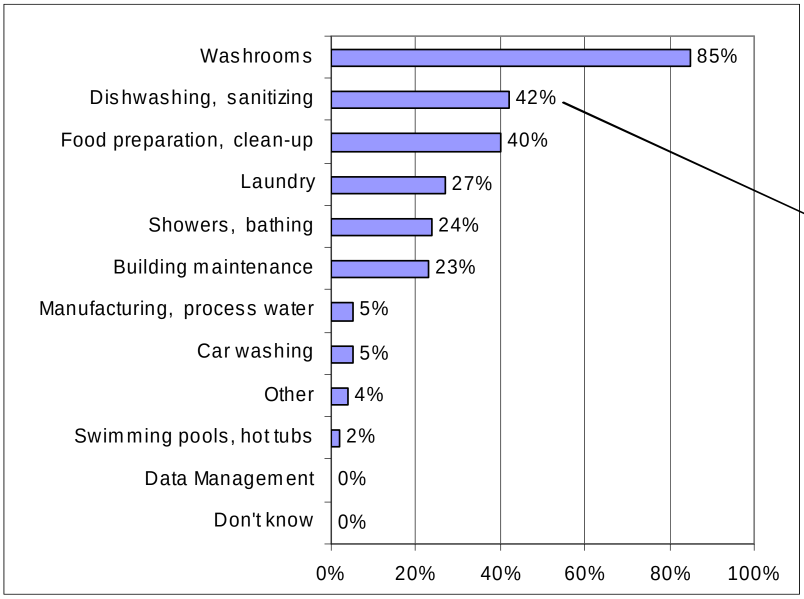
Offices (91%) and Retail outlets (92%) have the highest incidence of individual hot water heaters.
Education / Health Care / Public Assembly (18%) and Mixed Use (20%) the highest incidence of central boilers.

Main type of hot water equipment



Central Boilers are more common among Hydro commercial customers than Fortis.

62. What are the main uses for service hot water in the building?



Hot water is used in 85% of the buildings for washrooms, 42% for dishwashing, and 40% for food preparation.

		Total
"Do your dishwashers have electric booster heaters?"	"Yes"	40%
	"No"	43%
	"Don't know"	17%
Total	Base	92

Base: Respondents with service hot water heating equipment used for dishwashing, sanitizing

Among respondents that use hot water for dishwashing, 40% have electric booster heaters.

		Type of building					
		Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
What are the main uses for service hot water in the building?	"Washrooms"	76%	80%	92%	85%	84%	89%
	"Dishwashing, sanitizing"	67%	54%	17%	46%	39%	32%
	"Food preparation, clean-up"	75%	58%	14%	47%	16%	28%
	"Laundry"	56%	19%	12%	39%	7%	28%
	"Showers, bathing"	54%	10%	26%	41%	12%	15%
	"Building maintenance"	27%	21%	22%	32%	19%	20%
	"Manufacturing, process water"	4%		15%	11%		4%
	"Car washing"			3%	13%		10%
	"Other"		12%	3%	4%		2%
	"Swimming pools, hot tubs"	5%	1%				4%
	"Data Management"		2%				
	"Don't know"				2%		
Total	Responses	131	169	95	110	48	151
	Base	36	66	47	34	27	65

Base: Respondents with service hot water heating equipment
Column percentages may exceed 100% because multiple responses provided

Use of hot water for dishwashing was lowest in Industrial / Warehouse (17%). Food preparation was most common in the Food Store / Lodgings / Restaurant category (75%) and in Education / Health Care / Public Assembly buildings (58%).
Laundry made up 56% and showers / bathing (54%) of hot water use in Food / Lodging / Restaurant establishments.

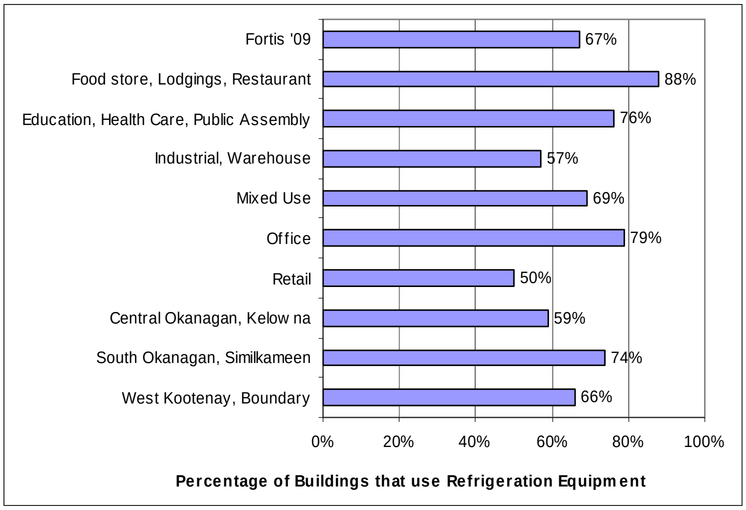
		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
What are the main uses for service hot water in the building?	"Washrooms"	93%	80%	82%
	"Dishwashing, sanitizing"	41%	46%	38%
	"Food preparation, clean-up"	26%	50%	44%
	"Laundry"	25%	33%	21%
	"Showers, bathing"	22%	28%	21%
	"Building maintenance"	15%	28%	25%
	"Manufacturing, process water"	4%	9%	2%
	"Car washing"	4%	6%	4%
	"Other"	4%	4%	5%
	"Swimming pools, hot tubs"	1%	3%	2%
	"Data Management"	1%		
	"Don't know"			1%
Total	Responses	210	308	201
	Base	88	108	82

Base: Respondents with service hot water heating equipment
Column percentages may exceed 100% because multiple responses provided

Fifty percent of the hot water produced in buildings in the South Okanagan is used for food preparation and clean-up, compared to 26% in the Central Region. Only 15% of hot water is used for building maintenance in the Central Region compared to the South Okanagan (28%) and 21% in the West Kootenay.

J. Refrigeration Equipment

63. Is there refrigeration equipment used on your electrical account?



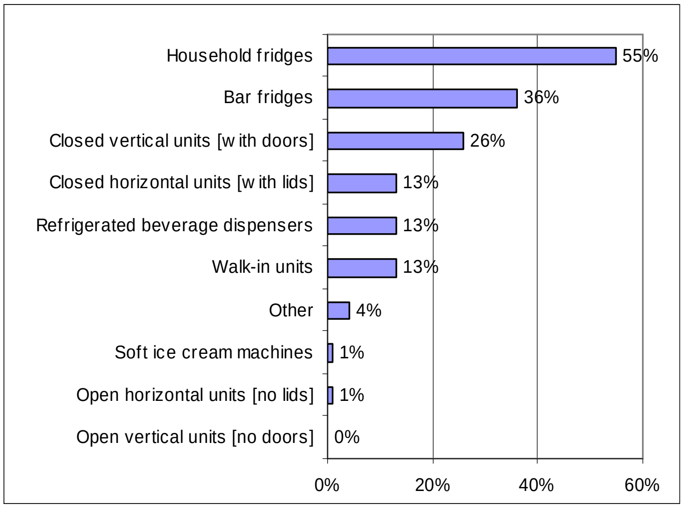
Almost 7 in 10 businesses have refrigeration equipment, with Food Stores / Lodgings / Restaurants being the most likely to have this type of equipment (88%). Retail (50%) and Industrial / Warehouse (57%) facilities are the least likely.

Refrigeration equipment is less likely to be found in the Central Region (59%) possibly due to a higher concentration of retail.

Please note that the rest of this section summarizes responses given by respondents with refrigeration equipment only.

64. Please indicate the number and total capacity of each of the following refrigeration units used in the building.

Type of refrigeration units used in building



Among businesses with refrigeration equipment, Household (55%) and Bar (36%) fridges make up the majority of refrigeration units.

Industrial units, which include closed vertical (26%) and horizontal (13%) units make up the next largest group. Walk-in units (13%) and beverage dispensers (13%) follow.

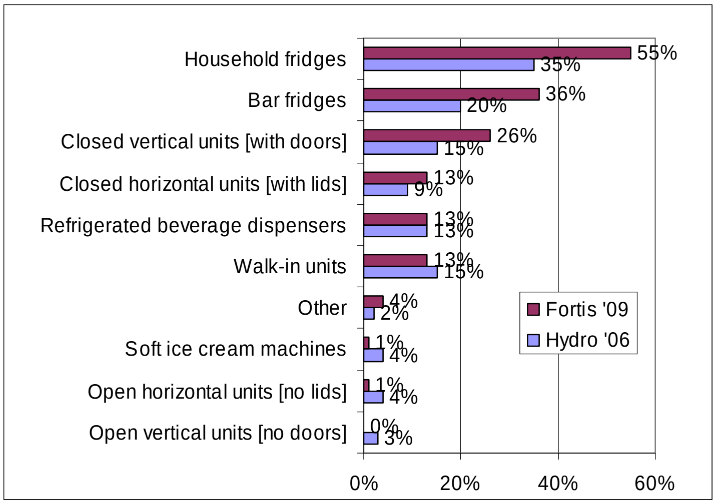
		Type of building					
		Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
Type of refrigeration units in the building	Household fridges	50%	59%	49%	80%	56%	40%
	Bar fridges	46%	30%	29%	16%	43%	46%
	Closed vertical units [with doors]	58%	31%	14%	18%	6%	18%
	Closed horizontal units [with lids]	39%	9%	9%	12%		10%
	Refrigerated beverage dispensers	15%	6%	12%	8%	19%	21%
	Walk-in units	37%	6%	13%	8%		13%
	Other	9%	2%	3%	4%		6%
	Soft ice cream machines	5%					1%
	Open horizontal units [no lids]	5%					
	Open vertical units [no doors]	3%					
Total	Responses	101	86	46	47	38	71
	Base	38	60	35	32	30	46

Base: Respondents with refrigeration units used in building
Column percentages may exceed 100% because multiple responses provided

Mixed Use buildings are the most likely to have regular household fridges (80%) with very few other types of refrigeration on site.

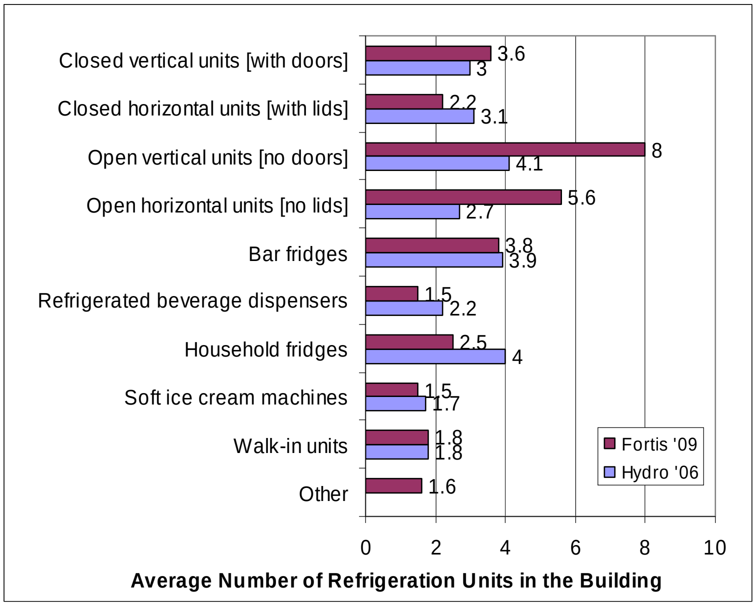
Food Stores / Lodgings / Restaurants have the widest number of refrigeration types especially the closed vertical (58%) and horizontal (39%) types and walk-in units (37%).

Retailers also have a variety of refrigeration units, especially beverage dispensers.



There is a higher percentage of household and bar fridges among FortisBC customers compared to the Hydro sample.

Number of Refrigeration Units



Although the number of buildings with open vertical (5%) and horizontal (3%) units is very low, the number of units per site is the highest - verticals 8/site and horizontals 5.6/site.

Typical Size

Please indicate the total capacity of refrigeration units used in the building:

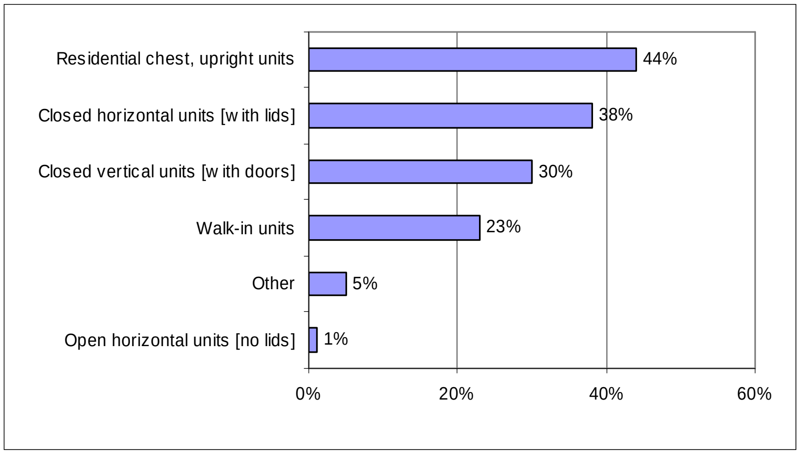
			Type of building					
		Total	Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
Closed vertical units [with doors]	Mean linear ft	18	31	6	2	14	8	4
	Base	26	12	7	1	3	1	2
Closed horizontal units [with lids]	Mean linear ft	8	9	.	3	10	.	6
	Base	12	8	0	1	1	0	1
Open vertical units [no doors]	Mean linear ft	4	4	.	.	.	.	.
	Base	1	1	0	0	0	0	0
Open horizontal units [no lids]	Mean linear ft	12	12	.	.	.	.	.
	Base	1	1	0	0	0	0	0
Bar fridges	Mean cubic ft	8	17	4	5	9	4	4
	Base	45	11	5	6	2	9	11
Refrigerated beverage dispensers	Mean cubic ft	5	8	2	.	3	5	5
	Base	10	1	1	0	1	4	2
Household fridges	Mean cubic ft	13	13	14	15	13	10	11
	Base	66	8	17	5	18	6	11
Soft ice cream machines	Mean cubic ft	1	1	.	.	.	.	.
	Base	1	1	0	0	0	0	0
Walk-in units	Mean cubic ft	1254	192	600	4945	200	.	598
	Base	16	8	1	3	1	0	3
Other	Mean cubic ft or linear ft	217706	10	.	15	921140	.	3
	Base	5	1	0	1	1	0	1

Base sizes include only cases where average capacity provided
Average capacity do not include zeros

As would be expected, Industrial / Warehouse facilities have large walk-in refrigeration units (4945 cubic ft). One Mixed Use facility reports a massive refrigeration unit of over 900,000 cubic ft.

65. Please indicate the number and total capacity of each of the following freezer units used in the building?

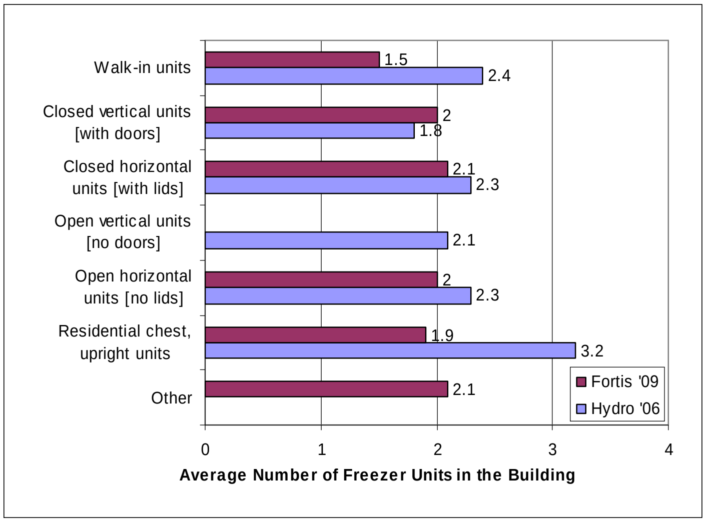
Type of Freezer Units used in building



Base: businesses with freezer units

Among businesses with freezer units, Residential chest upright freezers are found in 44% of buildings. Thirty-eight percent of the buildings have horizontal freezer units and 30% vertical freezers. Twenty-three percent of buildings have walk-in units.

Number of Freezer Units



Among businesses with walk-in units, the average number of units is 1.5. Among businesses with other types of freezer units, most have an average of about 2 units.

Capacity of Freezer Units

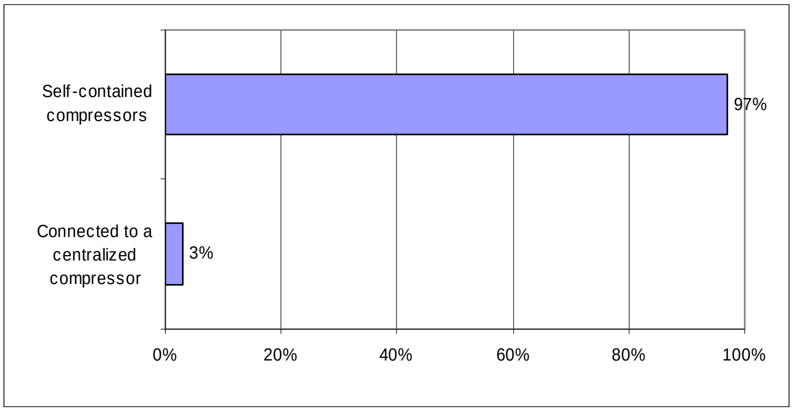
Please indicate the total capacity of freezer units used in the building:

		Total	Type of building					
			Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
Walk-in units	Mean cubic ft	638	201	.	911	2000	.	.
	Base	13	7	0	5	1	0	0
Closed vertical units [with doors]	Mean linear ft	27	29	.	.	14	.	.
	Base	10	9	0	0	1	0	0
Closed horizontal units [with lids]	Mean linear ft	10	9	9	21	20	6	5
	Base	15	6	4	1	1	1	2
Residential chest, upright units	Mean cubic ft	13	14	11	9	14	18	10
	Base	24	10	4	1	5	1	3
Other	Mean cubic ft, linear ft	3	.	.	2	4	.	.
	Base	2	0	0	1	1	0	0

Base sizes include only cases where average capacity provided
Average capacity do not include zeros

Among respondents who provided a capacity for their walk- in units, the average capacity was 638 cubic feet.

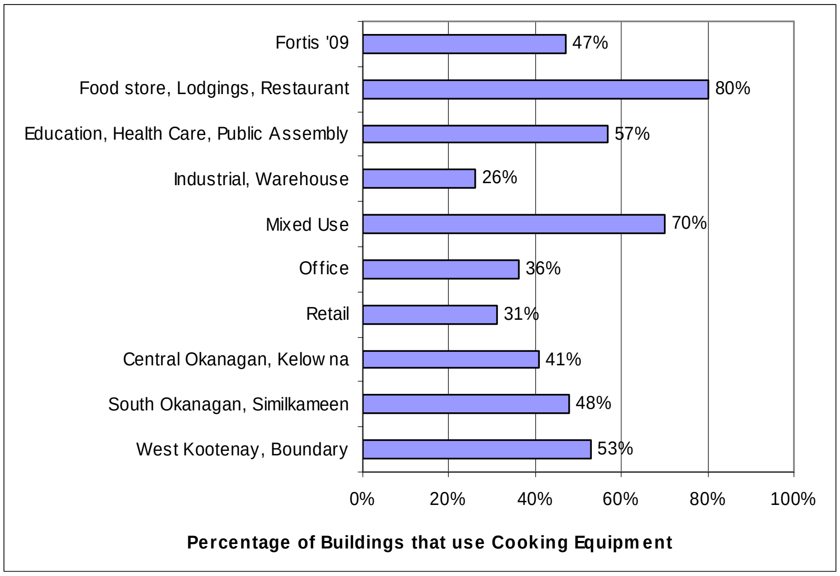
66. What percentage of your refrigerator/freezer units have self-contained compressors and what percent are connected to a centralized compressor, usually located in an equipment room?



Almost all (97%) of the freezer units were reported to have self-contained compressors.

K. Cooking Equipment

67. Is there cooking equipment used on your electrical account?



Less than half the buildings in the sample have cooking equipment on their electrical account.

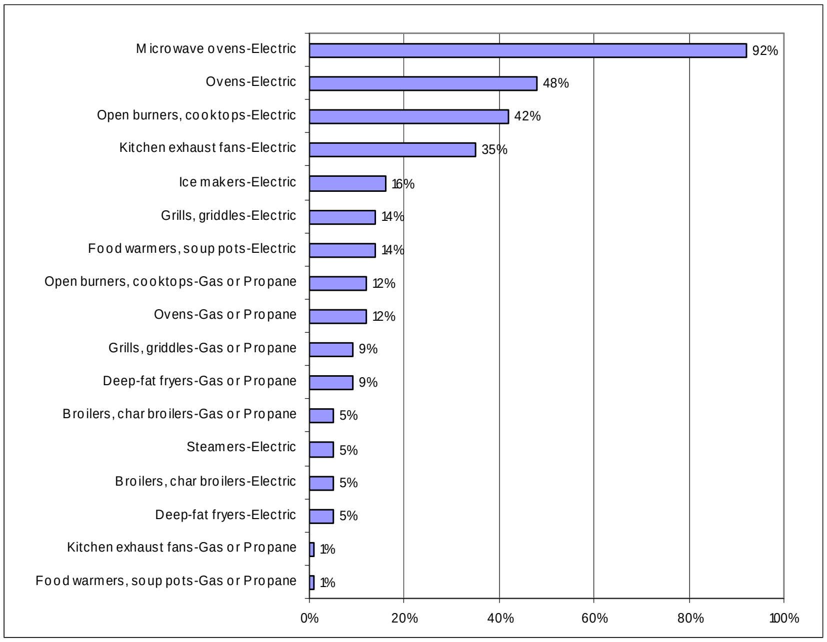
Food Stores / Lodgings / Restaurants (80%) and Mixed Use buildings (70%) being the highest and Industrial / Warehouse facilities the lowest (26%).

The highest incidence occurs in the West Kootenay (53%) and the lowest in the Central Region (41%).

Please note that the rest of this section summarizes responses given by respondents with cooking equipment only.

68. Please estimate the number of appliances in the building that use electricity, natural gas, or propane.

Type of Electrical, Natural Gas or Propane Appliances used in Building



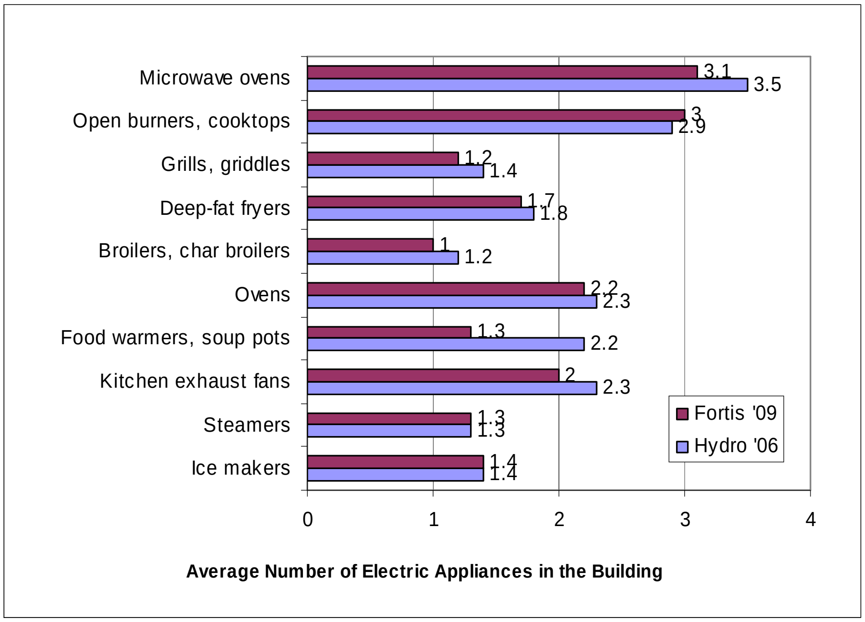
Among respondents with cooking equipment, Microwaves are found in almost all buildings (92%), whereas electric ovens (48%) and electric cooktops (42%) are not as common.

		Type of building					
		Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
Appliances in the building that use electricity, gas or propane	Microwave ovens-Electric	88%	93%	93%	83%	100%	96%
	Ovens-Electric	57%	64%	26%	45%	17%	37%
	Open burners, cooktops-Electric	54%	59%	22%	43%	16%	20%
	Kitchen exhaust fans-Electric	64%	45%		24%	8%	30%
	Ice makers-Electric	48%	1%	7%	8%	8%	15%
	Grills, griddles-Electric	20%	13%		11%	8%	24%
	Food warmers, soup pots-Electric	45%	9%		6%		13%
	Ovens-Gas or Propane	30%	15%		8%		4%
	Open burners, cooktops-Gas or Propane	30%	9%		4%		15%
	Deep-fat fryers-Gas or Propane	32%			11%		5%
	Grills, griddles-Gas or Propane	24%	5%		11%		2%
	Steamers-Electric	15%	1%		4%		9%
	Broilers, char broilers-Gas or Propane	24%			4%		
	Broilers, char broilers-Electric	10%			4%		13%
	Deep-fat fryers-Electric	8%	2%		4%		11%
	Kitchen exhaust fans-Gas or Propane		3%		3%		
	Food warmers, soup pots-Gas or Propane				3%		
Total	Responses	187	159	25	98	24	87
	Base	34	50	17	35	15	30

Base: Respondents with cooking equipment
Column percentages may exceed 100% because multiple responses provided

It certainly seems that apart from the use of microwaves, little cooking is performed in Offices and Industrial / Warehouses. Not surprisingly, propane stoves, grills, and fryers occur most frequently in the Food Store / Lodgings / Restaurant category.

Number of Electric Appliance Units



Among buildings with microwave ovens, the average number of microwave ovens is 3.1 and the average number of open burners/ cooktops is 3.0. Similar results were noted between the Fortis 2009 and BC Hydro 2006 study regarding numbers of electric food production appliances.

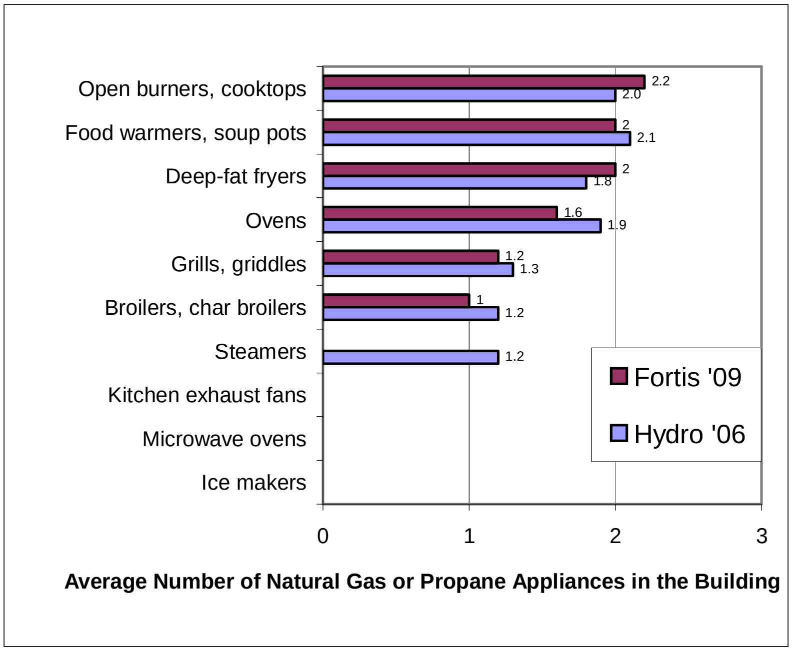
Please estimate the number of electric appliances in the building:

		Type of building					
		Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
Microwave ovens	Mean Units	10.0	1.5	1.1	2.0	1.4	1.8
	Base	30	46	16	30	15	29
Open burners, cooktops	Mean Units	6.6	2.2	1.4	1.6	1.5	1.7
	Base	18	29	4	15	2	6
Grills, griddles	Mean Units	1.3	1.4	.	1.0	1.0	1.1
	Base	7	7	0	4	1	7
Deep-fat fryers	Mean Units	2.0	1.0	.	1.0	.	2.0
	Base	3	1	0	1	0	3
Broilers, char broilers	Mean Units	1.0	.	.	1.0	.	1.0
	Base	3	0	0	1	0	4
Ovens	Mean Units	4.8	1.5	1.3	1.4	1.0	1.5
	Base	19	32	4	16	3	11
Food warmers, soup pots	Mean Units	1.4	1.0	.	1.0	.	1.8
	Base	15	4	0	2	0	4
Kitchen exhaust fans	Mean Units	2.5	2.2	.	1.1	2.0	1.1
	Base	22	22	0	9	1	9
Steamers	Mean Units	1.5	2.0	.	1.0	.	1.0
	Base	5	1	0	1	0	3
Ice makers	Mean Units	1.5	1.0	1.0	1.0	3.0	1.4
	Base	16	1	1	3	1	5

Base: respondents with cooking equipment; Base includes only cases where at least one appliance listed
Averages do not include zero appliances

In most buildings there are 1 to 2 microwaves and cooktop stoves and ovens. In the Food / Lodgings / Restaurant category, there is an average of 10 microwaves, 7 electrical cooktops, and 5 ovens.

Number of Natural Gas or Propane Appliances Units



Among businesses with open burners/ cooktops, they had an average of 2.2. The results for Fortis and Hydro were similar.

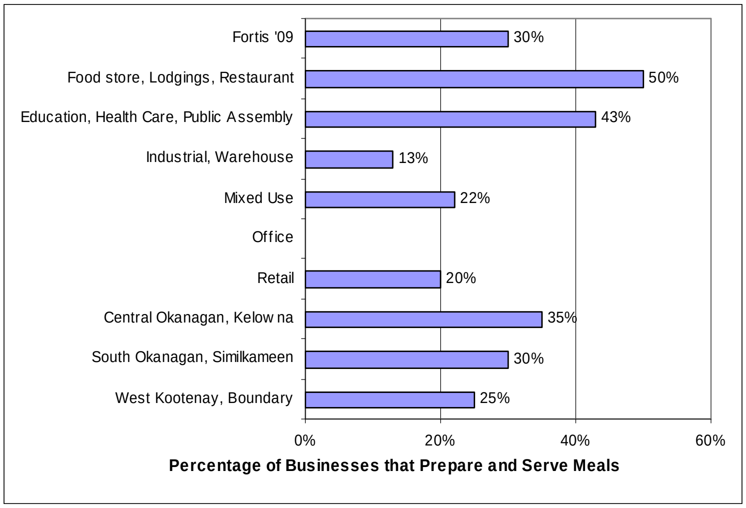
Please estimate the number of natural gas or propane appliances in the building:

		Type of building			
		Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Mixed Use	Retail
Microwave ovens	Mean Units	.	.	.	.
	Base	0	0	0	0
Open burners, cooktops	Mean Units	1.8	3.8	4.0	1.0
	Base	10	5	1	4
Grills, griddles	Mean Units	1.3	1.0	1.0	1.0
	Base	8	3	4	1
Deep-fat fryers	Mean Units	2.3	.	1.3	2.0
	Base	11	0	4	1
Broilers, char broilers	Mean Units	1.0	.	1.0	.
	Base	8	0	1	0
Ovens	Mean Units	1.8	1.4	1.5	1.0
	Base	10	7	3	1
Food warmers, soup pots	Mean Units	.	.	2.0	.
	Base	0	0	1	0
Kitchen exhaust fans	Mean Units	.	.	.	.
	Base	0	0	0	0
Steamers	Mean Units	.	.	.	.
	Base	0	0	0	0
Ice makers	Mean Units	.	.	.	.
	Base	0	0	0	0

Base: respondents with cooking equipment; Base includes only cases where at least one appliance listed
Averages do not include zero appliances

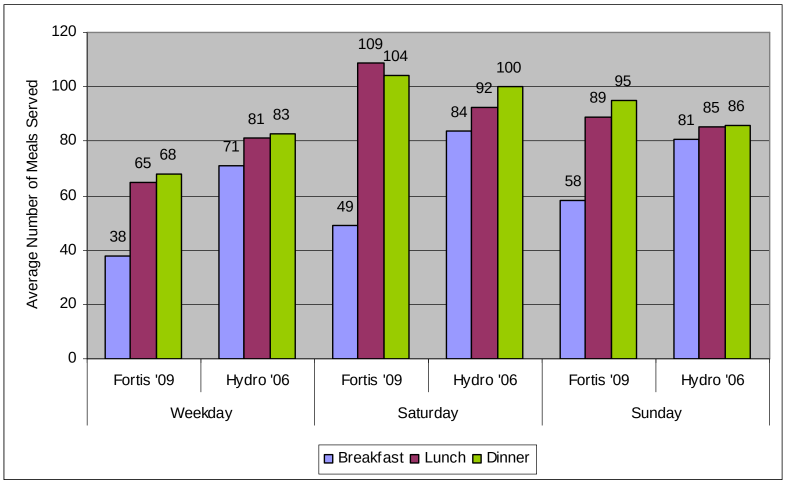
Gas stoves are more likely found in facilities that cater to larger numbers of people - the Education / Health Care / Public Assembly (3.8 stoves) and Mixed Use (4.0 stoves).

69a. Does your business prepare and serve meals?



Thirty percent of survey respondents indicated that meals were prepared on their premises with the highest being the Food Store / Lodgings / Restaurant category (50%), Education / Health Care / Public Assembly (43%), and lowest in Office buildings (0%).

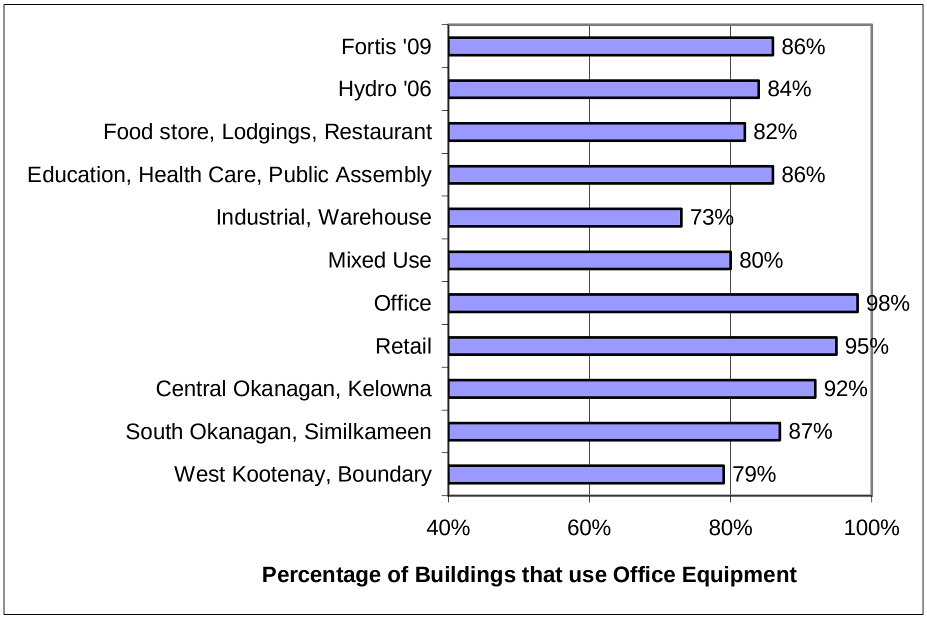
69b. If yes, please indicate the typical number of meals served in one day for each type of day:



Saturday meal production is the highest for lunches (109 meals) and dinner (104 meals). There are more Sunday breakfasts produced (58 meals) than on Saturday (49 meals) and midweek (38 meals).

L. Office Equipment and Other Commercial Equipment

70a. Is there office equipment used on your electrical account?

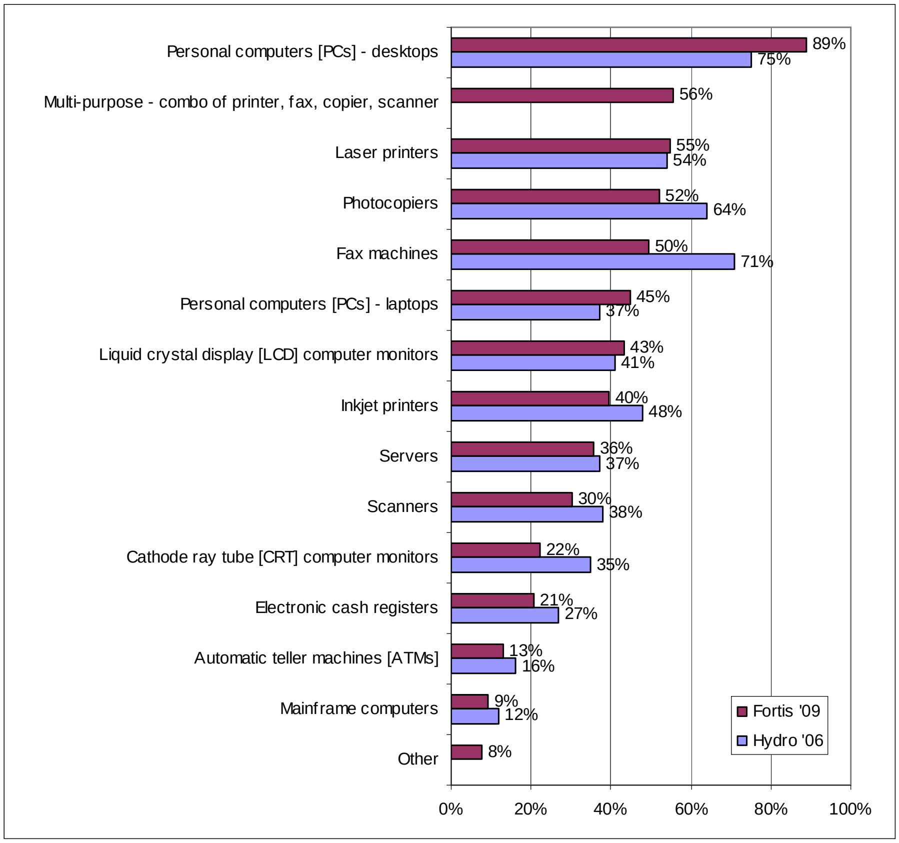


86% of all buildings have business machines that are electrically powered, led by Offices at 98% and the lowest being Industrial / Warehouse facilities at 73%.

Reflecting the different business / industrial structure of the three regions, 92% of Central Region buildings have electric office equipment on-site compared to 87% in the South Okanagan and 79% in the West Kootenay.

70b. Please estimate the number of each type of office equipment present in the building.

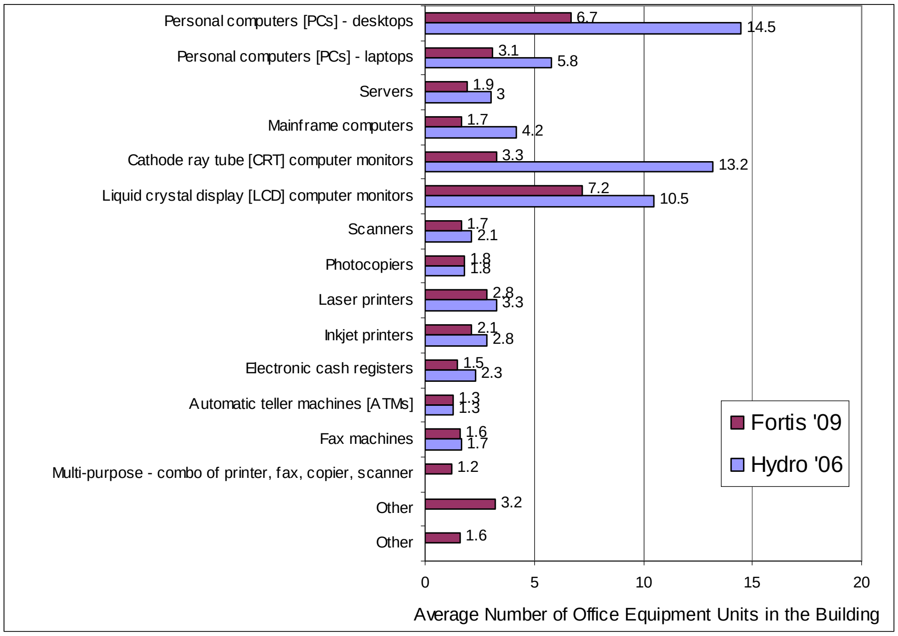
Type of Equipment Used



Desktop personal computers are present in almost 90% of buildings with office equipment. Fifty percent or more have multi-purpose combo's (printers, fax, copier, scanner), laser printers, photocopiers, and fax machines.

Reflecting technological change, more desktop and laptop PCs were reported in the 2009 survey than in 2006. Multi-purpose combinations were added to the survey and photocopiers and fax machines were less reported.

Number of Units



The results from the Fortis 2009 survey of the number of units of various office equipment shows significantly lower numbers than BC Hydro's 2006 survey.

How many of the following Office equipment items do you have?

		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
Personal computers [PCs] – desktops	Mean Units	9.6	4.9	5.5
	Base	105	111	69
Personal computers [PCs] – laptops	Mean Units	4.7	2.0	2.6
	Base	52	54	38
Servers	Mean Units	2.2	1.4	2.2
	Base	52	35	28
Mainframe computers	Mean Units	1.1	1.5	3.6
	Base	13	11	6
Cathode ray tube [CRT] computer monitors	Mean Units	4.0	2.8	2.7
	Base	33	23	16
Liquid crystal display [LCD] computer monitors	Mean Units	6.9	7.8	7.2
	Base	59	43	37
Scanners	Mean Units	2.0	1.5	1.4
	Base	41	34	22
Photocopiers	Mean Units	2.6	1.4	1.5
	Base	58	66	42
Laser printers	Mean Units	3.5	2.5	2.2
	Base	69	64	44
Inkjet printers	Mean Units	2.6	1.8	1.9
	Base	47	53	26
Electronic cash registers	Mean Units	1.1	1.7	1.6
	Base	12	31	23
Automatic teller machines [ATMs]	Mean Units	1.8	1.2	1.2
	Base	12	18	13
Fax machines	Mean Units	2.4	1.2	1.3
	Base	57	58	45
Multi-purpose – combo of printer, fax, copier, scanner	Mean Units	1.3	1.2	1.2
	Base	73	62	43
Other	Mean Units	1.2	1.6	6.9
	Base	6	7	6
Other	Mean Units	1.0	1.0	2.3
	Base	1	1	3

Base includes only cases where at least one type of office equipment listed
Averages do not include zero units

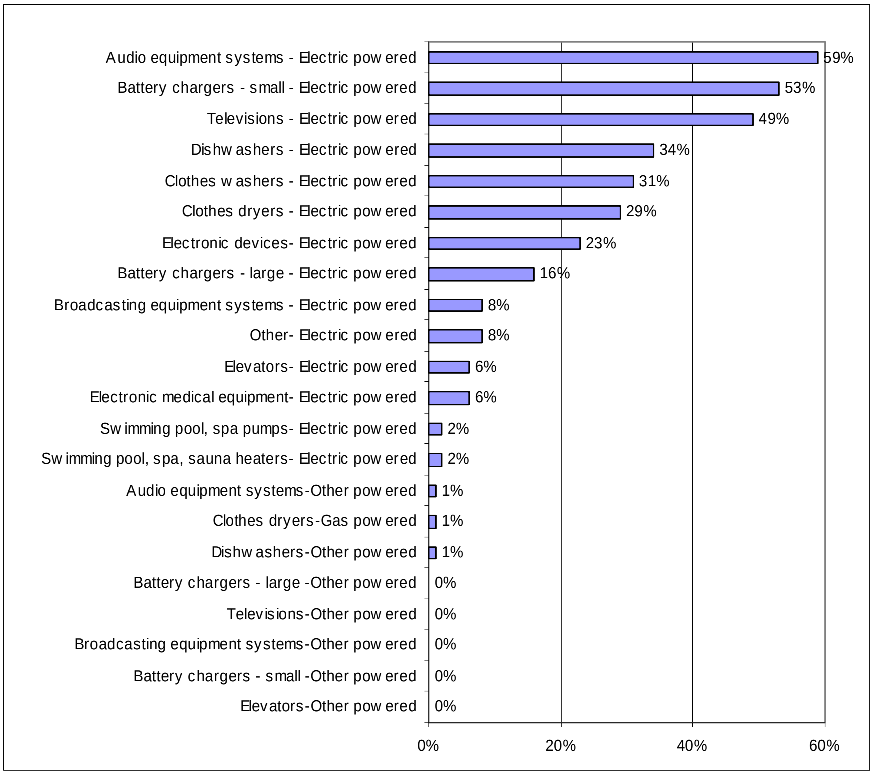
Buildings in the Central Okanagan have approximately twice as many desktop and laptop computers than the other two regions:
Desktops:
- Central 9.6
- South 4.9
- West Kootenay 5.5

Laptops:
- Central 4.7
- South 2.0
- West Kootenay 2.6

but fewer mainframes:
- Central 1.1
- South 1.5
- West Kootenay 3.6

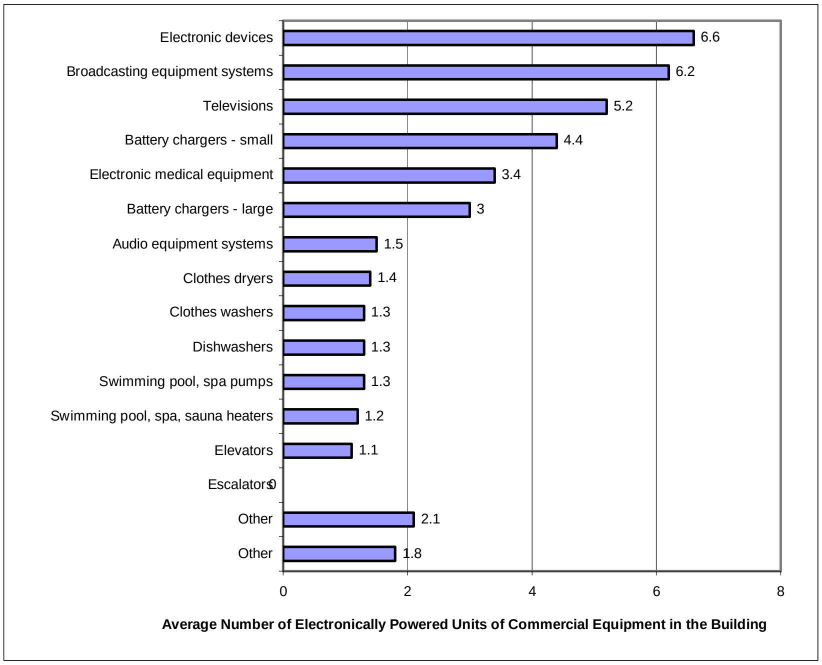
71. Number of units for each type of other commercial equipment used in the building.

Commercial equipment used in the building and the type of energy powering the equipment (Electric, Gas or Other powered)



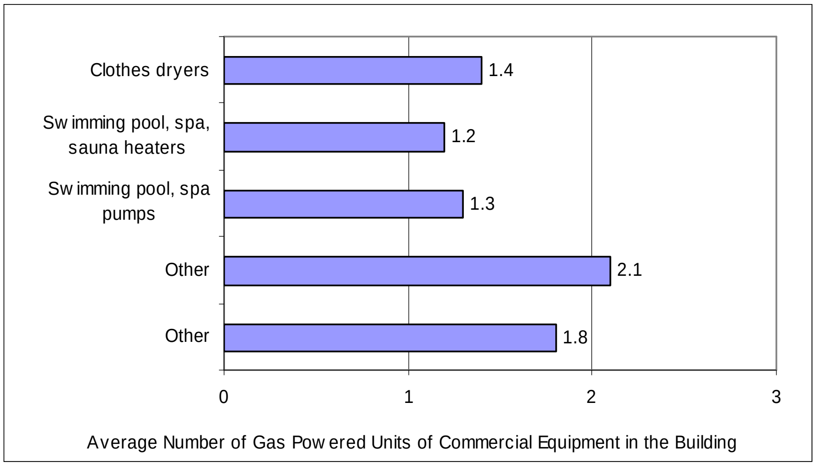
The majority of businesses (59%) have electronic audio equipment and small battery chargers (53%).

Electronically Powered Units



Among businesses that reported having electronic devices, the average number of devices was 6.6. The average number of electrically powered broadcasting equipment systems was 6.2.

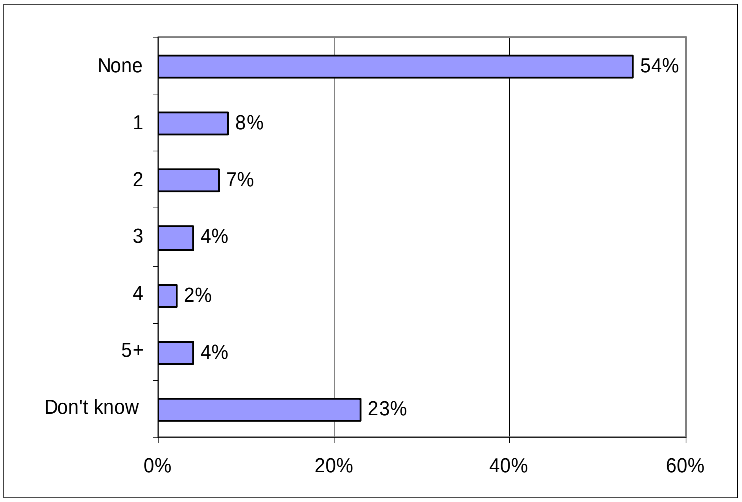
Gas Powered Units



Gas powered commercial equipment is essentially restricted to laundry and swimming pool applications. Businesses with gas powered clothes dryers had an average of 1.4.

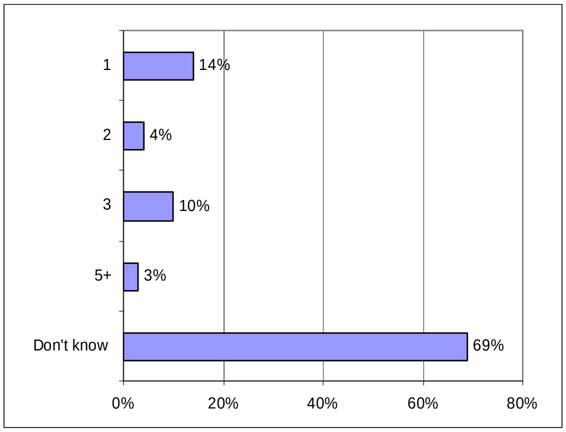
Only a few businesses used other sources of energy to power other commercial equipment. The sample size was 1 or less for most instances.

72. How many Uninterruptible Power Supplies (UPS) for systems are there within the building?



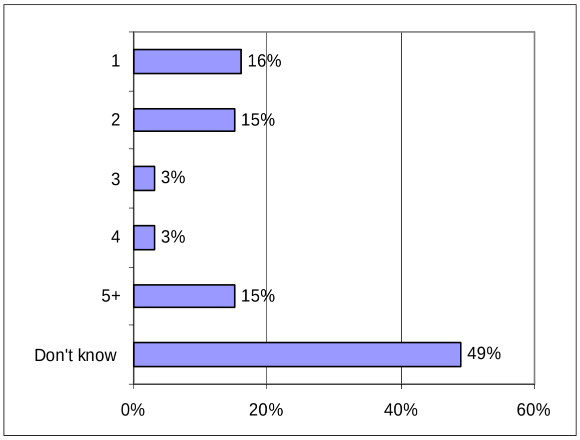
The majority of respondents who were aware of UPS protection reported none were installed in their buildings (54%).

If 1 UPS or more, please indicate how many were installed before 1998.



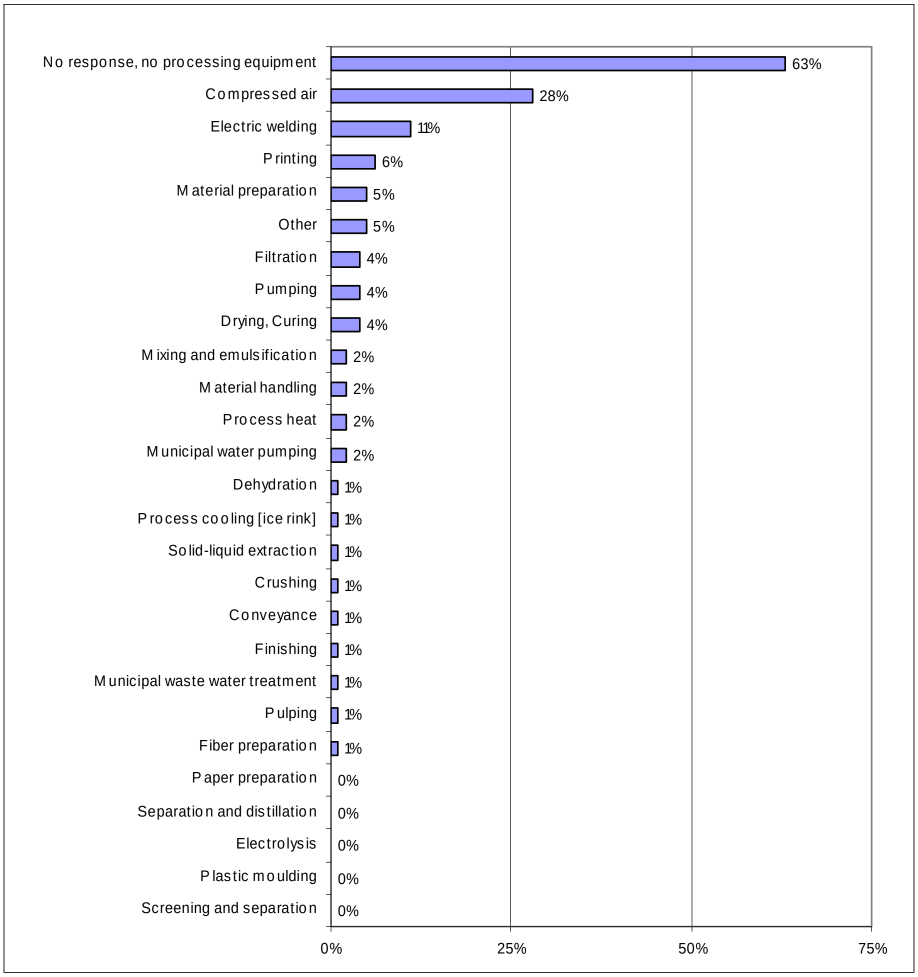
The majority of respondents did not know when the uninterrupted power source was installed.

If 1 UPS or more, please indicate how many were installed after 1998.



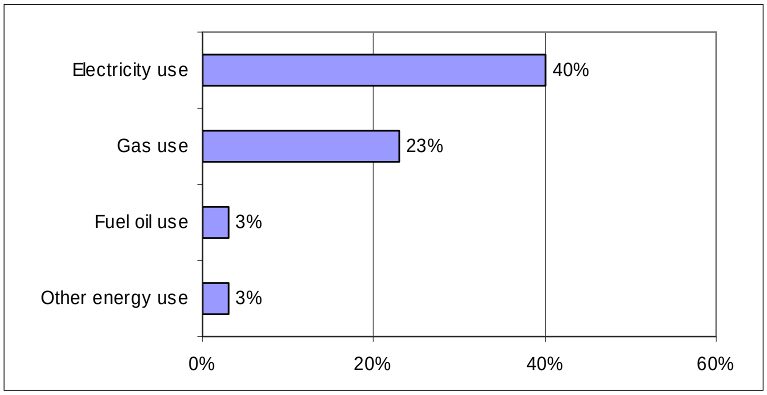
M. Process Equipment

73. Please check the types of process equipment, if any, being used on your electrical bill.



Apart from air compressors and electric welding equipment, very few respondents reported process equipment being electrically powered.

74. What percentage of the annual energy use for this space is for industrial purposes?



Among businesses that use energy for industrial purposes, on average 40% of the electricity used and 23% of gas used is for industrial processes.

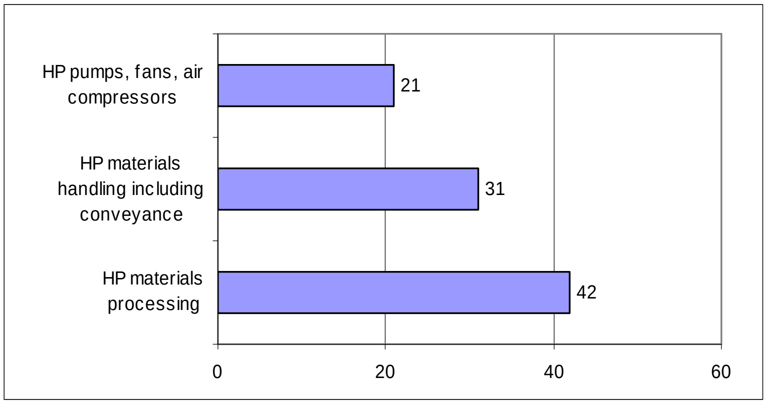
What percentage of annual energy use for this space is for industrial purposes?

		Type of building					
		Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
"Electricity use"	Mean %	16%	6%	78%	44%	28%	28%
	Base	17	32	54	28	22	50
"Gas use"	Mean %	11%	0%	44%	36%	24%	18%
	Base	16	25	28	15	21	36
"Fuel oil use"	Mean %	0%	0%	15%	0%	7%	0%
	Base	12	22	10	9	17	25
"Other energy use"	Mean %	0%	0%	14%	0%	7%	0%
	Base	12	22	10	9	17	27

Missing values not included
Average percent includes zero percent

The dependence on electricity for powering industrial applications varies widely based on the building category.

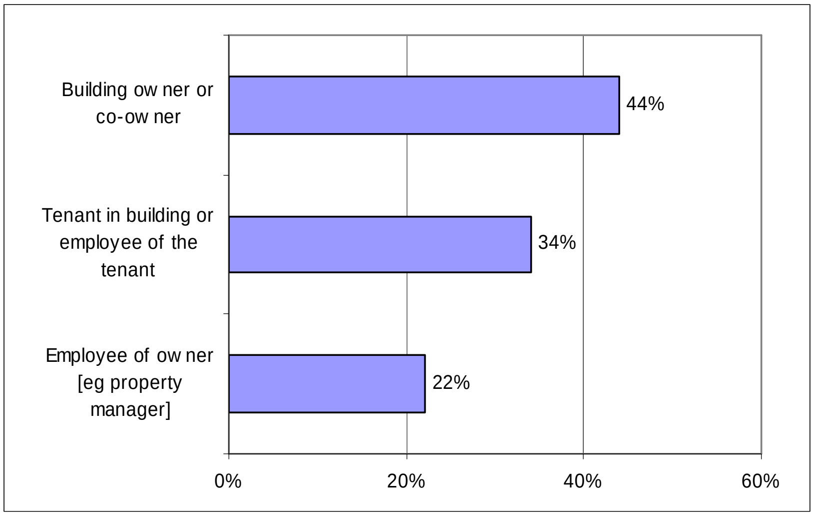
75. Please estimate the total horsepower for each type of motor used in the building?



The HP for motors used for material processing was on average 42.

N. About You

76. What is your relationship to the building?



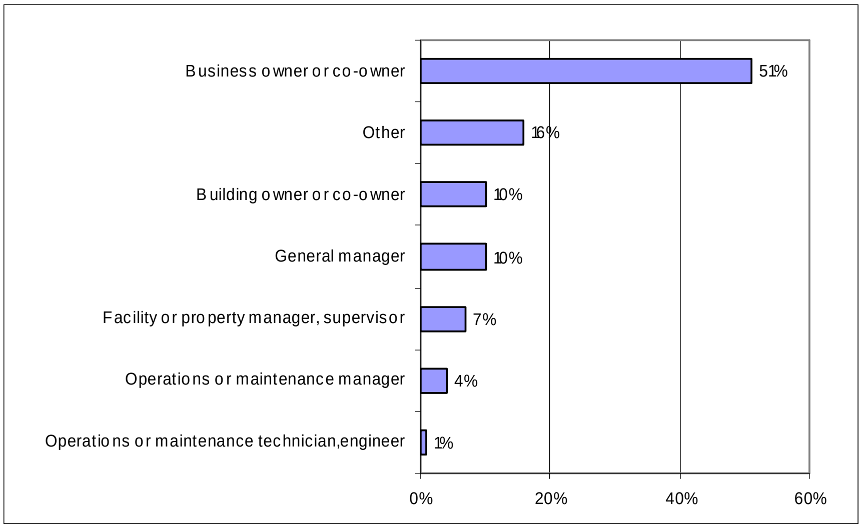
Forty-four percent of respondents were the building owners.

		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
"What is your relationship to the building?"	"Building owner or co-owner"	22%	53%	58%
	"Tenant in building or employee of the tenant"	57%	24%	21%
	"Employee of owner [eg property manager]"	21%	23%	22%
Total	Base	122	141	96

The fewest owners come from the Central Okanagan (22%) and the most from the West Kootenay (58%).

Fifty-seven percent of the respondents from the Central Region were tenant or employees of the tenants.

77. Which of the following best describes your position/title within the business:

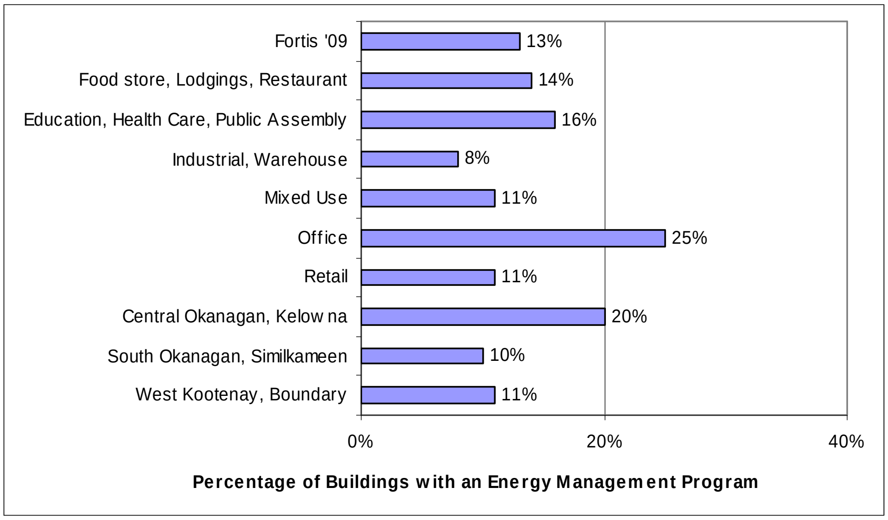


Half of the sample were the business owners.

		Type of building					
		Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
“Which of the following best describes your position\title within the business:”	“Business owner or co-owner”	67%	25%	59%	48%	28%	74%
	“Other”	9%	28%	17%	9%	20%	11%
	“General manager”	7%	11%	9%	4%	29%	7%
	“Building owner or co-owner”	12%	8%	8%	32%	10%	1%
	“Facility or property manager, supervisor”	1%	15%	5%	3%	10%	5%
	“Operations or maintenance manager”	3%	10%	2%	5%	3%	1%
	“Operations or maintenance technician,engineer”		4%				1%
Total	Base	42	75	65	48	38	90

The fewest business owners come from the Industrial / Warehouse (25%) and Office (28%) sectors, and the largest sub-sample of building owners from Mixed Use buildings (32%).

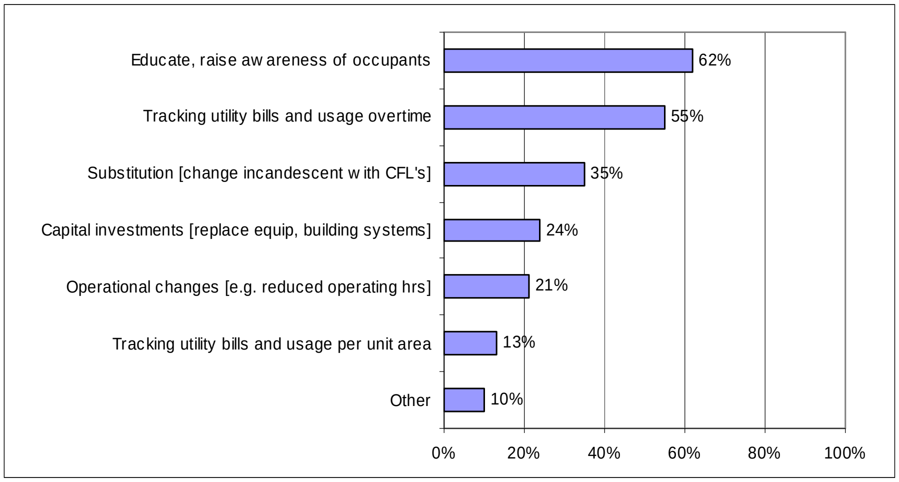
78a. Do you have an Energy Management Program in place?



Thirteen percent of all buildings have an Energy Management Program; Office buildings having the highest (25%) and Industrial / Warehouse facilities the lowest (8%).

Energy Management Programs are twice as frequently found in the Central Okanagan (20%) compared to 10%-11% in the other two regions.

78b. If yes - What energy management activities are going on?



Employee / Occupant education (62%) and monitoring energy use (55%) are the most frequently mentioned methods of managing energy consumption.

		Type of building					
		Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
If 'Yes' - What energy management activities are going on?	"Educate, raise awareness of occupants"	81%	75%	87%	25%	43%	56%
	"Tracking utility bills and usage overtime"	59%	70%	51%	50%	56%	44%
	"Substitution [change incandescent with CFL's]"	71%	31%	37%	49%	44%	11%
	"Capital investments [replace equip, building systems]"	32%	30%	37%	36%	26%	6%
	"Operational changes [e.g. reduced operating hrs]"		21%	24%	12%	32%	17%
	"Tracking utility bills and usage per unit area"		5%		75%		21%
	"Other"	10%	9%	13%		13%	12%
Total	Responses	16	31	12	13	21	19
	Base	6	13	5	5	10	11

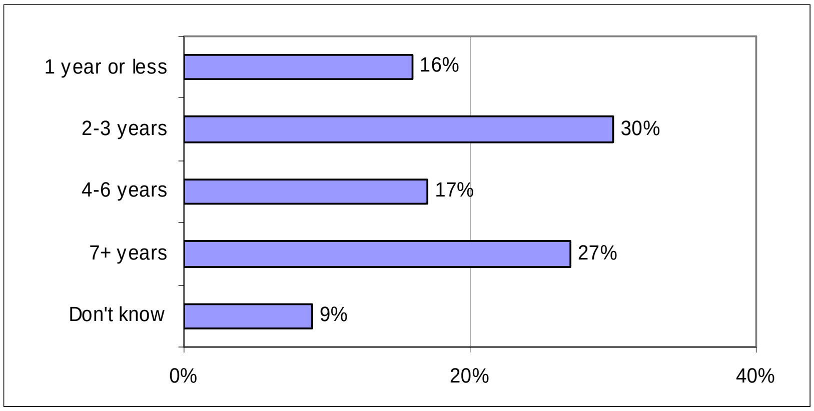
Base: Respondents with energy management programs
Column percentages may exceed 100% because multiple responses provided

Retailers are the least likely to have spent any monies to manage energy consumption.

Food Store / Lodgings / Restaurants are the most likely to have education in place and to have installed CFL's.

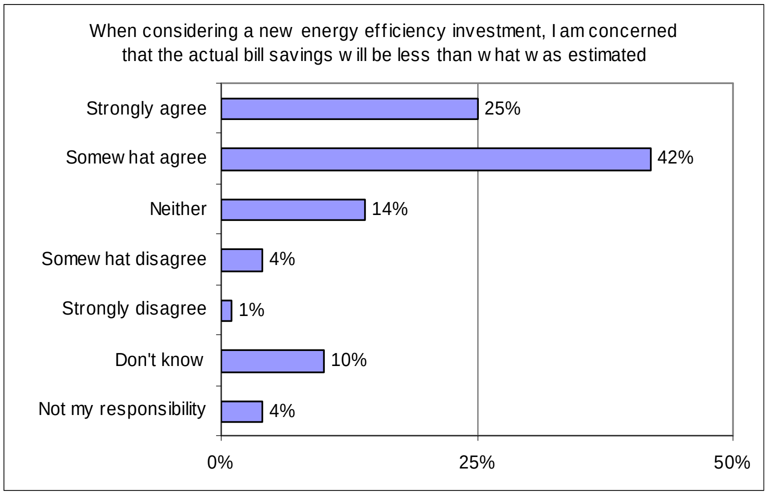
Mixed Use building managers, perhaps due to the higher incidence of owners responding from this category, are monitoring the energy consumption more closely.

78c. If yes – How long has your energy plan been in place?

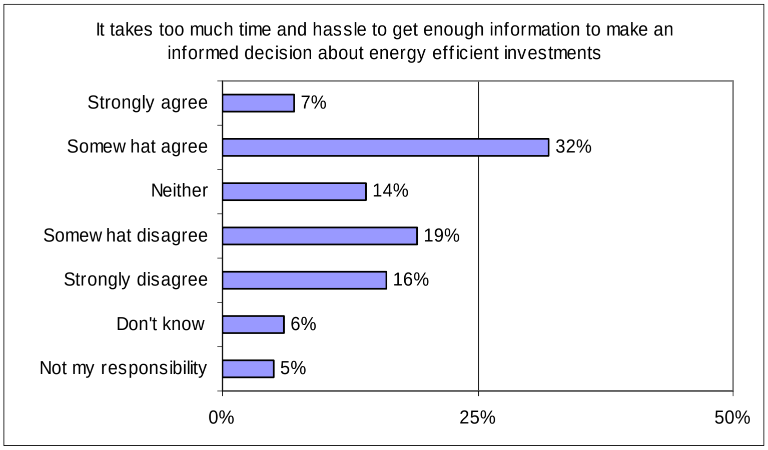


Energy plans are not new. Almost 50% have been in place for 4 years or more.

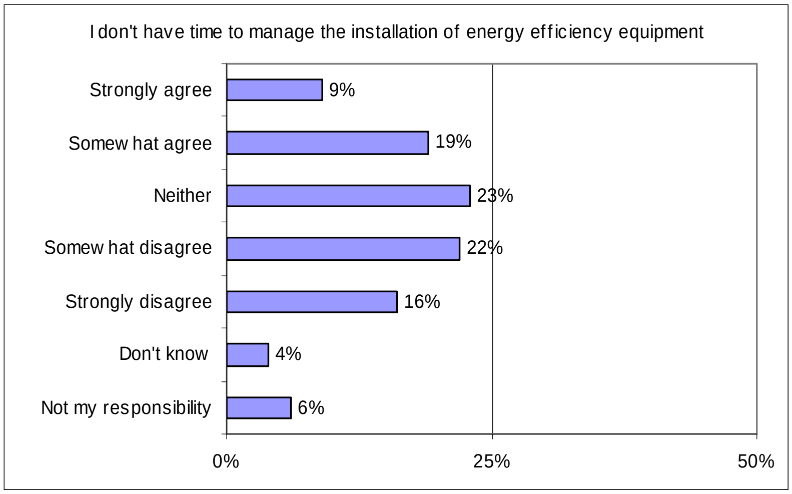
79. How well does each statement describe your beliefs about energy efficient investments or practices?



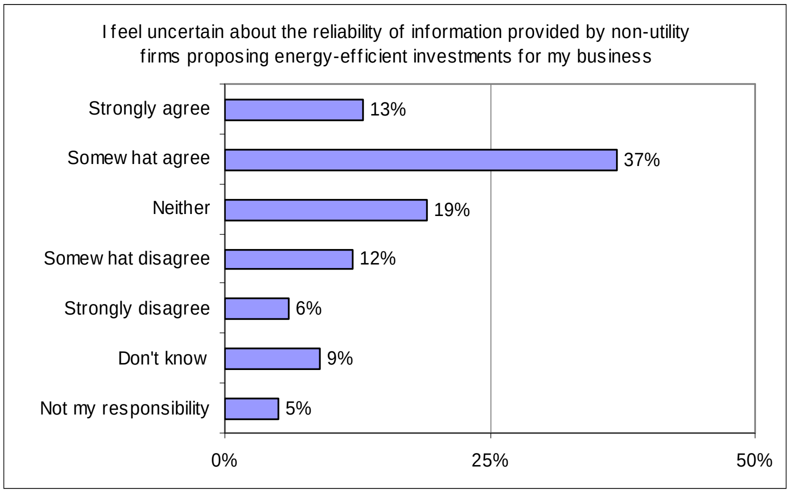
Sixty-seven percent of respondents generally expect that investments in energy efficiency will NOT result in the savings that were estimated.



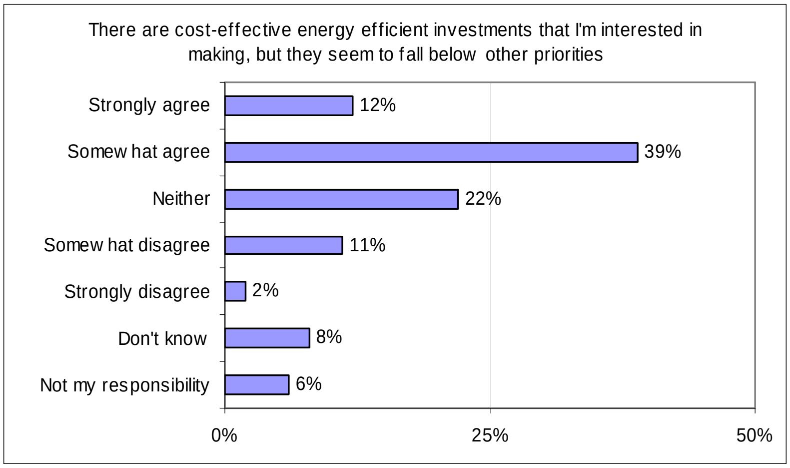
Almost as many respondents believe they have time to get this information on energy efficient investments (35%) compared to the 39% who agreed that such a process takes too much time and hassle.



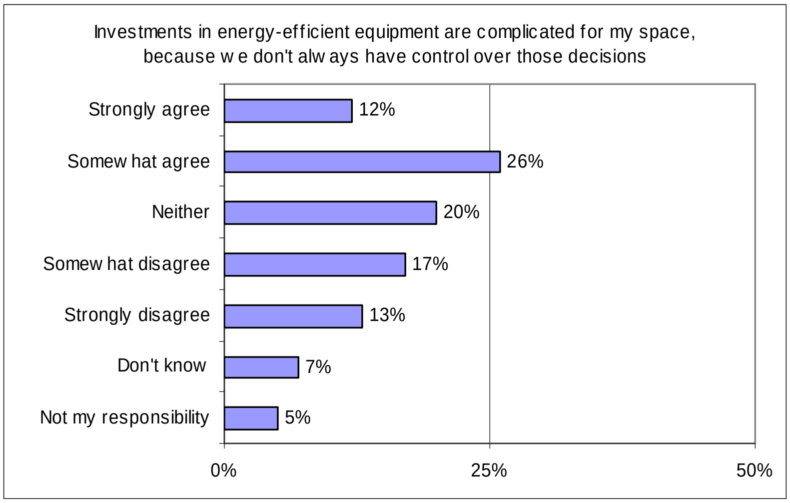
More respondents said they had time to manage the installation of energy efficient equipment (38%) than those who thought they did not have time for this process (28%).



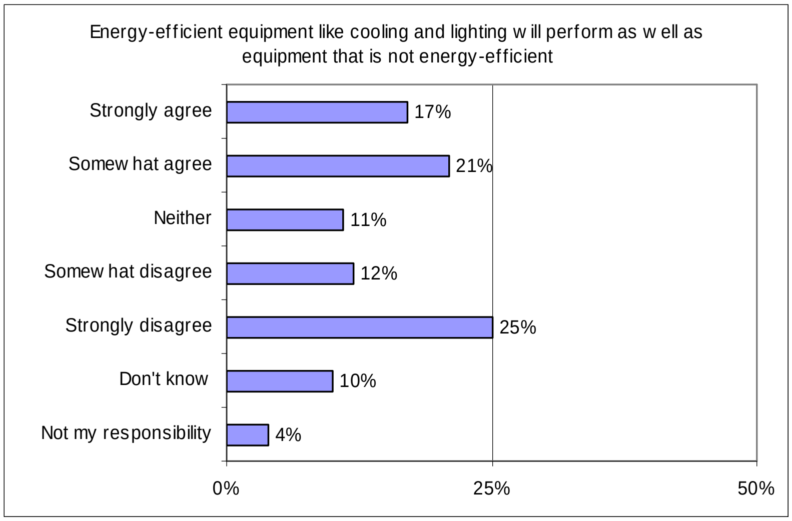
There is an uncertainty about information from non-utilities regarding proposals of energy efficient investments with 50% of those who could answer agreeing with this statement.



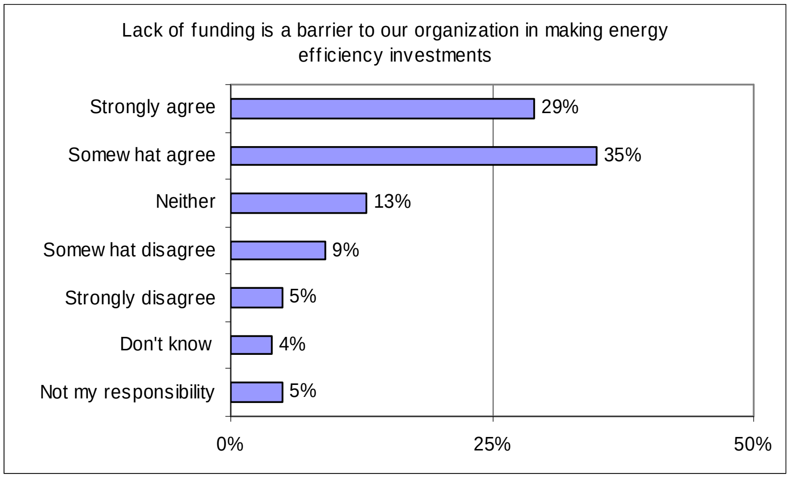
For 51%, energy efficient investments are a lower priority.



Many respondents (38%) agreed making changes to increase energy efficiency is not within their responsibility. Thirty percent, however, did not agree these types of changes would be difficult to implement.



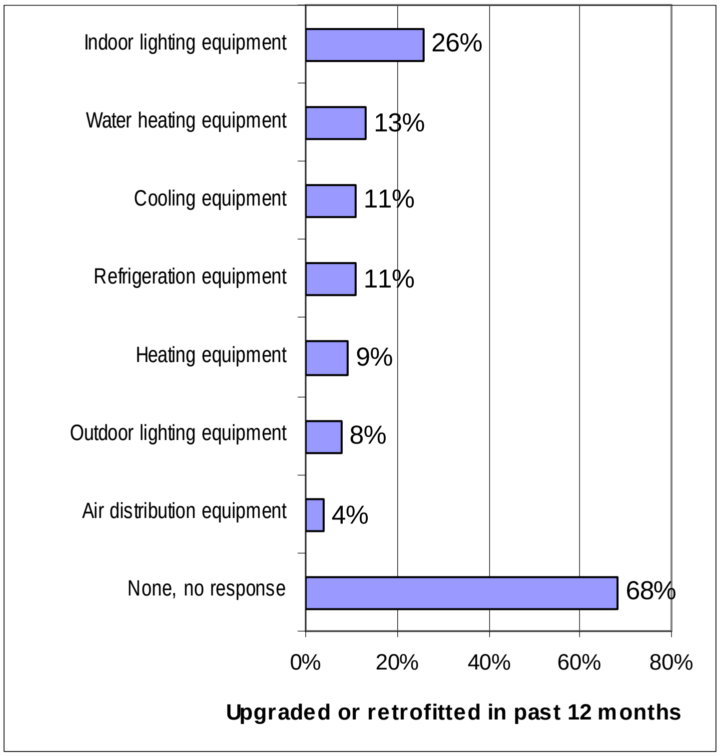
This topic splits the sample with 37% disagreeing about the effect energy efficient cooling and lighting equipment has and 38% agreeing that it could help conserve energy. Twenty-five percent strongly disagreed that such installations were not effective.



Funding, obviously, is a major deterrent to investing in energy efficient programs with 64% agreement.

O. The Business

80a. Which of the following equipment in the building has been significantly upgraded or retrofitted in the last 12 months?

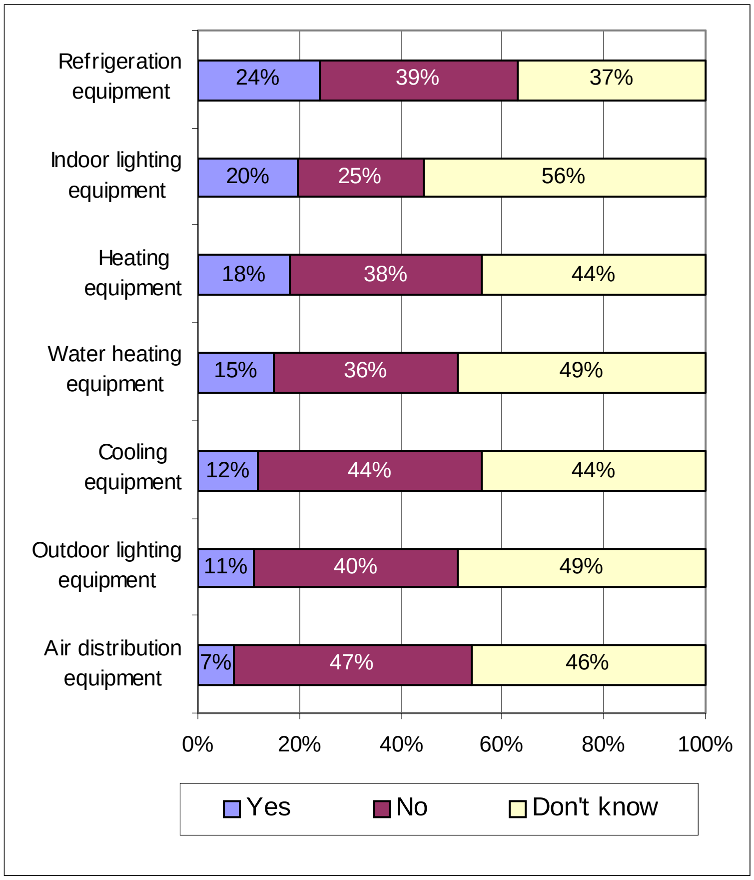


Almost 7 in 10 respondents reported that no upgrading or retrofits had been made in the last 12 months. Of those buildings to which upgrading had been made, 1/4 was for lighting, 1/6 for water heating equipment, and 1/10 had refrigeration and air cooling improvements.

		Type of building					
		Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail
Which of the following equipment in your building has been significantly upgraded or retrofitted in the last 12 months?	None, no response	58%	71%	75%	73%	65%	63%
	Indoor lighting equipment	26%	14%	28%	23%	38%	31%
	Water heating equipment	27%	20%	6%	5%	6%	13%
	Refrigeration equipment	37%	5%	4%	5%	13%	13%
	Cooling equipment	15%	8%	7%	8%	16%	14%
	Heating equipment	13%	8%	9%	9%	6%	11%
	Outdoor lighting equipment	14%	10%	10%	5%	5%	6%
	Air distribution equipment	9%	1%	3%	6%	3%	3%
Total	Responses	88	112	94	65	59	142
	Base	44	81	67	48	38	93

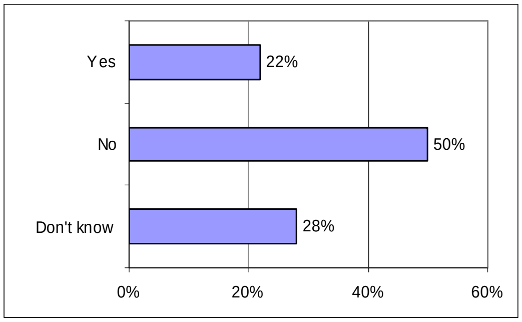
Thirty-eight percent of office buildings have upgraded or retrofitted their indoor lighting equipment in the past 12 months. Thirty-seven percent of Food store/ Lodgings/Restaurants have upgraded or retrofitted their refrigeration equipment in the past 12 months.

Did the upgrade or retrofit result in significant energy savings?



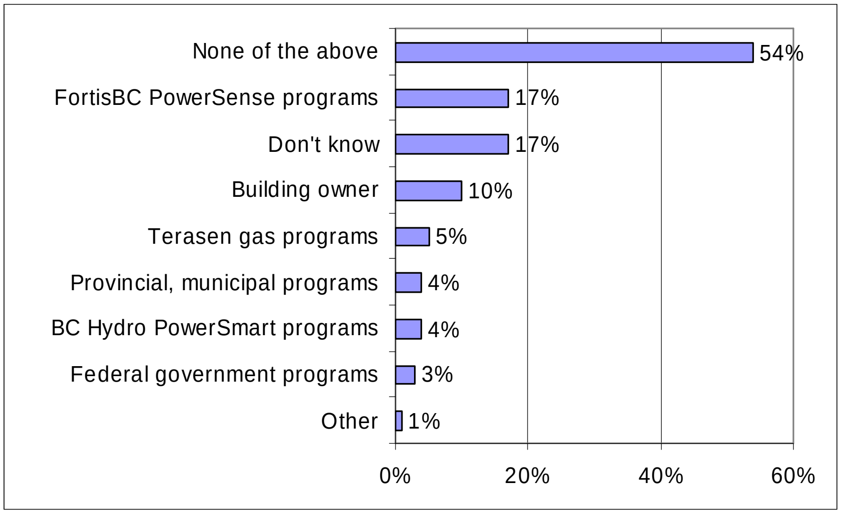
Among businesses that had their refrigeration equipment upgraded or retrofitted, 24% felt this upgrade resulted in significant energy savings. Twenty percent of businesses that upgraded indoor lighting equipment felt this upgrade resulted in significant energy savings. Almost half of respondents were not sure if any of their equipment upgrades or retrofits resulted in significant energy savings.

If the lighting equipment was upgraded, were electronic ballasts installed?



Among those who upgraded indoor lighting equipment, 22% installed electronic ballasts.

80b. Which of the following organizations provided financial assistance for the upgrades to above equipment?



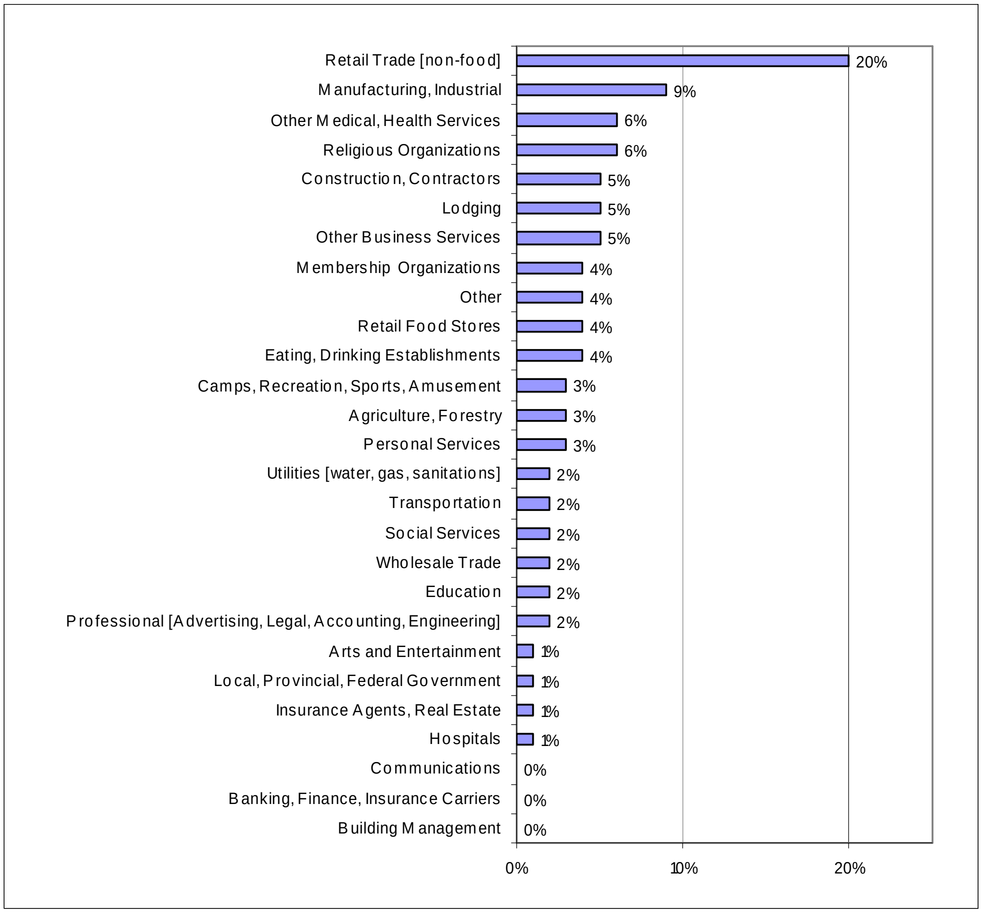
FortisBC helped finance 17% of equipment upgrades.

		Region		
		Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
If 'Yes' - Which of the following organizations provided financial assistance for the upgrades to the above equipment?	"None of the above"	61%	55%	46%
	"FortisBC PowerSense programs"	13%	18%	20%
	"Don't know"	17%	14%	20%
	"Building owner"	9%	8%	16%
	"Terasen gas programs"	4%	6%	3%
	"Provincial, municipal programs"	2%	6%	3%
	"BC Hydro PowerSmart programs"	2%	4%	5%
	"Federal government programs"	2%	4%	4%
	"Other"			3%
Total	Responses	62	77	57
	Base	56	66	48

Base: Respondent with upgraded or retrofitted equipment in their building"Column percentages may exceed 100% because multiple responses provided

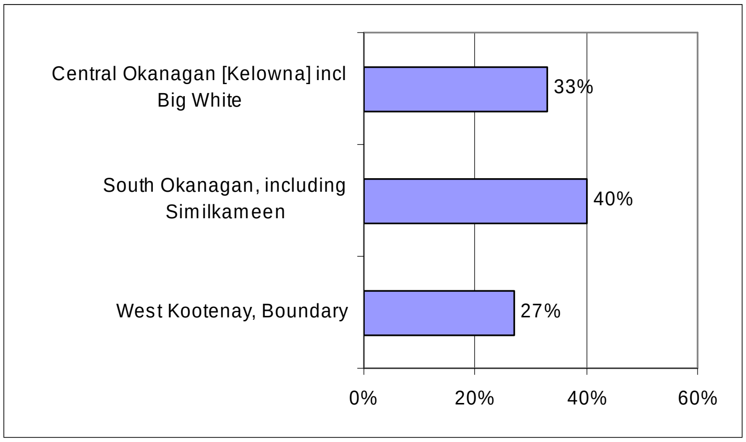
According to the survey respondents, FortisBC was most active in financing upgrades on electronic equipment in the West Kootenay (20%) and least in the Central Region (13%).

81. Please check the one box that indicates the primary activities of the businesses in the building at this location?



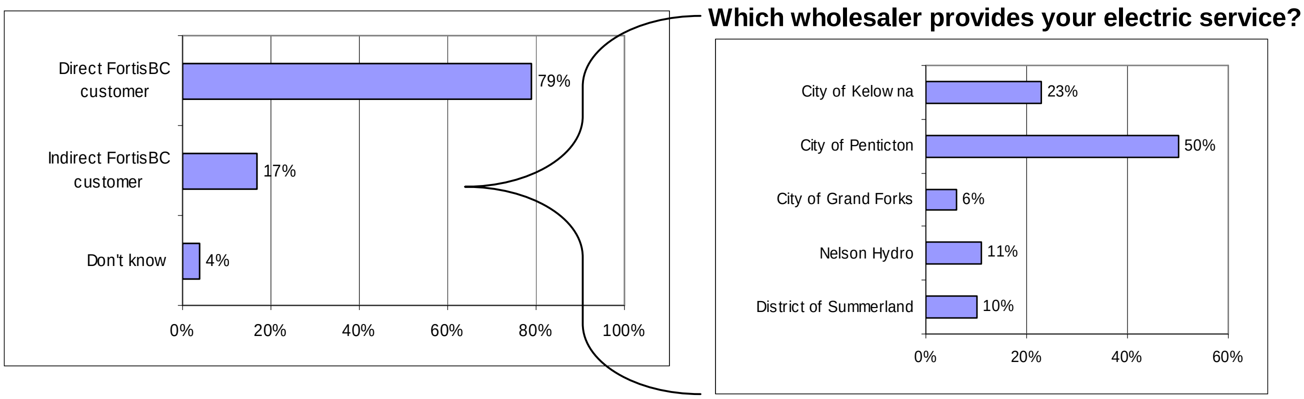
Over 24 primary business activities are represented in the FortisBC 2009 survey sample.

82. Which region do you reside in?



1/3 of the sample is from the Central Okanagan, 40% are from the South Okanagan and 27% are form West Kootenay/ Boundary.

83. Are you our direct or indirect customer?



Seventy-nine percent of the sample were direct FortisBC customers, 17% were Indirect commercial customers and 4% were not sure if they were direct or indirect. Among Indirect customers, the majority are serviced by the City of Penticton (50%).

84. May we have your account number?

		Total
"May we please have your permission for FortisBC to have your account number?"	No response	2%
	"Yes"	70%
	"No"	28%
Total	Base	383

Seventy percent of respondents said it would be alright for FortisBC to use their account number. Sixty percent actually provided an account number and 33% percent of the total sample (127 cases) provided a valid account number for which usage rates could be determined.

P. Annual Energy Consumption

Energy consumption: Total, Building type & Region

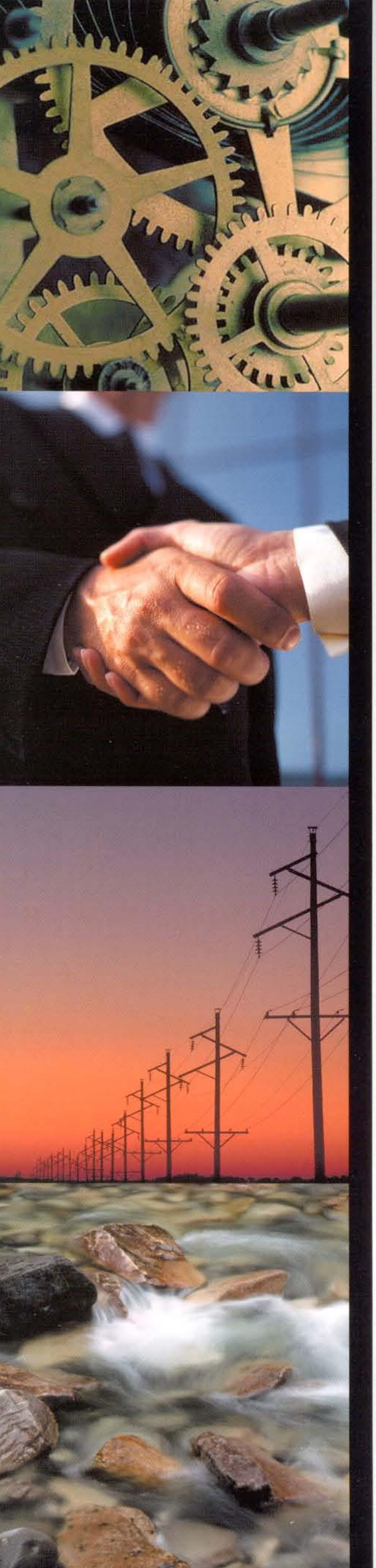
				Type of building						Region		
		Fortis '09	Hydro '06	Food store, Lodgings, Restaurant	Education, Health Care, Public Assembly	Industrial, Warehouse	Mixed Use	Office	Retail	Central Okanagan, Kelowna	South Okanagan, Similkameen	West Kootenay, Boundary
Annual Electricity Consumption (kWh)	Under 35,000 kWh	67%	42%	37%	68%	66%	67%	75%	76%	63%	66%	72%
	35,000 kWh+	33%	58%	63%	32%	34%	33%	25%	24%	37%	34%	28%
Total	Base	127	1609	14	33	24	11	13	30	36	47	43

Respondents who provided valid account numbers

Among businesses that provided valid account numbers, 67% had annual electricity consumption of 35,000 kWh or less compared to 42% among 2006 Hydro sample. Food store, Lodgings and restaurants had the highest energy consumption rates with 63% consuming over 35,000 kWh each year.

Appendix C

CONSERVATION AND DEMAND POTENTIAL REVIEW



FortisBC

EES Consulting

Conservation and Demand Potential Review

Final Report

June 10, 2010

EES Consulting

June 10, 2010

Mr. Keith Veerman, PE
Manager, Energy Efficiency
FortisBC Inc.
Suite 100, 1975 Springfield Road
Kelowna, British Columbia V1Y7V7

SUBJECT: 2010 Conservation and Demand Potential Assessment – Final Report

Dear Mr. Veerman:

Attached please find the FortisBC Conservation and Demand Potential Assessment Final Report.

We appreciate the effort by you and your staff to provide the background information and data necessary for a potential assessment. We have enjoyed working with you on this project.

Sincerely

Kevin L. Smit

Kevin Smit
Manager, Demand-Side Management

570 Kirkland Way, Suite 200
Kirkland, Washington 98033

Telephone: 425 889-2700 Facsimile: 425 889-2725

A registered professional engineering corporation with offices in
Kirkland, WA; Portland, OR; and Bellingham, WA

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Introduction

Objectives

The objective of this report is to describe the results of the FortisBC 2010 Conservation and Demand Potential Review (CDPR). This assessment provides estimates of energy and peak demand savings by sector for the period of 2011 - 2030. The assessment considered a wide range of conservation and demand resources that are reliable, available, and cost-effective. In addition, some emerging technologies, fuel switching, small scale generation, and behavioural measures were considered.

The conservation measures are based on sources such as the Ontario Power Authority, BC Hydro's 2007 Conservation Potential Assessment, and the Northwest Power and Conservation Council. The results provide estimates of peak demand and energy savings that will assist FortisBC in their future resource and program planning.

Background

FortisBC provides service to 110,000 customers in the province of British Columbia as well as 47,500 customers through wholesale supply to municipalities such as Summerland, Penticton, Kelowna, Grand Forks, and Nelson. Residential customers make up 87 percent of the total number of customers and nearly 40 percent of energy sales. Wholesale customers make up another 30 percent of energy, with the remaining 30 percent related to commercial, industrial and other retail classes. Energy sales for FortisBC are roughly 3.5 million MWh per year, with a winter peak demand of about 700 MW. The summer peak for the system is roughly 560 MW.

FortisBC owns generation from four hydro units collectively referred to as the Kootenay River Plants. Output from these plants is governed by a water coordination contract with BC Hydro, and other parties on the Kootenay River which predefines the amount of power that can be used at various times. Peak capacity for December 2009 for the Kootenay River Plants was 223.5 MW. Plant output reflects 47 percent of the 2009 energy requirement and 35 percent of the sum of the monthly capacity requirements. The remainder of FortisBC's power supply needs is met with power supply purchases, including a wholesale contract purchase of up to 200 MW per hour from BC Hydro. While FortisBC resources and contracts provide the majority of energy required by the utility, the system is constrained with respect to capacity.

The utility has made significant investments into its electrical infrastructure increasing its gross assets by more than 200% since 1997. Much of the investment was made to accommodate ongoing capacity constraints on the FortisBC transmission and distribution systems. In addition, customer peak electrical usage has been growing quicker in the summer than in the winter due in part to increased air conditioning load. From a government policy perspective, changes to the Utilities Commission Act and the introduction of the 2007 BC Energy Plan have also necessitated consideration in FortisBC's planning process.

The latest Resource Plan for FortisBC was filed with the BCUC in May of 2009. The *2007 BC Energy Plan* played a significant role in FortisBC's evaluation of potential sources for additional power, providing public policy guidance on directions that BC would like to take in making these types of decisions. Some of the specific policy measures outlined in the 2007 Capital Expenditure Plan include:

- Acquire 50 per cent incremental resource needs through conservation by 2020;
- Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia; and
- Encourage utilities to pursue cost effective and competitive demand side management opportunities.

The report, *Energy Efficient Buildings Strategy: More Action, Less Energy* goes a step further by setting new targets specifically for buildings that support the goals of the BC Energy Plan. These targets include:

- Reduce average energy demand per home by 20 per cent by 2020
  - Low income retrofit incentives
  - SolarBC project
  - Net zero energy homes project
- Reduce energy demand in commercial buildings by nine per cent per square meter by 2020
- Complete energy conservation plans for all B.C. communities

In 2008, FortisBC enacted policy to pursue demand-side resources prior to supply-side options. While FortisBC realizes that demand-side resources alone may not be able to close the capacity gap, the utility and its customers could benefit from these resources by reducing the need for added capacity, securing low-risk resources at relatively low costs, and realizing environmental benefits such as reduced or avoided greenhouse gas emissions.

Report Organization

This report is organized as follows:

- Methodology for Conservation Potential Estimation
- Historic FortisBC Conservation Achievement
- End-Use Load Forecast
- Residential Energy Efficiency Savings Potential
- Residential Peak Demand Savings Potential
- Commercial Energy Efficiency Savings Potential

- Commercial Peak Demand Savings Potential
- Industrial Energy Efficiency Savings Potential
- Industrial Peak Demand Savings Potential
- Infrastructure and Irrigated Agriculture Conservation Potential
- Behaviour Measures
- Scenarios
- Combined CDM Potential Summary
- Program Implications
- Glossary
- Acronyms

Within each potential section, service territory data is defined, conservation measures identified, and estimated potential is summarized. Potential estimates are summarized according to supply curves, tables, figures, and in comparison to the end-use load forecast.

In addition to the main report, the appendices contain detailed information regarding potential estimates as well as supplementary information.

Methodology

This study is a comprehensive analysis that focuses mainly on a bottom-up approach where energy efficiency measures are applied specific end-uses, such as number of refrigerators, and assigned a specific kWh/year savings. This approach differs from "top-down" approaches where, in many cases, a percentage savings is assumed for each end-use. This section describes how conservation potential is estimated in this study as well as the specific considerations, vocabulary, and reasoning behind the methodologies described. First, the types of conservation potential are defined followed by the methodology for estimating those types of potential.

Types of Potential

In developing this potential study, several different types or levels of efficiency potential are identified: technical, economic, and achievable. Technical potential is the theoretical maximum efficiency in the service territory. Economic potential is a subset of the technical potential that has been screened for cost effectiveness through various benefit-cost tests. Beyond cost effectiveness, there are physical barriers, market conditions, and other economic constraints that reduce the total potential savings from an energy efficient device. When these factors are applied, the result is called the achievable potential.

- Technical – Amount of energy efficiency potential that is available regardless of cost or other constraints such as willingness to adopt measures. It represents the theoretical maximum amount of energy efficiency if these constraints are not considered.
- Economic – Amount of potential that passes an economic cost/benefit test; in British Columbia the total resource cost test (TRC) is used. This generally means that the present value of the benefits exceeds the present value of the measure costs over its lifetime. The TRC costs include the incremental cost of the measure regardless of who pays (utility or customer). In British Columbia the Ministry of Energy, Mines and Petroleum Resources ("Ministry") has mandated that the cost effectiveness of measures be calculated either at the individual level, in a bundle with other measures, or at a portfolio level.
- Achievable – Amount of potential that can be achieved through a given set of conditions. Achievable potential takes into account many of the realistic barriers to adopting energy efficiency measures. These barriers include the willingness of consumers to adopt a measure, the non-measure costs, and the physical limitations of ramping up a program over time. The level of achievable potential can increase or decrease depending on the given incentive level of the measure.
- Program Achievable – Amount of potential that can be achieved through programs. The program achievable excludes potential that is achieved through future code changes.

Data Requirements

The data required for estimating conservation potential falls into three categories: measure data, customer characteristic, and utility data. Figure 1 illustrates specific data included in each of these categories.

Figure 1
Overview of Potential Assessment Data Requirements

Energy Efficiency Measure Data

- kWh, kW savings, load shapes
- Costs - incremental, O&M, replacement
- Energy and non-energy benefits/costs
- Measure Life

Customer Characteristic Data

- Residential: single family, multifamily, manufactured
- Commercial: Floor area by building segment, population, employment
- Industrial: consumption by sub-sector
- Building characteristics: heating fuel, vintage, basement type, HVAC types
- Appliance saturation: refrigerators, lighting
- Commercial building square footage; total and by segment
- Current measure penetration rate

Utility Data

- Load forecast
- Avoided cost
- Discount rates
- Line losses
- Past energy efficiency program achievements

Energy Efficiency Measure Data

The characterization of efficiency measures includes measure savings (kWh), demand savings (kW), measure costs ($), and measure life (years). Other features such as measure load shape, operation and maintenance costs, and non-energy benefits are also important for measure definition. Next, the end-use conservation measures data is another piece central to conservation potential modeling. Three primary sources were referenced for conservation measure data that apply to characteristics in FortisBC's service territory: the 2007 BC Hydro Conservation Potential Review, the Northwest Power and Conservation Council's 6th Power Plan, and Ontario Power Authority measure databases. Annual savings for heating, cooling, and weatherization measures are adjusted to reflect the FortisBC climate zones.

The measure data from some or all of the resources listed above include adjustments from raw savings data for several factors. The effects of space heating interaction, for example, are included for all lighting and appliance measures where appropriate. For example, if a house is retrofitted with efficient lighting, the heat that was originally provided by the inefficient lighting will have to be made up by the heating system. This energy is netted out of the savings.

Customer Characteristic Data

Customer characteristics data are another important component of a potential study. One of the best ways to obtain these data is through original research, especially end-use surveys. An end-use survey may provide all the detailed housing and commercial building data requirements. Defining service territory data is often referred to as characterizing the baseline. For this analysis, FortisBC has completed end-use surveys for their residential and commercial customers. The results are used to guide which conservation measures are applicable as well as the corresponding saturation levels of those measures.

The building, appliance, and equipment data is obtained from the FortisBC customer surveys. Using FortisBC survey data, the end-use model forecasts saturations and building segmentation data over the planning period. The end-use model allows for the estimation of conservation potential over a period of time, rather than a snap-shot in time, as survey results show. Therefore, the estimation of growth rates and saturation levels over the time period becomes an integral piece to conservation potential.

Utility Data

The third category is utility data which include current and forecasted loads, growth rates, avoided cost information, and line losses. FortisBC provided a load forecast by sector with average annual growth of 1.4 percent (gross load) over the planning period 2011 through 2030. Line losses are assumed at 8.8 percent over the period. The load forecast provided includes historic conservation trends through utility programs and code and standard changes.

The inflation rate assumed is 2 percent annually with a utility nominal discount rate of 10 percent.

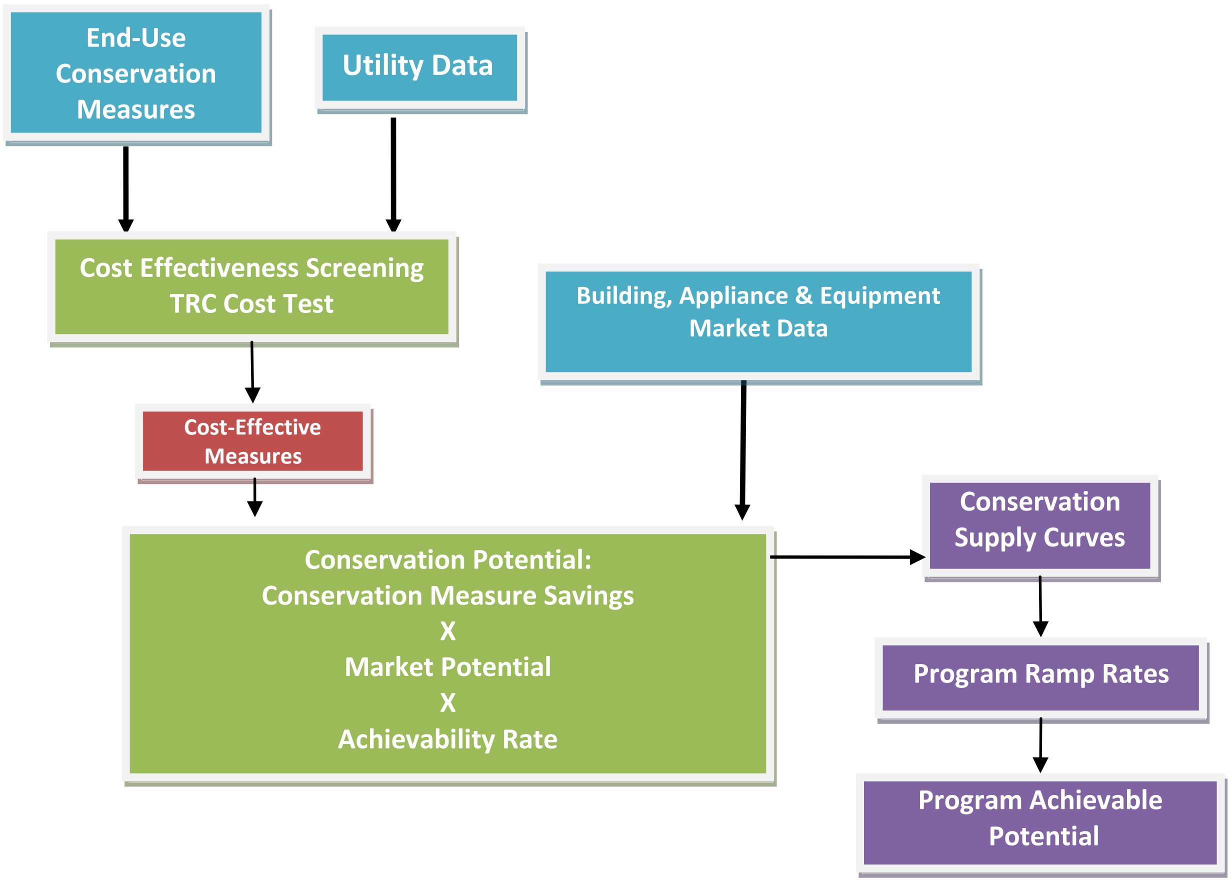
Energy Benefits

The avoided cost of electricity is the dollar value per MWh, of the conserved electricity, and accounts for the benefit value in cost effectiveness tests. In addition, avoided costs for transmission and distribution as well as peak summer and winter demand is also valued ($/kW). These energy benefits are often based on the cost of a generating resource, a forecast of market prices or an integrated resource planning process. For this study, BC Hydro's long-term avoided costs are used to value energy, peak demand, and transmission and distribution savings. Avoided costs for energy measures are $154/MWh in levelized cost terms (2010 dollars). This energy value includes local and bulk transmission savings. Winter peak savings for demand measures with primarily capacity savings are valued at $190/kW-yr (2010 dollars). This value includes both avoided capacity and infrastructure costs such as transmission and distribution. Summer peak savings are not valued.

Basic Modeling Methodology

There are two general analytical approaches to estimating conservation potential: a bottom-up approach and a top-down approach. The bottom-up approach is the primary method used for this assessment and is illustrated by Figure 2. The key factor is the number of kWh saved annually from the installation of an individual energy efficient measure. The savings from each measure is multiplied by the total number of measures that could be installed over the life of the program. Savings from each individual measure is then aggregated to produce the total potential.

Figure 2
Conservation Potential Assessment Process



Estimating Technical Potential

The technical potential is the sum of all measure savings and possible applications of the measure across the service territory. Estimating the technical potential begins with determining a value for the energy efficiency measure savings. Then, the number of "applicable units" must be estimated. "Applicable units" refers to the number of units that could technically be installed in a service territory. This includes accounting for units that may already be in place. A sample formula for calculating technical potential for a residential measure is shown below:

Measure Savings = (Per Unit Savings) x (# of households) x (Applicability) x (1- Saturation)

The "Applicability" value is highly dependent on the measure and the housing stock. For example, a heat pump measure may only be applicable to single family homes with electric space heating equipment.

In addition, technical potential should consider the interaction and stacking effects of measures. For example, if a home installs insulation and a high efficiency heat pump, the total savings in the home is less than if each measure were installed individually (i.e., interaction). In addition, the measure-by-measure savings depend on which measure is installed first (i.e., stacking).

Total technical potential is often significantly more than the amount of economic and achievable potential. The difference between technical potential and achievable and or economic potential is due to number of measures in the technical potential that are not cost-effective, and the applicability or total amount of savings of those non-cost effective measures.

Estimating Economic Potential

Energy efficiency potential assessments estimate the amount of energy savings potential that is available and cost-effective. To find cost-effectiveness potential, energy efficiency measures must pass economic screening. In British Columbia, economic potential is defined using a total resource cost (TRC) test to screen measures for cost effectiveness. A total resource cost perspective considers all costs and benefits for each energy efficiency measure regardless of to whom they occur. Costs and benefits include, capital cost, O&M cost over the life of the measure, disposal costs, program administration costs, environmental benefits, distribution and transmission benefits, energy savings benefits, economic effects, and non-energy savings benefits. Appendix B describes the TRC test as it applies in British Columbia in more detail.

Another common cost-effectiveness test is the utility cost test (UCT) (also known as the program administrator cost test). This test considers only those costs and benefits that accrue to the utility. The drawback of this method is that it does not ensure that public resources are allocated in the most efficient manner. Energy efficiency measures with significant non-energy benefits, but smaller energy benefits may not pass the screening. Also, this test does not include all the costs of the measure but only those that accrue to the utility. FortisBC requested that UCT results be presented for each measure. In addition, participant cost tests (from the participant perspective) as well as rate-payer impact tests are also included. Appendix C describes these various cost-effectiveness tests in more detail.

Estimating Achievable Potential

Achievability criteria can be applied either to technical potential or to economic potential. There are several methods for accounting for achievability, in the Pacific Northwest, the NWPCC applies achievability criteria prior to the economic cost-effectiveness tests. Specifically, the NWPCC uses an 85% achievability factor for all measures and has published a white paper describing the basis for using this value[1]. This value indicates that over the course of a 20-year potential study, 85% of all technical potential can be achieved, regardless of how it is achieved.

There are many different types of achievability factors and many ways to apply them. In addition, the achievability can be evaluated through different scenarios (e.g., high, medium, low). Scenarios can be based on the level of incentives offered or other program design factors.

Model Output - Supply Curves

Each type of potential can be summarized by a supply curve where savings potential (MWh) is graphed against the levelized cost ($/MWh). Measure costs are standardized (levelized) allowing for the comparison of measures with different lives. The supply curve facilitates comparison or demand-side resources to supply-side resources and is often used in conjunction with Integrated Resource Plans (IRPs).

Levelized Cost

The levelized cost of the measure is the discounted present value cost of the measure annualized over its life divided by the annual energy savings. The equation below illustrates how the levelized cost is calculated.

$$Levelized\ Cost = \frac{r}{1-\frac{1}{(1+r)^{measure\ life}}} \times (capitalcost + program\ administration\ costs)$$

Where r is the interest rate.

Dividing the equation above by the annual savings (MWh) produces levelized cost in terms of dollars per MWh. This levelized cost calculation is the same as BC Hydro's Cost of Conserved Energy (CCE).

Program Achievable Potential

The last step to estimating reasonably attainable conservation potential over the time period is to assign ramp rates to each measure. Ramp rates might be individual for each measure, or one type of ramping might apply to several similar measures. How quickly savings from a particular measure is ramped up over the period depends on several factors:

---

[1] "Achievable Savings: A Retrospective Look at the Northwest Power and Conservation Council's Conservation Planning Assumptions." August 2007. http://www.nwcouncil.org/library/2007/2007-13.htm.

- Availability of technology;
- Program readiness;
- Whether the measure is implemented before or at the end of building or unit life; and
- Changes in codes or standards.

Ramp rates are applied to achievable potential; the result is program achievable potential, or the amount of potential a utility could reasonably expect to obtain over the time period given best current knowledge.

Historic Conservation Achievement

Historic conservation achievements are examined to adjust the 2008 end-use consumption estimates as well as the baseline characteristics for potential estimation. FortisBC has been active in helping their customers become more energy efficiency through their PowerSense program since 1989. Previous programs have included residential, commercial, and industrial measures. Figure 3 illustrates historic conservation efforts from 1990 through 2008.

Figure 3
Historical Energy Efficiency Achievements

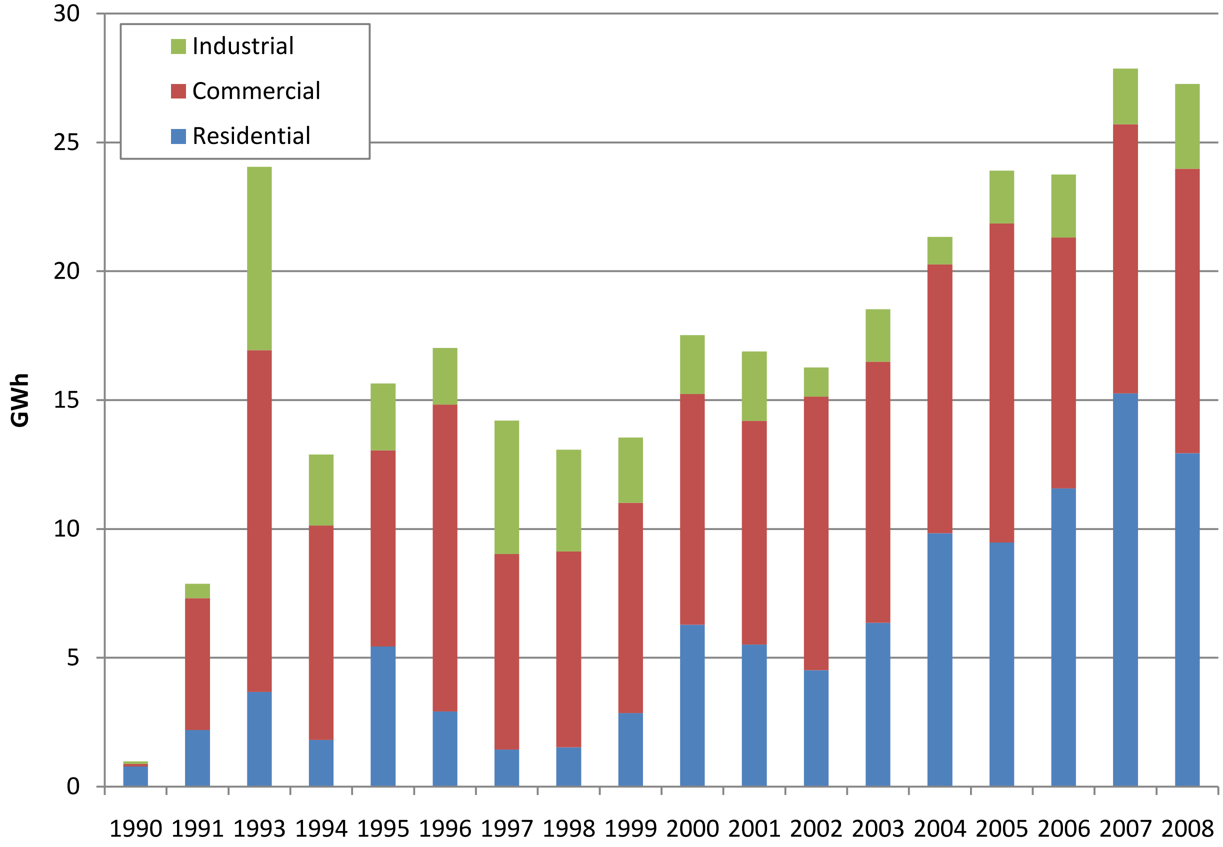
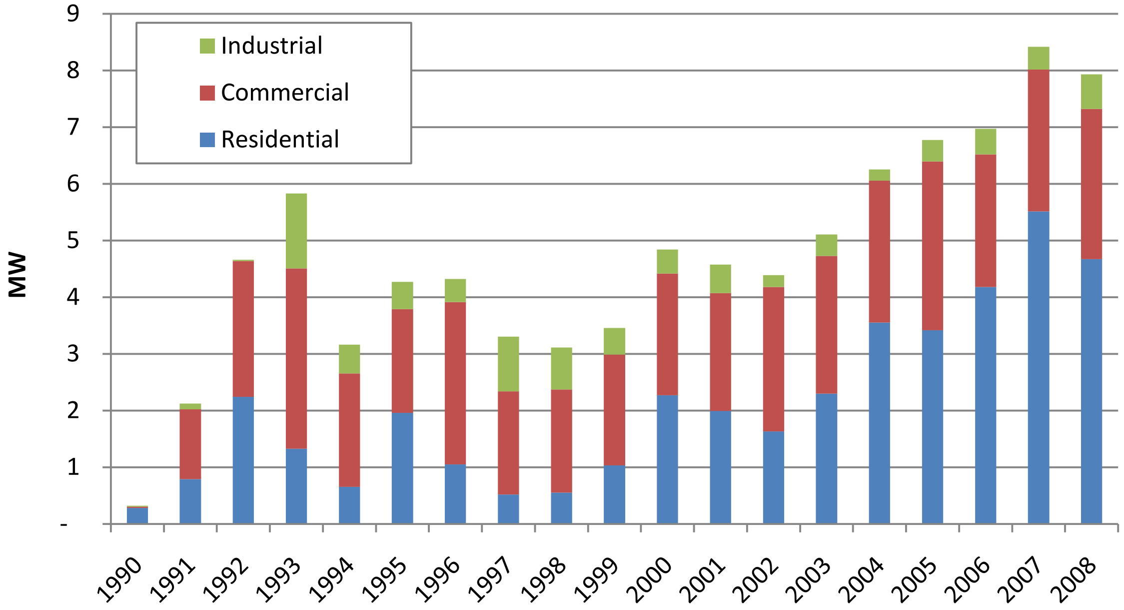


Figure 4 shows the associated demand savings for the energy savings in Figure 3.

Figure 4
Peak Demand Savings



The programs currently being utilized by FortisBC to acquire these savings are briefly described in the following sections.

Residential Incentives

LiveSmart BC - Provincial Program

To take advantage of FortisBC's energy efficiency incentives, some programs require that homeowners work through a government-run program called LiveSmart BC. This program coordinates utility, provincial, and federal promotions and has funding to operate through March 31, 2011. To take advantage of LiveSmart BC, homeowners must order an energy evaluation for their home. Some PowerSense rebates or loans are obtained through LiveSmart BC. These programs are identified in the descriptions below.

PowerSense

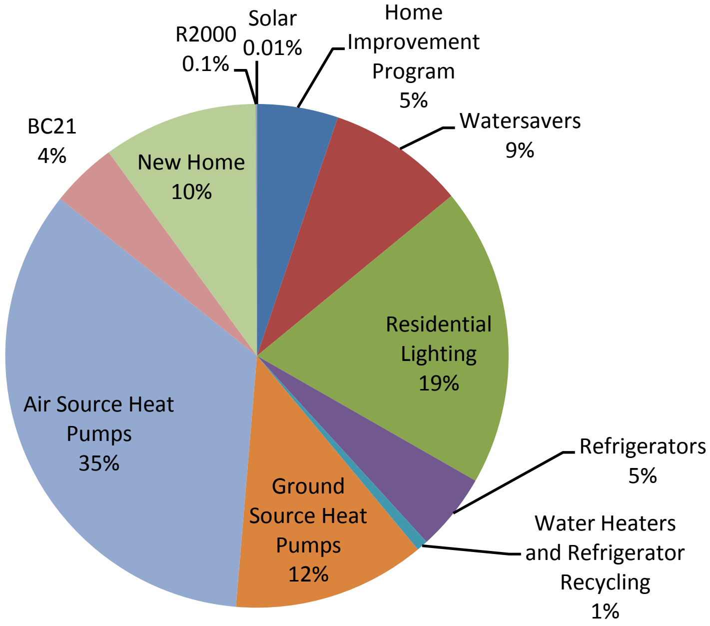
Residential energy efficiency programs include the following:

- **New Home Program (NHP)** – offers homeowners rebates on energy efficient windows, lighting, and technologies such as heat pumps for new construction projects.
- **Home Improvement Program (HIP)** – FortisBC offers several rebates for weatherization and heat pumps for electrically heated homes. Customers who receive rebates through the LiveSmart BC program are ineligible to receive rebates from the HIP.

- **Weatherization** – FortisBC offers rebates of $0.50 per square foot for windows, $0.05 per kWh savings for insulation upgrades.
- **Lighting** – Up to 10 free CFLs are available under the NHP and rebates of 50% the price of the bulb or up to $5/ bulb are available for retail sales.
- **Air Source Heat Pumps** – Customers can receive either a rebate or a low-interest loan for air source heat pumps for existing homes through the LiveSmart BC Program. The rebate amount is $0.05 per kWh savings (usually around $300per unit). The loan amount can be up to $5,000 over 10 years at 4.9%. Qualifying heat pumps must be EnergyStar rated for Canada. Incentives available through LiveSmart BC.
- **Ground Source Heat Pump** - Customers can receive either a rebate or a low-interest loan for ground source heat pumps for existing homes through the LiveSmart BC Program. The rebate amount is $0.05 per kWh savings(typically $900). The loan amount can be up to $5,000 over 10 years at 4.9%. System equipment design and installation must meet CSA Standards. Incentives available through LiveSmart BC.
- **Solar Hot Water Systems** – For new homes, a $1,000 Natural Resource Canada (NRCAN) rebate is available. Requires at least 6 square metres of South-facing roof space. A $300 rebate is available for existing homes with electric hot water heaters for the solar upgrade.

Figure 5 illustrates the share of historic energy savings by measure category. A significant share of historic savings is from heat pump installations.

Figure 5
Share of Residential Energy Efficiency Program Achievements 1990-2008



General Service Incentives

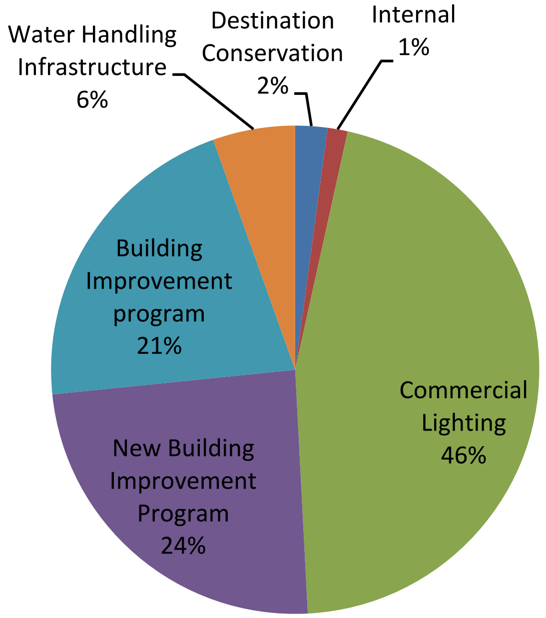
PowerSense

Commercial building energy efficiency programs include the following:

- **Lighting** – FortisBC provides rebates for compact fluorescent lighting, electronic ballasts, reflectorized luminaries, T8 fluorescents, LED and CFL exit lights, high density discharge lighting, and motion sensors or other lighting control systems.
- **New Building** – FortisBC offers a free initial assessment of new building design for energy efficiency. In cases where a more detailed assessment is required, FortisBC will cover 50% of the cost up to $5,000. Rebates are available for energy efficiency measures above the baseline construction standard.
- **Existing Buildings** – Qualified customers can take advantage of a free walk-through energy audit conducted by a qualified technical advisor to identify where conservation opportunities exist. If required, FortisBC will fund up to 50 percent, to a maximum of $5,000, of an approved consultant's fee to conduct a comprehensive energy study. Possible technologies include lighting, HVAC control systems or variable speed drives, water heating, refrigeration measures, building envelope, and motors.
- **Rebate structure –** General Service rebates are the lesser of:
    - Five cents per annual kWh saved;
    - 50% of installed retrofit cost;
        - 100% of incremental cost for new construction; or
    - Amount necessary to achieve a two-year payback.

Figure 6 illustrates the share of historic commercial energy efficiency achievements. Commercial lighting makes up almost half of historic achievement.

Figure 6
Share of Commercial Energy Efficiency Program Achievements 1990-2008



Industrial Incentives

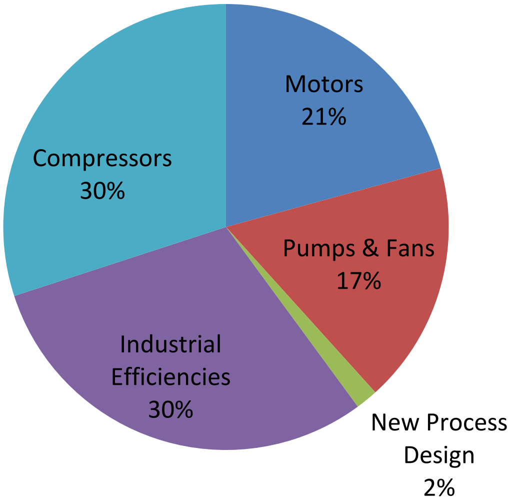
PowerSense

Industrial building energy efficiency programs include the following:

- **Walk Though Audit**– FortisBC offers a free walk through energy audit by a technical advisor to identify where potential energy savings opportunities exist. In cases where a more detailed assessment is required, FortisBC will cover 50% of the cost for an approved consultant. Energy efficiency measures may include motor upgrades, air compressor upgrades, process or non-process energy savings, pumps and fans, variable frequency drives, or other measures.
- **New Process Design** – A technical advisor or an approved consultant is available to assess new process design. Rebates are available for suggested technology upgrades for approved energy efficiency measures.
- **Rebate Structure** – same as General Service

Figure 7 illustrates the share of historic industrial energy efficiency savings.

Figure 7
Share of Industrial Energy Efficiency Achievements 1990-2008



Irrigation and Municipal Infrastructure

PowerSense

FortisBC offers audits or incentives up to 50% of an approved consultant's fee for energy audits in irrigation and municipal infrastructure. Financial incentives are available for identified projects 5 cents per kWh up to 50 percent of the incremental project cost or the amount required for a 2-year payback, whichever is less. The following areas are available for energy savings:

- Irrigation – Pumping systems can achieve increased energy efficiency through motor downsizes, upgrades, new gaskets, variable speed drives, digital control, or other equipment.

- Water and Waste Water Treatment – Annual capital improvement programs provide opportunities for energy efficiency upgrades that benefit ratepayers. FortisBC currently has agreements with each municipality to review energy efficiency potential each year.

- Traffic and Street Lighting – Similar to water and wastewater treatment agreements, energy efficiency is included in the annual capital improvement plan for city lighting. Due to successful past programs, virtually all traffic lights in FortisBC's service territory are already updated to LED technology.

Partner in Efficiency

FortisBC enters into a Partners in Efficiency (PIE) agreement with institutional, commercial, and industrial (ICI) customers such as schools, municipalities, hospitals, and other large commercial and industrial accounts. The PIE is a signed agreement that involves the following:

- Customer agreement to review their capital expenditure plan with FortisBC on an annual basis to identify key projects to improve energy use;
- FortisBC works with the customer to determine the economics for energy efficient upgrades to the project;
- Recommendations for improvements are presented with estimated costs, savings, applicable rebates;
- Rebates are presented upon project completion; and
- Monitoring and evaluation.

Summary

FortisBC has a strong history in energy efficiency achievement through its programs. FortisBC programs target energy efficiency across all customer classes including indirect customers. Energy efficiency programs target improvements from a whole-building or system perspective providing comprehensive efficiency upgrades. In addition, the Partner in Efficiency agreement continues energy efficiency conversations from year to year providing flexibility within each program for technology advancements.

End-Use Model

Introduction

This section summarizes the assumptions and results of the load forecast by end-use. End-use forecasts were prepared for commercial, residential, and industrial sectors. The end-use forecast includes all customers, both direct and indirect, that are served by FortisBC.

Residential End-Use Forecast - Energy

Methodology

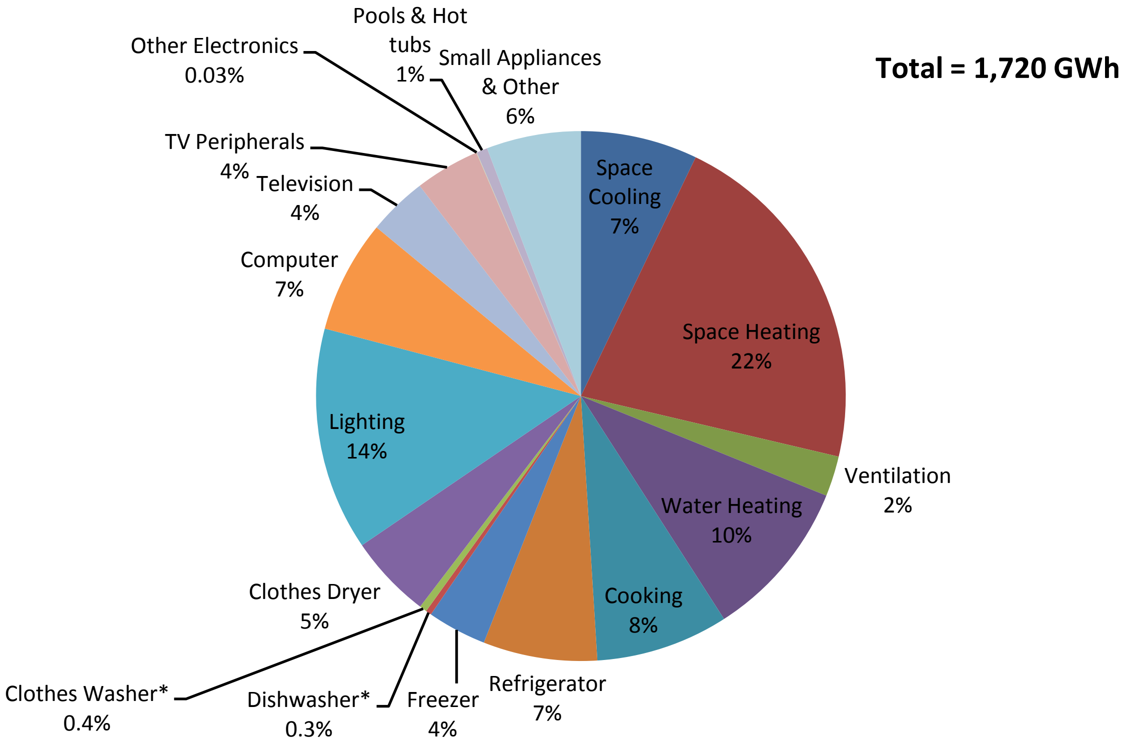
End-use consumption for residential customers was estimated based mainly on the 2009 Residential End-Use survey results. Appliance saturations, heating types and fuels as well as hours of use are used to define building characteristics. For instance, the number of refrigerators in single family homes built prior to 1976 was calculated from the survey data. Next, an average annual use was applied to the number of units. The result is energy consumption by appliance or end use.

Average use data was obtained from a combination of the BC Hydro 2007 Conservation Study as well as FortisBC’s survey. The BC Hydro data is used to determine the average annual electricity use by building type, vintage, and heating fuel (i.e. single family, pre-1976, electrically heated). Average use from the FortisBC Survey is used to benchmark how well the BC Hydro data describes FortisBC customer energy consumption. Overall, the BC Hydro average use data results in average customer use by building type (single family, apartment, etc.) that is similar to the average use presented in the FortisBC survey (shown later in Table 1).

2008 Base Results

The first step was to define current end-use energy consumption for FortisBC customers. Figure 8 illustrates the share of energy consumption by end-use category. Total consumption is estimated at 1,720 GWh for 2008 (weather adjusted).

Figure 8
2008 Base Level End-Use Consumption - Residential



*Energy use is for motors etc. Use of hot water for these appliances is captured under Water Heating.

A comparison of average use by customer building type is presented in Table 1 below. The average use across all building types is within 5% of the average use collected by the 2009 survey. Variation in weather may account for some of the differences in average use.

Table 1
Average Customer Use Comparison

Building Type	End-Use Model kWh	FortisBC Survey kWh	% Difference	Units/ Customers
Single Family	13,424	13,057	-2.81%	94,431
Mobile Home	9,375	9,014	-4.01%	10,737
Apartment Condo	5,913	5,109	-15.74%	17,620
Townhouse, Duplex, Row	8,925	8,521	-4.74%	14,867
Total	11,661	11,234	-3.80%	137,655

Once the 2008 baseline is established, energy-consuming units and average use are forecasted through the end of the planning period. The results are then compared to the utility's load forecast. Building growth rates range from 0.27 to 5.64% for new construction over the period with demolition rates near 0.25% for existing homes. Existing mobile homes have slightly higher demolition rates (0.35%). Table 2 shows average annual growth rate by building type. Historic building permit data was used to distribute the total customer growth rate among building types. Building permits for apartments have increased significantly since 2004.

Table 2
Average Annual Net Growth Rate[(1)]
Number of Buildings

	Single Family	Mobile Home	Apartment	Row	Total
2009-2012	0.52%	0.27%	5.03%	0.41%	1.46%
2009-2020	0.50%	0.28%	5.22%	0.41%	1.46%
2009-2030	0.50%	0.28%	5.64%	0.43%	1.18%

(1) Includes demolition rates.

Appliance saturation data is estimated on a case-by-case basis. Some saturation rates such as heat types, refrigerators, freezers, and clothes washers do not change significantly over the period. On the other hand, saturations such as televisions, television peripherals, and other electronics were estimated to increase over the period. The saturation of central air conditioning as well as room or portable air conditioners is also projected to increase.

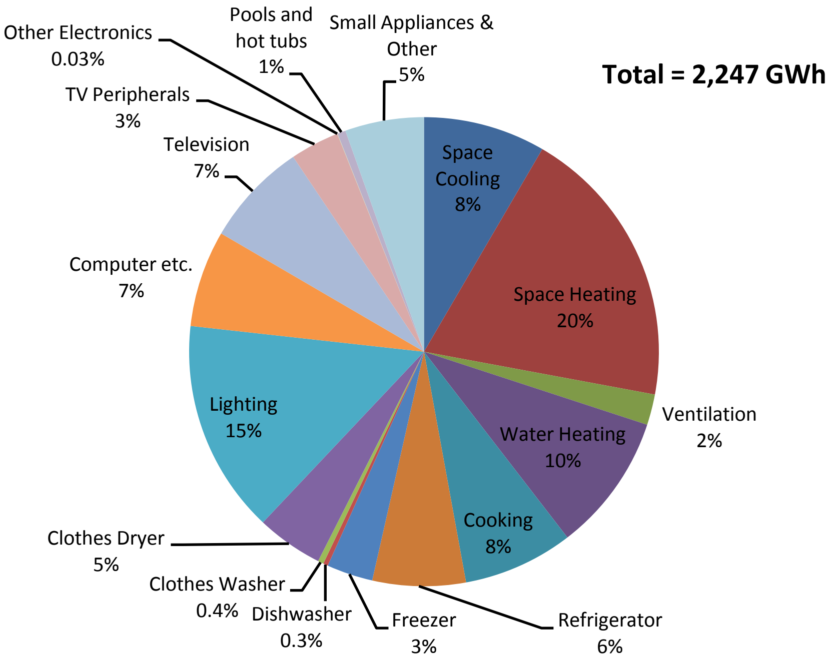
Table 3 compares the FortisBC forecast with the energy consumption estimated using end-use consumption and growth in residential building square footage. Because the FortisBC load forecast does not separate residential customer consumption from other classes within the wholesale forecast, the 2008 residential consumption from wholesale customers (Summerland, Nelson, Penticton, Kelowna, and Grand Forks) is projected at growth rates consistent with total wholesale sales growth.

Table 3
Residential Forecast Comparison - Energy

	FortisBC Load Forecast MWh	End-Use Model MWh	% Difference
2008	1,719,530	1,719,530	0.0%
2009	1,745,793	1,744,633	-0.1%
2010	1,772,466	1,771,657	0.0%
2011	1,783,712	1,800,177	0.9%
2012	1,807,542	1,822,257	0.8%
2013	1,831,541	1,844,574	0.7%
2014	1,855,710	1,866,484	0.6%
2015	1,880,701	1,888,620	0.4%
2016	1,906,346	1,910,985	0.2%
2017	1,932,249	1,933,580	0.1%
2018	1,957,970	1,956,408	-0.1%
2019	1,983,400	1,979,470	-0.2%
2020	2,008,728	2,002,769	-0.3%
2021	2,034,028	2,026,307	-0.4%
2022	2,059,050	2,050,086	-0.4%
2023	2,083,634	2,074,107	-0.5%
2024	2,107,779	2,098,374	-0.4%
2025	2,131,534	2,122,888	-0.4%
2026	2,154,780	2,147,651	-0.3%
2027	2,177,513	2,172,666	-0.2%
2028	2,199,772	2,197,989	-0.1%
2029	2,221,489	2,223,753	0.1%
2030	2,242,585	2,247,212	0.2%

Because house sizes and appliance saturation data changes over the period of the forecast, the share of end-use consumption also changes. Figure 9 illustrates the breakdown of energy consumption by end-use for 2030. Energy consumption by electronics has increased as well as lighting and space cooling energy consumption. In comparison, space heating and major appliances consume a smaller share of the total consumption.

Figure 9
2030 Residential Energy Consumption Breakdown



Residential End-Use Forecast – Peak Demand

Winter Peak Methodology

The winter peak demand forecast is estimated using the following inputs:

- FortisBC energy consumption by end use for each building type (single family, row or townhouse, apartment, and mobile home)
- BC Hydro coincident peak load by end-use and building type
- BC Hydro coincident peak demand for electric heat and annual kWh consumption[2]

Similar to FortisBC, BC Hydro's winter coincident peak occurs near either the 6:00 p.m. hour on a January or a December day. The peak is highly correlated with the coldest day of the year. Given this similarity, the relationship between energy demand by end use (kW) and total peak

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[2] Effectively, load factors from BC Hydro's study are used to estimate FortisBC load factors using data from BC Hydro's Southern Interior region.

demand for each housing type is used to estimate FortisBC peak. The advantage of using BC Hydro data in this top-down approach is that behaviours and energy use for people in similar service territories are captured. These behaviours reveal the components of coincident peak demand in the residential sector. The disadvantage of this methodology is that the differences between FortisBC customers and BC Hydro customers are not fully represented. Examples of important differences include the higher penetration of CFLs among FortisBC customers. On the other hand, differences in building types across service territories are accounted for.

2008 Base Results

The methodology above results in an estimated peak of 427 MW from residential customers (including wholesale). For comparison, the total system peak for is estimated at 701 MW (weather adjusted). Figure 10 illustrates the breakdown of the coincident peak demand. Twelve percent of coincident peak demand is due to cooking, which can be expected given the assumption that the peak occurs at 6 p.m. Also, as expected, space heating and lighting make up the largest share of peak demand for residential customers.

Figure 10 shows winter peak demand estimates by end-use for 2008. Average annual growth in winter peak demand is approximately 0.9%, according to the FortisBC load forecast.

Figure 10
2008 Winter Peak Demand - Residential

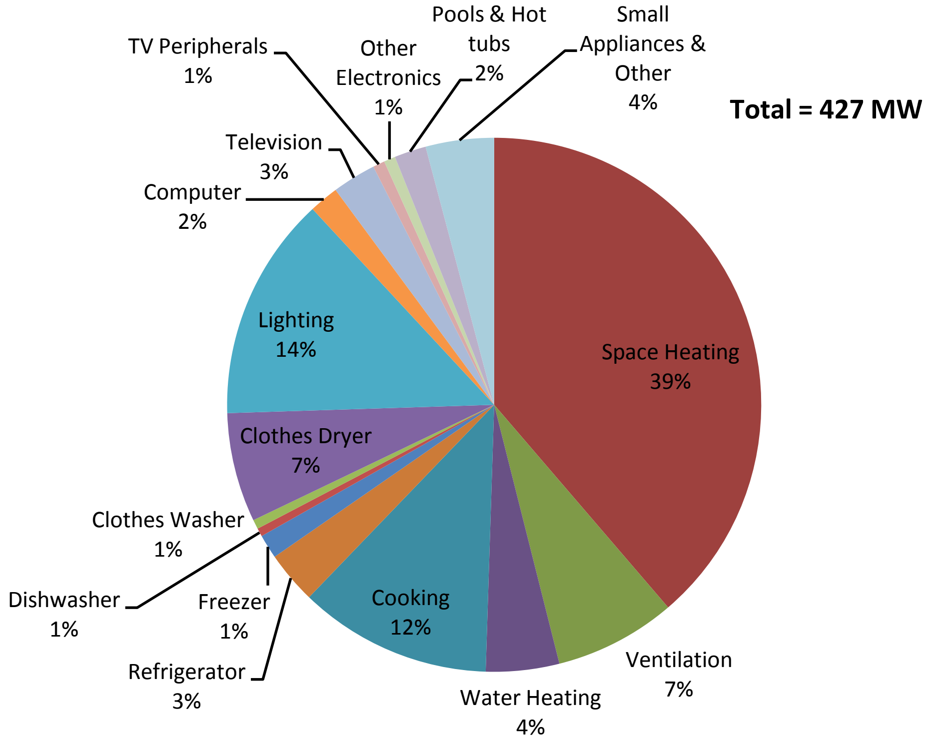
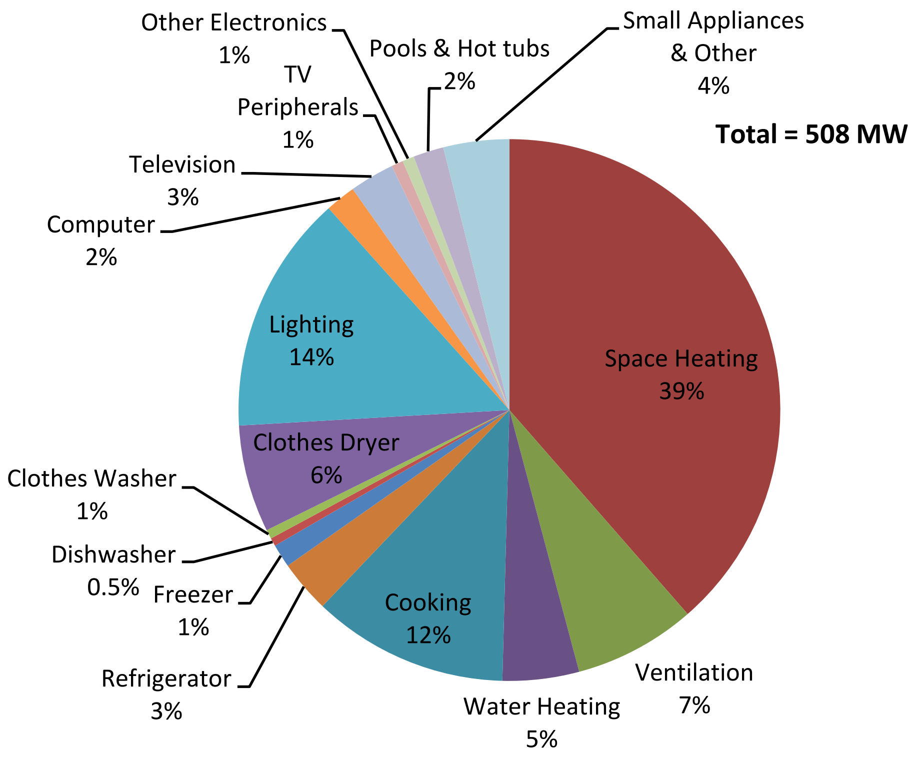


Figure 11 shows the forecast 2030 winter peak demand breakdown from the end-use model.

Figure 11
2030 Winter Peak Demand - Residential



Summer Peak Methodology

The summer peak demand forecast is estimated using the following inputs:

- FortisBC energy consumption by end use, and
- Summer peak load factor by end-use from statewide California load factors[3]

Load factors were adjusted to account for differences in weather between FortisBC and California based on population-weighted cooling degree days and maximum temperature. Load factors are applied to kWh consumption to produce kW demand. See calculation below for an example of how load factors are applied to energy to produce peak demand estimates.

$$\frac{kW_{peak}}{kWh_{annual}} \times kWh_{annual} = kW_{peak}$$

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[3] Brown, Richard E. and Jonathan G. Koomey. "Electricity Use in California: Past Trends and Present Usage Patterns." Berkeley, CA: May 2002. Available at: <http://enduse.lbl.gov/info/LBNL-47992.pdf>

2008 Base Results

Figure 12 illustrates the breakdown of summer peak demand. The 2008 residential peak summer demand is estimated at 271 MW.

Figure 12
2008 Summer Peak Demand - Residential

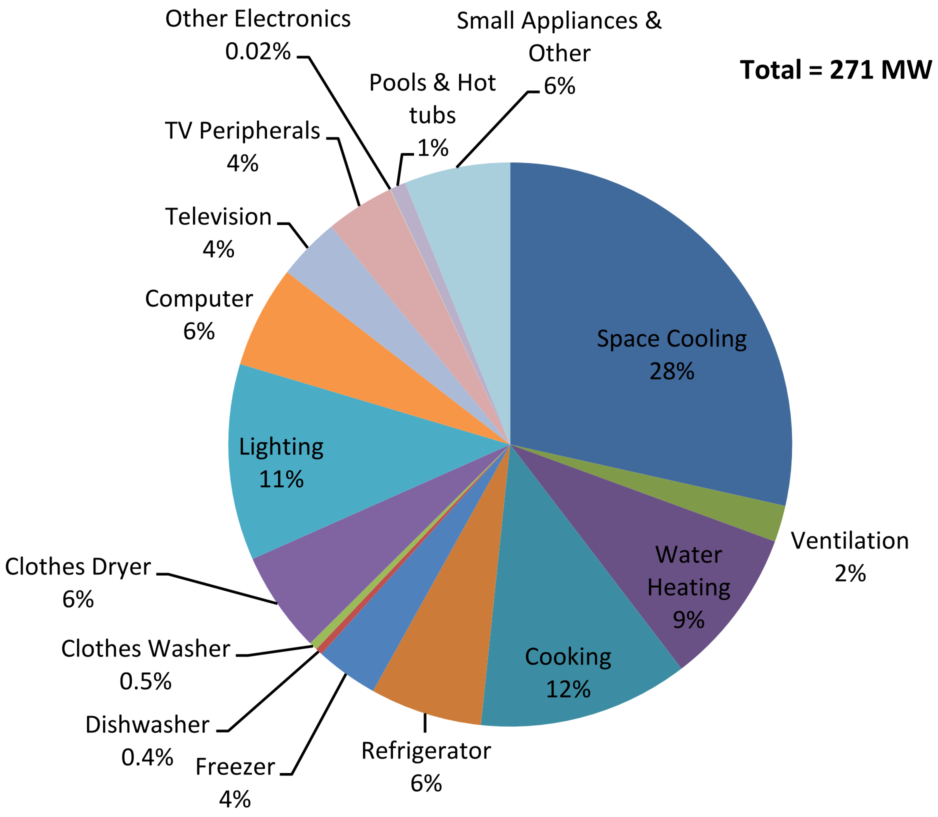
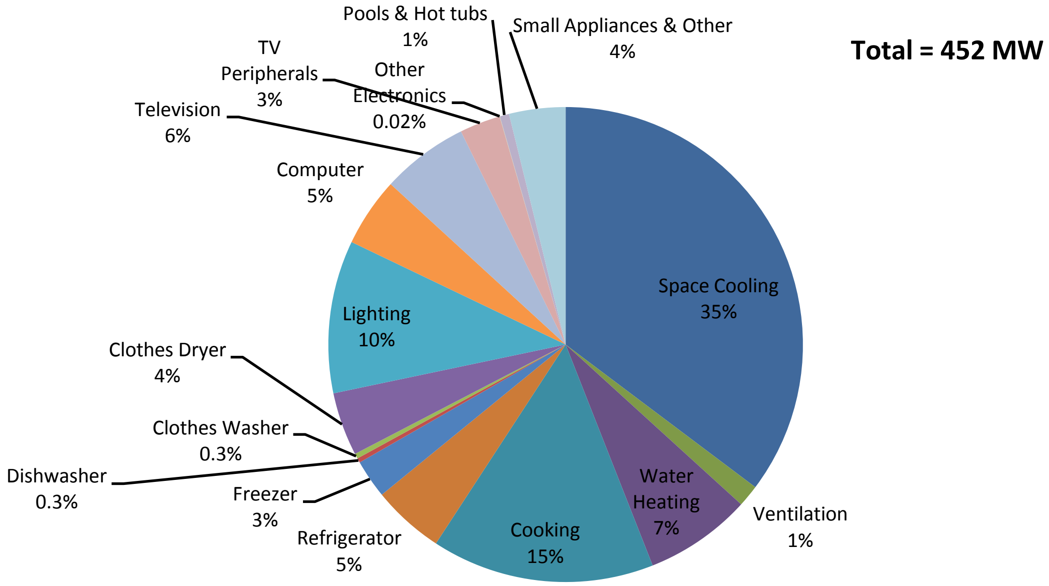


Figure 13 illustrates the forecast 2030 summer peak break down by end-use. Average annual growth in summer peak demand is 2.6%. The large growth rate can be attributed to significant growth in the penetration rate of air conditioning units and central AC.

Figure 13
2030 Summer Peak Breakdown by End-Use – Residential



Commercial End-Use Forecast - Energy

Methodology

The end-use forecast for commercial buildings was calculated according to the following steps:

1. Estimate the share of commercial buildings for each commercial building type (i.e. restaurant, office, retail etc) from FortisBC survey data;
2. Estimate the average square footage for each building type and benchmark against FortisBC survey data;
3. Utilize publicly available sources such as BC Hydro's conservation potential study (2007), FortisBC survey results, and the Northwest Power and Conservation Council for end-use intensity data (EUI data) in kWh/square foot;
4. Using the known number of commercial customers, estimate the number of customer per building so that the number of buildings can be estimated
5. Calibrate the number of buildings so that total end-use consumption matches weather adjusted 2008 load;
    a. EUI data is multiplied by estimated square foot data calculated using the number of buildings (calibrated) and average square footage by building type
6. Compare average customer use from end-use forecast model with average commercial consumption (actual or forecast data);
7. Forecast commercial square footage through 2030 by building type;

8. Forecast EUI for each end-use by building type;
9. Apply EUI to forecast of commercial floor space.

The equation form of this methodology is shown below:

$$\{2008\ \text{Load}\}_{\text{W.A.}} = \sum_{s=1}^{n=segments} \text{Buildings} \times \left(\%\ \frac{\text{Buildings}}{\text{Segment}}\right) \text{x} \left(\frac{\text{SqFt}}{\text{Building}}\right) \text{x(EUI)}$$

The 2008 weather adjusted load is equal to the sum of the load in each of the commercial building segments. The key calibration variable is the number of buildings per customer.

Assumptions

FortisBC survey data was used to estimate the share of buildings that are restaurants, offices, hospitals, etc. To estimate the breakdown of buildings the Commercial End Use Survey report is used.[4] Buildings were categorized as shown in Figure 14 below. The following assumptions were made to calculate the breakdown of buildings in Figure 14 below.

- Medium and light industrial buildings are excluded
- Other includes theatres, auditoriums, churches, museums, community and recreation centers and other buildings not in the major categories
- Mixed use commercial buildings were split between offices, retail, and restaurants based on the building function designated in the survey (i.e. personal services, retail trade, eating and drinking establishments etc)
- Three customers from industrial rate class schedules are included in commercial. These include UBC Okanagan, Selkirk College, and Trail Community Health (hospital).

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[4] FortisBC Inc. *2009 Commercial End-Use Study*. Discovery Research. August 2009. Page 17.

Figure 14
Commercial Building Breakdown, Number of Buildings

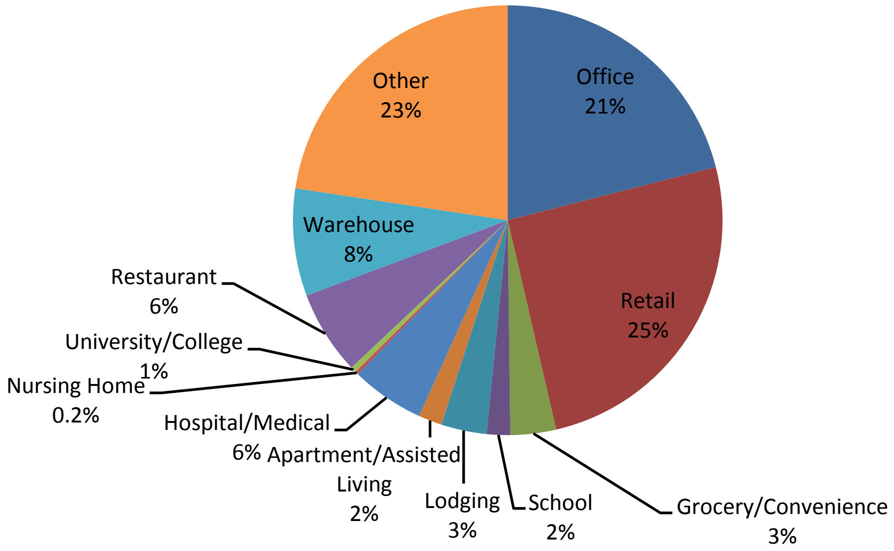

Table 4 defines the building types used in the analysis.

Table 4
Commercial Building Definitions

Building Category	Square Feet
Large Office	>100,000
Medium Office	50,000 to 100,000
Small Office	<50,000
Retail:	
Large Non-Food Retail	>100,000
Medium Non-Food Retail	50,000 to 100,000
Small Non-Food Retail	<50,000
Large Hotel	>100,000
Medium Hotel/Motel	50,000 to 100,000
Large School	>50,000
Medium School	25,000 to 50,000

EUI Data

The end-use forecast uses primarily EUI data from BC Hydro's 2007 study. The BC Hydro data corresponds to buildings in BC Hydro's "Southern Interior," or the climate zone most similar to FortisBC's climate. EUI data from the Northwest Power and Conservation Council was also considered but ultimately not incorporated since BC Hydro data is considered to better represent FortisBC data given that both territories are located in Canada and in similar climate zones. The table below shows FortisBC and BC Hydro EUI data by building type. Data from the NWPCC is also included for reference. The resulting average use per building is 192,017 kWh per year. Average use per customer is approximately 60,000 kWh per year.[5]

Table 5 compares EUI data by commercial building type.

Table 5
Building EUI Data, Annual kWh/Square Foot

	FortisBC End-Use Model	BC Hydro Southern Interior	NWPCC*
Large Office	22.0	22.0	16.4
Medium Office	18.5	18.5	15.4
Small Office	15.1	15.1	14.0
Large Retail	26.9	26.9	30.9
Medium Retail	24.5	24.5	15.2
Small Retail	18.9	18.9	12.9
Large Hotel	19.8	19.8	19.9
Medium Hotel/Motel	16.7	16.7	19.9
Large School	11.1	11.1	8.4
Medium School	8.7	8.7	8.4
Grocery/Convenience	58.3	58.3	53.7
Apartment/Assisted Living	13.4	13.4	19.9
Medical	27.7	27.7	17.8
Hospital	24.3	24.3	24.7
Nursing Home	13.4	13.4	19.9
University/College	17.7	17.7	17.9
Restaurant	66.1	66.1	41.6
Warehouse/Wholesale	16.4	16.4	5.8
Other	15.4	15.4	15.8

*For comparison purposes only.

Model Calibration

The next step is to calibrate the total number of commercial buildings so that the resulting total consumption matches the 2008 weather adjusted load. Then, the share of buildings can be applied to the total number of buildings for which FortisBC provides service. FortisBC has a total of 16,419 general service customers including both direct and indirect customers. However, many of these customers share buildings with one or more other customers or are not associated with buildings at all (such as railroad crossings). Since the total number of buildings is unknown, the commercial end-use forecast (total MWh) is calibrated to weather-adjusted 2008 actual energy consumption using the number of buildings variable. This methodology relies on accurate EUI data.

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[5] FortisBC general service customers consumed an average of 59,000 kWh per year, lower than the forecast suggests. The difference could be attributed to wholesale general service customers having higher average use.

Table 6 shows the results of model calibration in terms of the number of buildings and square footage. In segments where the number of buildings is known the model uses fixed values; for the unknown segments, the number of building is estimated based on the *Commercial End-Use Survey*.

Table 6
FortisBC Commercial Building Square Footage

Building Type	**Share of Buildings**	**Number of Buildings**	**Average Square Feet**	**Total Square Feet**
Large Office	0.0%	5	NA	490,000
Medium Office	0.8%	41	50,000	2,068,492
Small Office	20.2%	1,089	4,000	4,355,504
Large Non-Food Retail	0.0%	-	NA	-
Medium Non-Food Retail	0.0%	5	NA	350,000
Small Non-Food Retail	25.4%	1,369	9,314	12,746,742
Large Hotel	0.0%	-	NA	-
Medium Hotel/Motel	3.4%	185	8,540	1,580,422
Large School	0.0%	-	NA	-
Medium School	1.8%	96	7,000	668,608
Grocery/Convenience	3.4%	185	9,300	1,721,069
Apartment/Assisted Living	1.8%	96	6,819	651,320
Medical	5.5%	298	6,000	1,790,915
Hospital	0.1%	14	88,500	1,540,000
Nursing Home	0.2%	12	5,800	69,249
University/College	0.4%	24	8,000	191,031
Restaurant/Tavern	6.3%	342	4,544	1,552,986
Warehouse/Wholesale	8.1%	436	9,339	4,069,836
Other	22.6%	1,221	14,200	17,335,456
Total	**100%**	**5,397**		**51,181,629**

Some of the above categories have sub categories by building size (Office, Non-Food Retail, Hotels etc.) FortisBC's customer surveys were used to determine what share of buildings fit into the size bins (shown in Table 4). According to the survey, the great majority of buildings are small to medium sized and less than 5% of all buildings with more than 50,000 square feet.

Results

EUI data (Table 5) is combined with commercial floor space data (Table 6) to produce kWh consumption by end use for each building type. Summed across building types, Figure 15 illustrates the kWh consumption by end-use for all building types. Total consumption is estimated at 1,033 GWh for 2008.

Figure 15
Commercial End Use Consumption, Base Year 2008

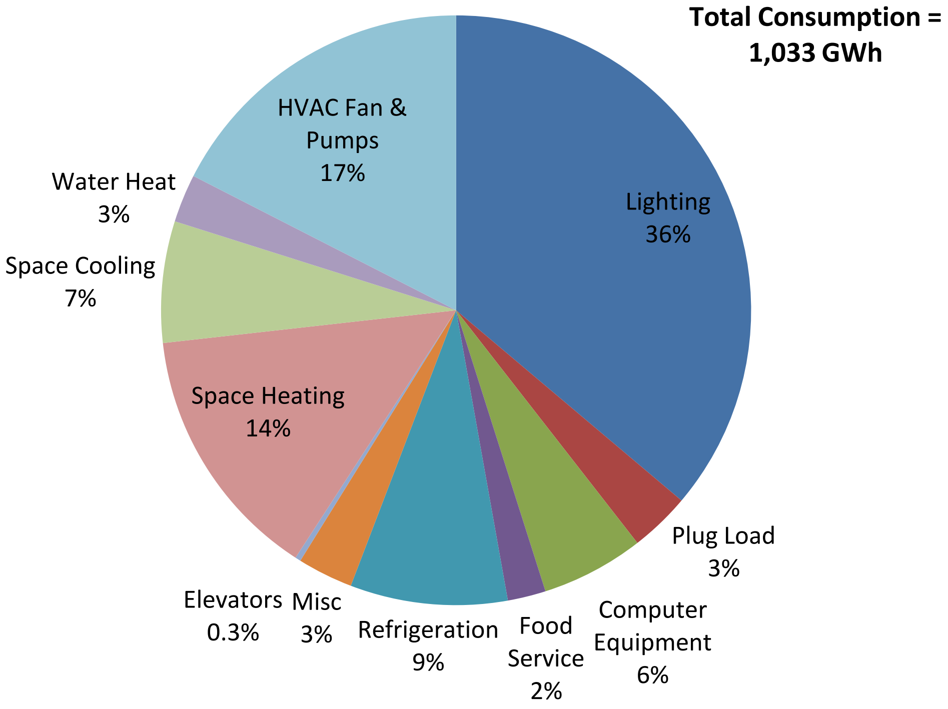
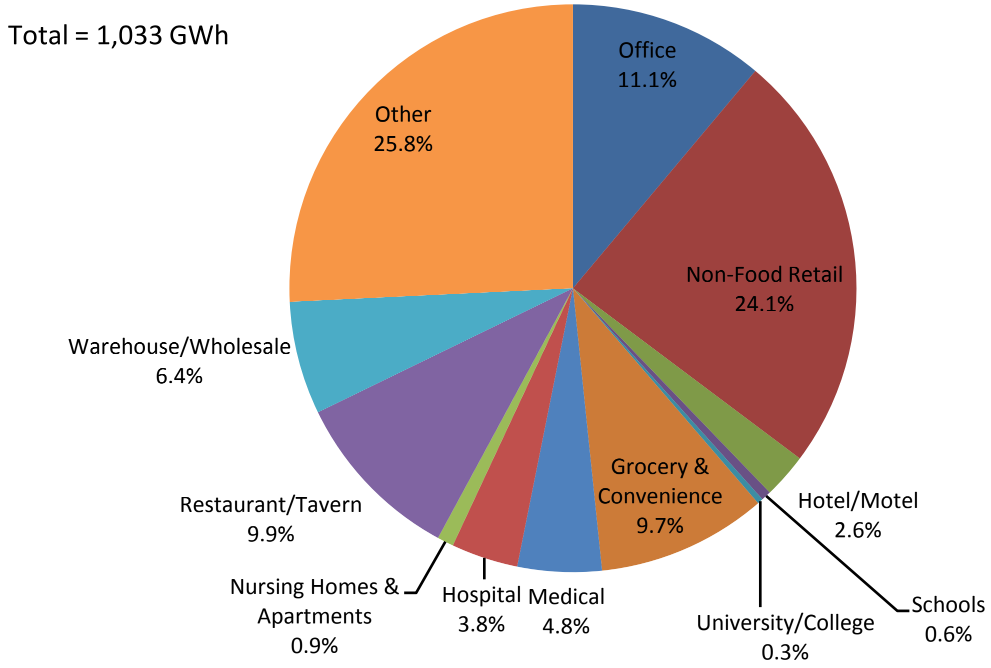


Figure 16 illustrates energy consumption by building type.

Figure 16
2008 Base Year End-Use Consumption by Building Type - Commercial



The total estimated use for 2008 is 1,033 GWh, or equal to 2008 weather-adjusted loads for commercial customers (plus the load from three commercial buildings classified under the industrial rate class).

Forecast

Average annual growth rates for building square footage were assigned by building type. Table 7 summarizes the growth rate assumptions which are based mainly on floor space growth rates in the Pacific Northwest as well as growth rates in BC Hydro's study.

Table 7
Building Growth Rates, Square Footage

Building Type	Building Growth Rates
Large Office	1.9%
Medium Office	1.3%
Small Office	1.7%
Large Retail	0.8%
Medium Retail	1.8%
Small Retail	1.8%
Large Hotel	1.3%
Medium Hotel/Motel	1.8%
Large School	0.9%
Medium School	1.2%
Grocery/Convenience	1.4%
Apartment/Assisted Living	2.6%
Medical	1.9%
Hospital	1.9%
Nursing Home	3.0%
University/College	1.3%
Restaurant	1.7%
Warehouse/Wholesale	3.2%
Other	1.9%

Table 8 compares the FortisBC forecast with the energy consumption estimated using end-use consumption and growth in commercial building square footage. Because the FortisBC load forecast does not separate commercial customers from other classes within the wholesale forecast, the 2008 commercial consumption from wholesale customers (Summerland, Nelson, Penticton, Kelowna, and Grand Forks) is projected at growth rates consistent with total wholesale sales growth.

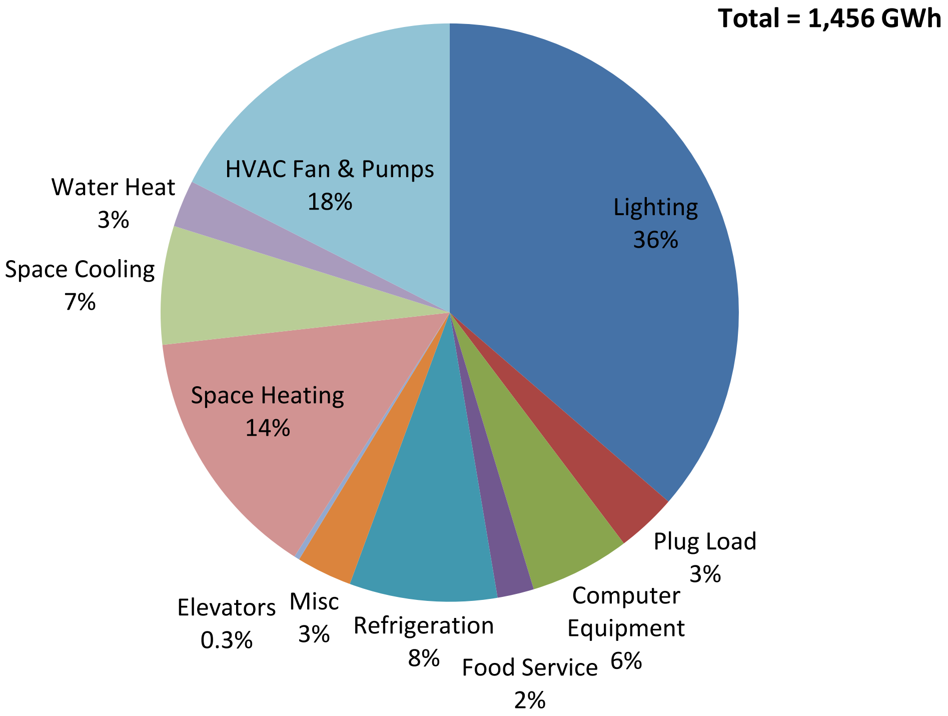
Table 8
Commercial Forecast Comparison - Energy

	FortisBC Load Forecast* MWh	End-Use Model MWh	% Difference
2008	1,033,440	1,033,440	0.0%
2009	1,036,928	1,036,896	0.0%
2010	1,061,161	1,060,909	0.0%
2011	1,086,944	1,086,469	0.0%
2012	1,114,152	1,113,455	-0.1%
2013	1,142,168	1,141,257	-0.1%
2014	1,166,264	1,165,182	-0.1%
2015	1,185,649	1,184,439	-0.1%
2016	1,203,756	1,202,432	-0.1%
2017	1,221,483	1,220,055	-0.1%
2018	1,239,774	1,238,246	-0.1%
2019	1,259,034	1,257,407	-0.1%
2020	1,278,251	1,276,533	-0.1%
2021	1,297,397	1,295,596	-0.1%
2022	1,316,781	1,314,905	-0.1%
2023	1,336,408	1,334,462	-0.1%
2024	1,355,875	1,353,869	-0.1%
2025	1,374,790	1,372,733	-0.1%
2026	1,393,482	1,391,384	-0.2%
2027	1,399,314	1,397,204	-0.2%
2028	1,419,208	1,417,064	-0.2%
2029	1,438,894	1,436,724	-0.2%
2030	1,458,361	1,456,175	-0.1%

*Excludes new DSM.

Figure 17 shows 2030 end-use consumption for the commercial sector.

Figure 17
2030 End-Use Consumption - Commercial



The EUI data for the buildings was forecasted to remain the same over the period. The EUI data were not adjusted to include energy efficiency or code changes. Change in future EUI or EUI for new buildings is accounted for in the conservation potential estimates. Energy efficiency potential due to code changes is later separated from potential available through utility programs.

Commercial End-Use Forecast – Demand

Methodology

The end-use forecast for energy was used together with load factors to estimate peak demand consumption for both the winter peak and the summer peak. The winter peak estimate is calculated by applying BC Hydro demand (kW) by end-use to FortisBC energy consumption across building types. The summer peak utilizes load factors from the Northwest Power and Conservation Council with some adjustments to account for FortisBC climate and other characteristics.

Winter Peak Demand

Figure 18 illustrates the breakdown of FortisBC winter peak by end-use. The winter peak usually occurs around the 6 p.m. hour in either December or January, depending on weather.

Using load factors and normalized annual energy, total commercial winter peak demand (normal) is estimated at 225 MW for 2008.

Figure 18
2008 Winter Peak Demand – Commercial

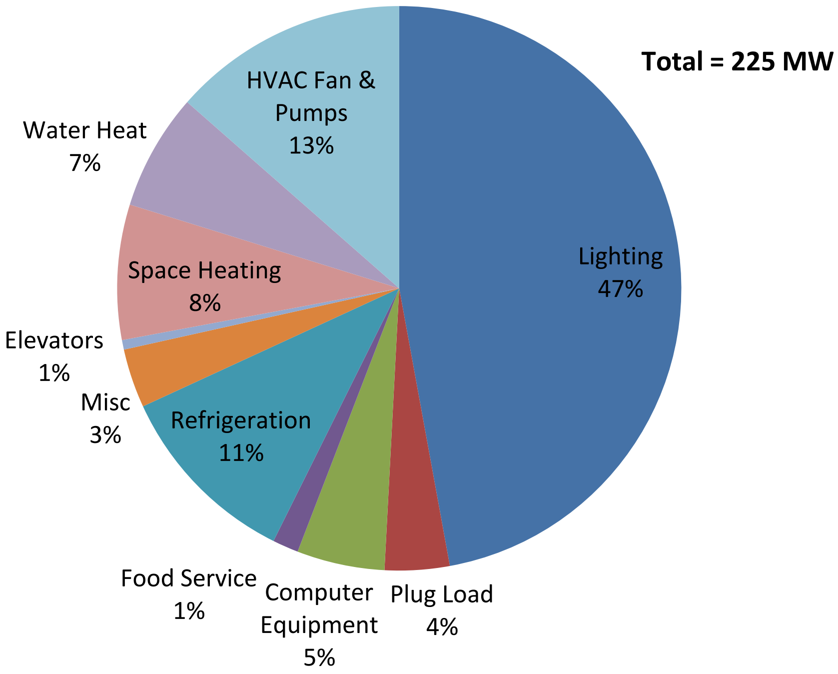
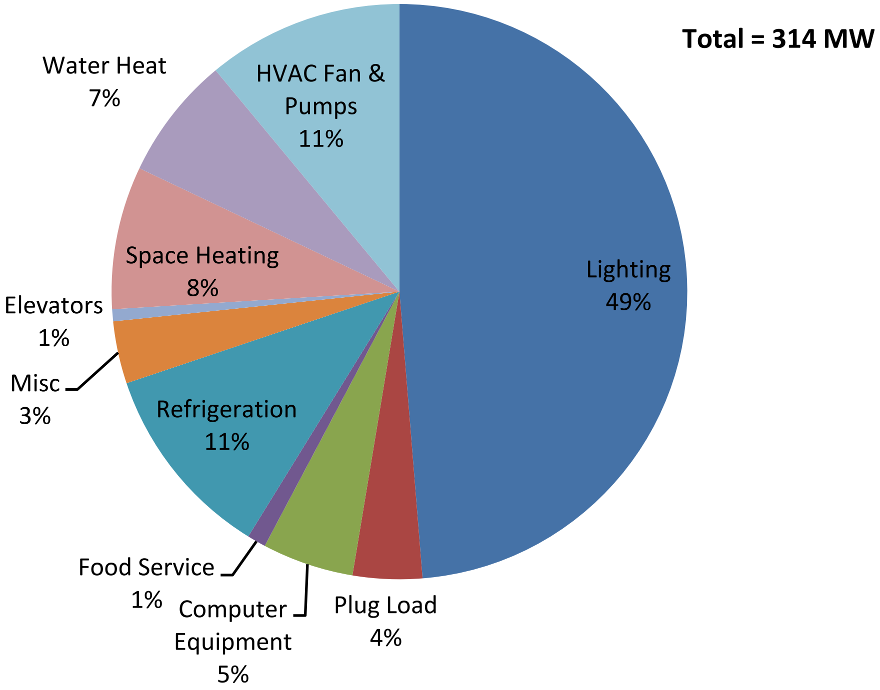


Figure 19 shows the forecasted winter peak breakdown in 2030. Average annual growth in peak demand is 1.8%. Because floor space growth rates varies across building types (See Table 7), the 2030 winter peak demand is slightly different from the 2008 winter peak demand profile.

Figure 19
2030 Winter Peak Demand – Commercial



The figure below shows the 2008 winter peak demand by end-use and customer type. Lighting is excluded in Figure 20 due to the large amount of consumption; however, lighting consumption by building type is shown in the subsequent figure. Figure 20 shows that the building types that contribute most to peak demand are small office, small retail, grocery, and other (see Table 9).

Figure 20
2008 Commercial Winter Peak Demand by Building Type and End-Use Excluding Lighting

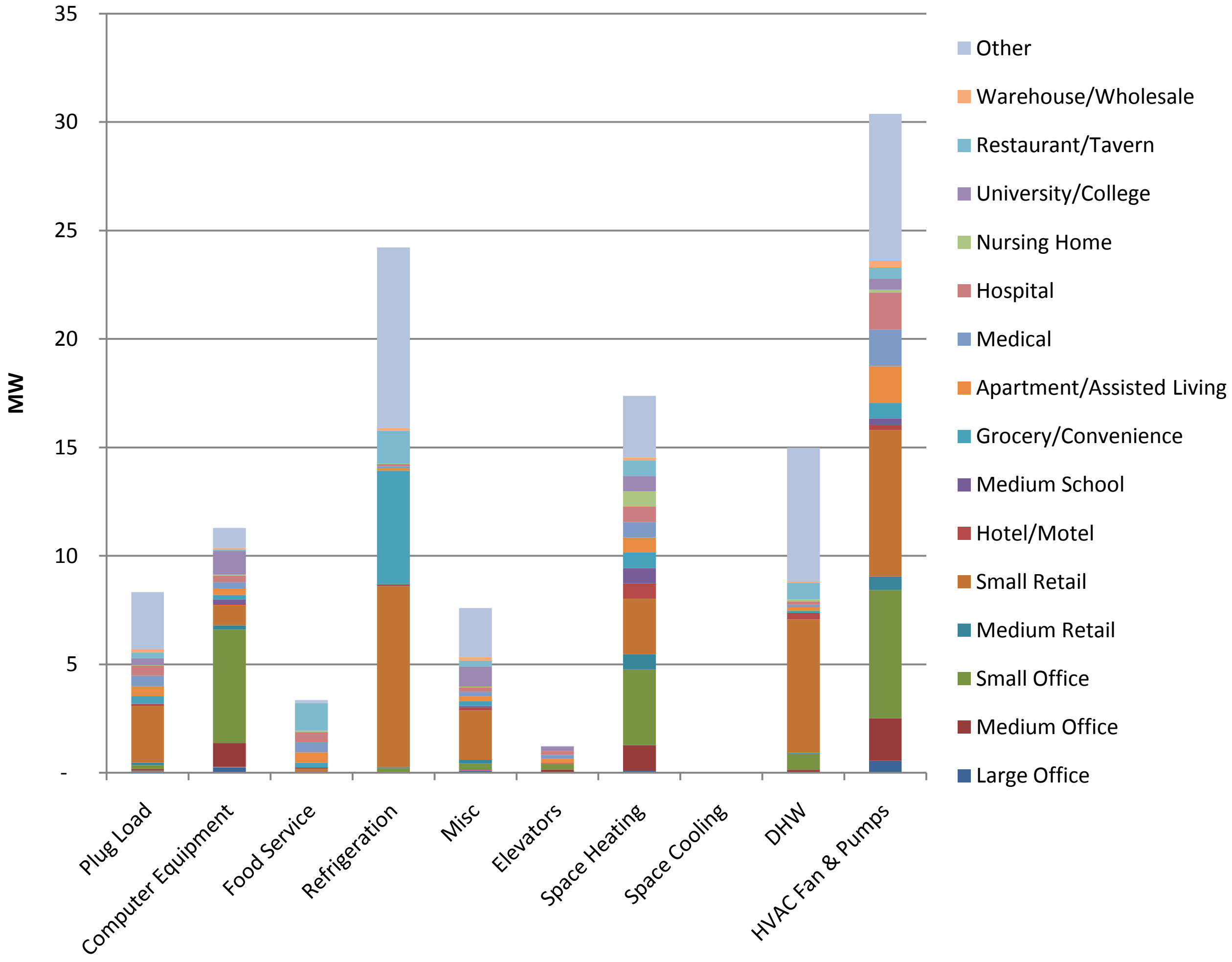
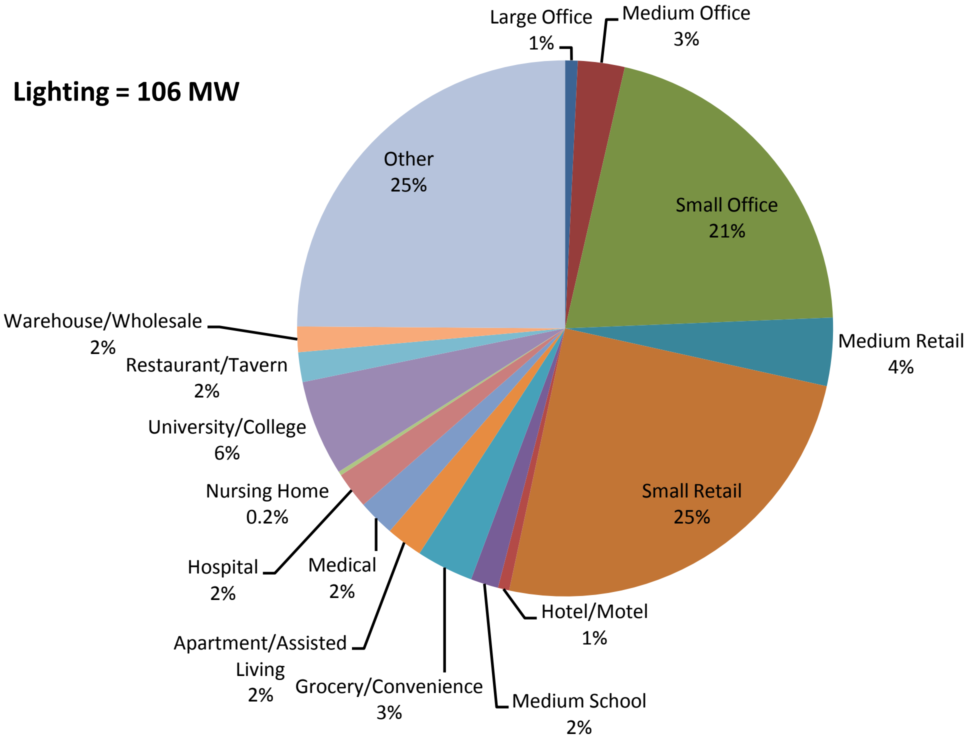


Table 9
2008 Commercial Winter Peak Demand, Top Four Building Types

	2008 Peak Demand, kW
Other	56
Small Retail	56
Small Office	38
Grocery/Convenience	11
All Commercial Buildings	225

Figure 21 shows that small office, small retail, and other building types contribute most significantly toward winter peak in terms of lighting consumption.

Figure 21
2008 Winter Commercial Peak Demand by Building Type – Lighting Only



Summer Peak Demand

Figure 22 illustrates the breakdown of FortisBC summer peak by end-use. The summer peak usually occurs in the late afternoon/early evening (around 5 P.M.) on July or August day, depending on weather. Total commercial summer peak demand is estimated at 193 MW for 2008.

Figure 22
2008 Summer Peak Demand - Commercial

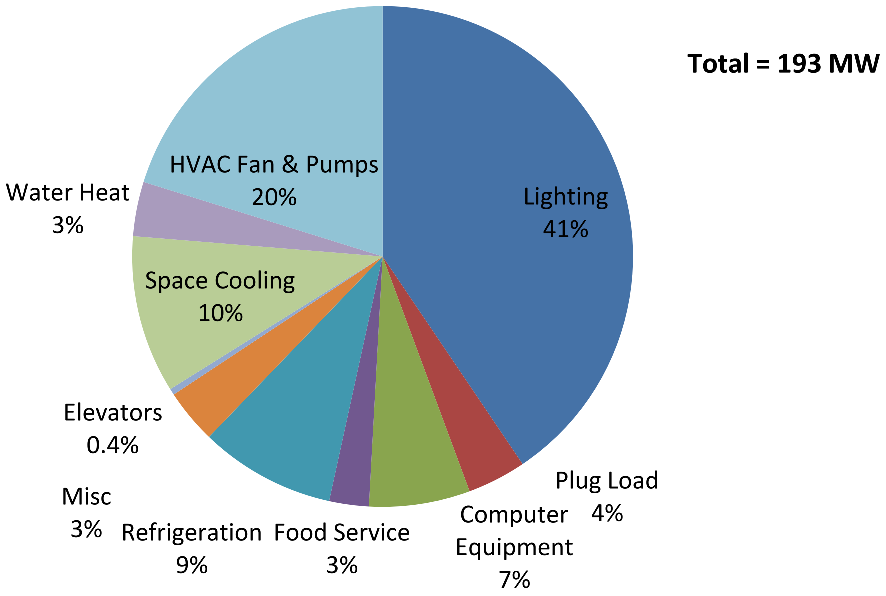


Figure 23 illustrates the forecasted summer peak demand for 2030. The average annual growth rate in peak demand is 1.4%.

Figure 23
2030 Summer Peak Demand - Commercial

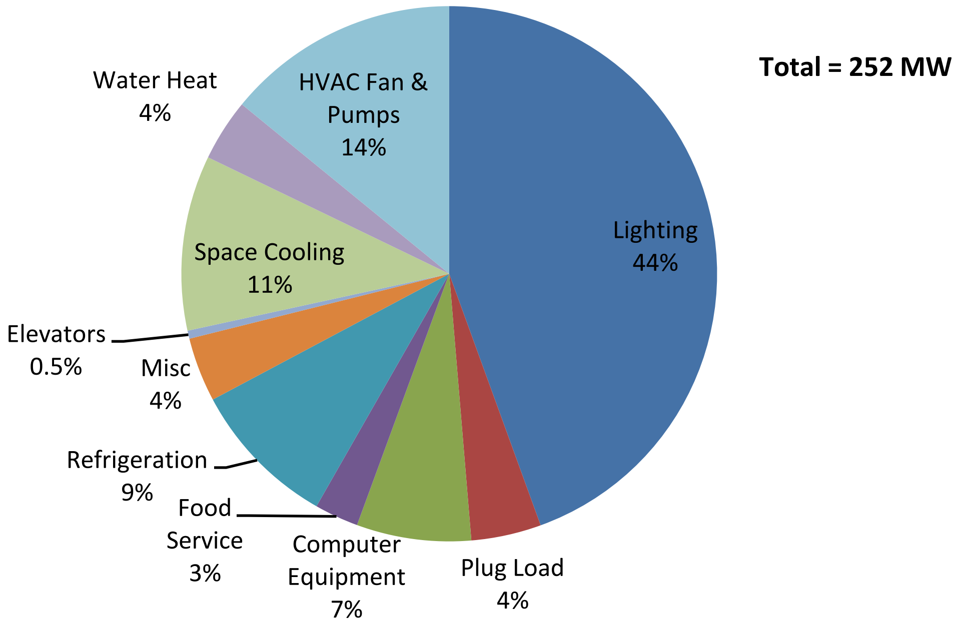


Figure 24 shows the 2008 summer peak demand by end-use and building type. Lighting is excluded in Figure 24 due to the large amount of consumption; however, lighting consumption by building type is shown in the subsequent figure. Figure 24 shows that the building types that contribute most to peak demand are small retail, grocery, restaurants, and other (see Table 10).

Figure 24
2008 Commercial Summer Peak Demand – by Building Type and End-Use
Excluding Lighting

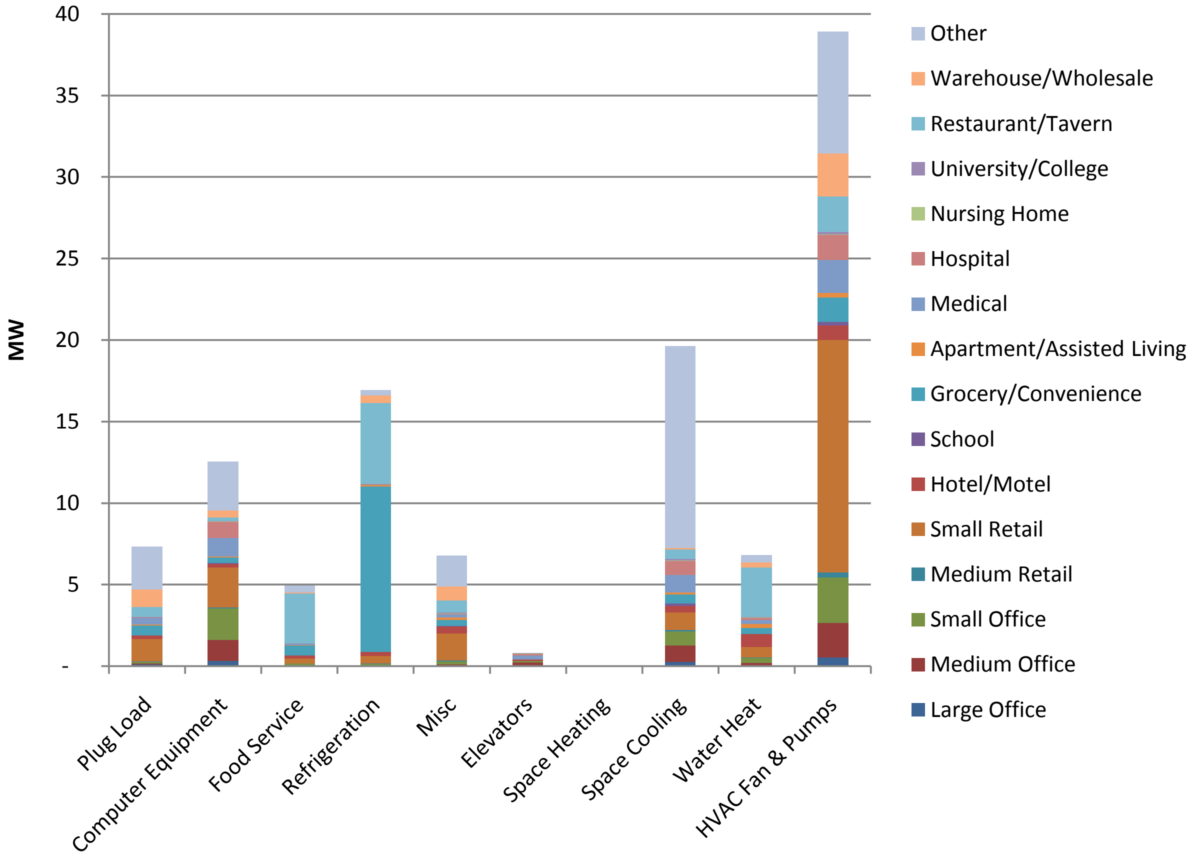
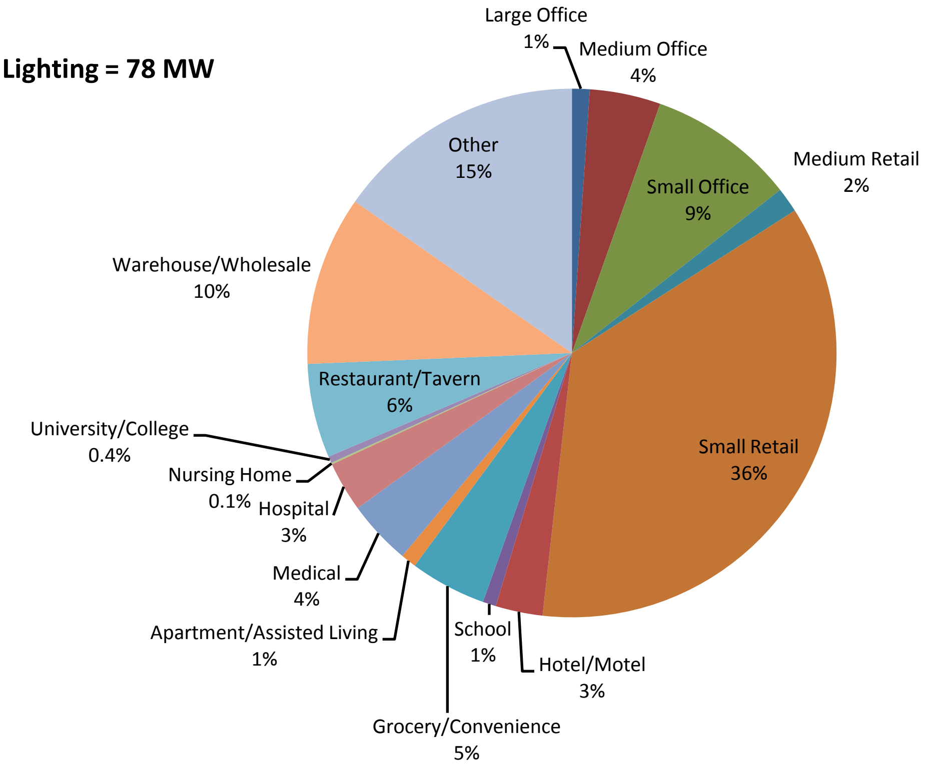


Table 10
2008 Commercial Summer Peak Demand, Top Four Building Types

	2008 Peak Demand, kW
Small Retail	50
Other	40
Restaurant/Tavern	20
Grocery/Convenience	18
All Commercial Buildings	193

Figure 25 shows that small retail, warehouse/wholesale, and other building types contribute most significantly toward summer peak in terms of lighting consumption.

Figure 25
2008 Summer Commercial Peak Demand by Building Type - Lighting



Industrial End-Use Forecast

Methodology

The base year for industrial sector consumption is calculated using the 2009 energy forecast for rate schedules 30, 31, and 33 and the Tolko sawmill (wholesale customer). As mentioned in the Commercial End-Use Forecast section, three customers were removed from the industrial rate class for conservation modeling purposes: UBC Okanagan, Selkirk College, and Trail Community Health. Some industrial customers are net metered; self-generation is not included in this forecast nor is it included in the FortisBC system forecast.

Customer consumption is grouped into classes according to the North America Industry Classification System (NAICS). Table 11 shows the industrial processes and annual kWh consumption for these customers.

Table 11
Industrial Sector Retail Sales by Segment, 2008

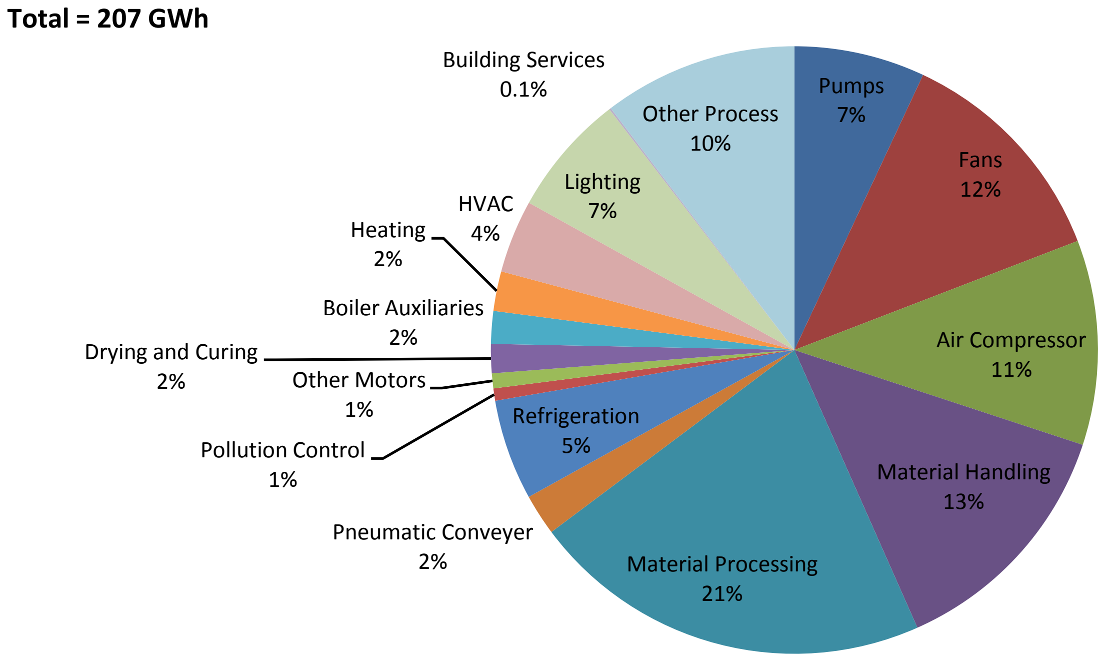
Industrial Process	**Energy Consumption kWh**
Wood products	90,054,330
Building Materials	53,000,000
Pulp and Paper	16,500,000
Food and Beverage	13,873,300
Miscellaneous	9,857,231
Mining	9,120,800
Fruit packers and storage	8,724,298
Other Manufacturing	3,621,000
Contractors & Construction	2,717,664
Total	207,468,623

Consumption within each industrial process was disaggregated into end-use by applying percentages from sources such as the BC Hydro Conservation Potential Assessment and the Northwest Power and Conservation Council. The result is a top-down methodology for classifying energy consumption by end-use.

2008 Industrial End-Use Consumption

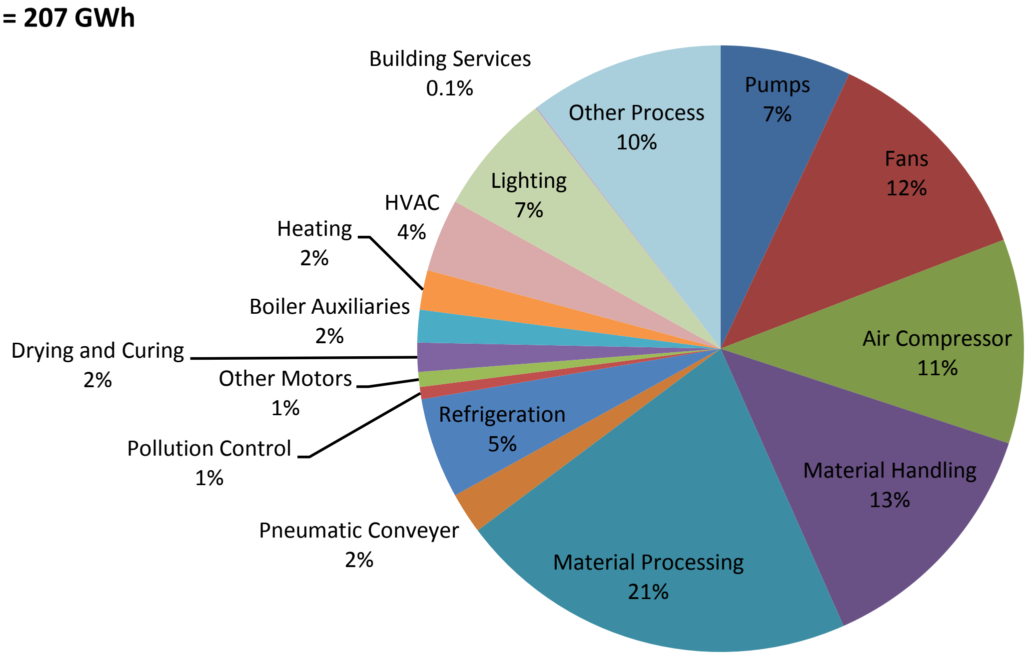
Using the methodology above, total sector consumption is split into several end-use categories. Figure 26 below shows the resulting break down for the base year. Total consumption is 207 GWh.

Figure 26
2008 End-Use Consumption - Industrial



Industrial loads are expected to remain flat over the planning period. Therefore the 2030 end-use breakdown will be identical as the 2008 break-down in terms of share and total consumption. See Figure 27.

Figure 27
2030 End-Use Consumption - Industrial



Peak Demand Forecasts

Winter and summer coincident peak demand for the industrial sector is estimated based on historical load factors by customer from FortisBC billing data as well as load factors for industries in California and British Columbia (BC Hydro). The methodology for forecasting peak demand by end use was first to calculate load factors for each type of industry (sawmill, pulp, manufacturing, etc). These load factors are applied to each end-use by industry. In cases where more details were known, such as refrigeration in food and beverage industries, specific load factors were used by end-use. The resulting summer and winter peak demand breakdowns are given in Figures 28 and 29. Since a 0% growth is assumed for the energy forecast, the 2030 peak demand breakdowns will be identical to Figures 28 and 29, and therefore are excluded from the report.

Figure 28
Industrial Winter Peak Demand

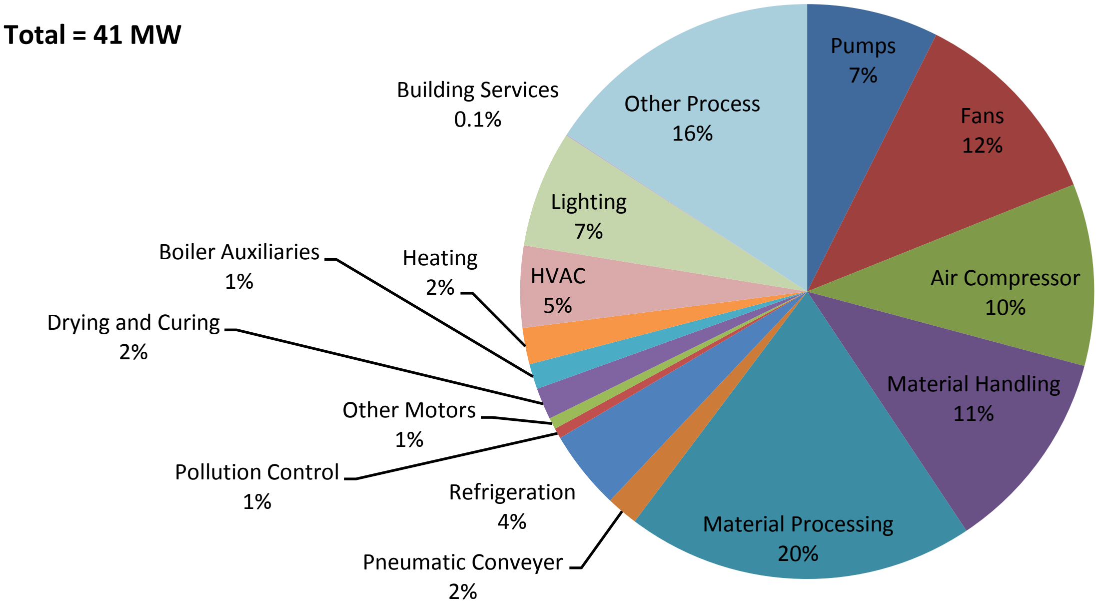
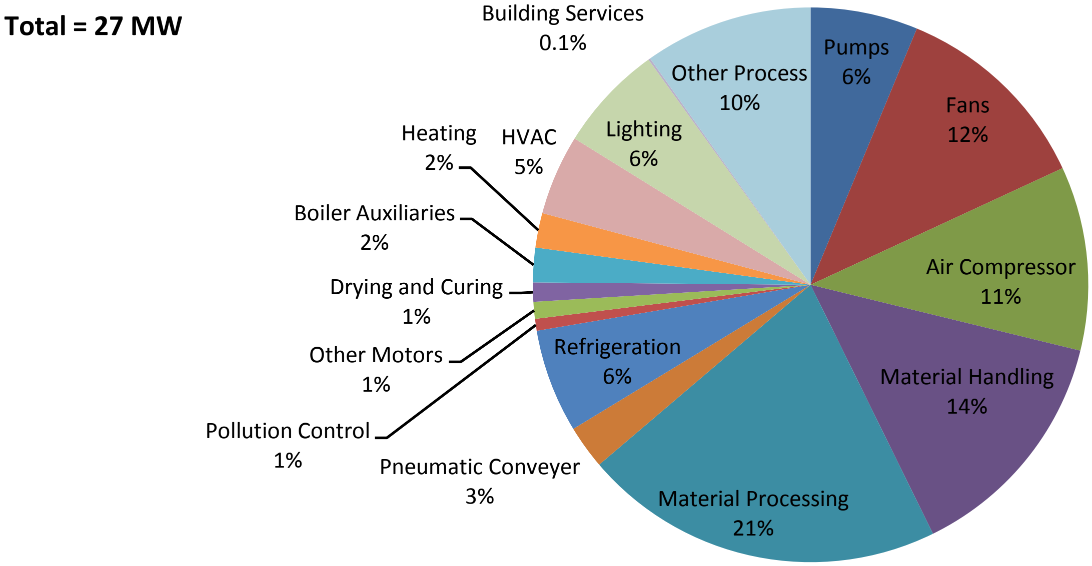


Figure 29
Industrial Summer Peak Demand



Total System

This section aggregates all sectors to compare the end-use forecasting models with the load data provided by FortisBC and its wholesale customers. First, Table 12 compares energy forecasts by sector. Irrigation and lighting sector consumption was not broken down due to lack of data. The end-use forecast model was calibrated to match normalized load data; therefore, there are no material differences in base year consumption.

Table 12
End-Use Model Comparison for 2008
(MWh)

	Residential	Commercial	Industrial	Lighting	Irrigation	Total
2008 Loads Provided by Utilities	1,719,530	1,033,440	207,469	13,538	52,071	3,026,047
2008 End-Use Model	1,719,530	1,033,440	207,469	13,538	52,071	3,026,047
% Difference	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Table 13 below compares the summer and winter peak demand forecasts. Load factors for Irrigation and lighting customers are assumed to produce the total peak. It was assumed that there is no irrigation during the winter peak and an 87% load factor for summer is used. It is assumed that lighting is not part of the summer peak demand.

Table 13
End-Use Model Comparison for 2008 (MW)

	Residential	Commercial	Industrial	Lighting	Irrigation	Total
Winter Peak						
Weather Adjusted Actual						701
2008 End-Use Model	427	225	47	3	4	706
% Difference						-0.7%
Summer Peak						
Weather Adjusted Actual						560
2008 End-Use Model	271	193	34	0	45	543
% Difference						3.0%

Residential Energy Savings Potential

Introduction

This section begins with a brief description of residential customer housing characteristics and appliance saturations. Next, energy efficiency measures are described followed by potential estimates calculated using the methodology described in the "Methodology" section. A couple of fuel switching measures, customer-owned renewable energy, and low-income measures are also addressed. The conservation potential results are presented as supply curves, tables, and compared to the end-use forecast.

Residential Customer Characteristics

FortisBC provides electric service directly to 95,282 customers and indirectly to an additional 42,373 customers through its wholesale customers. In 2009, FortisBC conducted a customer survey of both direct and indirect residential customers within their service territory. The surveys defined building characteristics and appliance saturations, type and age. These results are provided at an aggregate level as well as by sub region including West Kootenay, South Okanagan, and Central Okanagan.

Table 14 summarizes the key building characteristics for all FortisBC customers. Heat type, furnace age, insulation, window, and door characteristics were also defined for these buildings.

Table 14
Residential Building Characteristics

	Single Family	Mobile, Other	Apartment Condo	Duplex, Row, Townhouse
Building Type	**69%**	**8%**	**13%**	**11%**
Electric Heat	31%	27%	80%	42%
Gas Heat	57%	47%	18%	57%
Other Heat	12%	26%	2%	1%
Own Home	95%	92%	65%	82%
Before 1950	12%	0%	2%	1%
1950-1975	25%	25%	5%	14%
1976-1985	18%	31%	10%	19%
1986-1995	21%	21%	23%	28%
1996-2009	24%	22%	53%	32%
Full Basement	60%	2%	11%	46%
Partial Basement	12%	1%	2%	8%
Crawlspace	20%	26%	3%	27%
No Basement	8%	71%	85%	19%
Average Size (Sq Ft)	2,250	981	1,187	1,688

Table 15 summarizes key appliance saturations for FortisBC residential customers. The survey also identified the average age for the major appliances; these are shown below when provided for the main appliance.

Table 15
Residential Appliance Saturation

Cooking and Food	**Share**	**Average Age, Years**	**Electronics**	**Share**
Refrigerator Auto Defrost	90%	7.3	DVD	75%
Chest Freezer	52%	12.6	VCR	52%
Upright Freezer (not part of fridge)	21%	6.9	Digital Cable or Satellite TV	47%
Refrigerator Manual Defrost	20%	8.6	CRT TV <32 inches	61%
Microwave	87%		CRT TV >32 inches	24%
Electric Range (cook top + oven)	81%		LCD Flat Screen TV	38%
Electric Cook Top	11%	9.0	Laser Printer	15%
Gas Range (cook top + oven)	11%		Plasma flat screen TV	13%
Separate Electric Oven	10%		Rear projection TV	7%
Gas Cook Top	5%		Desktop Computer	69%
Cleaning			Inkjet printer	65%
Electric Clothes Dryer	92%	7.8	Laptop computer	49%
Automatic Dishwasher	82%	7.0	Fax	19%
Clothes Washer (top load)	64%	9.5	Audio entertainment video games	24%
Clothes Washer (front load)	35%	3.6	Surround System	32%
Gas Dryer	2%	8.7	Other	2%
Water Heating			**Miscellaneous**	
Gas Water Heater	50%	6.9	Jetted Bathtub	11%
Electric Water Heater	49%	6.6	Hot Tub (outdoor)	11%
AC			Swimming Pool (outdoor)	7%
Central Air Conditioning	50%	N/A	Indoor hot tub	2%
Window AC	16%		Separate workshop	18%
Portable AC	7%		Electric Car Block Heater	21%

Energy Efficiency Measures

Several measures for each end-use were analyzed to model energy efficiency potential. Measures were included where the data available supported cost and savings values. Many "non-traditional" measures such as shade trees or clothes lines have little solid basis for either cost or savings and so were excluded from this analysis. Future CPA work may include data collected from the many pilot programs currently being implemented in North America that seek to verify "non-traditional" measure cost and savings values. Non-traditional measures and/or new technologies may be viable and integral parts of program offerings, but because they are difficult to quantify, they are not used in this potential assessment. The table below summarizes the types of technology-based measures included in the analysis. While few categories are provided in the table, several permutations of each measure within these categories exist. There are over a hundred individual measures considered in the residential sector only.

Table 16
Residential Energy Efficiency Measure Categories

- Appliances
  - Refrigerator and Freezer Recycling
  - Clothes Washers and Dryers
  - Dishwashers
  - Refrigerators and Freezers
  - Ovens and Ranges
  - Microwave
- Lighting
  - CFLs
  - LEDs
- Electronics
  - Televisions
  - Computers and Monitors
  - Set Top Boxes
  - TV Peripherals
- New Home Whole House Measure
- Electric Thermal Storage (ETS)
- Domestic Hot Water
  - Tank Upgrades
  - Low-Flow Showerheads
  - Low-Flow Faucet Aerators
  - Heat Pump Water Heater
- Heating and Cooling
  - Heat Pump Upgrades
  - Heat Pump Conversions
  - Window and Portable Air Conditioning Upgrades
  - Electric Thermostats
  - ECM on Furnace Fans
  - Geothermal Heat Pumps
- Weatherization
  - Windows
  - Air Sealing
  - Insulation

Heat pump conversions are measures that take into account the incremental cost and energy savings from switching from some other electric heat source (like baseboard or forced air furnace) to heat pumps. Conversely, heat pump upgrade measures take into account the incremental cost and savings from upgrading from a less efficient heat pump to a more efficient model.

Electric Thermal Storage

Electric Thermal Storage (ETS) is a peak demand reduction measure evaluated alongside the energy efficiency resources in this section. Although there are no energy savings related to ETS, peak demand savings are evaluated assuming that ETS can be implemented with time-of-use rates (TOU) or some other customer incentive so that remote control or smart metering is not required. ETS is described in more detail below.

Thermal Storage, Room

Thermal storage systems heat enclosed ceramic bricks to as high as 1,650 degrees C during off-peak hours and slowly release the heat as needed during on-peak periods. While thermal storage has little or no energy benefits, it has the potential to shift almost the entire heating load to off-peak hours. If a unit is working exactly as installed, 100% of heating load can be curtailed during morning and evening winter peak. In practice, overrides and minimal on-peak usage make a 90% peak reduction possible. Lifetimes are 15-18 years and costs can be quite expensive ($5,000-$6,000 per house. A typical house would need three or four units ($1500 each). Steffes is the primary vendor in the region. Hayes Creek Electric reports good consumer acceptance of the technology and few problems, despite low participation in a Princeton, BC based program.

Thermal Storage, Central

Central thermal storage units are similar in savings and life to central systems. When applicable, they have a slightly lower cost. However, central thermal storage units also come with other retrofit concerns in addition to the substantial cost. Often houses require re-wiring and structural modifications to handle the weight of the units. Central thermal storage units require ducts through the house and are generally applicable to larger homes and new construction.

Emerging Technologies

Some emerging technology measures are included in the potential estimates. Measures such as heat pump water heaters and ductless heat pumps, which are not yet main stream but have equipment available in the market, have been included in the main potential assessment. In addition, whole house measures for new single family homes are included. These are known as EnerGuide80 and Energuide90[6] measures and include significant weatherization, energy efficient heating types and water heating. British Columbia plans to adopt EnerGuide80 standards as building codes by 2014.

EnerGuide90 homes are known as “near net zero” homes in British Columbia. While the technologies for these homes are available, programs for net zero homes are not yet mature. Net zero homes can be built for $10,000 to $30,000 more than the cost of a conventional home which can be recovered through savings on energy bills and increased value of the home. Currently, there are 1,697 homes in the southwestern United States, and at least fifteen demonstration projects are underway in Canada through CMHC.[7] EnerGuide90 homes are included in potential

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[6] EnerGuide90 homes are also known as “near net zero” homes in British Columbia. Though these homes consume significantly less energy than standard or older homes; they do not attain net zero electricity consumption on an annual basis.

[7] http://www.netzeroliving.ca/#what_is_a_net_zero_homeHC's EQuilibrium initiative.

estimates; however, due to the emerging nature of the programs, achievability rates are set conservatively for this measure group (65 percent).

In addition to the emerging technology measures included in this analysis, there are a variety of technologies/measures that are undergoing research and development, and others that have yet to be identified that may come to fruition during the 20-year timeframe of this study.

- Phase change materials – building materials that store thermal energy during the day and release during the night
- Vacuum panel insulation – panels that achieve insulating levels up to 7 times greater than existing materials
- Green roofs – roofing systems capable of growing plants; primarily for multifamily apartment buildings
- Vacuum panel windows – two glass panels with a partial vacuum in between
- Integrated PV windows – windows that incorporate photovoltaic cells in the window
- Advanced LED lighting – LED's are included in the potential estimates in a limited manner, but significant advances could result in the displacement of CFLs
- Fiber optic lighting and light pipes – day lighting is distributed throughout buildings through fiber optic cable
- Solar absorption cooling – gas-fired absorption chillers are widely available, but these cooling systems use solar energy as the heat source.
- Evaporative cooling – evaporative cooling is becoming more widely available in hot, dry climates and may eventually have some application in FortisBC service area
- Home Automation (optimized home energy use) – Home Automation fully integrated with the smart grid will help to optimize energy consumption and peak demand beyond individual measure savings
- On-site generation (e.g., waste to energy, widespread PV, wind, fuel cell) – to obtain true net zero energy consumption, some on-site generation will likely be required.

At this point these measures/technologies are either unproven or too costly to be implemented as cost-effective conservation. However, it is likely that development will continue and some or all will be tested, verified, and included in future potential assessments.

Fuel Switching

In addition to the energy efficiency measures, one fuel switching measure category was analyzed in the residential sector. Due to the large share of demand from cooking during peak times, electric savings from the conversion of electric ranges (oven and stove top) to gas-fuelled ranges is examined. Also conversions from electric to gas-fuelled clothes dryers are analyzed. Approximately 92 percent of residential clothes dryers are electric. While these electric savings are quantified in this report, government policies preclude the electric utility from offering programs in this area.

Customer-Owned Renewable Energy

Several customer-owned renewable energy technologies were assessed for this conservation potential study. Customer-owned renewable energy measures include:

- Solar (photovoltaic);
- Wind turbines; and
- Solar hot water heating.

Micro hydro resources are sometimes included under the “customer-owned renewable energy” category. However, these resources are most commonly found as a supply-side resource rather than a demand side measure. Costs and annual generation for these projects vary significantly by site. In their study, BC Hydro notes that the main components of a micro hydro system include the pipeline, turbine, generator and controls. Generator costs vary from $2,000 to $3,000 per kW for small systems, but some systems are more complex and therefore cost more. The costs for installing pipelines and controllers are highly location dependent. Large components of micro hydro costs are site-specific, and this study does not attempt to develop a cost for these projects (similarly treated in the BC Hydro DSM study).

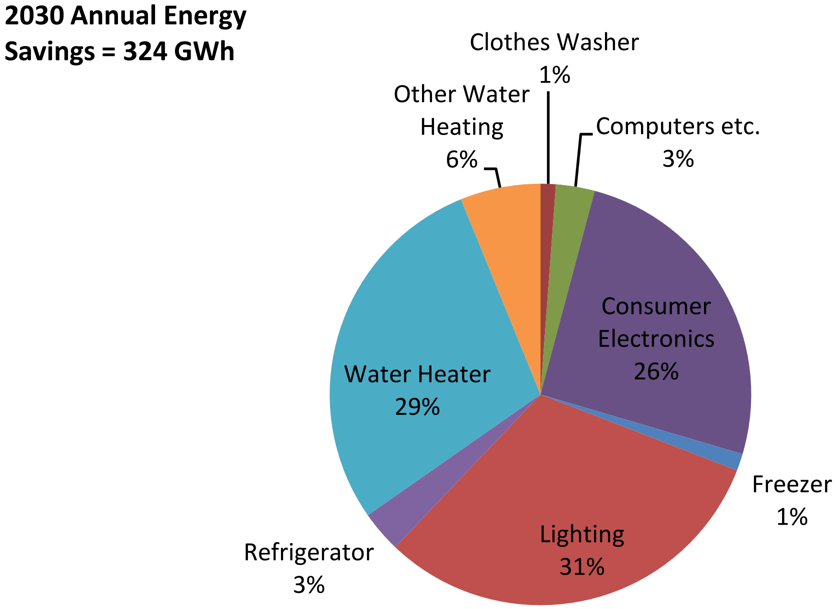
Potential Estimates

As described in the methodology section, end-use load forecast data and energy efficiency measures are combined to produce estimates of energy efficiency. In this analysis, energy efficiency potential is presented separately from the electric savings from fuel switching measures. The total economic and achievable potential is 479 GWh annually by 2030 or energy savings of 21 percent of 2030 forecasted residential load. In this section, economic and achievable potential are discussed followed by program achievable potential.

Appliances

Figure 30 illustrates the breakdown of economic and achievable energy efficiency potential for appliance measures. It is estimated that a total of 324 GWh of energy can be saved annually by 2030 through these measures. The potential estimates include measures that apply to both new and existing construction. Fuel switching measure potential is not included in the chart below but is discussed later in this section. The measure categories are described in further detail below.

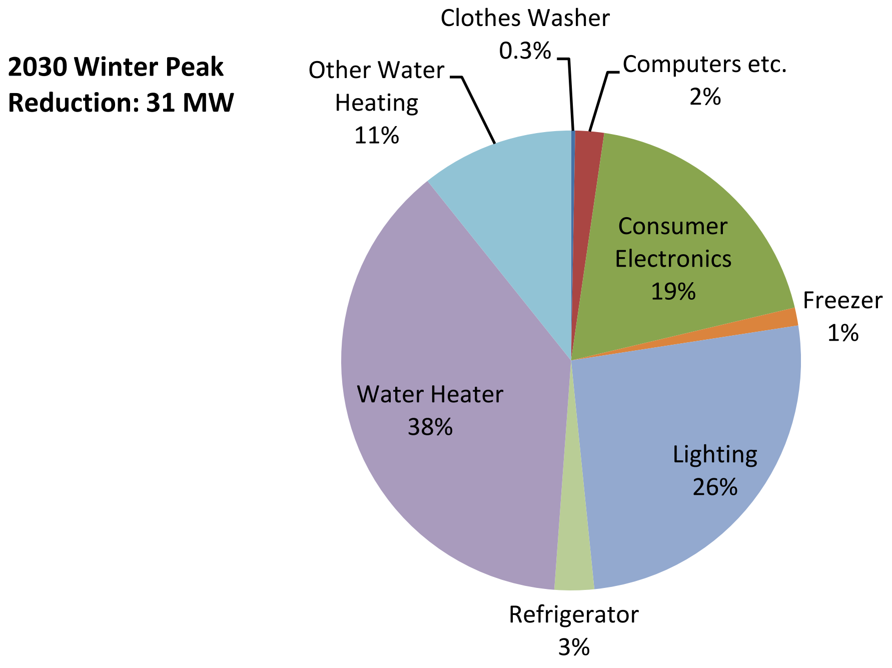
Figure 30
2030 Achievable Energy Savings Potential – Appliances



- **Clothes Washer** – Savings potential for 3 Tiers of clothes washer efficiency are applied to applicable units. The efficiency levels are: Tier 1is MEF (Modified Energy Factor) 2.0 to 2.19; Tier 2 is MEF 2.2 to 2.45; and Tier 3 is MEF 2.46 or greater.
- **Clothes Dryer** – Applies to electric clothes driers. Minimum efficiency level is EF (Energy Factor) 3.15. Due to high costs relative to energy savings, this measure does not pass TRC test, so it is excluded from chart above.
- **Computers** – Includes residential desktop computers and monitors.
- **Consumer Electronics** – Includes Energy Star Televisions and Set-Top Boxes.
- **Cooking** includes efficient microwave ovens and convection ovens. These measures do not pass the TRC so are not included in the chart above.
- **Dishwasher** measures have a minimum efficiency rating of EF 72. Does not pass TRC.
- **Freezers and Refrigerator** categories include both Energy Star rated appliance upgrades as well as retirement or recycling of old appliances.
- **Lighting** includes compact fluorescent light bulbs and fixtures.
- **Water Heaters** include upgraded efficiency as well as heat pump water heaters.
- **LED Lighting** – applies to whole house (new construction). Does not pass TRC.
- **Other Water Heating** measures include low-flow shower heads, bathroom and kitchen faucet aerators, and wastewater heat recovery systems in 2-storey, single family homes.

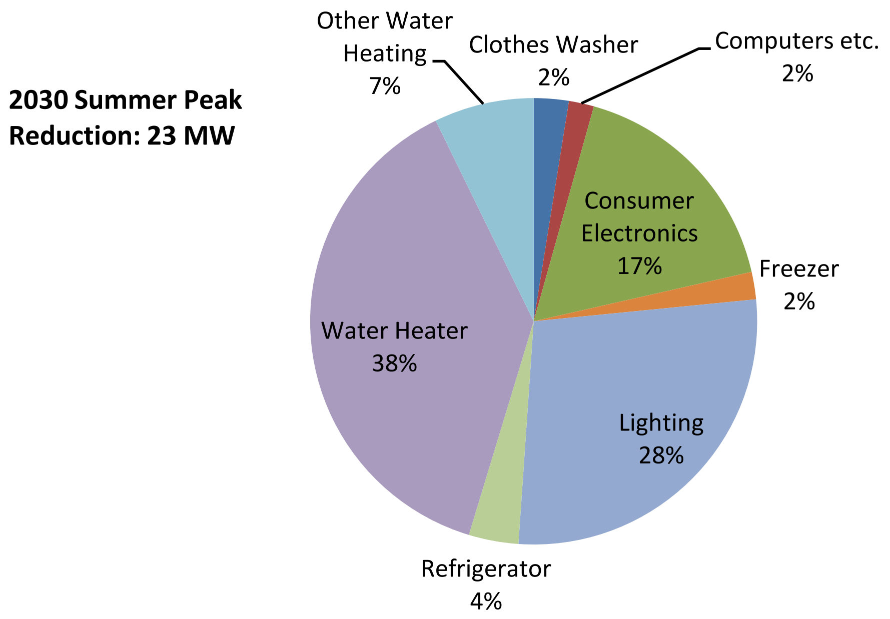
Winter peak reduction from these energy efficiency measures are shown in Figure 31. Peak energy savings are derived according to the timing of energy savings by measure.

Figure 31
Winter Peak Savings from Appliance Energy Efficiency Measures
Achievable Potential



Summer peak reduction from these energy efficiency measures are shown in Figure 32.

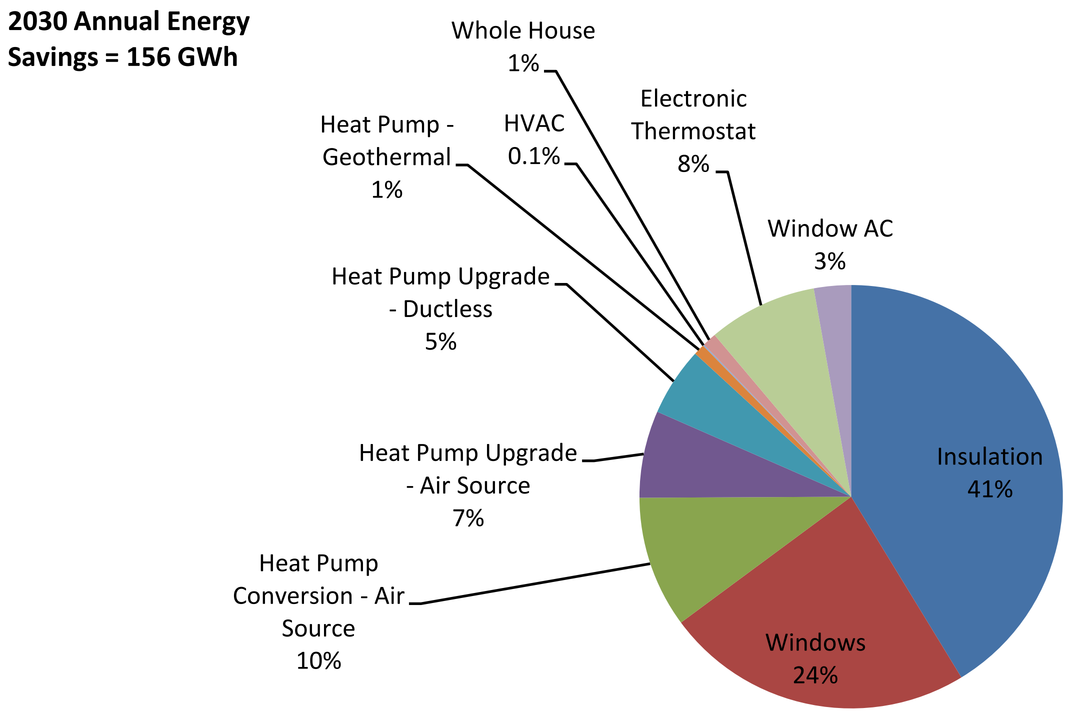
Figure 32
Summer Peak Savings from Appliance Energy Efficiency Measures
Achievable Potential



Space Conditioning

Figure 33 illustrates economic and achievable energy efficiency potential that is available annually by 2030. These space conditioning measures apply to electrically heated homes. The measure categories are described in more detail below.

Figure 33
2030 Achievable Potential from
Space Conditioning Energy Efficiency Measures



- **Insulation** – upgrades attic insulation to RSI-6.7, RSI-5.3, RSI-5.8 (R38, R30, R33) for single family, apartments and row, and manufactured houses respectively. Floor insulation is upgraded to RSI-5.3 (R30) for each building type and Wall insulation is upgraded to RSI 1.9 (R11).
- **Windows** – include upgrading single pane, double pane wood or aluminum frame to Energy Star rated windows. Also, an upgrade from U-Factor 1.7 to U-Factor 1.4 W/m^2 (0.30 to 0.25 Btu/h·ft^2·°F) windows in new and existing construction is included.
- **Heat Pump Conversion – Air Source** includes conversions from electric forced air furnace to heat pumps with ratings of HSPF 8.5/ SEER 14 or higher.
- **Heat Pump Upgrade – Air Source** applies to existing buildings with heat pumps of lower efficiency.
- **Heat Pump Upgrade – Ductless** applies to all housing types with baseboard or zonal heat.
- **Geothermal Heat Pumps** (ground source) - are cost-effective for existing single family homes.

- **HVAC** measures include ECM on furnace fans in homes with forced air furnaces, regardless of heating fuel, and air sealing in electrically heated homes.

Figure 34 shows the breakdown of winter peak savings potential from space conditioning energy efficiency measures.

Figure 34
Winter Peak Savings from Space Conditioning Energy Efficiency Measures
Achievable Potential

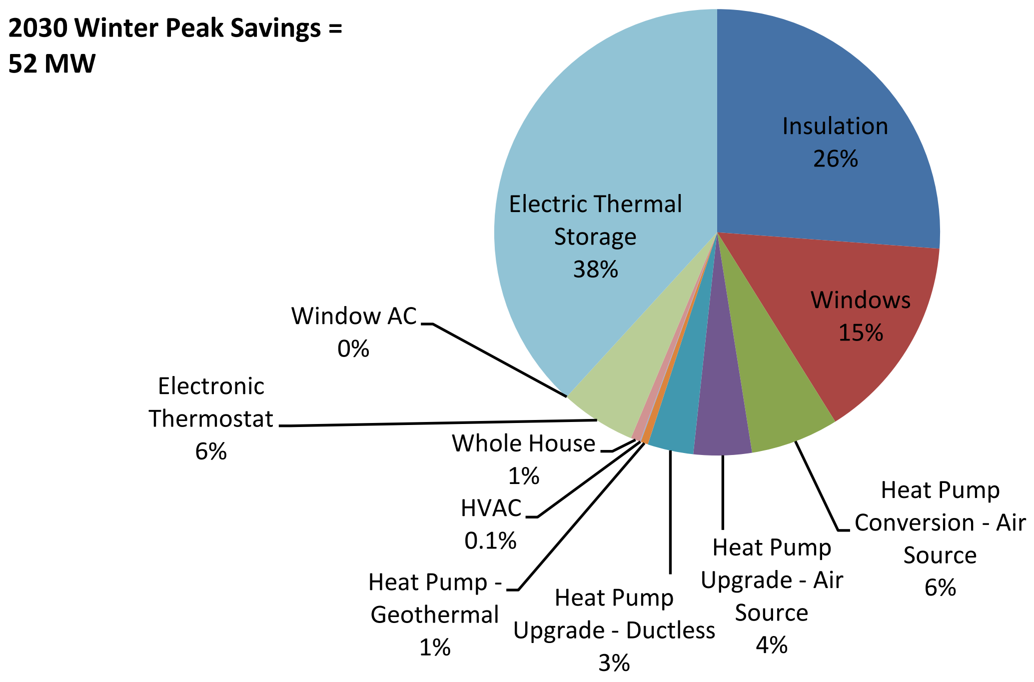
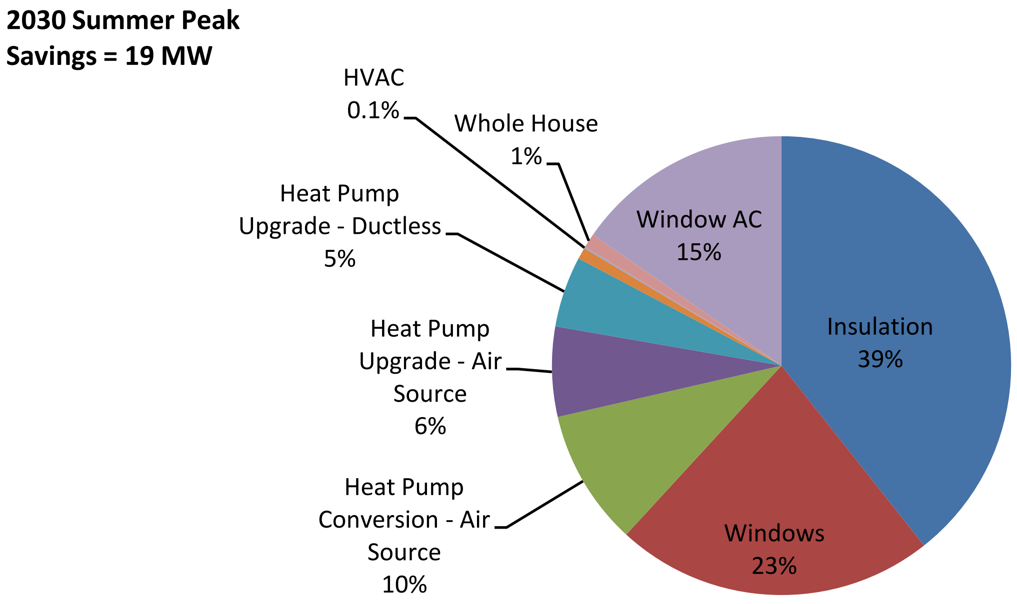


Figure 35 shows the breakdown of summer peak savings potential from space conditioning energy efficiency measures.

Figure 35
Summer Peak Savings from Space Conditioning Energy Efficiency Measures
Achievable Potential



A few other energy saving measures not quantified in this report include awnings and shade trees. Awnings and shade trees can reduce summer air conditioning load while maintaining the benefit of winter solar gain. These measures are difficult to quantify for a variety of reasons, in part because they can significantly interact with behaviour measures such as closing window blinds.

Low-Income Potential

The British Columbia Ministry of Energy, Mines and Petroleum Resources ("Ministry") amended the Public Utilities Commission Act (Bill 15-2008) to require public utilities to estimate cost-effective demand side resources (DSM) as part of their long term resource plan and to provide a plan to acquire those resources as a first priority over supply-side options. Under this mandate, the Ministry requires that residential energy efficiency measures be evaluated using several scenarios such as measure-by-measure TRC tests, grouped measure TRC tests, and low-income TRC tests. This last evaluation criterion allows low-income DSM programs to value additional benefit not accounted for in energy savings alone. As mandated by the government of British Columbia, an additional benefit of 30 percent is to be added to measures to evaluate cost-effectiveness for low income program measures.

According to Statistics Canada, 16.5 percent or approximately 27,000 households[8] in the FortisBC service territory are below the Low-Income Cut-Off (LICO). For this study, most of the residential measures analyzed pass the TRC test without the added benefit for low-income. No additional measures become cost effective when low income benefits are added to the TRC test.

Low-Income Programs

According to work prepared by FortisBC, low-income households have some key characteristics that suggest potential opportunities for energy efficiency improvements. Low-income customers that live in single family homes have a higher level of energy intensity per square foot than customers living in the same housing type who are not low-income, even though low-income customers' total consumption is, on average, less than that of non-low-income customers. In addition, specific product and end use comparisons highlight additional opportunities for improving energy efficiency in the homes of low-income customers. In addition, FortisBC found that CFL penetration in low-income houses is lower than the average penetration for the entire service territory. These characteristics indicate that there are significant barriers to energy efficiency adoption for low-income families. FortisBC is currently working on program design and mechanisms to address low-income barriers.

Fuel Switching

The electric range fuel switching measures analyzed in this analysis are cost effective in both new and existing construction. In existing buildings, the incremental capital cost is the installation of a gas line to the appliance, approximately $600.[9] In new homes, the incremental cost to install a gas line is estimated at $200. Incremental capital costs for gas ranges are $130[10].

In addition to fuel switching in cooking appliances, measures for fuel switching to natural gas dryers are also included in the analysis. According to FortisBC's customer survey, 92 percent of clothes dryers are electric. Gas line installation costs in new and existing homes is assumed to be the same as for the cooking appliance fuel switching measures discussed above. Incremental capital costs for gas clothes dryers are $93[11].

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[8] Statistics Canada. "BC Progress Board Performance Indicator #22 Low Income Cut-Offs (LICO)." 2006.

[9] Terasen Gas estimates installation of gas lines to be in the $200 to $1,000 range. $600 is used as the average.

[10] FortisBC staff

[11] FortisBC staff

Table 17 summarizes electric energy savings potential for the two fuel switching measures discussed above.

Table 17
Fuel Switching Electric Savings Potential

Fuel Switching	Energy Savings GWh	Winter Peak Demand Savings MW	Summer Peak Demand Savings MW
Electric Range, New	10.3	12.0	11.3
Electric Range, Existing	5.8	6.8	6.4
Electric Clothes Dryer, New	4.9	7.3	4.1
Electric Clothes Dryer, Existing	38.8	8.2	4.7
Total	**59.9**	**34.2**	**26.5**

Customer-Owned Renewable Energy

Cost and savings data for renewable energy measures were primarily obtained from the BC Hydro study; however, the NWPCC data base was used to benchmark the cost and savings data.

Technical potential for solar is calculated assuming that 30 percent of single family and row houses and 45 percent of apartment buildings are applicable for solar PV and solar water heating (based on BC Hydro Southern Interior Climate zone). The availability of wind resources is expected to be low. The BC Hydro study assumes an achievability rate of 0.1 percent for residential customer-owned wind generation, and this rate is applied to FortisBC homes as well. Lastly, 45 percent of homes with electric water heaters are assumed to applicable for solar water heat.

At current costs, none of the above technologies are cost-effective. However, a second scenario was analyzed assuming cost declines estimated in the BC Hydro study. BC Hydro estimated that costs would decrease to 42 percent of their current level by 2013, 21 percent the current level by 2018, and 11 percent of the current level by 2023. Using this declining cost structure and ramp rates to define achievability, economic potential is estimated and shown in the last column of the Table 18. Once a measure is cost effective, the ramp rate begins at 1% of technical potential per year and escalates to 5 or 10 percent of technical potential annually. The effective achievability rates are between 25 and 50 percent depending on when the measure becomes cost-effective.

Table 18
Residential Customer-Owned Renewable Energy
$2009

	Annual Generation kWh	Capital Cost	Installation Cost	Annual O&M	Life	TRC BC Ratio	Technical Potential MWh	Economic Potential* MWh	Year Technology Becomes Cost-Effective
Residential 3 kW PV, Detached	3,300	$27,999	$6,461	$194	20	0.14	133,678	66,839	2023
Residential 15 kW PV, Apt	16,500	$83,997	$19,384	$582	20	0.24	152,136	76,068	2018
Residential Wind, 400 W	700	$1,185	$969	$0	15	0.44	95	80	2013
Solar Hot Water 5 m^3 collector	2,200	$5,923	$0	$1	20	0.6	84,522	71,843	2013

*Assumes decreasing cost trend

Costs

TRC measure costs, utility costs, and participant costs are calculated for the economic and achievable potential. For the utility cost calculation, it is assumed that utility incentives are 60% of the incremental measure cost and that program administration costs are 20% of the full incremental measure cost. Participants incur OM&R costs/benefits. Table 19 summarizes TRC costs as well as compares a weighted average of the TRC levelized cost with savings potential. All cost and savings potential data in the table are for economic and achievable quantities of energy efficiency potential obtainable over a 20-year period.

Table 19
Residential 20-Year Achievable Energy Efficiency Savings and Cost Summary
2009 Dollars

	Ramp Rate	Total Measure Cost ($1000s)	Winter Peak Savings MW	Summer Peak Savings MW	Average TRC Levelized Cost $/MWh	Weighted B/C Ratio	Savings Potential MWh
Appliances Total		**$86,352**	**31**	**23**	**$44.04**	**10.98**	**324**
Lighting	CFL Code Change	$19,797	7.9	6.2	$28.34	6.41	101.1
Water Heater	EmergTech	$41,910	11.7	8.6	$45.01	3.05	92.5
Consumer Electronics	Electronics	$0	5.8	3.9	$52.81	12.62	82.3
Other Water Heating	20YearEven	$1,288	3.3	1.6	$7.23	75.17	19.9
Refrigerator	20YearEven	$6,728	0.9	0.8	$58.70	3.76	10.3
Computers etc.	EmergTech	$3,624	0.6	0.4	$79.97	2.84	9.6
Freezer	15YearEven	$1,759	0.4	0.4	$49.13	3.28	4.2
Clothes Washer	15YearEven	$11,246	0.1	0.6	$305.41	2.81	3.8
Clothes Dryer	20YearEven	$0	0.0	0.0	$0.00	0.00	0.0
Cooking	20YearEven	$0	0.0	0.0	$0.00	0.00	0.0
Dishwasher	20YearEven	$0	0.0	0.0	$0.00	0.00	0.0
Lighting LED	EmergTech	$0	0.0	0.0	$0.00	0.00	0.0
Space Conditioning Total		**$168,311**	**52**	**19**	**$61.19**	**1.95**	**156**
Insulation	20YearEven	$43,982	13.5	7.6	$40.80	2.22	64.3
Windows	20YearEven	$34,967	7.7	4.3	$35.15	2.06	36.7
Heat Pump Conversion - Air Source	20YearEven	$19,039	3.3	1.8	$105.28	1.31	15.7
HVAC	20YearEven	$215	0.0	0.0	$126.98	1.43	13.0
Heat Pump Upgrade - Air Source	20YearEven	$7,197	2.2	1.2	$60.16	2.27	10.4
Heat Pump Upgrade - Ductless	EmergTech	$11,430	1.7	1.0	$121.35	1.22	8.2
Whole House	EnerGuide90	$4,357	0.4	0.2	$98.70	1.31	4.4
Electronic Thermostat	20YearEven	$10,404	2.8	0.0	$79.71	1.72	1.7
Heat Pump - Geothermal	EmergTech	$1,554	0.3	0.2	$101.84	1.71	1.3
Window AC	2011 Code Change	$582	0.0	2.9	$17.95	7.92	0.2
Electric Thermal Storage	20YearEven	$34,585	19.7	0.0	NA	1.23	0.0
Fuel Switching		**$46,327**	**13**	**9**	**$305.04**	**1.06**	**16**
Electric to Gas Clothes Dryer	NA	$24,287	6.6	3.8	$280.42	1.06	9.0
Electric to Gas Range	NA	$22,039	6.0	5.7	$337.72	1.07	6.8
Total		**300,989**	**95**	**51**	**$57.73**	**7.83**	**495**

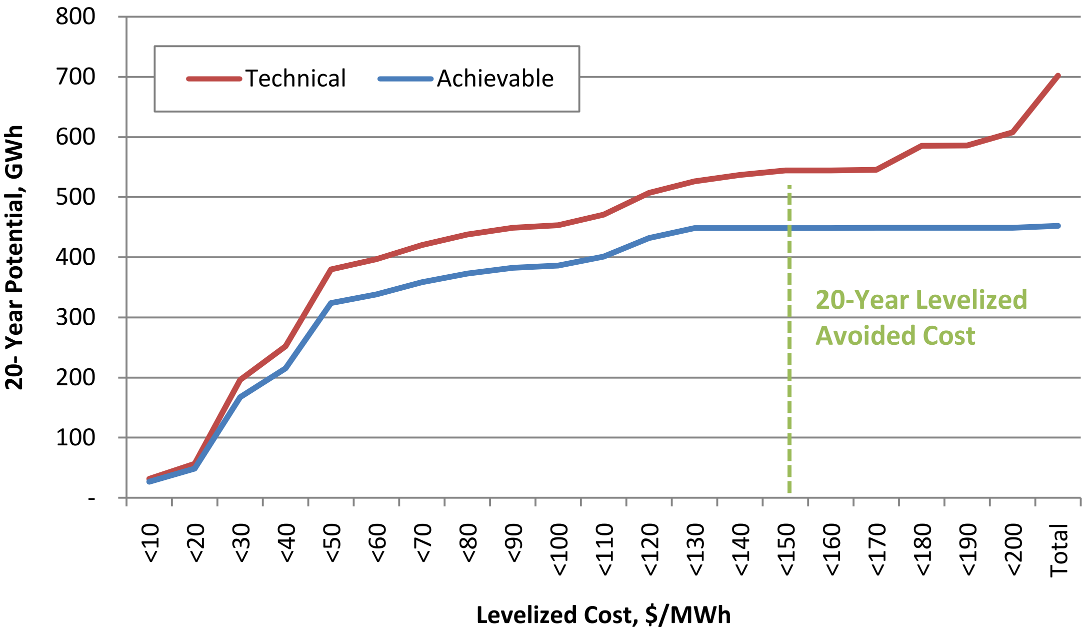
The definition of each column heading is listed below:

- **Ramp Rate** – reference to ramp rate used in estimating program achievable potential, discussed later.
- **Total Measure Cost** – incremental capital costs, O&M, replacement costs, and program administration costs. Costs are in thousands.
- **Winter Peak Savings** – MW peak savings associated with energy efficiency measure
- **Summer Peak Savings –** MW peak savings associated with energy efficiency measure
- **Average TRC Levelized Cost** – weighted average of levelized costs in measure category (weighted by share of measure category savings).
- **Weighted Benefit-Cost Ratio** – benefit-cost ratio for category weighted by the share of measure category savings.
- **Savings Potential** – Economic and achievable savings potential. Includes potential achieved through codes and standards.

Supply Curves

Energy efficiency resources are often summarized as supply curves. The supply curves in the figure below show how much energy efficiency (MWh) is available at different price levels. The x-axis shows measure levelized costs. These costs can be compared to supply side resources; however, unlike supply-side resources, the total quantity of the resource may not be available immediately. The curves in Figure 36 show the 20-year technical potential as well as the achievable potential. Note that the achievable potential in the figure includes potential that might be achieved through code and standard changes.

Figure 36
Residential Energy Efficiency Supply Curves



Program Achievable Potential

The previous section defined energy efficiency potential that is both economic and achievable through utility programs, codes, and standards. This section of the memo identifies potential that is both economic and achievable through utility programs only. Or, energy efficiency potential that is expected to be achieved through known code changes and product standards is not included in the following estimates.

In order to define utility program achievable potential, or "Program Achievable Potential," ramp rates are assigned by measure category to approximate the amount of energy efficiency potential that could be reasonably obtained through utility program efforts over the planning period. Figure 37 shows the Program Achievable Potential cumulatively by measure category and does not include fuel switching measures. The ramp rates used for program achievable potential can be found in Appendix D. Please reference Table 18 for measure category and applicable ramp rate names.

Figure 37
Residential Program Achievable Potential

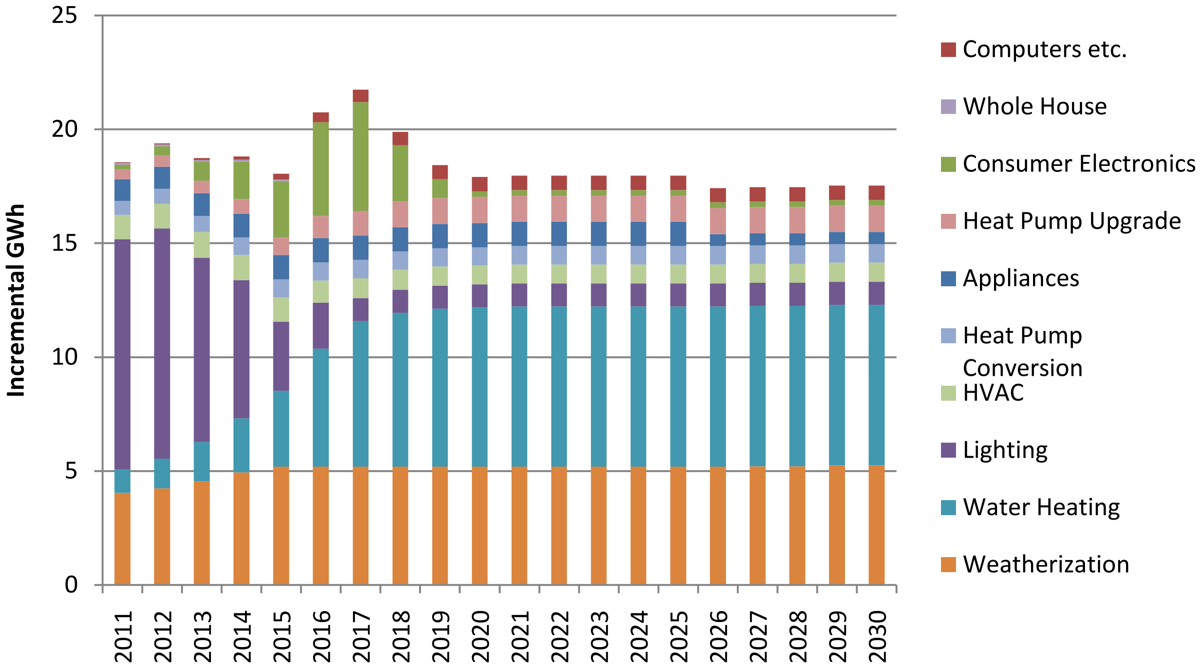


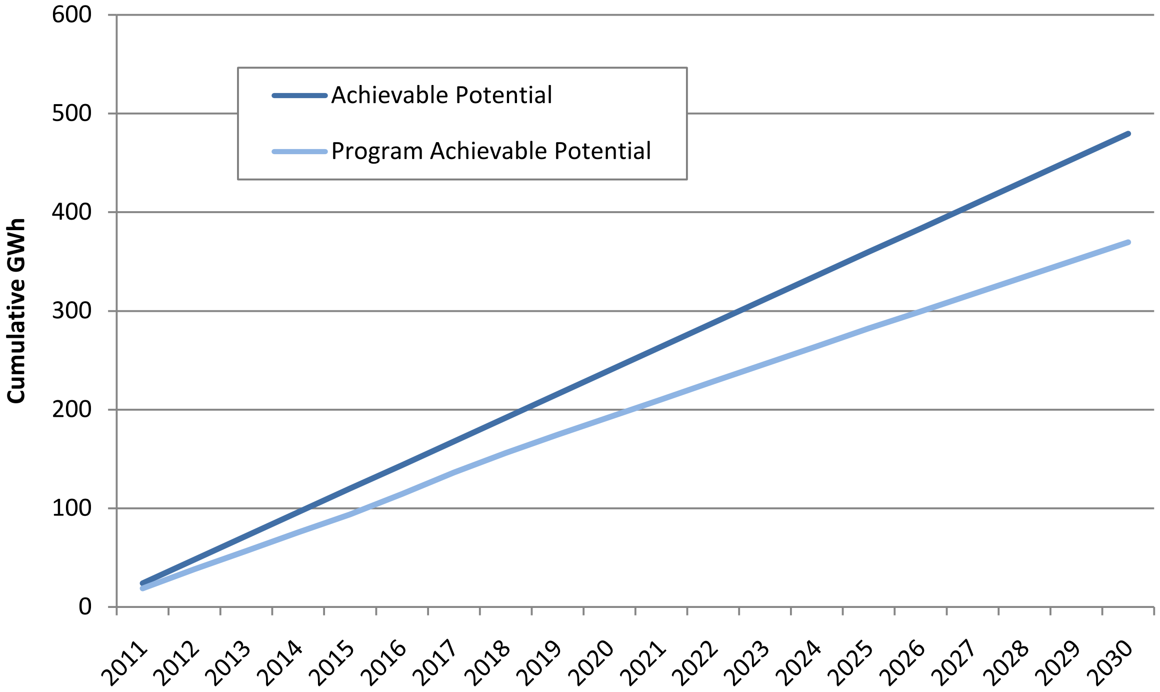
Table 20 shows measure category ramp rates and the associated larger measure category in Figure 37. The ramp rates dictate the pace (over time) that energy efficiency can be achieved. The infrastructure (e.g., availability of contractors) and cost (e.g., first cost, incentive levels) can affect the ramp rate, especially related to new technologies or measures that may take longer to become accepted in the marketplace.

Table 20
Measure Ramp Rates

Measure Category	Ramp Rate	Category in Figure 37
Lighting	CFL Code Change	Lighting
Water Heater	EmergTech	Water Heating
Consumer Electronics	Electronics	Consumer Electronics
Other Water Heating	20 Year	Water Heating
Refrigerator	20 Year	Appliances
Computers etc.	EmergTech	Computers etc.
Freezer	15 Year	Appliances
Clothes Washer	15 Year	Appliances
Dishwasher	20 Year	Appliances
Windows	20 Year	Weatherization
Insulation	20 Year	Weatherization
Heat Pump Conversion - Air Source	20 Year	Heat Pump Conversion
HVAC	20 Year	HVAC
Window AC	2011 Code Change	HVAC
Furnace Fan	2011 Code Change	HVAC
Heat Pump Upgrade - Air Source	20 Year	Heat Pump Upgrade
Heat Pump Upgrade - Ductless	EmergTech	Heat Pump Upgrade
Whole House	EnerGuide90/80	Whole House
Electronic Thermostat	20 Year	HVAC

Figure 38 compares Program Achievable Potential with total Achievable potential.[12] The difference between the curves in Figure 38 is the potential achieved through codes and standards for new building lighting. Figure 38 does not include savings from fuel switching. The residential code changes expected to occur during the 2011 – 2030 timeframe will result in an estimated 121 GWh of energy efficiency. See Appendix A for more information on residential code and standard changes.

Figure 38
Ramped Achievable[13] vs. Program Achievable Potential



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[12] Note that all energy efficiency potential referenced in these paragraphs is cost-effective, or economic.

[13] Includes potential achieved through codes and standards and uses a constant ramp rate of 5 percent annually.

Summary

The following three tables compare the energy efficiency potential estimates with the end-use load forecast for the year 2030. The potential in the table below is both economic and achievable. Additional columns show the total savings potential including fuel switching measures.

Table 21
Comparison of End-Use Model and Achievable Energy Efficiency Potential (MWh)

End-Use	End-Use Model 2030 MWh	Total Achievable Potential	Total Potential as % of 2030 Forecast
Energy Efficiency			
Space Conditioning & Ventilation	675,066	153,995	23%
Water Heater	213,607	112,375	53%
Lighting	330,840	101,104	31%
Consumer Electronics	238,031	82,276	35%
Refrigerator	144,015	10,306	7%
Computers etc.	149,560	9,622	6%
Freezer	71,560	4,228	6%
Clothes Dryer	103,092	3,797	4%
Whole House Measures		1,679	NA
Dishwasher	7,377	0	0%
Clothes Washer	8,764	0	0%
Misc	134,833	0	0%
Total Energy Efficiency	**2,076,746**	**479,381**	**23%**
Fuel Switching			
Cooking	170,465	8,976	9%
Clothes Dryer	103,092	6,764	4%
Total Fuel Switching	**273,557**	**15,740**	**6%**
Total	**2,247,212**	**495,121**	**22%**

Table 22 compares estimated winter peak demand reduction to the disaggregated forecast from the end-use model.

Table 22
Comparison of End-Use Model and Achievable Winter Peak Savings Potential (MW)

End-Use	End-Use Model 2030 Winter MW	Total Achievable Potential	Total Potential as % of 2030 Forecast
Energy Efficiency			
Space Conditioning & Ventilation	233.0	51.2*	22%
Water Heater	23.2	15.0	65%
Lighting	72.6	7.9	11%
Consumer Electronics	20.7	5.8	28%
Refrigerator	15.9	0.9	5%
Computers etc.	9.2	0.6	7%
Freezer	7.1	0.4	6%
Clothes Dryer	32.5	0.1	0%
Dishwasher	2.5	0	0%
Whole House Measures		0	NA
Clothes Washer	2.8	-	0%
Misc	29.2	-	0%
Total Energy Efficiency MWh	**416**	**82**	**20%**
Fuel Switching			
Cooking	59.5	12.6	20%
Clothes Dryer	33	7	21%
Total Fuel Switching	**92**	**19**	**21%**
Total	**508**	**102**	**21%**

*Includes approximately 20 MW of electric thermal storage

Table 23 compares estimated summer peak demand reduction to the disaggregated forecast from the end-use model.

Table 23
Comparison of End-Use Model and Achievable Summer Peak Savings Potential (MW)

End-Use	End-Use Model 2030 Summer MW	Total Achievable Potential	Total Potential as % of 2030 Forecast
Energy Efficiency			
Space Conditioning & Ventilation	166.3	19.0	11%
Water Heater	32.9	10.2	31%
Lighting	47.0	6.2	13%
Consumer Electronics	39.5	3.9	10%
Refrigerator	22.2	0.8	4%
Clothes Dryer	19.5	0.6	3%
Freezer	11.9	0.5	4%
Computers etc.	21.3	0.4	2%
Whole House Measures		0.3	NA
Dishwasher	1.4	0	0%
Clothes Washer	1.6	0	0%
Misc	20.2	-	0%
Total Energy Efficiency	**384**	**42**	11%
Fuel Switching			
Cooking	68.7	9.4	19%
Clothes Dryer	19.5	4	14%
Total Fuel Switching	**88**	**13**	**15%**
Total	**452**	**55**	**12%**

Table 24 illustrates the 1, 5, 10, and 20 year energy efficiency potential that is achievable through utility programs.

Table 24
Residential Program Achievable Energy Efficiency Potential
GWh

Measure Category	Year 1	Year 5	Year 10	Year 20
Weatherization	4.0	23.0	48.9	101.0
Water Heating	1.0	9.8	42.0	112.4
Lighting	10.1	37.4	43.5	53.6
Consumer Electronics	0.2	5.6	18.0	20.4
Heat Pump Upgrade	0.4	2.9	8.3	19.8
Appliances	0.9	5.0	10.3	18.3
HVAC	1.1	5.4	9.8	18.2
Heat Pump Conversion	0.6	3.6	7.6	15.7
Computers etc.	0.02	0.5	3.4	9.6
Whole House	0.1	0.4	0.4	0.4
Total	**19**	**94**	**192**	**369**

Commercial Energy Efficiency Savings Potential

Introduction

FortisBC commercial customers consume approximately 34 percent of total load (both direct and indirect customers). This section of the report estimates the amount of energy efficiency potential available through these commercial customers. First customer characteristics are summarized using the end-use forecast developed in a previous section and the FortisBC Commercial Customer Survey completed in August 2009. Next, energy efficiency measures are defined followed by a summary of savings potential compared to the end-use load forecast.

Commercial Customer Characteristics

Figure 39 summarizes the distribution of building types for FortisBC commercial customers. Building type, heat type, and average building size are the key parameters used to define FortisBC's commercial sector. These parameters are developed and forecasted in the End-Use Consumption Forecast section.

Figure 39
Commercial Building Breakdown, Number of Buildings

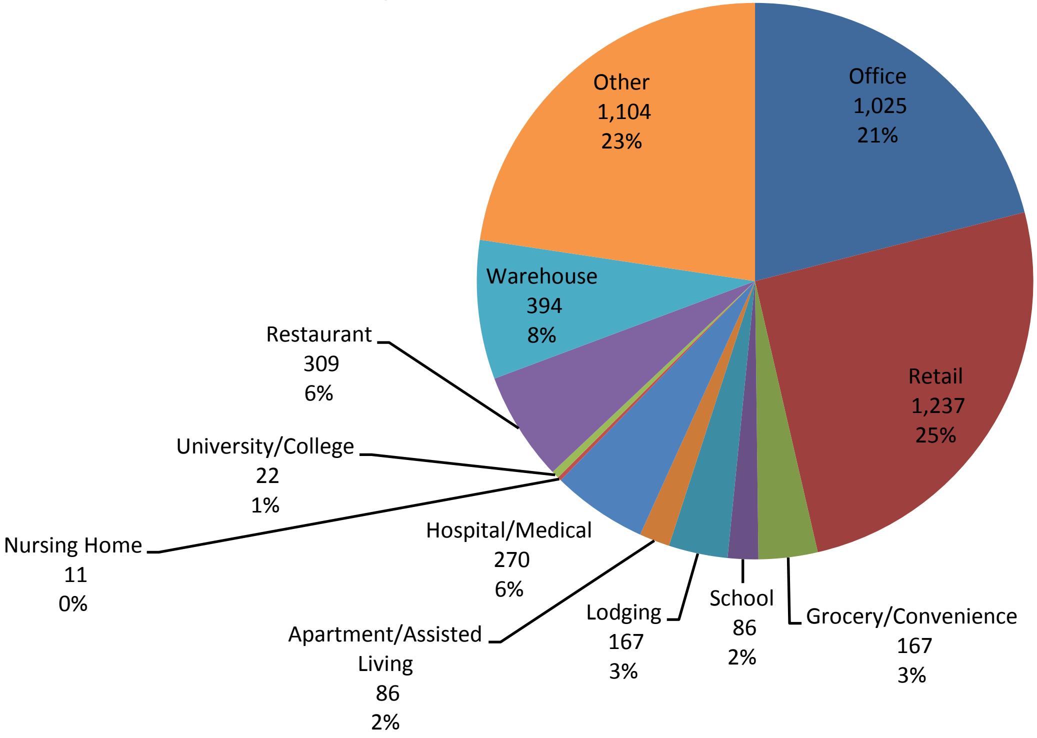


Table 25 illustrates the lighting types for commercial floor space. The percent share is of commercial square footage for each building type. Compact fluorescent lights (CFLs) are installed in up to 30 percent of commercial floor space for some building types.

Table 25
Commercial Building Lighting Characteristics

Building Type	No lighting	Linear fluorescent	Incandescent	CFL	Halogen, Quartz	High Pressure Sodium	Mercury Vapour	Metal Halide	Other
Large Office	1%	74%	16%	7%	2%	0%	0%	0%	0%
Medium Office	1%	74%	16%	7%	2%	0%	0%	0%	0%
Small Office	1%	74%	16%	7%	2%	0%	0%	0%	0%
Large Non-Food Retail	2%	65%	9%	6%	10%	2%	0%	5%	1%
Medium Non-Food Retail	2%	65%	9%	6%	10%	2%	0%	5%	1%
Small Non-Food Retail	2%	65%	9%	6%	10%	2%	0%	5%	1%
Large Hotel	1%	34%	27%	30%	6%	1%	0%	3%	0%
Medium Hotel/Motel	1%	34%	27%	30%	6%	1%	0%	3%	0%
Large School	1%	63%	23%	8%	4%	1%	0%	0%	0%
Medium School	1%	63%	23%	8%	4%	1%	0%	0%	0%
Grocery/Convenience	1%	34%	27%	30%	6%	1%	0%	3%	0%
Apartment/Assisted Living	1%	34%	27%	30%	6%	1%	0%	3%	0%
Medical	1%	63%	23%	8%	4%	1%	0%	0%	0%
Hospital	1%	63%	23%	8%	4%	1%	0%	0%	0%
Nursing Home	1%	34%	27%	30%	6%	1%	0%	3%	0%
University/College	1%	63%	23%	8%	4%	1%	0%	0%	0%
Restaurant/Tavern	1%	34%	27%	30%	6%	1%	0%	3%	0%
Warehouse/Wholesale	1%	62%	16%	4%	6%	3%	1%	9%	0%
Other	1%	74%	16%	7%	2%	0%	0%	0%	0%

Table 26 summarizes heating fuel shares among commercial buildings. Many of these buildings have more than one heating fuel and most are primarily heated by utility gas. These data are from the customer surveys completed in 2009.

Table 26
Commercial Building Heat Types

Building Type	Electricity	Natural Gas	Other	Natural Gas plus Supplemental fuel
Large Office	15%	79%	2%	81%
Medium Office	15%	79%	2%	81%
Small Office	15%	79%	2%	81%
Large Non-Food Retail	7%	81%	11%	92%
Medium Non-Food Retail	7%	81%	11%	92%
Small Non-Food Retail	7%	81%	11%	92%
Large Hotel	44%	38%	16%	54%
Medium Hotel/Motel	44%	38%	16%	54%
Large School	25%	65%	8%	73%
Medium School	25%	65%	8%	73%
Grocery/Convenience	25%	65%	8%	73%
Apartment/Assisted Living	25%	65%	8%	73%
Medical	25%	65%	8%	73%
Hospital	25%	65%	8%	73%
Nursing Home	25%	65%	8%	73%
University/College	25%	65%	8%	73%
Restaurant/Tavern	25%	65%	8%	73%
Warehouse/Wholesale	26%	62%	10%	72%
Other	35%	58%	4%	62%

Energy Efficiency Measures

Several measures for each end-use were analyzed to model energy efficiency potential. The table below summarizes the types of technology-based measures included in the analysis. While few categories are provided in the table, several permutations of each measure within these categories exist. In total, there are over 1,300 individual measures in the commercial sector.

Table 27
Commercial Energy Efficiency Measure Categories

Commercial Refrigeration
Grocery Store Measures
Pre-Rinse Spray Valve
Cooking
Premium HVAC Equipment
Demand Control Ventilation
ECM Motors in Variable Air Volume HVAC Systems
Continuous Optimization HVAC
Package Roof Top Optimization & Repair
Municipal Wastewater Treatment
Water Treatment
Existing Building Lighting Upgrades
New Building Lighting Upgrades
Lighting Controls
Parking Lighting
LED Street Lighting
Window Upgrades
Roof Insulation Upgrades
Network PC Power Management
Computer Servers

Emerging Technologies

Many of the emerging technologies identified in the Residential section also will have application in the commercial sector. These measures include advanced windows, green roofs, efficient lighting, solar air conditioning, on-site generation, and advanced controls (integrated with Smart Grid). However, the major advancements in the commercial sector are likely to come from the following general areas:

- Net zero or whole building measures,
- Efficient lighting, including LEDs, fibre optics,
- On-site generation; and
- Advanced controls.

Customer-Owned Renewable Energy

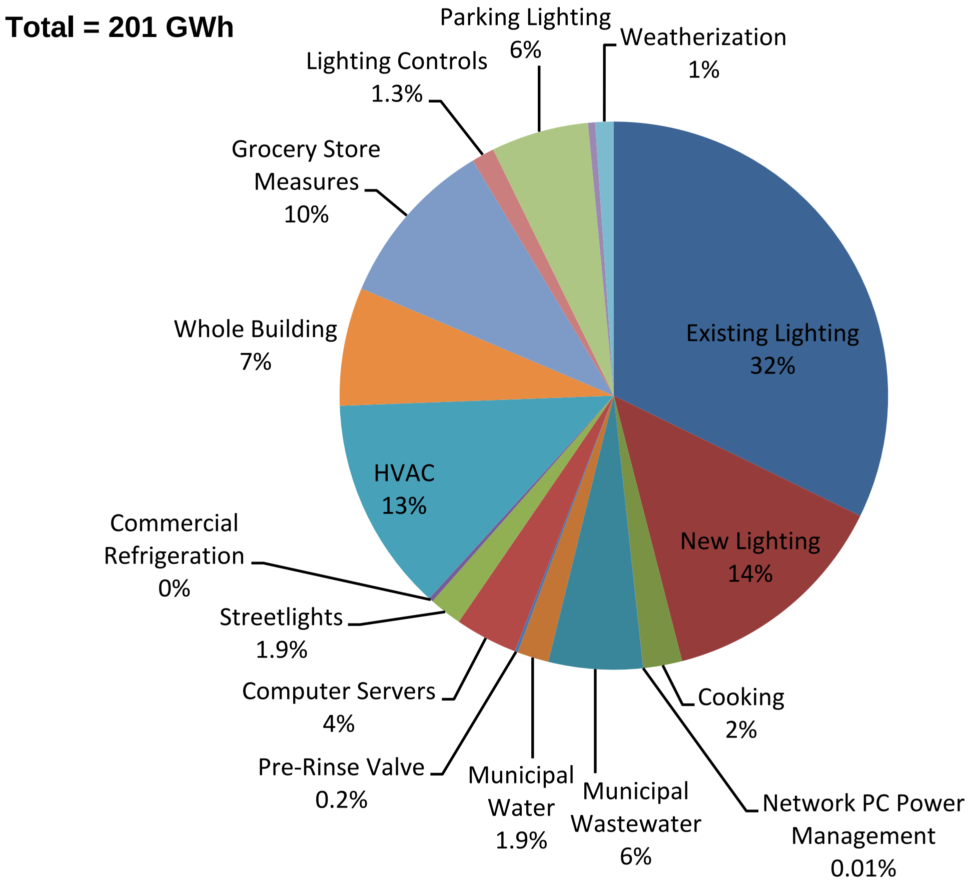
Solar PV on new and existing buildings is analyzed in this study. The measure data is from the BC Hydro 2007 study. Solar PV in commercial applications is generally sized at 100 kW. The Southern Interior of British Columbia has medium to high solar resources or approximately 4 kWh/m^2/day. The energy savings for renewable energies are reported separately from savings from energy efficiency measures. As reported in the Residential section, potential estimates for micro-hydro systems are not included.

Potential Estimates

As described in the methodology section, end-use load forecast data and energy efficiency measures are combined to produce estimates of energy efficiency. In this analysis, energy efficiency potential is presented separately from the electric savings from fuel switching measures. The total achievable potential is 201 GWh annually by 2030 or energy savings of 14% of 2030 forecasted commercial load. In this section, economic and achievable potential are discussed followed by program achievable potential.

Figure 40 illustrates the breakdown of energy efficiency potential that is both economic and achievable. The potential estimates include measures that apply to both new and existing construction. The measure categories are described in further detail below.

Figure 40
2030 Achievable Energy Savings Potential – Commercial

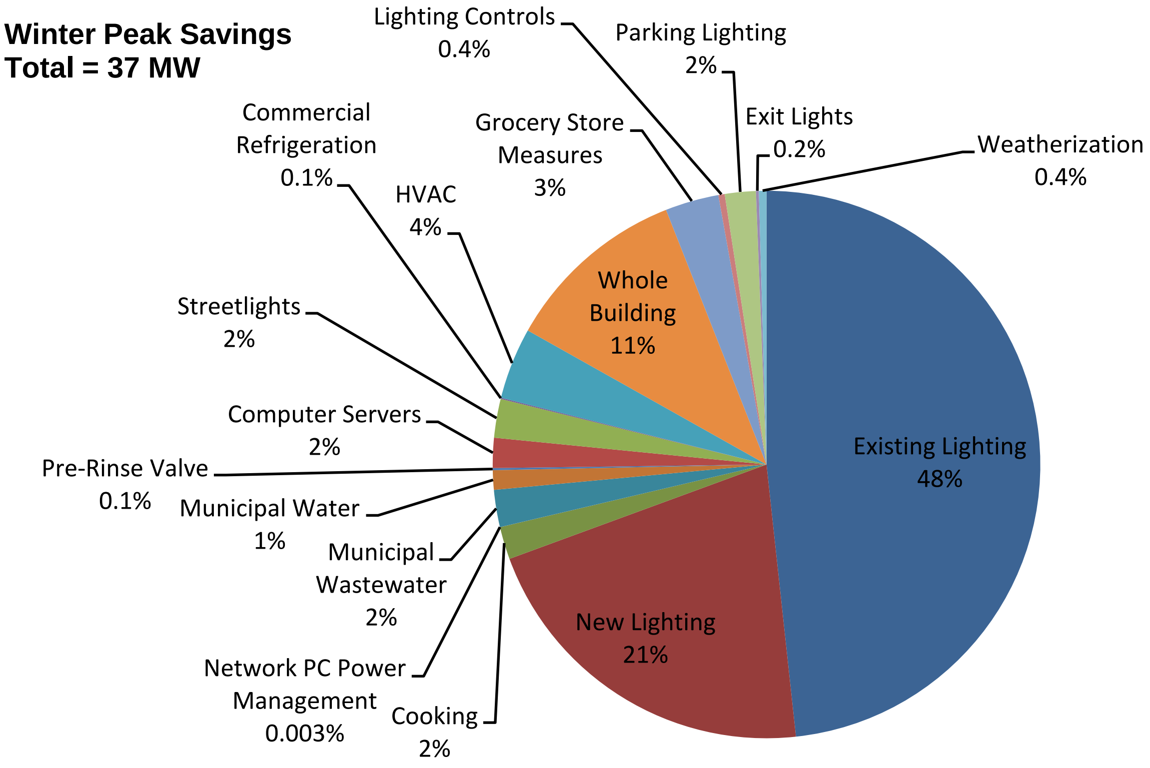


- Lighting – New and retrofit lighting for building interiors and exteriors
- Cooking – Hot food holding cabinet, steamers, and ovens.
- Network PC Power Management – Includes residential desktop computers and monitors.
- Municipal Water – optimization based on design capacity calculated as a rate per population. Includes both wastewater treatment and drinking water treatment.
- Pre-Rinse Spray Valve – includes high-efficiency, low-flow spray valves for food service applications.
- Computer Servers – applies to number of units calculated as a rate based on employment.
- Streetlights – street and roadway lighting.
- Commercial Refrigeration – applies to specific freezers, refrigerators, and ice-makers that are not included in the grocery store measure category.
- HVAC – includes premium HVAC equipment, controls commission HVAC, ECM on VAV boxes, package roof top optimization and repair, and demand control ventilation.
- Grocery Store Measures – refrigeration, fan, case lighting, compressors, visicoolers, compressors, anti-sweat controls, and motors.

- Weatherization – includes roof insulation and window upgrades
- Lighting Controls
- Parking Lighting
- Exit Lights

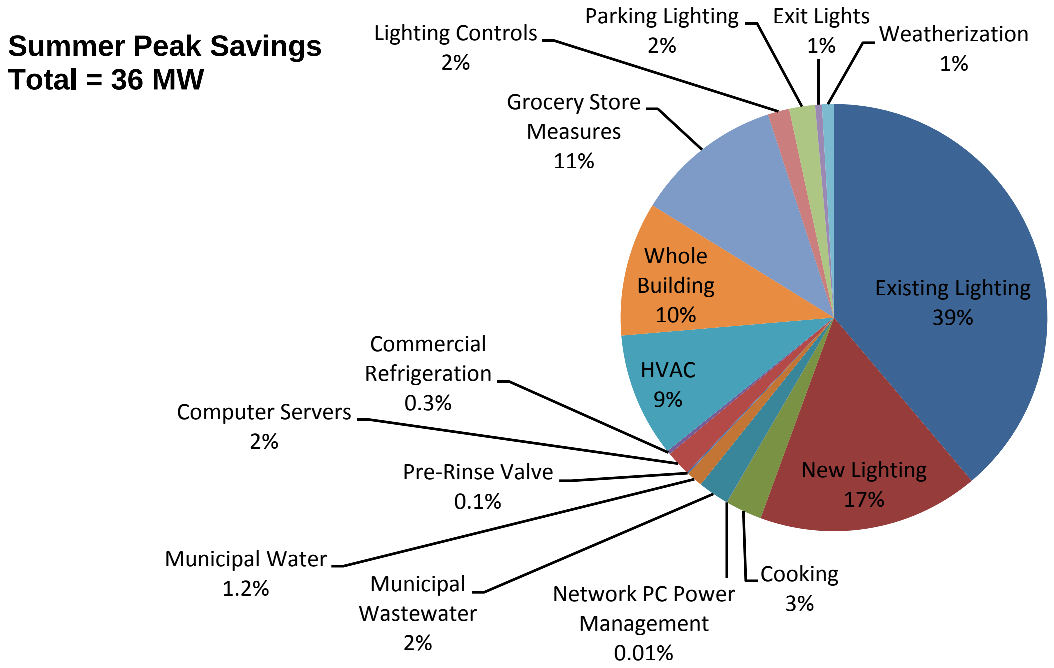
Winter peak reduction from these energy efficiency measures is shown in Figure 41.

Figure 41
Winter Peak Savings from Commercial Energy Efficiency Measures Achievable



Summer peak reduction from these energy efficiency measures is shown in Figure 42.

Figure 42
Summer Peak Savings from Commercial Energy Efficiency Measures Achievable



Customer-Owned Renewable Energy

Cost and savings data for renewable energy measures were primarily obtained from the BC Hydro study. Technical potential is calculated assuming that 30% existing commercial buildings have appropriate installation sites and 45% of new construction buildings have appropriate installation sites. The result is that 1,600 existing buildings and 1,300 new buildings might be appropriate for commercial PV units.

Commercial PV units do not pass the TRC at current costs; however, similar to residential, a second scenario is analyzed where costs are decreased over the planning period (consistent with cost decreases from the BC Hydro study). Costs are estimated at 42 percent of their current levels by 2013, 21 percent the current level by 2018, and 11 percent current levels by 2023. Solar PV is cost effective by 2018; therefore, achievable potential is ramped up from 1 percent annually to 8 percent over the remainder of the period. A total of 1,418 units are installed over the period 2018 through 2030. Table 28 summarizes the measure data and results of the analysis.

Table 28
Commercial Customer-Owned Renewable Energy

	Annual Generation kWh	Capital Cost	Installation Cost	Annual O&M	Life	TRC BC Ratio	Technical Potential MWh	Achievable Potential(1) MWh
Commercial PV Unit, 100 kW New and Existing Buildings	118,000	$430,756	$215,378	$6,461	20	0.26	341,439	167,305

(1) Achievable Potential is economic and achievable based on decreasing cost scenario.

Costs

TRC measure costs, utility costs, and participant costs are calculated for the economic and achievable potential. For the utility cost calculation, a proxy for utility incentives of 60% of the incremental measure cost is used and program administration costs of 20% of the incremental measure cost are assumed. Participants incur O&M costs/benefits. Table 29 summarizes these costs as well as compares a weighted average of the levelized cost with savings potential. All cost and savings potential data in the table are for economic and achievable quantities of energy efficiency potential.

Table 29
Cost Summary, $2009

Measure Category	Ramp Rate	Total Measure Cost ($1000s)	Winter Peak Savings MW	Summer Peak Savings MW	Average TRC Levelized Cost $/MWh	Weighted Benefit-Cost Ratio	Achievable Savings Potential MWh
Existing Lighting	15YearEven	$14,802	17.92	13.43	$22.59	4.05	64,776
New Lighting	New Lighting - Program	$9,481	7.84	5.79	$2.55	4.98	27,666
HVAC	HVAC - Code Change	$17,352	1.57	3.25	$68.17	3.32	25,443
Grocery Store Measures	20YearEven	$4,788	1.17	3.87	$36.67	5.49	20,135
Whole Building	20YearEven	$13,663	4.04	3.51	$87.83	2.45	14,028
Parking Lighting	20YearEven	$5,949	0.68	0.68	$82.10	2.10	11,554
Municipal Wastewater	15YearEven	$7,085	0.81	0.81	$6.60	2.33	11,153
Computer Servers	20YearEven	$1,763	0.66	0.66	$15.97	2.41	7,401
Cooking	20YearEven	$2,185	0.71	0.96	$4.93	4.04	4,606
Streetlights	20YearEven	$5,140	0.85	0.00	$8.09	1.11	3,898
Municipal Water	15YearEven	$3,920	0.43	0.43	$12.82	1.00	3,739
Lighting Controls	20YearEven	$775	0.14	0.56	$32.22	6.48	2,687
Weatherization	20YearEven	$1,862	0.17	0.31	$75.67	2.99	2,189
Exit Lights	10YearEven	$995	0.06	0.18	$141.90	1.09	839
Commercial Refrigeration	20YearEven	$608	0.02	0.10	$12.75	95.94	505
Pre-Rinse Valve	5YearEven	$75	0.04	0.04	$9.53	3.23	354
Network PC Power Management	20YearEven	$5	0.00	0.00	$9.84	4.18	23
Total		**$90,449**	**37.1**	**34.6**	**$34.14**	**3.97**	**200,995**
Solar PV, Customer Renewable(1)		**$44,918**			**$722.37**	**1.25(2)**	**167,305**

(1) Potential estimates and benefit-cost ratio assumes decreasing costs over planning period.
(2) Average benefit-cost ratio over planning period. Solar PV for commercial buildings is cost-effective beginning in 2018

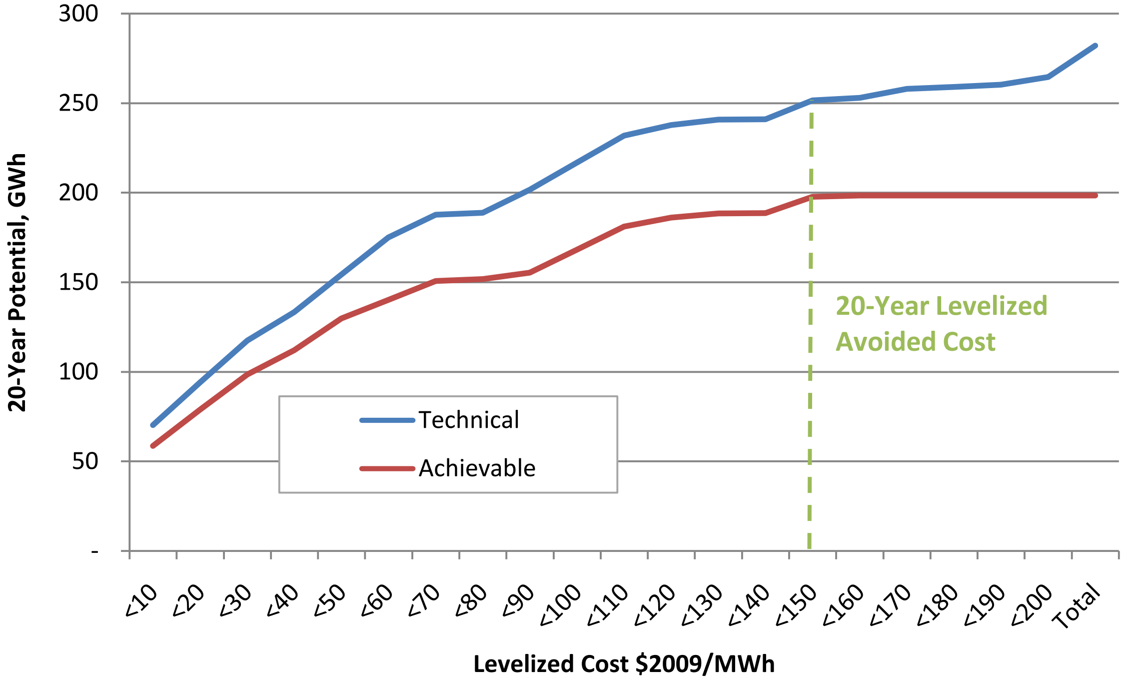
- **Ramp Rate** – reference to ramp rate used in estimating program achievable potential, discussed later.
- **Total Measure Cost** – incremental capital costs, O&M, replacement costs, and program administration costs. Costs are in thousands.
- **Winter Peak Savings** – MW peak savings associated with energy efficiency measure.

- **Summer Peak Savings –** MW peak savings associated with energy efficiency measure.
- **Average TRC Levelized Cost** – weighted average of levelized costs in measure category (weighted by share of measure category savings).
- **Weighted Benefit-Cost Ratio** – benefit-cost ratio for category weighted by the share of measure category savings.
- **Savings Potential** – Economic and achievable savings potential. Includes potential achieved through codes and standards.

Supply Curves

Energy efficiency resources are often summarized as supply curves. The supply curves in the figure below show how much energy efficiency (GWh) is available at different price levels. The x-axis shows measure levelized costs. These costs can be compared to supply side resources; however, unlike supply-side resources, the total quantity of the resource may not be available immediately. The curves in Figure 43 show the 20-year technical potential as well as the economic potential that can be reasonably obtained during that time period. Note that the economic and achievable potential in the figure includes potential that might be achieved through code and standard changes.

Figure 43
Commercial Energy Efficiency Supply Curves

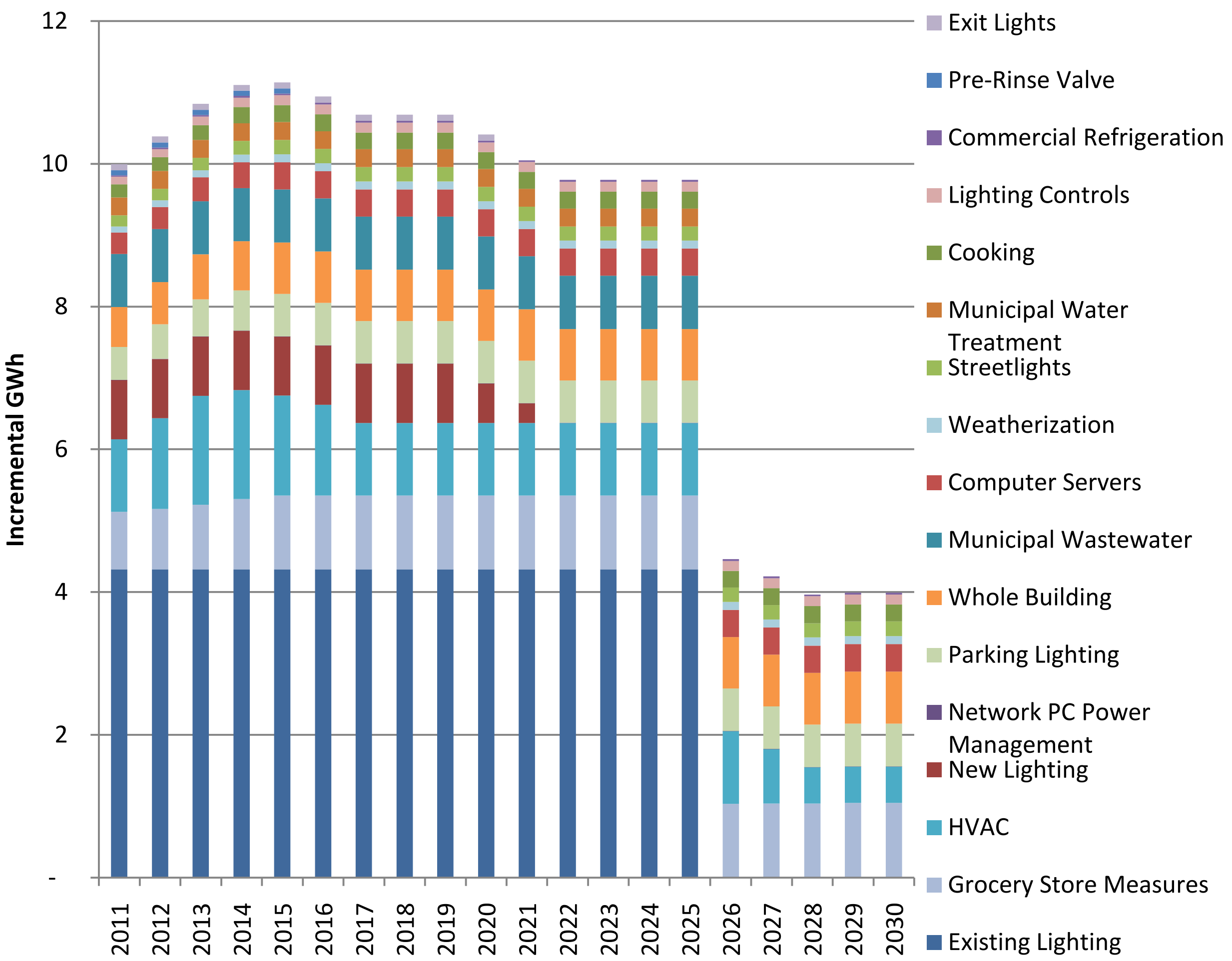


Program Achievable Potential

The previous section defined energy efficiency potential that is both economic and achievable through utility programs, codes, and standards. This section of the memo identifies potential that is both economic and achievable through utility programs only. Or, energy efficiency potential that is expected to be achieved through known code changes and product standards is not included in the following estimates.

In order to define utility program achievable potential, or “Program Achievable Potential,” ramp rates are assigned by measure category to approximate the amount of energy efficiency potential that could be reasonably obtained through utility program efforts over the planning period. Figure 44 shows the Program Achievable Potential cumulatively by measure category.

Figure 44
Commercial Program Achievable Potential[14]



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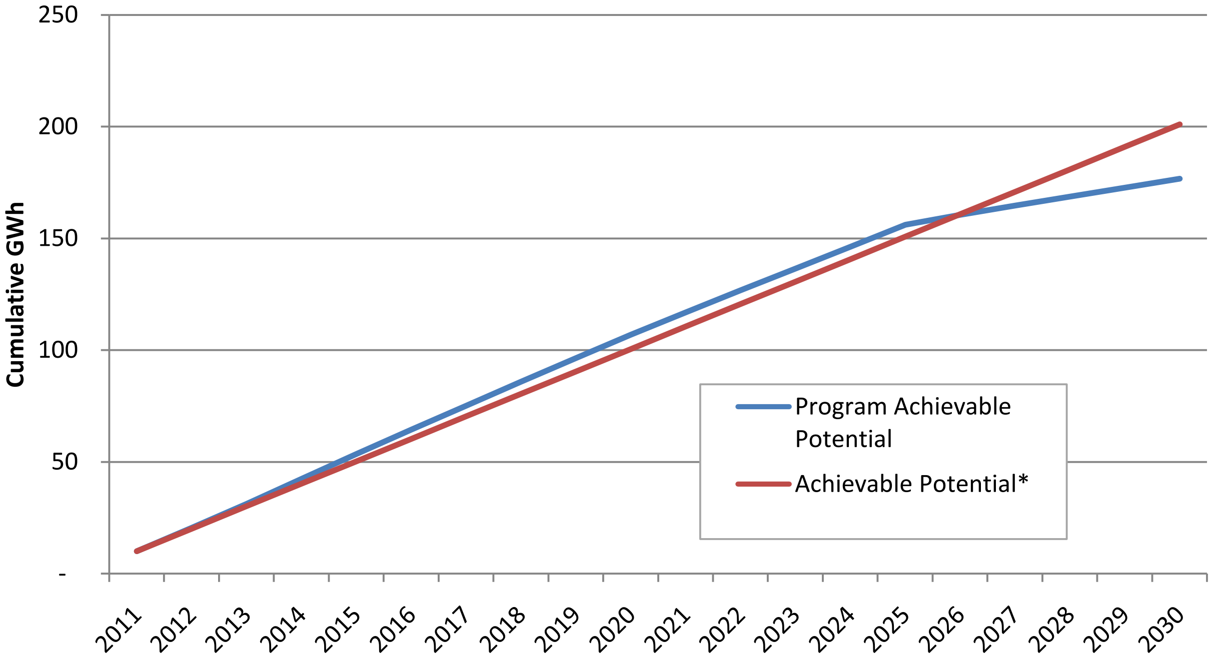
[14] Excludes savings potential achieved through codes and standards.

Figure 45 compares Program Achievable Potential with total Achievable potential.[15] The difference between the curves in the out years (Figure 45) is the potential achieved through codes and standards for new building lighting and HVAC. Program Achievable Potential is higher than Achievable Potential for the first 15 years due to aggressive ramp rates for commercial lighting. The commercial code changes expected to occur during the 2011 – 2030 timeframe will result in an estimated 24 GWh of energy efficiency. See Appendix A for more details on code changes in the commercial sector.

Figure 45
Achievable vs. Program Achievable Potential



*Includes efficiency from codes and standards.

Summary

The following three tables compare the energy efficiency potential estimates with the end-use load forecast for the year 2030. When customer-owned renewable energy is added to the energy efficiency savings potential, FortisBC could achieve a 25 percent savings from their forecasted 2030 consumption in the commercial sector. Overall, energy efficiency potential can be used to meet 46 percent of load growth within the commercial sector.

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[15] Note that all energy efficiency potential referenced in these paragraphs is cost-effective, or economic.

Table 30 compares the achievable energy efficiency potential to the forecast of 2030 load from the end-use model. The miscellaneous category includes municipal water and wastewater measures.

Table 30
Comparison End-Use Forecast with Conservation Potential Estimates

End-Use	End-Use Model 2030 Load MWh	Energy Efficiency Achievable Potential MWh	Percent of 2030 Load
Lighting	529,139	107,522	20%
HVAC	558,372	27,632	5%
Refrigeration	120,347	20,640	17%
Misc	45,224	14,892	33%
Whole Building		14,028	NA
Computer Equipment	81,467	7,424	9%
Food Service	29,816	4,606	15%
Streetlights	13,538	3,898	29%
Water Heat	38,333	354	1%
Elevators	4,374		0%
Plug Load	49,103		0%
Total	1,469,713	200,995	14%
Solar PV, Customer Renewable(1)		167,305	
Total	1,469,713	368,300	25%

(1) Assumes decreasing costs as noted in this section.

Table 31 illustrates the breakdown for winter peak savings. The energy efficiency potential estimated provides 12 percent winter peak savings.

Table 31
Comparison End-Use Forecast with Conservation Potential Estimates, 2030 Winter Peak

End-Use	End-Use Model Winter Peak MW	Energy Efficiency Achievable Potential Winter MW	% of 2030 Load
Lighting	153	26.6	17%
Whole Building		4.0	NA
HVAC	60	1.7	4%
Refrigeration	35	1.2	3%
Misc	11	1.2	11%
Streetlights	3	0.8	32%
Computer Equipment	16	0.7	4%
Food Service	3	0.7	22%
Water Heat	22	0.04	0%
Plug Load	12		0%
Elevators	2		0%
Total	316	37.1	12%

Table 32 illustrates the breakdown of summer peak savings. The energy efficiency potential estimated provides 14 percent summer peak savings.

Table 32
Comparison End-Use Forecast with Conservation Potential Estimates, 2030
Summer Peak

End-Use	End-Use Model Summer Peak MW	Energy Efficiency Achievable Potential Summer MW	% of 2030 Peak Demand
Lighting	111	20.6	19%
Refrigeration	23	4.0	17%
HVAC	63	3.6	7%
Whole Building		3.5	NA
Misc	10	1.2	13%
Food Service	7	1.0	14%
Computer Equipment	18	0.7	4%
Plug Load	11		0%
Water Heat	10	0.0	0%
Elevators	1		0%
Streetlights	0	0.0	0%
Total	252	34.6	14%

Table 33 illustrates the 1, 5, 10, and 20 year energy efficiency potential that is achievable through utility programs.

Table 33
Commercial Program Achievable Energy Efficiency Potential
GWh

Measure Category	1 Year	5 Year	10 Year	20 Year
Lighting	6.0	30.3	60.8	92.1
HVAC	1.0	6.7	12.1	20.5
Grocery Store Measures	0.8	4.6	9.8	20.1
Municipal	1.0	5.0	9.9	14.9
Whole Building	0.6	3.2	6.8	14.0
Computer Servers	0.3	1.7	3.6	7.4
Cooking	0.2	1.0	2.2	4.6
Weatherization	0.1	0.5	1.1	2.2
Commercial Refrigeration	0.02	0.1	0.2	0.5
Pre-Rinse Valve	0.07	0.4	0.4	0.4
Network PC Power Management	0.001	0.01	0.01	0.02
Total	**10.0**	**53.5**	**106.9**	**176.7**

Industrial Energy Efficiency Savings Potential

Introduction

This section describes the methodology, data, and energy efficiency measures used to estimate energy efficiency potential in the industrial sector. The methodology for potential estimation is a top-down approach, rather than the bottom-up approach used in the commercial and residential sectors. The results of the analysis are given as supply curves and detailed tables.

Industrial Customer Characteristics

The end-use model segments industrial load by both sector (paper, mining, fruit packing, etc) and end-use within those sectors (fans, pump, motors, etc). Consumption within each industrial process is disaggregated by applying percentages from sources such as the BC Hydro Conservation Potential Assessment and the Northwest Power and Conservation Council. The result is a top-down methodology for classifying energy consumption by end-use.

The base year for industrial sector consumption is calculated using the 2009 energy forecast for rate schedules 30, 31, and 33 and the Tolko sawmill (wholesale customer). Three customers were removed from the industrial rate class for conservation modeling purposes: UBC Okanagan, Selkirk College, and Trail Community Health. Net energy consumption was available only. Some industrial customers are net metered; self-generation is not included in this forecast nor is it included in the FortisBC system forecast.

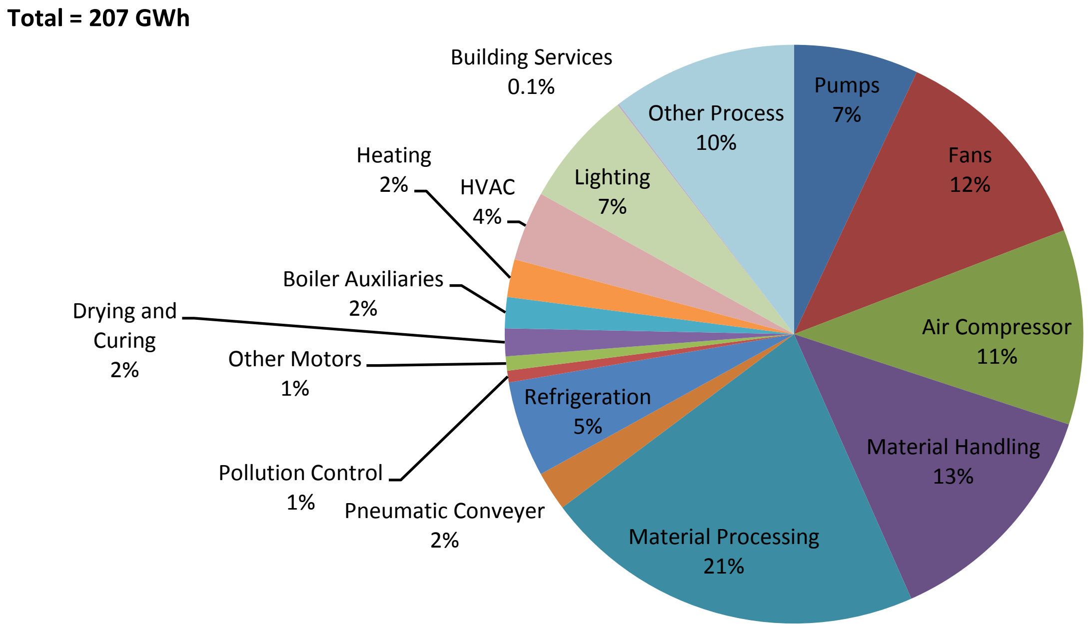
Customer consumption is grouped into classes according to the North America Industry Classification System (NAICS). Table 34 illustrates the industrial processes and annual kWh consumption for these customers. Note that the pulp and paper load is the net conservation of a major manufacture in the FortisBC service territory.

Table 34
Industrial Sector Consumption by Process, 2008

Industrial Process	Energy Consumption GWh
Wood products	90.1
Building Materials	53.0
Pulp and Paper and Paper	16.5
Food and Beverage	13.9
Miscellaneous	9.9
Mining	9.1
Fruit packers and storage	8.7
Other Manufacturing	3.6
Contractors & Construction	2.7
Total	207

Figure 46 shows the resulting break down of industrial electricity consumption for the base year. Total industrial consumption is 207 GWh and is expected to remain flat over the planning period. Therefore the 2030 end-use breakdown will be identical as the 2008 break-down in terms of share and total consumption.

Figure 46
Industrial End-Uses



Energy Benefits

The avoided cost of electricity is the dollar value per MWh, of the conserved electricity, and accounts for the benefit value in cost effectiveness tests. These energy benefits are based on the cost of a generating resource, a forecast of market prices or an integrated resource planning process. As mandated by the British Columbia Ministry of Energy, BC Hydro's avoided costs are used to value energy, peak demand, and transmission and distribution savings.

Modeling Methodology

The methodology used to calculate industrial potential differs from the approach in the residential and commercial sectors. There are two general analytical approaches to estimating conservation potential: a bottom-up approach, and a top-down approach.

The bottom-up approach is the method used in the residential and commercial sectors. The key factor is the number of kWh saved annually from the installation of an individual energy efficient measure. The savings from each measure is multiplied by the total number of expected installations over the life of the program. Each individual total measure savings is then summed and aggregated to total potential.

The top-down approach starts with the load forecast over the study period. These load forecasts are then disaggregated by end-use. Energy savings by measure, end-use, program, or sector are then expressed as a percent of the total energy consumption. For example, pumps are a common component of manufacturing and industrial operations whose improved performance has the potential to save energy. With improved pumps, a certain percentage of the disaggregated pump load can be saved. Savings from each end-use is summed and aggregated to total potential.

Energy Efficiency Measures

There are several classes of industrial measures: cross-industry systems, industry-specific processes and whole plant optimization.

Cross-Industry

Cross-industry measures are improvements of common industrial components found in most manufacturing and industrial settings. These are widespread equipment like fans, pumps, motors, lighting, etc. Cross-industry measures are listed in Table 35 followed by a brief description of major improvements in each measure type.

Table 35
Cross-Industry Measures

Measure Type	Conservation Measure
Belts	Synchronous Belts
Compressed Air	Air Compressor Demand Reduction Air Compressor Equipment Air Compressor Optimization
Lighting	High Bay Lighting 1-Shift, 2-Shift, or 3-Shift Efficient Lighting 1-Shift, 2-Shift, or 3-Shift Lighting Controls
Motors	Motors: Rewind 20-50 HP, 51-100 HP, 101-200 HP
Fans	Efficient Centrifugal Fan Fan Energy Management Fan Equipment Upgrade Fan System Optimization
Pumps	Pump Energy Management Pump Equipment Upgrade Pump System Optimization
Transformers	Transformers-Retrofit

- **Belts** - V-Belts are commonly used to drive industrial processes. By replacing the pulley sheaves with synchronous belt pulleys and installing synchronous belts onto the end use (e.g., fans or pumps), an efficiency gain of 3%-5% can be achieved from reduced slippage and friction.[16]

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[16] Northwest Power and Conservation Council. *System Optimization Measures Guide*. 6th Power Plan. March 23, 2009

- **Compressed Air** - The primary measure is retrofit of air compressors. Modern models have built-in adjustable speed drive (ASD) can achieve 40% savings over conventional fixed speed compressors. Additionally, better distribution systems and end-use improvements (use blowers in place of compressors) also contribute to savings.

- **Lighting** - In lighting, there are two main categories of measure savings: major lighting retrofits and replacement of high bay lighting. Lighting retrofits are most applicable to pulp and paper subsector and involves replacing low-efficiency mercury vapor lighting and installation of lighting control. These tend to be in large and older facilities. Replacement of high bay lighting includes changing metal halide bulbs with fluorescent T5 high-output lighting.

- **Motors** - Motors efficiency improvement is fairly straightforward and is already occurring in the FortisBC service territory. There are several difference classes of motors separated by horsepower, but each replaces standard efficiency motors with premium-efficiency motors.

- **Fans** - Savings from industrial fans come from the optimization of fan operation and retrofit with more efficient models. Operation and maintenance improvements include changing filters, maintaining belts (tension, alignment), repair duct leaks, lube bearings and maintain dampers. Additionally, fan retrofits include more efficient timers, adjustable speed drives, and low friction ducts. [17]

- **Pumps** - Pump savings come from both retrofit of pumps in addition to improved operation and maintenance of those currently in operation. New equipment includes replacement of pump at time of major repair or shutdown, proper sizing of trim impeller and control valve. Better maintenance includes coupling alignment, lubrication, seal maintenance, and vibration analysis.

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[17] Northwest Power and Conservation Council. *System Optimization Measures Guide*. 6th Power Plan. March 23, 2009

Industry-Specific

Industry-specific processes are improvements of specialized manufacturing components or processes. Like cross-industry measures, it is an improvement of a single technology or process. Common examples are refrigeration in the food service and fruit storage industries and material handling performance improvements. Cross-industry measures are show in Table 36.

Table 36
Industry-Specific Measures

Measure Industry	Conservation Measure
Hi-Tech	Clean Room: Change Filter Strategy
Hi-Tech	Clean Room: Clean Room HVAC
Hi-Tech	Clean Room: Chiller Optimize
Food Processing	Food: Cooling and Storage
Food Storage	Food: Refrigeration Storage Tune-up
Food Storage	Fruit Storage Refer Retrofit
Food Storage	CA Retrofit -- CO2 Scrub
Food Storage	CA Retrofit -- Membrane
Food Storage	Fruit Storage Tune-up
Material Handling	Material Handling2
Material Handling	Material Handling VFD2
Mining Process	Grinding Optimization, Improved Flotation Cells
Paper	Paper: Efficient Pulp Screen
Paper	Paper: Premium Fan
Paper	Paper: Material Handling
Paper	Paper: Large Material Handling
Paper	Paper: Premium Control Large Material
Wood	Wood: Replace Pneumatic Conveyor

Whole plant optimization measures are improvement of whole systems rather than discrete equipment upgrades used in cross-industry systems and industry-specific processes. This accounts for interactive effects in industrial technologies. Such measures require a much more tailored approach that includes: demand-side assessment; proper design, sizing, and/or reconfigurations to match supply to demand; system "commissioning;" sustainable O&M; and supporting management practices.[18] The savings and approach to plant optimization is categorized in a tiered system based the review of numerous case studies and regional program data: Plant Energy Management (First Tier), Energy Project Management (Second Tier), Integrated Plant Energy Management (Third Tier).

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[18] Northwest Power and Conservation Council. *System Optimization Measures Guide*. 6th Power Plan. March 23, 2009

Estimating Technical Potential

The technical potential is the sum of savings from all industrial measures and each industrial sub-sector. It represents the amount of energy efficiency potential that is available regardless of cost or other constraints such as willingness to adopt measures.

Estimating the technical potential begins with determining the amount of energy consumed for each end-use (e.g. pumps, fans, motors, etc) in each industrial subsector (paper, wood, mining, etc). Data for this step was calculated in the end-use model. For example, in the wood products industry, 11% of load (10,266,194 kWh/yr) is used for drying fans. Table 37 illustrates an example of end-uses for wood manufacturing. All other industries (mining, construction, fruit packing, etc) have a different associated top-down savings percentage for each component of disaggregated load. An applicability value determines the amount of the end-use load eligible for measure savings. The applicability value is highly dependent on the measure and the industrial sector. For example, certain motors sizes are only applicable to select industries.

Table 37
End-Use Disaggregation Example, Wood Products

	Share	GWh
Drying Fans	11%	10.3
Air Compressor	13%	12.0
Material Handling	23%	20.7
Material Processing	29%	26.1
Pneumatic Conveyor	5%	4.5
Pollution Control	1%	0.9
Boiler Auxiliaries	4%	3.6
Heating	3%	2.7
HVAC	2%	2.1
Lighting	6%	5.6
Other Process	2%	1.5
Total		**90**

Estimating Achievable Potential

Achievable efficiency is the amount of energy savings potential that is achievable and cost-effective. To find cost-effectiveness potential, energy efficiency measures must pass economic screening. In British Columbia, economic potential is defined using a total resource cost (TRC) test to screen measures for cost effectiveness (discussed in more detail in the "Methodology" section of the report). All of the measures discussed in this section pass the TRC. Therefore the "Achievable" potential in this section means that the potential is both economic (cost-effective) and achievable. Previous conservation by FortisBC will also be addressed.

Potential Estimates

As described in the methodology section, end-use load forecast data and energy efficiency measures are combined to produce estimates of energy efficiency. Energy efficiency potential accounts for previous industrial conservation by FortisBC using saturation factors.

Technical Potential

The total technical potential is 35.2 GWh by 2030 or energy savings of 17% of 2030 forecasted load. Table 38 illustrates savings by industrial sector. The wood industry has the largest potential savings, but fruit and pulp industries have a large potential as a percentage of their load.

Table 38
Summary of Energy Efficiency Potential – Technical

		Energy Efficiency	
Sub-Sector	**2030 GWh from End-Use Model**	**Technical Potential GWh**	**Total Potential as % of 2030 Forecast**
Pulp and Paper	17	5	29%
Mining	9	1	12%
Food & Beverage Manufacturing	14	4	27%
Wood Products	90	15	17%
Fruit Packers and Storage	9	3	34%
Miscellaneous Manufacturing	69	7	11%
Total MWh	207	35	17%

Figure 47 illustrates technical potential by measure group. Cross-industry systems have the largest technical potential, with the most savings coming primarily via fans, lighting, and compressed air measures.

Figure 47
Technical Potential by Measure Category

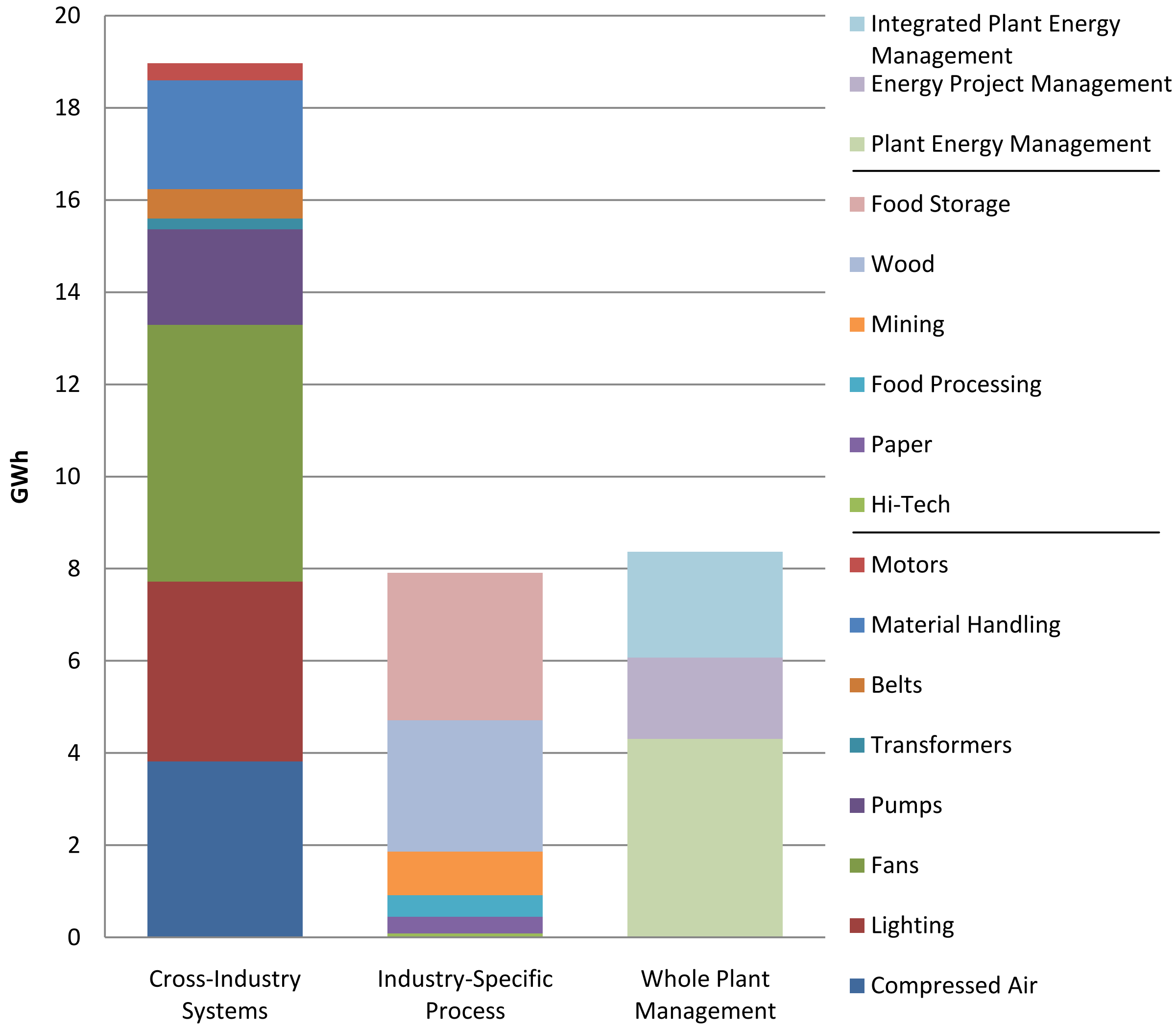


Table 39 illustrates industrial energy efficiency savings potential by end-use.

Table 39
Summary of Energy Efficiency Potential Technical

Measure Group	Measure Type	Potential Savings GWh
Cross-Industry Systems	Compressed Air	3.8
Cross-Industry Systems	Lighting	3.9
Cross-Industry Systems	Fans	5.6
Cross-Industry Systems	Pumps	2.1
Cross-Industry Systems	Transformers	0.2
Cross-Industry Systems	Belts	0.6
Cross-Industry Systems	Material Handling	2.4
Cross-Industry Systems	Motors	0.4
Industry-Specific Process	Hi-Tech	0.1
Industry-Specific Process	Paper	0.4
Industry-Specific Process	Food Processing	0.5
Industry-Specific Process	Mining	0.9
Industry-Specific Process	Wood	2.9
Industry-Specific Process	Food Storage	3.2
Whole Plant	Plant Energy Management	4.3
Whole Plant	Energy Project Management	1.8
Whole Plant	Integrated Plant Energy Management	2.3

Achievable Potential

Using achievability factors, technical potential results are adjusted to realistic levels of conservation over the 20 year study period. Achievability percentages for most measures are 85%.

FortisBC has achieved notable energy saving from industrial measure over the past six years. Conservation by category is shown in Table 40. However, data for past industrial efficiency improvement is built into the top-down savings estimates. For example, in the wood sub-sector, one-third of process equipment is assumed to be upgraded to adjustable speed drive control prior to assessment of potential. Similarly, synchronous belts are assumed to be installed on about 20% of large motors. FortisBC conservation achievements are in line with improvements in the region, so there is no further reduction in the potential due to past conservation.

Table 40
Summary of Past Industrial Conservation
GWh

	2003	**2004**	**2005**	**2006**	**2007**	**2008**	**Total**
Motors	0.00	0.00	0.00	0.00	0.01	0.00	0.01
Pumps & Fans	0.67	0.57	0.97	0.00	0.09	0.00	2.32
Industrial Efficiencies	1.13	0.00	0.39	1.92	1.66	3.08	8.19
Compressors	0.23	0.50	0.69	0.52	0.39	0.21	2.54

Therefore, total achievable potential is 27.8 GWh by 2030 or energy savings of 13% of 2030 forecasted load. Table 41 illustrates savings by industrial sector. Again, the wood industry comprises the largest potential savings. Ramp rates are used distribute the savings potential over the 20-year period.

Table 41
Summary of Achievable Energy Efficiency Potential

		Energy Efficiency	
Sub-Sector	2030 GWh from End-Use Model	Total Achievable Potential GWh	Total Potential as % of 2030 Forecast
Pulp and Paper	17	3	21%
Mining	9	1	10%
Food & Beverage Manufacturing	14	3	20%
Wood Products	90	12	14%
Fruit Packers and Storage	9	3	30%
Miscellaneous Manufacturing	69	6	8%
Total MWh	207	27.8	13%

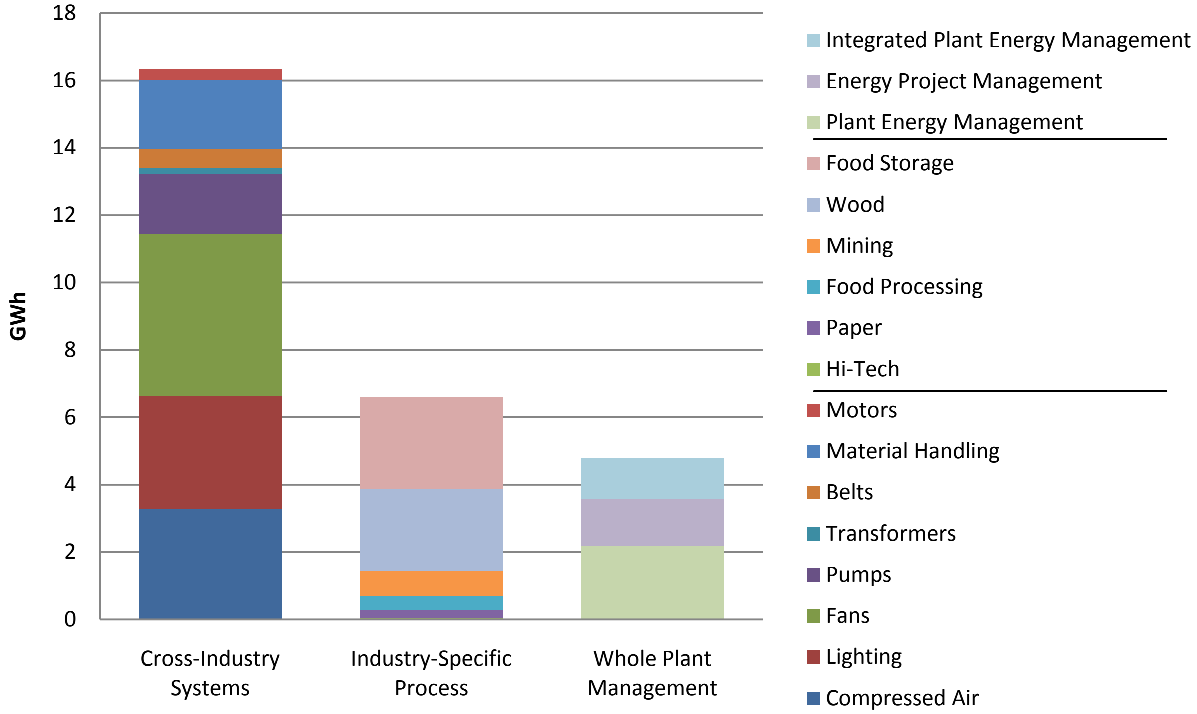
The cumulative achievable potential for 1, 5, 10 and 20 year periods are shown in Table 42. Ramp rates by year are listed in Appendix D.

Table 42
Achievable Potential - Adjusted by Year Using Ramp Rates
GWh

			Year			
		Ramp Rate	**1**	**5**	**10**	**20**
Cross-Industry Systems	Fans	10YearEven	0.25	1.25	2.49	4.80
Cross-Industry Systems	Lighting	New Measure Fast	0.10	1.01	2.69	3.37
Cross-Industry Systems	Compressed Air	10YearEven	0.28	1.52	3.16	3.28
Industry-Specific Process	Food Storage	10YearEven	0.27	1.37	2.74	2.74
Industry-Specific Process	Wood	New Measure Medium	0.04	0.36	1.05	2.43
Whole Plant	Plant Energy Management	New Measure Medium	0.03	0.33	0.95	2.19
Cross-Industry Systems	Material Handling	New Measure Medium	0.03	0.31	0.90	2.07
Cross-Industry Systems	Pumps	20YearEven	0.09	0.44	0.89	1.78
Whole Plant	Energy Project Management	New Measure Medium	0.02	0.21	0.60	1.37
Whole Plant	Integrated Plant Energy Management	New Measure Medium	0.02	0.18	0.53	1.22
Industry-Specific Process	Mining Process	20YearEven	0.04	0.19	0.38	0.75
Cross-Industry Systems	Belts	10YearEven	0.05	0.27	0.54	0.54
Industry-Specific Process	Food Processing	10YearEven	0.04	0.20	0.41	0.41
Cross-Industry Systems	Motors	New Measure Medium	0.00	0.05	0.13	0.31
Industry-Specific Process	Paper	20YearEven	0.01	0.06	0.12	0.25
Cross-Industry Systems	Transformers	20YearEven	0.01	0.05	0.10	0.20
Industry-Specific Process	Hi-Tech	10YearEven	0.00	0.02	0.03	0.03
Total (GWh)			**1.3**	**7.8**	**17.7**	**27.7**

Achievable potential by measure group is shown in Figure 48.

Figure 48
Industrial Achievable Potential by End-Use



Peak Demand Reduction

Tables 43 and 44 summarize winter and summer peak demand reduction potential provided by the energy efficiency measures analyzed in this section. Approximately 10 percent winter peak reduction can be achieved through the energy efficiency measures identified as cost-effective.

Table 43
Comparison Industrial End-Use Forecast with Winter Peak Reduction Estimates

	2030 Winter Peak from End-Use Model MW	Energy Efficiency Achievable Potential Winter MW	Percent of 2030 Load
Pulp and Paper	8.6	0.55	6.5%
Mining	4.2	0.42	10.0%
Food and Beverage	1.6	0.33	20.3%
Wood Products	14.6	1.89	13.0%
Fruit packers and storage	1.6	0.49	29.9%
Miscellaneous Manufacturing	16.4	0.91	5.5%
Total	**47.0**	**4.59**	**9.8%**

Table 44
Comparison Industrial End-Use Forecast with Summer Peak Reduction Estimates

	2030 Summer Peak from End-Use Model MW	Energy Efficiency Achievable Potential Summer MW	Percent of 2030 Load
Pulp and Paper	9.9	0.55	5.6%
Mining	1.5	0.16	11.1%
Food and Beverage	2.5	0.60	24.4%
Wood Products	13.3	1.95	14.7%
Fruit packers and storage	1.0	0.41	39.8%
Miscellaneous Manufacturing	6.0	0.94	15.5%
Total	**34.2**	**4.62**	**13.5%**

Summary

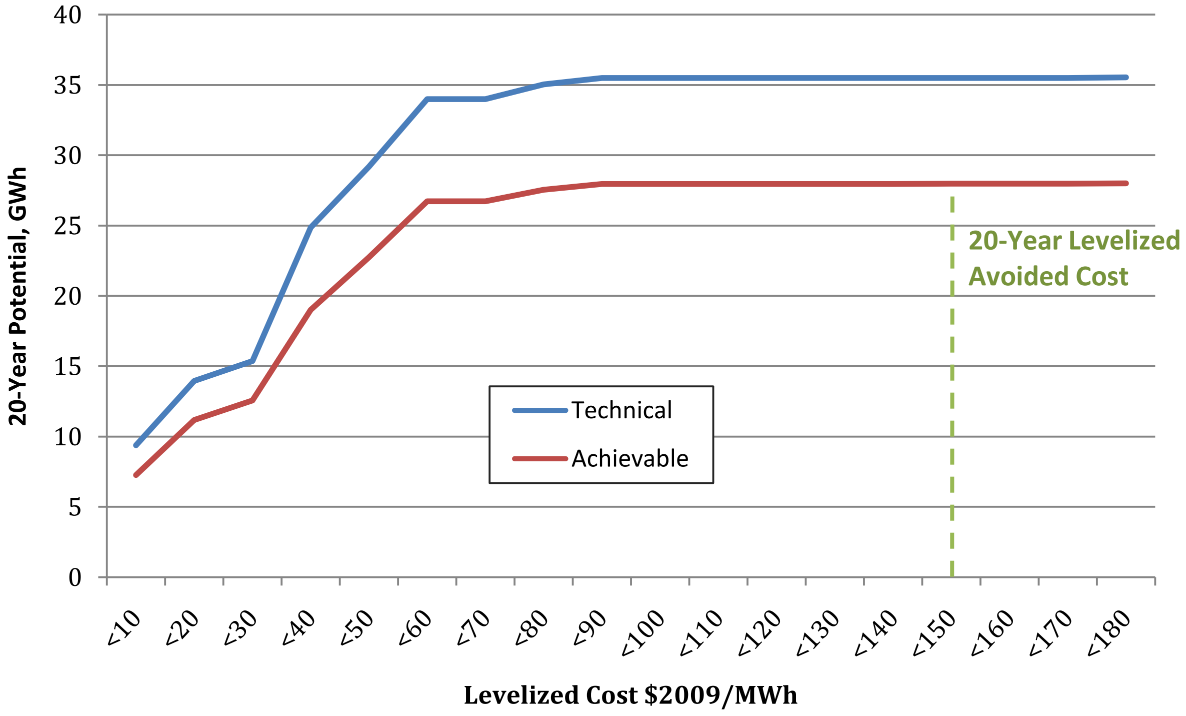
Table 45 compares achievable and technical potential to the end-use load forecast for the year 2030. Achievable potential ranges from 8% to 30% of industrial load based on manufacturing sector. A bulk of the savings comes from measures with low levelized cost of $0.03-$0.04/kWh.

Table 45
Summary of Energy Efficiency Potential

		Technical		Achievable	
Sub-Sector	2030 GWh from End-Use Model	Total Technical Potential GWh	Total Potential as % of 2030 Forecast	Total Achievable Potential GWh	Total Potential as % of 2030 Forecast
Pulp and Paper	16.50	4.8	29%	3.5	21%
Mining	9.12	1.1	12%	0.9	10%
Food & Beverage Manufacturing	13.87	3.8	27%	2.7	20%
Wood Products	90.05	15.1	17%	12.2	14%
Fruit Packers and Storage	8.72	3.0	34%	2.6	30%
Miscellaneous Manufacturing	69.20	7.4	11%	5.9	8%
Total	**207.47**	**35.2**	**17%**	**27.7**	**13%**

Figure 49 illustrates the supply curve of levelized cost and savings for all industrial measures.

Figure 49
Supply Curve – Industrial



Irrigated Agriculture Energy Efficiency Potential

Specific industrial processes and technology are required for savings in the agricultural sector. There are three main categories of potential measures: irrigation hardware, irrigation scheduling and milk production. Currently, FortisBC has a designated rate class for irrigation consumption, all of which are direct customers. Load is not segmented for dairy production, so it is assumed that FortisBC does not have applicable dairy farms for agricultural measures. Also, irrigation scheduling measures are applicable to large field crops, while irrigation load in FortisBC is associated with fruit, apple and grape production.[19]

Therefore, improved irrigation hardware, such as the conversion to low-pressure delivery systems and improved pumps, are measures in the agricultural sector. Table 46 shows measure savings, cost and life for applicable measures from the NWPCC 6th *Power Plan*.

Table 46
Irrigation Hardware Measures

Measure Name	Incremental Capital Cost ($/unit)	Measure Life (yr)	Savings per Applicable Acre (kWh/yr)	Applicable Acres
Convert High Pressure Center Pivot to Low Pressure System	$58	10	504	20%
Convert Medium Pressure Center Pivot to Low Pressure System	$22	10	336	15%
Pump, Nozzle & Gasket Replacement Average Well	$111	10	412	11%
Pump, Nozzle & Gasket Replacement Deep Well	$134	10	765	19%

An estimation of irrigation potential from hardware improvement is possible using a bottom-up approach as in the residential and commercial sector calculations. Irrigation consumption is 52,071 MWh/yr and remains flat over the study period. Assuming 1,400 kWh/yr for each acre, 37,193 acres of agricultural land is irrigated in the FortisBC service territory. Using the irrigated acres and applicability factors in Table 42, technical potential is 12,716 MWh. To be consistent with the NWPCC, an applicability factor of 85% is used to calculate achievable potential of 10,809 MWh. Results for irrigation are show in Table 47.

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[19] *2006 Agriculture Community Profiles: Kelowna*. Statistics Canada. www.statcan.gc.ca

Table 47
Irrigation Savings

	2030 Consumption (MWh)	2030 Technical Potential (MWh)	Achievable %	2030 Achievable Potential (MWh)
Irrigation	52,071	12,716	85%	10,809

Demand Response Savings Potential

Introduction

Demand response measures cycle, or shut down, building equipment during peak load events in order to reduce system peak and the need for new capacity. Options for demand response include direct load control, dynamic real-time pricing, time-of use pricing, payment for reductions, and demand buyback. Table 48 compares each method of demand response and its applicable sectors (residential, commercial, and industrial). The focus of this section of the report is on estimating the potential of the direct load control portion of demand response.

Table 48
Demand Response Methods

		Description	Residential	Small & Medium Commercial	Large Commercial	Industrial
Curtailment Based	Interruptible Load	Utility signs agreement with larger customers to reduce their load at peak periods				X
	Direct Load Control	Utility controlled curtailment of household appliances and HVAC equipment using installed communications gateway	X	X		
	Contractual Demand Response	Payment to selected larger industrial customers to reduce load at select periods			X	X
Price Based	Time of Use (TOU) Pricing	Adjust power price for different times of day and year. Periods are pre-determined	X			
	Dynamic Real Time Pricing	Dynamically adjust power price as demand increases.	X	X	X	X
	Critical Peak Pricing	TOU Rates that correspond to extreme peak hours. Prices reflect the power of generating or purchasing electricity at peak times.	X	X	X	X

Demand response is an area of significant uncertainty because of relatively limited experience in large-scale programs. However, direct load control has more predictability and reliability from the utilities perspective when compared to other forms of demand response. Direct load control is not a new idea, but it is gaining momentum due to better technology and successful pilot programs. Other utilities in the region, namely BC Hydro, have quantified the savings for demand specific conservation measures.

Therefore, direct load control is the focus of demand response estimates. Relevant concepts, case studies and pertinent technology information are included in this report. The FortisBC direct load control potential can be estimated using customer survey data and regional data sources for measures performance.

Technology and Communication Equipment

At its simplest, direct load control is a method of demand response that utilizes a control device to briefly curtail major appliances or space conditioning units – namely hot water heaters and space conditioning units. Curtailments are intended to shave peak demand for utilities, with a limited, if any, effect on consumers.

Direct load control requires both specific technology and management from a utility’s operations department. The system relies on controller switches that interrupts customers’ electrical load to specific devices during peak load events. These events are called curtailments and usually last 1-3 hours (less if cycling HVAC equipment).

There are several main components to a direct load control system and these are descibed below:

- An electronically-controlled power switch (often 30A) which is used to switch power ON or OFF to the managed load. This can control the device directly, like a water heater or baseboard heating unit, or a central control device like a thermostat.
- A modem for communication with a server capable of initiating and controlling curtailments from a remote location. In the past, these have opperated on radio frequencies, but recent units operate on cell (SMS), wireless and WiMAX networks.
- Non-volatile memory which contains device identity, load scheduling and load-tracking information.

The FortisBC Advanced Metering Infrastructure (AMI) will be the core to any future load control or demand response progam.

Programs and Data Sources

Direct load control technology is relatively new when compared to energy efficiency measures. As such, the data sources for savings, cost saturation and achievability are not as well established. Organizations in the Northwestern United States and British Columbia have attempted to reduce the uncertainly around predicting load control potential. There are several recent pilot programs or potential studies in the Northwest. The most prominent being the

Powershift Program on the Olympic Peninsula in Washington State and the Goodwatts program in Ashland, Oregon. A brief summary of each program is presented in Appendix E.

Most large-scale load control programs have focused on the curtailment of summer cooling load. There are limited programs in winter peaking service territories that are not pilot programs. Therefore, we focused on several potential studies that included data for winter peaking systems.

Data for this potential study are predominantly based on recent potential studies from BC Hydro *(2007 Conservation Potential Review),* the Northwest Power and Conservation Council *(6th Power Plan)* and PacifiCorp *(Demand Response Proxy Supply Curves)*. These sources were referenced for cost, savings, lifetime, applicability and achievability values.

Methodology

The demand reduction potential from direct load control technology was calculated according to the following steps:

1. Calculate peak winter and summer demand in end-use forecast;
2. Estimate the share of residential and commercial buildings applicable to direct load control (i.e. electric heat, etc) from FortisBC survey data;
3. Select direct load control measures applicable to FortisBC service territory from data sources;
4. Determine the peak demand savings per residential or commercial unit;
5. Compile cost data, exclusive of program costs and AMI meters, as requested by FortisBC;
6. Combine savings and building data to calculate technical potential;
7. Determine initial achievability percentages for each measure;
8. Calculate 5-year achievable potential for direct load control measures and compare with total demand;
9. Forecast achievability percentages for full 20 year study period and calculate savings;

The equation form of this methodology is shown below:

$$\{\text{Annual Demand Reduction}\} = \begin{pmatrix}\text{\# Applicable} \\ \text{Buildings}\end{pmatrix} \text{x} \left(\frac{\text{kW Saving}}{\text{Building}}\right) \text{x}(\text{Achievability \%})$$

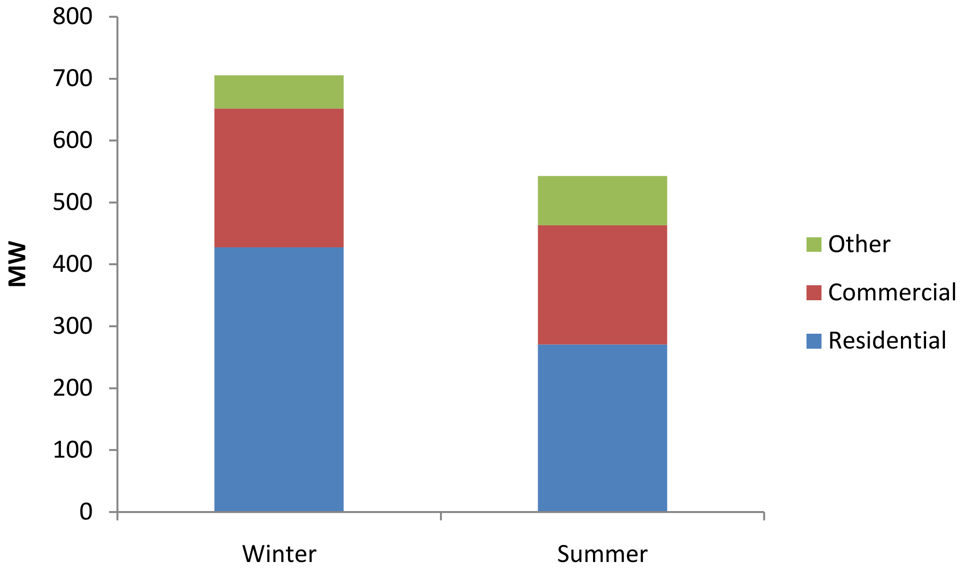
FortisBC Peak Loads

The FortisBC total system winter peak in 2008 was 706 MW and total summer system peak was 560 MW. These peaks are weather-adjusted values. These values will change as the end-use model is modified.

In the Residential Sector, coincident peak load in 2008 was 405 MW in the winter and 219 MW in the summer (see Figure 50). The largest contributor to coincident peak is space heating.

In the Commercial Sector, coincident peak load in 2008 was 225 MW in the winter and 193 MW in the summer (see Figure 50). The largest contributor to commercial peak is lighting.

Figure 50
FortisBC Winter and Summer Coincident Peak, 2008



Direct Load Control - Residential

Measures

All direct load control measures are a curtailment of certain aspects of a home's load at peak periods. The primary candidates for load control are those that have the largest relative contribution to residential peak load and can be curtailed without significant inconvenience to homeowners. Unlike energy efficiency measures, such as weatherization, windows or HVAC upgrades, load control relies on a device to control a major appliance or thermostat, rather than replacing it the appliance itself. Therefore, the communications installed in residential homes drive measure performance and determine future upgrades to the communications protocol and curtailments. The cost of AMI meter installation, operation and maintenance were excluded from this analysis as requested by FortisBC. It is possible to implement direct load control measures without advanced meters. However, in the case of two-way communication units, like those installed on thermostats, AMI is required.

Cost for each measure includes the technology, installation and maintenance over the technology life. To compare measures, the total cost is annualized per or expected savings.

The following DLC measures in Table 49 are included in this study.

Table 49
Residential Direct Load Control Measures

	Description	Winter	Summer
Central Heating	Cycling or setbacks controlled via a central thermostat capable of commutating with grid operators. 2-way communications gives feedback from on-site AMI meters.	X	
Baseboard Heating	Utility controlled switches connected directly to heating units or heating equipment circuits.	X	
Water Heating	Curtailment of water heats using switches installed on water heater or water heater circuit	X	
Air Conditioning Control - Cooling	Curtailment or setbacks of central air-condition units capable of communicating with grid operators.		X

Load control includes three distinct classes of measures: winter space conditioning, hot water heating and summer cooling.

Winter Space Conditioning Measures

Central Heating

Although both thermostat and switch controlled devices reduce heating load during peak periods, they have different performance, cost and applicability. Thermostat controllers shave on average, approximately 30%, of peak heating load at a cost of $40-$50/kW-yr. These are average savings per unit and applicable to homes with central heating. While all heating units might not be on at the same time, savings percentages represent expected peak savings used for annual technical potential. The 30% value accounts for performance, customer overrides, communication failures, and is based on data from pilot program experience. Lifetime is expected to be 10-15 years which is consistent with the life of a conventional thermostat.

Baseboard Heat

Switch-based units are control devices installed directly on baseboard heating equipment or circuits rather than on a central thermostat. They are applicable to homes with zonal electric heat. These devices are generally less sophisticated than thermostat-based controllers. Switch units are less expensive, but are often damaged or not re-configured when heating units are replaced. On average, 15-20% of peak zonal heating load can be controlled at a cost of $28-$35/kW-year.

Thermal Storage

Although is it not a direct load control measure, electric thermal storage units (ETS) have the potential to shave peak demand. This potential is address in the residential and commercial potential sections and is not included in demand response potential.

Water Heating Measures

Water Heating

Water heaters can be curtailed using switches similar to those used for baseboard heating. Heating elements are cycled or turned off during peak curtailment periods by grid operators. This is a very reliable method for peak reduction representing approximately a 0.4 kW per unit savings. While this value may seem low, this is a program level estimate. FortisBC winter and summer daily peak load periods in the late afternoon do not align well with peak water heater usage. During some curtailment events, water heating units might not be running, and therefore will not realize savings. In morning peaking systems, water heater curtailments are more effective and align well with the sharp morning peak in water heater consumption. Also, water heater use is similar year round and does not respond dramatically to outside temperature. Therefore, savings are consistent throughout

Summer Cooling Measures

Air Condition Control - Cooling

Technology for summer cooling curtailments is similar to central heating thermostats for winter heating. The central thermostat controls setbacks and cycling of central AC units based on curtailment commands from utility operators. BC Hydro’s conservation potential study does not include an estimate of summer peak savings from cooling measures. However, the PacifiCorp study does include cost and savings information for cooling direct load control and is shown in Table 48.

Table 50 has a range for costs and savings for each measure. Savings are in kW per residential unit and annual cost averages over the life of the measure. For consistency and depth, values in Table 50 are based primarily on BC Hydro's potential study. However, values are in agreement with savings and cost from the PacifiCorp and NWPCC studies. For example, central thermostat controls have a savings of 1.5 kW/unit in the PacifiCorp study and $60-$100/kW-yr cost in the NWPCC study.

Table 50
Cost and Savings Data for Residential Direct Load Control Measures

	Peak Reduction Low *kW/SFD*	**Peak Reduction High** *kW/SFD*	**Cost Low** *$/kW/Yr (1)*	**Cost High** *$/kW/Yr (1)*
Winter				
Baseboard Heating	0.74	0.92	$28.00	$35.00
Central Heating	1.2	1.5	$40.00	$50.00
Water Heating	0.4	0.4	$49.00	$55.00
Summer				
Water Heating	0.4	0.4	$49.00	$55.00
Air Conditioning Control - Cooling	1.5	1.5	$64.90	$64.90

(1) This is an annualized cost of technology and installation per kilowatt of expected annual demand savings from curtailments.

Other DLC Measures

Other DLC measures include non-essential lighting and pool/spa heating; these measures were included only in the BC Hydro study. Therefore, we have included some information here for reference; potential estimates are not included. Costs in Table 51 are incremental and are based on existing communications infrastructure.

Table 51
Secondary Residential DLC Measures

	Peak Reduction Low *kW/unit*	**Peak Reduction High** *kW/unit*	**Cost Low** *$/kW/Yr*	**Cost High** *$/kW/Yr*
Lighting				
Non-essential Lighting, 1-way switch-based control	0.234	0.234	34	34
Pools and Spas				
Pool/Spa, 1-way switch-based control	0.5	0.5	61	61

Technical Potential

Technical potential is the amount of energy efficiency potential that is available regardless of cost or other constraints such as willingness to adopt measures. It represents the theoretical maximum amount of peak load reduction if these constraints are not considered.

The main component for determining technical potential is the housing stock characteristics in FortisBC's service territory. In the *2009 Residential Customer End-Use Study*, FortisBC compiled a list of residential characteristics such as heat type, water heating fuel, central thermostats usage, etc. Dwelling saturations and the total number applicable building are shown in Table 52. There are several assumptions used to generate saturation percentages. These are described below.

For heating controls, 38% of homes are currently heated with electric heat and are eligible for load control. Of homes heated by electricity, half (19%) are assumed to have central thermostats and are applicable to thermostat based load control. The remainder of the electrically heated homes (19%) is known to have baseboard heat and applicable to switch-based devices. Water heater controls are applicable to homes with electric hot water heating, which, from the end-use study is 49% of all housing units. Again, while all water heat units are not on at the same time, savings are assumed on an annual per unit basis. For summer cooling, utility load control measures are applicable to units with central AC units and central thermostats. From the survey data, this saturation is 32%.

Given savings values from Tables 50, the technical potential of direct load control measures in the FortisBC service territory was estimated. The technical potential assumes that all homes that can have a particular technology installed will participate and achieve the savings associated with the measure. For example, all homes with electric heat and central programmable thermostats are assumed to participate in load control programs. In effect, there is no cap on the saturation or participation in direct load control measures in the applicable population. These assumptions allow for the estimation of the total potential resulting in the theoretical maximum reduction in peak load from direct load control programs (see Table 52).

Table 52
Residential Direct Load Control Technical Potential

	Dwelling Saturation	Applicable Count	Savings (MW)
Total Number Homes		***137,655***	
Winter			
Baseboard Heating	19%	26,154	19.4
Central Heating	19%	26,154	31.4
Water Heating	49%	67,451	27.0
Summer			
Water Heating	49%	67,451	27.0
Air Conditioning Control - Cooling	32%	44,050	66.1

Achievable Potential

Achievable potential is usually calculated as the portion of technical potential that is cost effective and achievable. For reference, BC Hydro uses $179/kW-yr (in 2009 dollars) as the avoided capacity cost. Therefore, using this value, the direct load control measures included in this study are all cost effective. Avoided demand cost for FortisBC are $189/kW-year (2010 dollars) based on a blended value of BC Hydro's avoided capacity and FortisBC blended capacity. All measure costs are well below the $189/kW-yr threshold even when program costs are included. Direct load control programs are hinged on achievability rates rather than the selection of cost effective measures.

The achievability rates used in this study are based on BC Hydro's study and are shown in Table 53. The low achievability rates can be assumed if Time of Use (TOU) pricing structure is optional while the high achievability case can be assumed when TOU pricing is mandatory.

Table 53
Achievability Rates for Residential Direct Load Control Measures

Measure Name	Low Achievability	High Achievability
Baseboard Heating	10%	20%
Central Heating	10%	20%
Water Heating	10%	20%
Water Heating	10%	20%
Air Conditioning Control - Cooling	5.%	15%

The achievability rates were then applied to the technical potential to obtain the range of achievable potential for direct load control. A table demand savings and incremental cost is shown in Table 54. There are two columns for potential savings, one for high and low achievability, respectively. Again, these represent optional and mandatory TOU pricing. The two values show a range of savings based on how aggressive FortisBC is in implementing new programs. There large and steady increases in demand savings from roughly $30/kW-yr to $60/kW-yr. This corresponds with space and water heating measures.

Table 54
Achievable Peak Savings for Residential DLC Measures

	Cost	Savings (MW)	
	$/kW/Yr	**Low Achievability**	**High Achievability**
Winter			
Baseboard Heating	31.5	1.9	3.9
Central Heating	45.0	3.1	6.3
Water Heating	52.0	2.7	5.4
	Total	7.7	15.6
Summer			
Water Heating	52.0	2.7	5.4
Air Conditioning Control - Cooling	64.9	3.3	9.9
	Total	6.0	15.3

Direct Load Control – Commercial

Small to medium sized commercial buildings are largely similar to residential buildings in their function and potential for direct load control technology. Therefore, the commercial sector is modeled in the same way as residential potential, but only the largest commercial buildings are excluded (i.e. large office building with energy management systems). Savings and cost values for commercial sector measures are slightly different from in the residential measure data, and are also based on BC Hydro’s potential study.

Because lighting comprises the largest percentage of commercial demand, utility control of non-essential lighting is the primary measure in commercial buildings. The required technology is similar to switch-based heating measures, except installed on lighting circuits. Savings are 10% of total lighting demand. In addition to air conditioning, lighting and refrigeration can also be curtailed to reduce demand in the summer.

Table 55 shows savings and cost for commercial measures.

Table 55
Secondary Residential DLC Measures

	Peak Reduction Low *kW/SFD*	Peak Reduction High *kW/SFD*	Cost Low *$/kW/Yr (1)*	Cost High *$/kW/Yr (1)*
Winter				
Baseboard Heating	0.64	0.87	$32.00	$44.00
Non Essential Lighting	0.85	1.26	$31.00	$46.00
Refrigeration Load Control	2.6	2.9	$38.00	$44.00
Central Heating	1.07	1.43	$45.00	$60.00
Summer				
Non Essential Lighting	0.85	1.26	$21.00	$32.00
Refrigeration Load Control	2.6	2.9	$38.00	$44.00
Air Conditioning Control - Cooling	1.5	1.5	$64.90	$64.90

(1)This is an annualized cost of technology and installation per kilowatt of expected annual demand savings from curtailments.

Technical Potential

From the *2009 Commercial Customer End-Use Study*, 13% of commercial buildings are heated solely by electricity in the FortisBC Service territory. Similar allocations between different heating measures resulted in an even split for each thermostat and switch-based measures heating.

Lighting is a distinctly different measure in the commercial sector. Non-essential lighting has the potential to be controlled in 100% of buildings. Conversely, curtailment of refrigeration load is only applicable to commercial kitchens and retail, which comprise 1% of total commercial buildings.

Saturation rates and applicable buildings (out of 7,002 total small/medium commercial buildings) are shown in Table 56.

Table 56
Commercial Direct Load Control Technical Potential

	Saturation	Applicable Count	Savings (MW)
Total Number Buildings		***7,002***	
Winter			
Baseboard Heating	6.5%	455	0.29
Non Essential Lighting	100.0%	7002	5.95
Refrigeration Load Control	1.0%	70	0.18
Central Heating	6.5%	455	0.49
Summer			
Non Essential Lighting	100.0%	7002	5.95
Refrigeration Load Control	1.0%	70	0.18
Air Conditioning Control - Cooling	12.0%	840	1.26

Economic Potential

Due to the low measure cost relative to avoided demand rates, all measures are assumed to be cost effective similar to the methodology presented for the residential sector. See previous discussion on Economic Potential.

Achievable Potential

A range of achievability factors are used for each measure based on BC Hydro information. See Table 57. In the commercial sector, the difference between high and low achievability is often threefold due to the inherent variability from a smaller stock of buildings.

Table 57
Achievability Rates for Commercial Direct Load Control Measures

Measure Name	Low Achievability	High Achievability
Central Heating, 2-Way Thermostat-Based	5.0%	15.0%
Zonal Heating, Switch-Based	5.0%	15.0%
Non Essential lighting, 1-Way Switch-Based	5.0%	15.0%
Air Conditioning Control - Cooling	5%	15%
Refrigeration Load Control	20%	30%

Achievable savings are shown for winter and summer peak periods, respectively, in Table 58. There is a range of low and high achievability factors. Commercial lighting and cooling are the two largest relative contributors to commercial demand reduction potential.

Table 58
Achievable Peak Energy Savings, Commercial Direct Load Control

	Cost	Savings (MW)	
	$/kW/Yr	**Low Achievability**	**High Achievability**
Winter			
Non Essential Lighting	38.0	0.01	0.04
Baseboard Heating	38.5	0.30	0.89
Refrigeration Load Control	41.0	0.04	0.05
Central Heating	52.5	0.02	0.08
	Total	0.37	1.06
Summer			
Non Essential Lighting	26.5	0.30	0.89
Refrigeration Load Control	41.0	0.04	0.05
Air Conditioning Control - Cooling	64.9	0.06	0.19
	Total	0.4	1.1

Direct Load Control – Industrial

While small and mid-sized commercial buildings can benefit from more widget based load control options like water heater and furnace controls, larger building and industrial buildings require a more tailored approach. Irrigation scheduling, standby generation and commercial/industrial programs are also viable options, but require specific technology and commissioning to meet the specific needs of the building function. These programs tend to have higher upfront and administrative costs. However, if designed well, larger building curtailments can provide significant reductions in peak demand, and, therefore, significantly reduce the need for capacity infrastructure. While specific buildings and industries in the FortisBC service territory were not modeled for direct load control, commercial and industrial settings could be a cost effective solution for capacity constraints in the future. These programs require careful selection of buildings and a comprehensive knowledge of larger building energy management.

There are a limited number of programs in the region especially in winter peaking systems. The most notable is Northwest Open Automated Demand Response Program run by Seattle City Light. Seattle City Light found that 0.57 W/ft2, or roughly 14% the building's peak demand was possible to curtail during events from of lighting and HVAC measures. The Seattle Open ADR program is the first of its kind in the region and gives an idea of what is possible in the large commercial sector. However, a tailored and process based engineering analysis is required before pursuing a similar program.

Conclusions

While direct load control is a new area of demand side management relative to energy efficiency, direct load control can provide resources to meet peak demand. Direct space conditioning and water heating control, in addition to commercial lighting are viable options now and for new demand response programs. These measures alone result in roughly 8.1 – 16.7 MW of winter peak and 6.4 – 16.4 MW of summer peak load reduction potential for under $189/kW-yr. They provide system reliability at a low first cost and are relatively simple to install, in line with voluntary programs. FortisBC might also consider implementing other direct load control measures such as residential lighting and plug loads as incremental measures.

In total, an estimated 3.6%-5.3% reduction in winter peak demand (of which 1.4-2.9% is from DLC measures) is possible by 2015. Total summer peak reduction is 3.6%-5.5%. There is variability in the range of savings based on high and low achievability rates. These estimates exclude expensive thermal storage measures and are consistent with studies from other utilities, which are shown in Table 59.

Table 59
Comparison of Demand Response Forecasts Across Utilities

Utility	Target Year	Forecasted Demand Response as Percent of Peak Load
BC Hydro[20]	2011 (5 Year)	2.30%
BC Hydro	2016 (10 Year)	4.60%
PacifiCorp	2009	5.10%
Idaho Power	2013	8.10%
Portland General Electric	2012	4.10%
New York ISO	2009	5.90%
PJM	2008	3.20%
California ISO	2011	6.50%

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[20] Values are average savings for direct load control (capacity specific) measures from the *2007 Conservation Potential Review*.

Savings are forecasted out for the full 20 year study scope in Table 60. This analysis assumes that, as programs become more developed, participation will increases from better marketing and consumer acceptance. Conservative achievability rates were used and derived from the lower end of those in the BC Hydro study.

Table 60
20-Year Forecasted Direct Load Control Savings

	Achievability Percent				Annual Savings (MW)			
	5 Year	**10 Year**	**15 Year**	**20 Year**	**5 Year**	**10 Year**	**15 Year**	**20 Year**
Residential								
Winter								
Baseboard Heating	10%	23%	30%	33%	1.94	4.45	5.81	6.44
Central Heating	10%	23%	30%	33%	3.14	7.22	9.42	10.45
Water Heating	10%	23%	30%	33%	2.70	6.21	8.09	8.98
Summer								
Water Heating	10%	23%	30%	33%	2.70	6.21	8.09	8.98
Air Conditioning Control - Cooling	5%	10%	23%	30%	3.30	6.61	15.20	19.82
Commercial								
Winter								
Baseboard Heating	5%	11%	14%	15%	0.01	0.03	0.04	0.04
Non Essential Lighting	5%	11%	14%	15%	0.30	0.63	0.83	0.89
Refrigeration Load Control	20%	46%	60%	67%	0.04	0.08	0.11	0.12
Central Heating	5%	11%	14%	15%	0.02	0.05	0.07	0.07
Summer								
Non Essential Lighting	5%	11%	14%	15%	0.30	0.63	0.83	0.89
Refrigeration Load Control	20%	46%	60%	67%	0.04	0.08	0.11	0.12
Air Conditioning Control - Cooling	5%	10%	23%	30%	0.06	0.13	0.29	0.38
				Total Winter	10.1	22.5	30.1	34.7
				Total Summer	6.4	13.7	24.5	30.2

Energy Savings

Additionally, while direct load control measures are designed to shave peak demand, there is a minimal amount of associated energy savings. The total number and length of curtailment events will alter the amount of savings. To estimate this, 35 winter and 17 summer curtailment events were assumed. Each event is 2 hours long. This is consistent with pilot study results from the Goodwatts Program in The City of Ashland. Table 61 shows energy savings for both high and low achievability. Assuming conservative achievability, peak demand measures have 942 MW of associated energy savings in the FortisBC service territory. Note that all measures with the exception of water heating have energy benefits. For hot water heaters, the load is shifted to off-peak hours, but the total energy consumption is the same using direct load control.

Table 61
Energy Savings from Peak Demand Measures

	Peak Reduction kW/unit	Units Low Achievability	Units High Achievability	Savings (MWh) Low Achievability	Savings (MWh) High Achievability
Residential					
Winter					
Baseboard Heating	0.74	2615	5231	139.4	278.7
Central Heating	1.2	2615	5231	226.0	451.9
Summer					
Air Conditioning Control – Cooling	1.5	2202	6607	112.3	337.0
Commercial					
Winter					
Baseboard Heating	0.64	23	68	1.0	3.1
Non Essential Lighting	0.85	350	1050	21.4	64.3
Refrigeration Load Control	2.6	14	21	2.6	3.9
Central Heating	1.07	23	73	1.8	5.6
Summer					
Non Essential Lighting	0.85	350	1050	10.1	30.4
Refrigeration Load Control	2.6	14	21	1.2	1.9
Air Conditioning Control – Cooling	1.5	42	126	2.1	6.4
			Total Summer	***517.9***	***1,183.2***

Behaviour Conservation Savings

Introduction

Behavioural measures or programs are those where energy or peak demand savings are based on customers changing their patterns of energy consumption. Behavioural measures are reviewed in this study; however, it is recommended that FortisBC conduct more thorough studies before implementing these programs.

Behavioural Measures

Behavioural programs might include a combination of education, awareness campaigns, or incentives regarding things like turning the thermostat down at night or unplugging small appliances when not in use. Table 62 (from the BC Hydro 2006 study) summarizes behavioural measures applicable in the residential sector. Among these, BC Hydro found that behaviours related to computers, domestic hot water use, lighting, and space heating showed the greatest potential for energy savings.

Table 62
Residential Behavioural Measures

Space Heating and Cooling
- Turning down the temperature at night or day
- Heating only occupied parts of the building
- Maintain draft proofing
- Install storm windows
- Covering windows when using the AC
- Increasing temperature when using the AC

Lighting
- Select low-watt bulbs, reduce lumens
- Using only necessary safety lighting
- Turning off lights when leaving the room

Water Heating
- Turn off or down water heater when away
- Lower water temperature

Small Appliances
- Unplug charger power supplies

Refrigeration and Freezers
- Maintain proper temperature
- Defrost freezer more frequently

Appliances
- Air dry dishes in dishwasher
- Minimize hot and warm water washing
- Use temperature/moisture sensor in dryer

Computers and Peripherals
- Activate power management features
- Shutting of PC and/or monitor when not in use

TV and Entertainment
- Turning off TV when not in use
- Unplug TV regularly and when away
- Unplug entertainment system regularly

Table 63 (from the BC Hydro 2006 study) summarizes behavioural measures applicable in the commercial sector. Among these, BC Hydro found that behaviours relating to lighting showed the greatest potential for energy savings.

Table 63
Commercial Behavioural Measures

Space Heating and Cooling

- Adjusting heat up in summer
- Adjusting heat down in winter
- Using shades/blinds in summer
- Using shades/blinds in winter
- Using natural ventilation
- Keeping doors closed

Lighting

- Making use of daylighting
- Turning off task lights when not in use
- Using task lights instead of ambient lighting
- Reducing or eliminating unnecessary lighting

Refrigeration and Freezers

- Maintaining proper temperature

Plug Loads

- Activating power management features
- Shutting off PC and monitor when not in use
- Shutting off monitor when not in use
- Switching off computer power bar when not in use
- Shutting off idle equipment

Whole Building

- Taking stairs rather than the elevator
- Changing hours of activity

BC Hydro found that approximately 11 percent of energy could be saved through behavioural measures among the residential sector and 3.8 percent of energy in the commercial sector. The percentage of savings assumes base load prior to any DSM implementation or additional programs.

Clotheslines are another behaviour measure that might save clothes drying energy consumption for FortisBC customers during warm months. This measure was not specifically included in the potential estimates; however, the Ontario Power Authority quantified clothesline savings at 225 kWh per year at a cost of approximately $85 and a life of 10 years. Using these cost and savings data, clotheslines are cost-effective using the TRC test.

FortisBC Results

Results of a similar analysis for FortisBC, using data obtained from the BC Hydro 2006 study, show a potential savings of 12 percent of base load in the residential sector and 5.3 percent of base load in the commercial sector from behavioural measures (Tables 64 and 65).

Table 64
Behavioural Programs - Residential Energy Savings
Unbundled Technical Potential

	Base Year Consumption *(GWh/yr)*	**Behaviour Measure**	**Unused Energy Services** *(% of Base Year)*	**Unbundled Potential** *(GWh/yr)*
Space Heating	370	Temperature setback - over night	3%	10
	370	Temperature setback - daytime	2%	7
	370	Heat only occupied parts of house	1%	3
	370	Maintain weatherproofing	2%	8
	370	Install storm windows	1%	4
		Sub-Total	9%	33
Air Conditioning	123	Close windows and blinds	4%	5
	123	Increase temperature 3 deg. C	10%	12
		Sub-Total	14%	17
Lighting	234	Low wattage incandescent bulbs	2%	5
	234	Only necessary outdoor lighting	2%	5
	234	Turn off lights when no one in room	10%	23
		Sub-Total	14%	33
DHW	168	Turn off DHW when on vacation	1%	1
	168	Reduce temperature of DHW	1%	2
	168	Minimize hot and warm wash	27%	45
		Sub-Total	29%	48
Refrigeration	112	Maintain proper refrigerator temp.	3%	4
	62	Maintain proper freezer temp.	3%	2
	62	Defrost freezer more frequently	1%	1
		Sub-Total	10%	6
Appliances	6	Air dry dishes in dishwasher	18%	1
	88	Use sensor for clothes dryer	1%	1
	0	Brick chargers	3%	0
		Sub-Total	2%	2
Computers	118	Activate power management	29%	34
	118	Shut off PC and monitor	6%	7
	118	Shut off monitor	3%	3
		Sub-Total	37%	44
TV & Entertainment	62	Turn off TV when no-one watching	15%	9
	62	Unplug TV regularly	19%	12
	62	Unplug TV when on vacation	1%	1
	9	Unplug stereo regularly	31%	3
	9	Unplug stereo when on vacation	2%	0
		Sub-Total	35%	25
Residential Total	**1,720**		**12%**	**207**

Table 65
Behavioural Programs - Commercial Energy Savings
Unbundled Technical Potential

	Base Year Consumption *(GWh/yr)*	**Behaviour Measure**	**Unused Energy Services** *(% of Base Year)*	**Unbundled Potential** *(GWh/yr)*
Lighting	374	Make use of daylighting	2.3%	8.6
	374	Turn off task lights	0.4%	1.5
	374	Use task instead of ambient light	3.8%	14.2
	374	Reduce unnecessary lights	0.8%	3.0
		Sub-Total:	7.3%	27.3
HVAC	69	Adjust heat up in summer	0.6%	0.4
	145	Adjust heat down in winter	0.7%	1.0
	69	Use shades/blinds - summer	1.1%	0.8
	145	Use shades/blinds - winter	1.6%	2.3
	69	Use natural ventilation - summer	4.4%	3.0
	145	Keep doors closed - winter	1.1%	1.6
	69	Keep doors closed - summer	0.4%	0.3
		Sub-Total	4.4%	9.4
Plug Loads	34	Activate Power Management	44.7%	15.3
	34	Turn off PC and monitor	4.3%	1.5
	34	Turn off monitor only	1.4%	0.5
		Sub-Total	50.4%	17.2
Whole Building	89	Refrigerator	0.6%	0.5
	3	Elevator	0.9%	0.0
		Sub-Total	0.6%	0.6
Commercial Total	**1,033**		**5.3%**	**54.5**
Commercial and Residential Unbundled Total Technical Potential				**262**

Achievable Potential

The technical potential for behavior measures is significant. However, when the achievability factors are applied the potential is reduced to fewer than 50 percent of the technical potential. The BC Hydro 2007 Conservation Potential Review included detailed surveys and analysis of behavior achievability factors. Table 66 shows the achievability rates and subsequent achievable potential by sector.

Table 66
Behavioural Programs Achievable Potential (Unbundled)

	Technical Potential, GWh	Achievable Percent	Achievable Potential, GWh
Residential	207	40%	82
Commercial	54	63%	34
Total	262		116

Programs

While utility pilot program results are limited, several recent programs examples will help illustrate the potential energy savings of these approaches:

- Hydro One and NSTAR installed PowerCost Monitor devices. The average savings resulting from these units in addition to findings from in-home display studies in both Nevada and Florida, suggest that average savings of 3% to 7% with a midpoint of around 5% are likely to be achieved for participants of these kinds of direct feedback programs. It is important to note, these programs did not make use of a control group. These savings were achieved with a motivated population.

- Electricity use reports developed by Positive Energy (rebranded OPower Inc.) offer neighbour comparisons to help motivate SMUD's customers (Sacramento Municipal Utility District) to make changes to energy use, lowering demand by 2% in a broad non-targeted population. The concept of this program is that individuals are motivated by their perceptions of what other people do and find acceptable.

  Connexus Energy is wrapping up a 12 month pilot program for 40,000 customers, reporting a two to three percent reduction in energy consumption. The utility is pleased with the results and intends to continue the program for the next several years. About two percent have opted out of the program.

  Xcel Energy Inc. is currently implementing a three year pilot study targeting 35,000 gas and electric customers. The reports are mailed to customers and compare a customer's combined electric and gas use from the previous month to 100 neighbours in similar-size homes. The report provides a second comparison against the most efficient neighbours. Each household is provided a ranking among the 100 neighbours with those in the top 20 receiving positive feedback.

- BC Hydro has found the use of personal commitments, incentives, and online information tools to be an effective means to drive behavior changes. The utility has enrolled more than 60,000 customers in the first few months of this effort.

Costs

Cost data for behavioural programs is limited and unreliable. However a couple cost points were identified from early results of pilot programs. These costs range from $0.03 per first year-kWh for Positive Energy (OPower) programs (from SMUD) to $0.30 per first year-kWh for PowerCost monitor technologies. When levelized[21], these costs represent a range of approximately $20/MWh to $80/MWh, well under the cost-effectiveness limit. Another cost consideration is the life of these programs. It may become increasingly costly to continually make programs such as Positive Energy new and exciting as time passes and customers tire of participating. Because costs are uncertain, a range of cost estimates are included for FortisBC behavioural program potential. These 20-year total costs are provided in Table 67 below. If the potential were distributed evenly over the planning period, this would represent an annual cost range of $147,000 to $2 million.

Table 67
Behavioural Potential Total Cost Estimates

	Potential, GWh	Low Cost Estimate	High Cost Estimate
Residential	82	$2,460,000	$24,600,000
Commercial	34	$1,020,000	$16,345,485
Total	116	$3,480,000	$40,945,485

Summary

The pilot programs described above will provide important cost data for future behavioural program analyses. Overall, the above analysis concludes that FortisBC could save approximately 116 GWh in the residential and commercial sectors through behavioural programs.

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[21] Assuming a discount rate of 5% and 2 and 4 year measure lives, respectively

Conservation and Risk

Conservation resources have generally been known as low-risk resources. The risks that apply to energy efficiency resources are those associated with utility investment in capital that is not owned or maintained by the utility. "Risk" in terms of energy efficiency refers to the likelihood that the predicted savings will be achieved over the life of the measure. Risk components of conservation resources include:

1. Failure of measure before end of useful life
2. Removal or early replacement
3. Actual energy savings are less than estimated

Risks 1 and 2 above are often considered when evaluating measure savings. In the Northwest US, the Northwest Power and Conservation Council discounts measure savings to account for early removal, failure, or modified use patterns. In addition, risk premiums may be added to measure costs when evaluating cost-effectiveness from a total resource cost perspective. Programs that are mature and are based on trusted technologies present the least amount of risk while programs based on emerging technologies present significantly greater risk.

Risk 3 above is an issue of contention in many areas. Actual savings values vary across house types, climate, and interactions with other measures. Savings estimates for CFLs are a good example of how different regions or planning agencies assign savings values for energy efficiency measures. Based on a dated (2004) M&E report, FortisBC's assigns an nominal savings value of 87 kWh for a CFL in their service territory. On the other hand, BC Hydro uses a savings value of 63 kWh per year. Lastly, the Bonneville Power Administration (BPA) currently gives a credit of 33 kWh per CFL to their wholesale customers. The 33 kWh per CFL value includes factors for take-back, space conditioning interaction, and removal. All three of these entities are located in similar climate zones with similar housing characteristics and yet the savings value for CFLs varies from 33 to 87 kWh per year. In order to address this risk, the more conservative savings values are used in this study.

Energy efficiency resources are generally viewed as risk mitigation strategies rather than viewed for their inherent risk. Energy efficiency resources are used to mitigate risks such as increasing generation or power purchase costs, limited transmission and distribution systems, fuel price volatility, and increasing costs due to possible climate change legislation. Energy efficiency is a clean, localized resource strategy that reduces a utility's dependence on fossil fuels, transmission resources, and costly new resources or market power price variations.

Combined CDM Potential Summary

Table 68 summarizes the energy efficiency savings potential for all sectors. The savings estimates below are for program achievable potential (savings from codes and standards are excluded). Also, savings from fuel switching measures, behavioural measures, and customer-owned renewable projects are reported separately in subsequent tables. Through energy efficiency measures, FortisBC can expect to meet 14.7 percent of the forecasted 2030 load. These estimates indicate that, given the load forecast assumptions, FortisBC could meet 59 percent of load growth with program achievable potential energy efficiency resources across all sectors.

Table 68
Comparison End-Use Forecast with Energy Efficiency Potential Estimates

	2008 Base Year Consumption (GWh)	2030 Forecast Consumption (GWh)	Energy Efficiency Program Achievable Potential (GWh)	% of 2030 Load
Residential	1,720	2,247	369	16.4%
Commercial	1,033	1,456	173	11.9%
Industrial	207	207	28	13.4%
Lighting	14	14	4	28.8%
Irrigation	52	52	11	20.8%
Total	3,026	3,976	585	14.7%

Table 69 illustrates energy efficiency potential summarized above in five-year increments. Note that street lighting potential is included in the commercial sector potential

Table 69
Program Achievable Potential, MWh

	2011	2015	2020	2025	2030
Residential	19	94	192	281	369
Commercial(1)	10	53	107	142	177
Industrial	1	8	18	23	28
Irrigation	1	3	5	8	11
Total	**30**	**158**	**322**	**453**	**585**

(1) Includes street lighting potential

Figure 51 illustrates the potential given in the tables above. The majority of the potential is from the residential sector, which is not surprising since residential customers consume 57 percent of total load.

Figure 51
Summary of Energy Efficiency Potential 20-Year Program Achievable Potential

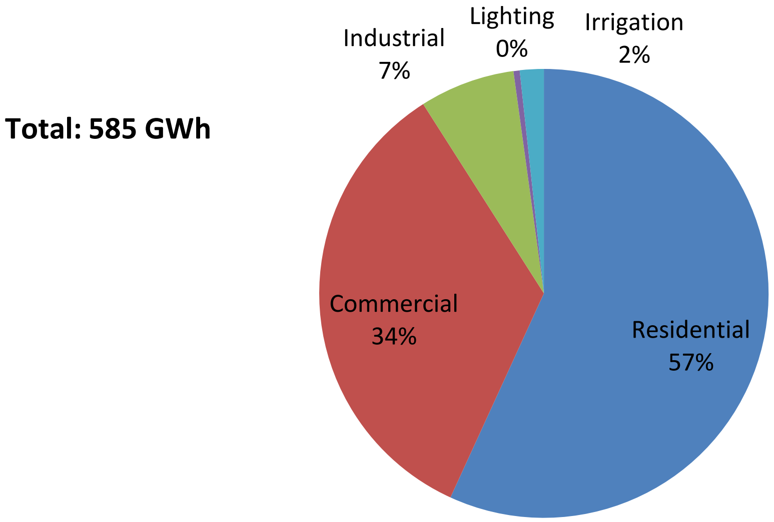
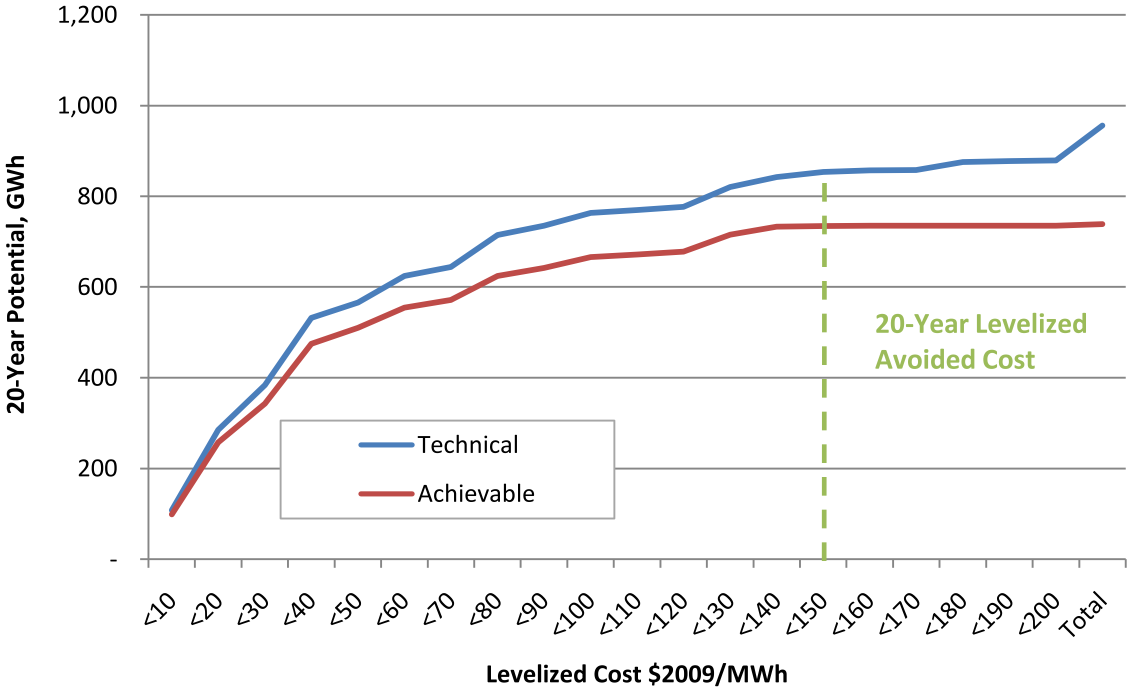


Figure 52 illustrates the supply curve for energy efficiency potential across all sectors.

Figure 52
Energy Efficiency Supply Curve – All Sectors



Demand savings potential is summarized in Table 70 below. Peak demand savings from energy efficiency measures and demand response measures are separated. Overall, approximately 16.2 percent of 2030 winter peak demand can be saved through a combination of energy efficiency and demand response programs.

Table 70
Total Demand Savings Potential, MW

	Energy Efficiency	Demand Response	Total
Winter	124	35	159
Summer	81	30	111

FortisBC Naturally Occurring Conservation

Naturally occurring conservation refers to the amount of conservation that would be achieved in absence of utility programs. This includes:

1. Efficiency gains from the turnover of older equipment to current standard equipment (with higher efficiency);
2. The adoption of high-efficiency equipment due to natural market forces; and
3. Market effects that include national or provincial government programs, past utility programs or marketing efforts, or equipment vendor efforts.

With regard to the FortisBC conservation potential assessment, the amount of naturally occurring conservation is accounted for in two ways. The first is in the load forecast. Since the end-use load forecast was calibrated to the system forecast, in includes a basic level of naturally occurring conservation, based on past experience. Second, some of the energy efficiency measure savings values are adjusted for market saturation and turnover rates for equipment that is naturally replaced over the planning period.

While it is difficult to quantify naturally occurring conservation, a few organizations have attempted it. The published data indicate that a range of between 6 and 10 percent of achievable potential is naturally occurring. For FortisBC, this amounts to approximately 1.2 percent of 2030 load.

Given the assumption that naturally occurring conservation is 1.2 percent of 2030 load, FortisBC might expect to meet 56.5 percent of load growth with DSM resources through 2030.[22]

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[22] Naturally occurring conservation = 1.2 percent of 2030 load = 48 GWh. Load Growth = 950 GWh. Program achievable conservation potential = 585 GWh. Percent of load met with utility program conservation = (585-48)/950 = 56.5%

Behavioural Measure Scenarios

The table below summarizes different levels of program planning to achieve behavioural potential. The scenarios are developed based on average behavioural measure costs and the percent of annual DSM budget allocated to those programs. Budget percents are 2.5, 5, and 10 percent for the low, medium, and high scenarios respectively.

Table 71
Behavioural Measure Scenarios

	Savings			Costs	
Behavioural	**MWh**	**Winter MW**	**Summer MW**	**Annual Cost**	**First Year $/kWh**
Low	497	0.00	0.00	$82,016	$0.17
Medium	2,175	0.00	0.00	$358,799	$0.17
High	10,678	0.00	0.00	$1,761,897	$0.17

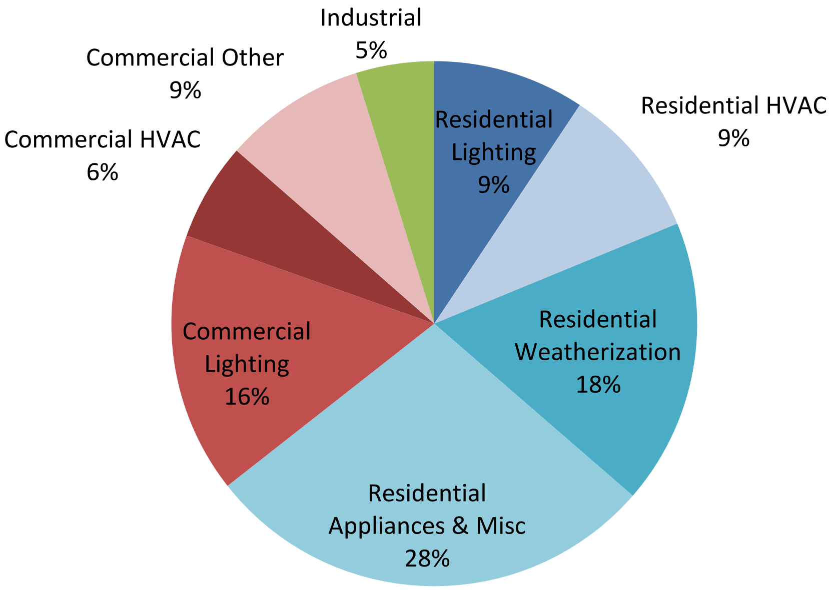
Program Implications

This conservation and demand potential assessment provides information and data for resource planning. In addition, the results can assist with DSM planning efforts. This section highlights some of the DSM program opportunities available to FortisBC

Energy Efficiency

The overall approach to energy efficiency in the FortisBC service territory can be assisted by looking at the significant categories of energy efficiency. Figure 59 summarizes the energy efficiency potential by major categories across all sectors. Over half of the energy efficiency potential is in the residential sector and only a small portion (5 percent) in the industrial sector, with the remaining 31 percent is in the commercial sector.

Figure 53
Energy Efficiency Achievable Potential Summary



Residential

Residential Weatherization

Windows, insulation and air sealing measures make up the largest category in the residential sector. These are traditional utility programs and should continue. The end-use survey indicated there are plenty of un-weatherized homes in the service territory.

Residential Lighting

There is still time to acquire significant savings through lighting programs before code changes dictate efficient lighting beginning in 2012. After 2012, savings potential will be achieved under codes and standards rather than utility programs. Standard (spiral) CFLs phased out at the end of 2009. Only specialty CFLs (3-way, dimmable, reflector) types are now eligible for incentive. After 2012, new lighting measures will be available that will focus on CFL specialty bulbs not included in the new standard and LED applications.

Residential HVAC (Heat Pumps)

Heat pumps should also continue to be part of a future program. All electrically heated homes without heat pumps are prime targets for this measure. Even homes with older heat pumps could benefit from a heat pump upgrade. Included in the potential estimates are the ductless heat pumps which are recently being introduced into the North American market. These heat pumps appear to be an excellent choice for homes with existing baseboard heat, and may be good applications for manufactured homes, condos, and row houses.

Residential Water Heating and Appliances

Electric water heating upgrades for electric water heaters continues to be strong measure. Low flow showerheads are another measure that is program-ready. Also included in this study are heat pump water heaters. While this technology has tried and failed in the past, there is renewed interest and numerous pilot studies and research projects are underway with this technology. Three major brands, including GE, have launched HPWH product lines in the past year. FortisBC should strongly consider initiating a pilot program with this technology.

The appliance category includes conservation measures such as Energy Star refrigerators, refrigerator and freezer recycling (decommissioning), efficient clothes washers, and dishwashers. Most of these measures have a relatively low savings per unit, but also offer low-cost incentive opportunities. Aligning with the Energy Star brand is also beneficial to overall consumer education and program marketing.

Commercial

Commercial Lighting

Commercial lighting is a significant portion of the conservation potential representing approximately 19% of the total potential. This category represents a huge number of individual measures and options depending on the building type and lighting technology. FortisBC may wish to streamline commercial lighting projects by developing a program for specific applications such as small office or retail. A significant portion of commercial sector conservation potential is in lighting upgrades and previous efforts have not exhausted these resources. Some utilities find that residential CFL lighting spills over to commercial applications. Allowing for the spillover increases measure saturation though creates difficulty in tracking program effectiveness.

Commercial HVAC

The HVAC category includes variable speed chillers, premium rooftop HVAC systems, HVAC controls, ECM on VAV boxes, packaged roof top optimization and repair, and integrated building design (new construction).

Commercial Other

Grocery store refrigeration measures, computer and office equipment, and stand-alone commercial refrigerators and freezers are part of the other commercial potential.

Industrial

The industrial sector requires personal connections with the large industrial customers resulting in custom energy efficiency projects.

Demand Response

Control Space Heating

Peak demand can be controlled in part through controlling space heating equipment. A variety of measures were analyzed in this report. A comprehensive program could include several options for heating system control:

- *Central Heating Controls*- Central heating can be controlled through one or two-way devices. Through the implementation of smart meters, heating system control becomes relatively easy to accomplish.
- *Zonal Heating Controls*- Switch-based units are control devices installed directly on zonal heating equipment or circuits. These devices do not require meter infrastructure and could be used in areas where the smart meters are not installed.
- *Thermal Storage* - Central thermal storage units require significant investment for purchase and installation of equipment. Room-based thermal storage units are similar in savings and life to central systems, but require several smaller units. A typical house would need four units. Cost is slightly higher and units are generally applicable situations where baseboard heating would be avoided.

Water Heating

Electric water heaters can be curtailed using 1-way switches. Heating elements are cycled or turned off during peak curtailment periods by grid operators. This is a reliable method for peak reduction representing approximately a 0.4 kW per unit savings. Water heater use is similar year round and does not respond dramatically to outside temperature.

Air Condition Control - Cooling

Technology for summer cooling curtailments is similar to central heating thermostats for winter heating. The central thermostat controls setbacks and cycling of central AC units based on curtailment commands from utility operators. A program that implements this measure could be helpful in offsetting FortisBC's growing summer peak.

Other DLC Measures

Other DLC measures include non-essential lighting and pool/spa heating and could be implemented in addition to other programs. For the commercial sector, controlling non-essential lighting could result in significant peak reductions.

Summary

Through their energy efficiency program efforts, FortisBC plans to meet at least 50 percent of forecasted load growth through 2020 with demand-side resources. In order to achieve this goal, FortisBC must reduce forecasted load growth (553 GWh/year) by 277 GWh/year. FortisBC is well on their way to meeting this goal. From 2006 through 2008, average annual energy efficiency achievement was an additional 26 GWh per year. Projecting these savings over the next 10 years would save a total of 263 GWh/year. The potential study shows that 318 GWh of program achievable potential is available to FortisBC by 2020. With the addition of program measures such as ductless heat pumps, Energy Star® appliances, and streamlined program design for commercial lighting, FortisBC is on track to meet 50 percent of load growth with DSM through 2020. This program achievable potential is based on current codes and standards in place and known to be implemented during the study period. The Provincial and Federal governments are on track to accelerate the adoption of energy efficiency codes and standards. As these codes and standards are adopted, a larger portion of the achievable savings would realized through this avenue.

In addition to utility programs, Fortis BC will continue to promote Province-wide programs such as LiveSmartBC, investigate demand response programs, time-of-use rates, behavioural programs, and emerging technologies.

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Appendix A – Codes and Standards

A significant number of new code changes have been enacted between 2008 and 2010 for both residential and commercial buildings. The code changes that take effect after 2010 impact the portion of the potential that will be achieved through programs. For residential, significant energy efficiency will be achieved through the General Service Lamps code change in 2012 which will effectively require most light bulbs to have the efficiency of a CFL or better. In addition, it is expected that new efficiency standards will significantly impact consumer electronics, including televisions and standby power equipment. Other near-term residential code impacts include furnace fan motors and room and portable air conditioners.

The known residential code changes expected to occur during the 2011 – 2030 timeframe will result in an estimated 121 GWh of energy efficiency. The Province of British Columbia or the Federal government may adopt more aggressive energy efficiency codes and standards, in which case more of the achievable savings potential would be attributed to code changes. See Table A1 for current code details.

Table A1
Residential Code Changes (National and BC)

End-Use Technology	New Code Effective Date
Recent Changes	
Ceiling Fans	2008
Refrigerators and Freezers	2008
Windows	2009
Building Code	2010
Clothes Washers	2010
Dishwashers	2010
Electric Storage Water Heaters	2010
Residential Dishwashers	2010
Torchieres	2010
Near-Term Changes	
Lighting (General Service Lamps)	January 1, 2012 (high lumen) December 31, 2012 (low lumen)
General Service Electric Motors	January 1, 2011
Room and Portable Air Conditioners	January 1, 2011
Small Motors (Furnace Fans)	January 1, 2011
Consumer Electronics, Including Standby Power	January 1, 2011 (for standby) TBD for TVs, etc.

For the Commercial sector, recent changes have been made to codes impacting commercial clothes washers, ice-cube makers, and large motors. In the near term, changes will impact HID lamps and ballasts, large air conditioners, and package terminal air conditioners.

The commercial code changed expected to occur during the 2011 – 2030 timeframe will result in an estimated 26 GWh of energy efficiency. See Table A2 below for code change details.

Table A2
Commercial Code Changes (National and BC)

End-Use Technology	New Code Effective Date
Recent Changes	
Commercial Clothes Washers	2008
Ice-Cube Makers	2008
Large Motors	2010
Near-Term Changes	
HID Lamps and Ballasts	2012
Large Air Conditioners	2012
Package Terminal Air Conditioners	2012

Appendix B – Cost-Effectiveness in British Columbia

Introduction

The British Columbia Ministry of Energy, Mines and Petroleum Resources (“Ministry”) amended the Public Utilities Commission Act (Bill 15-2008) to require public utilities to estimate cost-effective demand side resources (DSM) as part of their long term resource plan and to provide a plan to acquire those resources as a first priority over supply-side options. This memo summarizes how the Ministry expects utilities to estimate cost-effectiveness.

Long-Term Resource Plan

Section 44.1, Long-term resource and conservation planning, of the Public Utilities Act[23] requires that a public utility’s Long-Term Resource Plan (LTAP) must include all 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; and
>
> (g) any other information required by the commission.

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[23] Utilities Commission Act [RSBC 1996] Chapter 473. Current to September 9, 2009 available online at: http://www.bclaws.ca/Recon/document/freeside/--%20U%20--/Utilities%20Commission%20Act%20%20RSBC%201996%20%20c.%20473/00_96473_01.xml#section44.1

Demand-Side Resources

Cost-effective measures to be examined include rate, measure, action or program measures. The DSM evaluations must be approved by the British Columbia Utilities Commission (BCUC). In order for the BCUC to consider a portfolio of DSM programs complete, that portfolio must include:

- *Low-Income Programs* – Low-income households are defined by Statistics Canada's Low-Income Cut-Offs (LICO) for a particular year
- *Rental Programs* – Programs may target either tenant and or landlord. The focus must be on the accommodation rather than the residents (emphasis on technology).
- *Education Programs* – Includes funding of the development of education program regarding energy efficiency and conservation.
- *Post-Secondary Programs* – Includes funding of programs such as the integration of energy efficiency into a business or MBA program curriculum and trades training.

Cost-Effectiveness

The cost effectiveness of each measure may be calculated either at the individual level, in a bundle with other measures, or at a portfolio level.

Low-Income

Low income DSM programs have additional benefits that are not accounted for in energy savings such as fewer shutoff/reconnect costs, fewer rearranges, and less bad debt to be written off. Therefore, 30 percent in additional benefit is to be added to low income program measure cost-effectiveness tests.

Specified DSM and Technology Innovation

- Specified DSM includes the following measures:
  - Education
  - Funding energy efficiency training for manufacturers, sellers, installation tradesmen, brokers, managers of energy efficiency products and buildings.
  - Community engagement programs that assist, cooperate or directly increase stakeholders' awareness of energy efficiency. Stakeholders include first nation, government, or non-profit groups.
- Technology innovation programs including market transformation.

These measures will be evaluated in a group with other measures or as a portfolio to help support the expenditures. The reasoning behind the grouping of measures for the purpose of cost-effectiveness tests is that these measures are supportive and long term rather than immediate or standalone.

Total Resource Cost

Avoided Cost

Bulk electricity purchasers from BC Hydro must use BC Hydro's long-term marginal cost rather than the purchase price of power. This avoided cost requirement for bulk purchasers increases the amount of DSM that is cost-effective.

Summary

It appears the British Columbia does not require specific total resource costs and benefits be included in the benefit-cost analysis. In their 2007 study, BC Hydro uses avoided transmission and avoided power costs to evaluate measure cost-effectiveness. BC Hydro escalated their avoided power costs (energy) by 50%. Measure costs are either full or incremental capital costs.

Appendix C – Cost-Effectiveness Tests

Two general screening methods can be used to rank demand and supply options. These are benefit-to-cost ratios and levelized cost. A benefit-to-cost ratio divides resource benefits by resource costs to calculate a ratio. If the ratio is greater than one, the resource is cost-effective; if the ratio is less than one, the resource is not. Levelized costs sum the fixed and variable costs of a resource over its life, taking into account the time value of money, and divide them by the associated output or savings. A cost per unit of output or savings is developed and is usually expressed in a constant dollar year. This levelized cost can then be compared with a fixed generating resource or power contract to determine cost effectiveness.

Several different economic tests are available for evaluating resource options. All of the tests incorporate benefit-to-cost analyses. However, the perspective from which the costs and benefits are evaluated differs among the tests. The five tests are the total resource cost (TRC) test, ratepayer impact measure (RIM) test, participant test, utility cost test, and societal test. The tests are used primarily to evaluate DSM resources.

In the Northwest, the Council uses the TRC as the primary cost test to determine cost effectiveness of DSM options. Using the TRC benefit cost ratio, all DSM measures can be compared with available supply resources. Other tests can then be applied to determine the cost effectiveness from the various perspectives (e.g., utility, ratepayer).

Cost and Benefit Components

Changes in Supply Costs. One of the main benefits of a DSM option is its associated reduction in supply costs. This can occur as a result of a decrease in energy use or as a result of a shift of energy from a more expensive period to a less expensive period. The avoided supply cost is calculated by multiplying the reduction in total net generation by the marginal cost. If energy has been shifted instead of reduced, the resulting increase has to be included on the cost side. The changes in supply cost for periods where energy use increases are costs (increased supply cost), and the changes in supply costs for periods where energy use decreases are benefits (avoided supply cost).

Changes in Revenue and Bills. Another large effect of DSM programs is revenue reduction. Lost revenues are a cost to the utility and tend to increase rates on a per-unit basis. On the other hand, DSM program participants receive equivalent benefits, because their consumption is reduced.

Utility Costs. This category includes all costs of planning, implementing and evaluating a DSM program, except for incentives paid directly to the participant. Also included are those for marketing, administrative, equipment and program monitoring and evaluation.

Participant Costs and Avoided Participant Costs. Participant costs include all out-of-pocket expenses that a participant incurs as a result of participating in the program. These costs are calculated before the participant receives any rebate or incentive payment. If the participant avoids some cost by participating, it is considered a benefit to the participant.

Incentives and Participation Charges. Incentives are any dollar amount that the utility pays directly to the participant. These include rebates, bill reductions, rate discounts and below-market loans. The incentive that a utility pays a dealer or builder is a utility cost unless the incentive is passed through to the participants. A participation charge is the payment by the participant to the utility related to a DSM program.

Tax Credits and Payments by Third Parties. If the participant receives any tax credit for participating, it is accounted for in this benefit category. Any payment made to the participant by a non-utility source (e.g., a manufacturer's rebate) also falls under this account.

Externalities. This category includes any costs or benefits that are external to standard cost-accounting methods. Externalities include effects, both positive and negative, to society.

Overview of the Tests

This section briefly describes the five most commonly used cost-effectiveness tests. Each test represents a different perspective in determining the cost-effectiveness of a program.

Total Resource Cost Test. The TRC test is a measure of the total net expenditures of a DSM program from the perspective of the utility and its ratepayers. The benefits are avoided supply costs, net avoided participant costs and tax credits. The costs include increased supply, net participant costs and utility costs. Since the utility and its ratepayers are considered together by this method, transfer payments between the two are ignored. This test is a measure of the change in the average cost of energy services. The following formula explains the relationships within the TRC method.

$$B_{TRC} = \sum_{t=1}^{N} \frac{UAC_t + TC_t + PAC_t *}{(1+d)^{t-1}}$$

$$C_{TRC} = \sum_{t=1}^{N} \frac{UC_t + PC*_t + UIC_t}{(1+d)^{t-1}}$$

* Participant costs and participant avoided costs in this test are net of free riders.

Utility Cost Test. The utility cost test is a measure of the changes in total costs to the utility from a DSM program. It evaluates the DSM program from the perspective of a utility's total cost. The benefit component is avoided supply costs. The cost components are increased supply costs, incentives, and utility program costs. The test measures the change in the average energy bills across all customers.

The utility cost test is identical to the RIM test, except that the utility's revenue losses are not included as a cost input in the utility cost test, and revenue gains from increased sales are not included as a benefit. The following formula describes the utility cost test calculations.

$$B_{UC} = \sum_{t=1}^{N} \frac{UAC_t}{(1+d)^{t-1}}$$

$$C_{UC} = \sum_{t=1}^{N} \frac{UC_t + INC_t + UIC_t}{(1+d)^{t-1}}$$

Participant Test. The participant test measures the quantifiable benefits and costs to the customer as a result of program participation. Benefits include reductions in customers' utility bills, avoided customer costs, incentives and tax credits. Participant costs include any customer out-of-pocket expenses resulting from participation. The test is a measure for the average customer and ignores free riders. The participant test provides a good indication of the attractiveness of the program to the average non-free rider expected to participate. The participant test calculation is based on the calculation that follows.

$$B_p = \sum_{t=1}^{N} \frac{BR_t + TC_t + INC_t + PAC_t}{(1+d)^{t-1}}$$

$$C_p = \sum_{t=1}^{N} \frac{PC_t + BI_t}{(1+d)^{t-1}}$$

Societal Test. A common variation on the total resource cost test is the societal test. It measures the benefits and costs to all of society (i.e., including other utilities, government agencies, and citizens outside the jurisdiction). The societal test differs from the total resource cost test in three ways. First, a societal discount rate is used to place value on all future benefits and costs, reflecting society's low-risk view of future investments. Second, environmental externalities are included in the benefit-to-cost equations. Third, this test excludes tax credits because they are transfer payments within society. The mathematical equations for the societal test follow.

$$B_S = \sum_{t=1}^{N} \frac{UAC_t + PAC*_t + EB_t}{(1+s)^{t-1}}$$

$$C_S = \sum_{t=1}^{N} \frac{UC_t + PC*_t + UIC_t + EC_t}{(1+s)^{t-1}}$$

* Participant costs and participant avoided costs in this test are net of free riders.

Ratepayer Impact Measure Test. The ratepayer impact measure (RIM) test quantifies the impacts on customers' rates resulting from changing utility revenues and operating costs. It assumes that DSM reduces utility revenues and increases costs and that customer rates must be increased to balance the utility's books.

Benefits considered by the RIM test are avoided supply costs and revenue gains. Costs for the RIM test are increased supply costs, utility program administration, incentives and reduced revenues from energy savings. The calculation of the RIM test is as follows.

$$B_{RIM} = \sum_{t=1}^{N} \frac{UAC_t + RG_t}{(1+r)^{t-1}}$$

$$C_{RIM} = \sum_{t=1}^{N} \frac{UIC_t + RL_t + UC_t + INC_t}{(1+r)^{t-1}}$$

Glossary of Symbols

B_P	Benefit to participants (participants test)
B_{RIM}	Benefits to rate levels or customer bills (ratepayer impact measure test)
BI_t	Bill increases in year t
BR_t	Bill reduction in year t
B_S	Benefits of the program (societal test)
B_{TRC}	Benefits of the program (total resource cost test)
B_{UC}	Benefits of the program (utility cost test)
C_P	Costs to participants (participants test)
C_{RIM}	Costs to rate levels or customer bills (ratepayer impact measure test)
C_S	Cost of the program (societal test)
C_{TRC}	Costs of the program (total resource cost test)
C_{UC}	Costs of the program (utility cost test)
d	Discount rate
EB_t	External benefits to society due to the program in year t
EC_t	External costs to society due to the program in year t
INC_t	Incentives paid to the participant by the sponsoring utility in year t
PAC_t	Participant avoided costs in year t
PC_t	Participant costs in year t
r	Return on investment
RG_t	Revenue gains from increased sales in year t
RL_t	Revenue loss from reduced sales in year t
s	Societal discount rate
TC_t	Tax credits in year t
UAC_t	Utility avoided supply costs in year t
UC_t	Utility program costs in year t
UIC_t	Utility increased supply costs in year t

For additional information regarding these and other cost effectiveness test, refer to the California Standard Practice Manual.[24]

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[24] California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects. July 2002. http://drrc.lbl.gov/pubs/CA-SPManual-7-02.pdf

Appendix D – Ramp Rates

Table D-1
Ramp Rates

	Year																			
Ramp Type	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Electronics	0.3%	0.5%	1.0%	2.0%	3.0%	5.0%	5.8%	3.0%	1.0%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
HVAC- Code Change	4.0%	5.0%	6.0%	6.0%	5.5%	5.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	3.0%	2.0%	2.0%	2.0%
EnerGuide80	5.0%	5.0%	5.0%	5.0%	5.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
New Measure Medium	1%	2%	3%	4%	5%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%
New Lighting - Code Change	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
New Measure Fast	2%	4%	6%	8%	10%	10%	10%	10%	10%	10%	10%	10%	0%	0%	0%	0%	0%	0%	0%	0%
New Lighting - Program	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	2.0%	1.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
20YearEven	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
EnerGuide90	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
12YearEven	8.3%	8.3%	8.3%	8.3%	8.3%	8.3%	8.3%	8.3%	8.3%	8.3%	8.3%	8.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
CFL Code Change	10%	10.0%	8.0%	6.0%	3.0%	2.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
10YearEven	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
10YearEven, CC 2014	10.0%	10.0%	10.0%	10.0%	10.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2011 Code Change	10.0%	10.0%	10.0%	8.0%	6.0%	4.0%	2.0%	2.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
5YearEven	20.0%	20.0%	20.0%	20.0%	20.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Appendix E – Direct Load Control Case Studies

The pilot programs surveyed for the FortisBC study differ but seem to agree on several key points. First, load control must be carefully planned to coincide with peak demand, otherwise, any demand reduction will not reduce a utility's coincident peak demand. This may seem obvious, but different service territories and climates have different peak periods and can benefit from different load control schedules.

Second, technology is evolving rapidly. These changes present challenges when applying numbers from one utility's potential or pilot study to another area difficult. There are areas of overlap, but understanding exactly the technology used is essential.

Third, customer willingness to participate and remain in load control programs is as important as the technology itself. Retaining participants requires providing feedback to consumers and understanding if they are comfortable with the curtailments. If work is not done to secure participants, customers will drop out of the programs causing estimates of load reduction potential to be inaccurate. An overview of two prominent programs follows.

Direct load control programs can cycle many household appliances and space conditioning units. Most pilot programs have used control devices on several components of residential load. The logic being: if you spend the money to install the infrastructure, it should control all large components of load. Table E1 lists potential energy savings for different components.

Table E1
Potential Load Reduction by End-Use

End Use Load	Average Load Reduction per Event (KW)
Water Heater	0.6 (Winter)
Heat Pump Strip Heat	1.02 (Winter)
Forced Air Strip Heat	0.85 (Winter)
Electric Forced Air Cooling	0.78 (Summer)

Source: Goodwatts and Power Shift

Goodwatts

There are several pilot programs in the Northwest, but the GoodWatts Program is an especially pertinent case study that highlights several key findings and program design. The GoodWatts Program was a demand response pilot program initiated in 2005 and 2006 in Ashland, Oregon. The program was supported by the Bonneville Power Administration. Ninety-two residential customers of Ashland Electric had 2-way communicating meters, programmable thermostats, load control meters for pool pumps and water heaters, and communication technology placed in their home to send signals of curtailment in controlled appliances on event days during the summer and winter periods. Curtailment events were called during the summer periods of 2005 and 2006 (June – September) and the winter 2005 and 2006 (January – March).

Unlike weather-related energy use, the water heater system daily load profile is consistent throughout the year with usage peak between 6:15 a.m. and 8:15 a.m., and a second, but less pronounced peak, between 5:00 p.m. and 7:00 p.m. (Figure 5).

Total residential use, conversely, tends to have a morning peak in the winter (Figure 5) and late afternoon/early evening peak in the summer (Figure 6).

Figure E1
Daily Winter Load

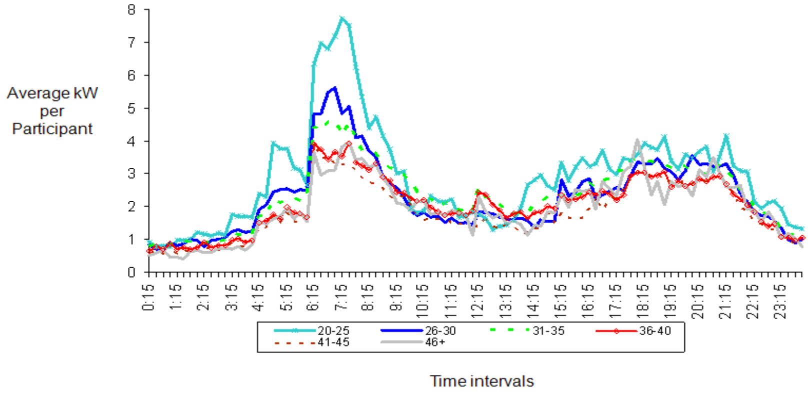
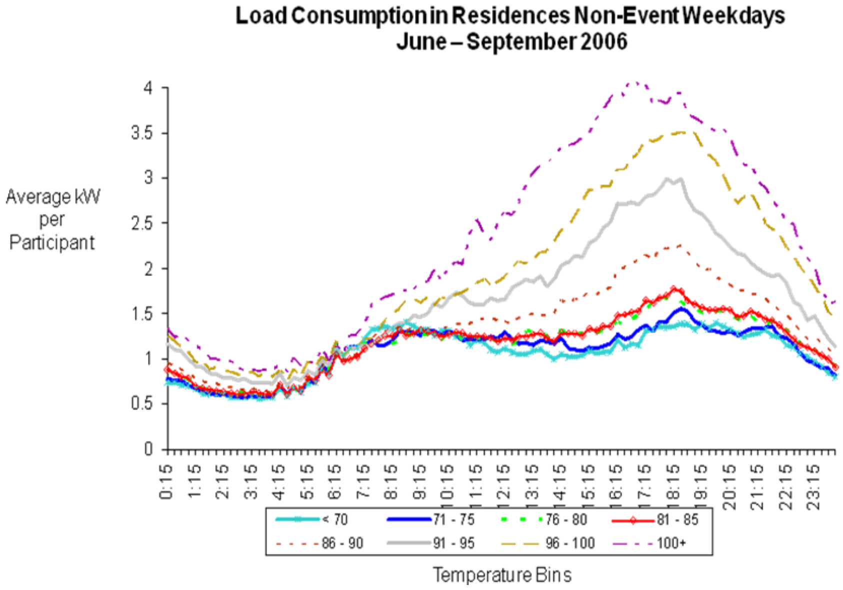


Figure E2
Daily Summer Load

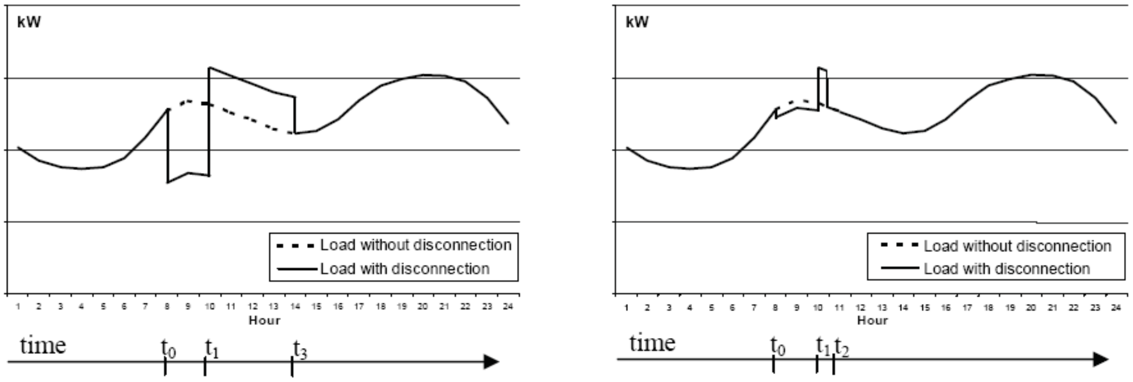


For hot water heater curtailments, load drop is highest when coincident with system peak – as more appliances are in use during that period. Therefore, for winter events where system peak is 6:15 a.m. to 8:30 a.m., curtailing water heaters resulted in observed in load drop of up to 15% on days colder than 30°F (6% on other days). Additionally, GoodWatts results suggest that events duration should be around 2 hours.

The potential savings are also affected by the households targeted for control devices. Figure 7 shows hypothetical household energy consumption from a Norway study. Group (a) is high demand users while Group (b) is low demand users. It is assumed that hot water tanks are the same size across all users. The white area in the bar graphs is the time period where the water heater recovers after use given no interruption. It is assumed that water heaters begin recovery the same instant the hot water is being drawn. The black area, or payback area, is the recovery period given an interruption has occurred.

Figure E3 illustrates that after reconnection, low demand consumers experience a larger peak than otherwise would have occurred. High-demand consumers produce flatter, longer peaks after reconnection occurs.

Figure E3
Water Heater Demand Example



(a) **(b)**

Source: Ericson, Torgeir. "Direct Load Control of Residential Water Heaters." Discussion Papers No. 479, October 2006. Statistics Norway, Research Department.

These hypothetical load curves are based on consumers that do not anticipate disconnection. This also suggests that the timing of household water consumption is important in determining load shapes. Also, the duration of the disconnection will directly influence the payback demand.

Other Pilot Programs

GridWise

http://gridwise.pnl.gov/docs/pnnl_gridwiseoverview.pdf

The GridWise demonstration program addressed consumer behavior, price-responsive household technology, and dynamic electricity pricing in 112 homes on the Olympic Peninsula. The project combines real-time pricing, smart appliances that respond to pricing signals, and an internet-based event driven software. The average participating household saved 10 percent on their electricity bill over the 1 year period. The results of the Olympic Peninsula Project showed that if all customers were engaged at a similar level as test subjects, about $70 billion of new generation, transmission, and distribution could be avoided over 20 years.

East Kentucky Power Cooperative

http://www.psc.state.ky.us/pscscf/2007%20cases/2007-00553/psc_order_032008.pdf

The East Kentucky Power Cooperative (EKPC) implemented a direct load control demonstration program over a period of 12 months from October 2006 through September 2007. The program involved a total of 386 participants in two service territories. Over the 12 month period, water heater demand reduction averaged to 0.46 kW and 0.59 kW per appliance in the summer and winter months respectively. These appliances were controlled for the 4 hour period of on-peak use.

Norway

http://ideas.repec.org/p/ssb/dispap/479.html

In Norway, 475 households participated over the November 2003 through April 2004 period. The study interrupted water heater service in both morning and evening peaks hours, alternatively. The hour of interruption was varied. The results of the study found that between 0.6 and 0.58 kW per household in the morning hours can be saved while between 0.18 and 0.60 kW can be saved in the afternoon.

Portland General Electric

http://www.nwcouncil.org/energy/dr/library/dr_assessment.pdf

During a 37 day period in January and February 2003, Portland General Electric (PGE) collected data for their water heat direct load control project. The utility remotely turned off electric water heaters for 2 hours each weekday morning in 81 participant households. The average peak demand savings for these months was between 0.65 and 0.69 kW per water heater.

Louisville Gas & Electric

http://www.eon-us.com/rsc/lge/default.asp

GE has partnered with (LG&E) to initiate a new line of smart appliances that use wireless technology and energy conservation meters to help consumers save electricity. These appliances are paired up with smart electric meters that communicate with the appliance. For example, a washing machine may skip a wash cycle or a refrigerator may skip a defrost cycle during peak demand periods. GE plans to spend nearly $1 billion on marketing and development of smart appliances in the next 3 to 5 years. These appliances are expected to cost consumers 5 to 10 percent more than standard GE appliances. As more utilities implement advanced metering and tiered pricing, the market for smart appliances can expand.

Xcel Energy® - Boulder Smart Grid City™

http://smartgridcity.xcelenergy.com/index.asp

The plan is to install over $100 million worth of smart grid technology to improve reliability and cut costs for both consumers and the utility. The project includes direct load control among an expansive smart grid program that includes:

- Online tools for home energy use tracking, planning, and budgeting
- Real-time energy pricing or green power energy price signals allowing users to reduce energy costs or use more green energy
- Advanced smart meters that communicate with home appliances that provide opportunity for energy and cost savings

Appendix D

2012-14 MONITORING AND EVALUATION PLAN

FORTIS BC™

DSM Monitoring and Evaluation Plan 2012 through 2014

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Contents

1. Introduction

FortisBC and its predecessors have been implementing DSM programs since 1989, and as a part of their efforts to assess the energy and demand savings impact of these programs and to understand the effectiveness of the implementation and delivery processes, monitoring and evaluation (M&E) studies are undertaken on a periodic basis. Priorities for M&E studies are established based on: magnitude of energy savings reported, investment, level of perceived risk, and level of resources required for demonstrating due diligence.

As a result of the BC Energy Plan of 2007 and its target to offset 50% of load growth through DSM efforts by 2020, FortisBC has increased its DSM efforts as opportunities to save energy are increasing, given a trend to higher avoided costs for new electricity purchases, and new cost-effective opportunities to reduce energy consumption. Public consultation conducted in early 2010 suggests that stakeholders would support increased levels of spending on DSM, and so new and enhanced programs are being developed and are being unveiled in F2011.

The portfolio of **PowerSense** programs is designed to acquire direct energy efficiency (energy and demand) savings, as well as to accelerate the adoption of energy efficient technologies and practices and to affect Market Transformation. FortisBC also participates with the Canadian Standards Association (CSA) and other electrical utilities across Canada in the development of energy performance standards which support the enactment of Federal and Provincial energy efficiency regulations.

In 2011 FortisBC is enhancing the majority of its programs and is adding new elements to its portfolio. A new initiative which commenced in 2009 is an effort to promote a conservation culture through behavioural change by way of community engagement and information and awareness activities. New methodologies will be required to evaluate the benefits from these activities.

This M&E plan covers the three-year period ending December 2014 and will cover programs that have been operational since 2009, and new programs introduced in 2011. This M&E Plan identifies the objectives and primary issues to be researched and addressed in the various types of studies. It does not provide details on all possible issues likely to arise when an M&E study is undertaken. It is intended to be flexible enough that methodologies or priorities can be modified as programs are approved and/or implemented and as new information becomes available.

M&E results will provide feedback to program staff, indicating how well the program is running, identifying areas where improvements are required, and make recommendations to management to support decision-making in the area of energy acquisition and energy management, and measuring the associated costs and benefits. Where the program offers vary significantly over time, the offer associated with the sample of most recent participants will be used for the M&E study as this will provide the greatest benefit for making enhancements going forward.

The smaller a DSM initiative is the greater the relative cost to conduct a full scale M&E study. Given the size of FortisBC and it DSM programs, the resources allocated to accomplish M&E studies is of the order of 5% of the total DSM investment and is sufficient to carry out effective M&E activities. FortisBC plans to conduct two full scale M&E studies annually in addition to three Mini Reviews. A full scale review would normally consist of a process, market and an impact study. The Mini Review consists of a Process study and some measurement and verification activities using a sample of projects.

1. Purpose and Objectives

Monitoring and evaluation (M&E) of energy efficiency programs provides internal and external accountability by reducing uncertainty in the estimates of energy and demand savings, and by determining the cost effectiveness of these programs compared to other energy resources. An M&E study of a DSM or energy efficiency program involves:

- Objective and systematic measurement of program operations and performance;
- Use of social-science (behaviour) and engineering data and methods;
- Verifying actual (achieved) energy and demand savings attributable to the program;
- Estimating permanent changes in the market penetration (Market Transformation) of energy efficient technologies attributable to the program; and
- Providing a basis for future decisions related to a program or portfolio of programs (modifies, expands, or discontinues).

2. Monitoring &Evaluation (M&E) studies

3.1 Types of M&E studies

- **Process studies** – how efficient and effective is program delivery? Objectives for process evaluations include improving program implementation, program delivery and the satisfaction of customers, trade allies and the utility through quality service delivery. Areas reviewed include incentive and rebate levels; communication and promotional initiatives; program operations and implementation; customer awareness and acceptance as a customer service (satisfaction) of energy efficient technologies and measures; and trade ally (distribution & implementation) awareness and acceptance.

- **Market studies** – how effective the program is at increasing the market penetration (market share) of energy efficient technologies and measures? Objectives for market evaluations include measuring increases in market penetration of energy efficient technologies and assessing the share of measures attributable to the program. Market effects often have a larger impact on the adoption rate of a product or technology than they receive credit for, and taking credit for this can often negate some of the free rider impacts. Areas reviewed include assessing market potential and market penetration over time through a review of the availability, accessibility and affordability of energy efficient technologies and measures.

- **Impact studies** – determine the magnitude of savings (change in energy consumption and or demand that are directly attributable to the program?) Objectives for impact studies include
    - measuring decreases in energy consumption/demand (gross savings);
    - estimating free-rider and spill-over (market) effects to determine net savings impacts
    - determining the cost effectiveness of the program relative to other energy/demand resource options

- **Pilot Studies -** Before the launch of system-wide programs, pilot projects are often run on a district or regional basis, or within a specific segment of the market. The purpose of the pilot is to learn more about the technology and the associated savings, and to learn about the program delivery issues in a low risk situation. A mini M&E study, consisting of a process study and an assessment of the energy and demand savings estimates, is completed after implementation of the pilot. The process study for the pilot cannot be as complete as one held twelve months or more after a program's implementation, but a good deal of information is obtained, including a preliminary check to determine the potential risks in the energy savings estimates, delivery effectiveness and consumer acceptance, thereby clarifying the requirements for the full impact study.

- **Behavioural Studies**
  Behavioural activities which are new to M&E planning at FortisBC will be evaluated by first documenting the objectives and strategies of the relevant program activities, developing the logic that links program activities to issues such as changes in behaviour, and using this information where practical, to estimate the energy savings that result from these behaviour changes.

  This will be accomplished by starting with the behaviour component of the 2009 Residential end-use survey and updating this with a baseline behaviour research study in 2011. The baseline survey will study attitudes and the associated energy efficiency behaviours linked to these program activities and future progress studies will assess the change in attitudes and associated behaviours. Metrics from the baseline study (similar to those adopted in the 2007 BC Hydro Conservation Potential Review) and the results of the progress studies will be used to assess the energy savings that can be attributed to these program activities. It must be noted that this M&E methodology is evolving and the best practice should be used when this M&E report is undertaken.

3.2 M&E Studies relationships

Impact studies measure the quantitative results of programs, the energy and demand effects, which are necessary for a traditional utility cost-effectiveness analysis. For DSM programs, the greatest uncertainty is in determining the actual load impact. This uncertainty occurs in three general areas:

- What would have occurred if there was no program?
- What load impact did the program induce?
- How long will the load impact persist?

The primary objective of the **PowerSense** programs is to increase the efficient use of electricity relative to what would have happened had there been no program. Therefore, for each program or end-use, a projection is required regarding the trends in efficiency improvements occurring naturally in the FortisBC service area. To measure what the customers would have done without the program, sometimes quasi-experimental design techniques are adapted from educational, agricultural, medical and social science research for use in DSM analysis.

Ideally, for these types of DSM studies, the quasi-experimental design involves pre and post measurement of the appropriate parameters with comparison group(s). This design includes measurement of the electricity consumption and demand before (baseline) and after program implementation for participants, which is compared to the electricity consumption and demand before (baseline) and after program implementation of a comparison group of non-participants, in the same time period. These types of studies are only applicable when a suitable comparison group can be found.

The change in consumption is compared to the estimated or projected rate of natural conservation or product adoption. This approach allows determination of impact at the point in time of the M&E study, allowing for weather differences, economic changes, rate changes and some natural changes in energy use.

Persistence: To meet the FortisBC long-term resource needs, these efficiency improvements must persist over time. Persistence studies have been done by a number of organizations in California and elsewhere in the USA, and by their very nature require considerable time and financial resources. FortisBC has not undertaken any such studies, but will adopt persistence information for comparable programs undertaken in other jurisdictions, where available. If the Province of BC adopts standardized persistence estimates, then FortisBC will use those. The expected life of energy and demand savings can also be addressed in M&E studies, but FortisBC has not addressed these explicitly in its studies. FortisBC in conducting its M&E studies proposes to adopt the “effective measure life” of DSM measures from larger jurisdictions, such as BC Hydro or California, where more elaborate studies and techniques have been used to assess persistence. Again, if the Province of BC adopts standardized “effective measure life” estimates for DSM measures, then FortisBC will adopt those estimates for the purpose of their energy and demand savings reporting and for cost-effectiveness analysis.

The **PowerSense** M&E studies are used to address the areas of uncertainty for DSM electrical resource acquisition in a systematic manner. M&E findings will result in current and forward savings forecasts being adjusted. Impact studies may use several different methodologies and data gathering techniques to deal with the attribution of savings and assessing the influence of external factors. Examples of data gathering techniques are: interviews, surveys, audits, electrical billing data, end-use metered data, and building simulation modeling. More than one methodology can be used in the M&E study to assess program impacts and the results can be compared, or used as upper and lower bounds for cost-effectiveness analysis. Multiple lines of evidence may be assembled to assess more complex programs. The methodologies vary with the maturity of the program, and the availability of information. To accommodate for weather, economic and some natural changes in energy usage, when applying billing analysis, there is a requirement for a minimum of twelve months consumption history after the installation of an energy efficient technology or measure, and that the magnitude of the energy savings should be at least 10% of the total consumption measured by the electric meter.

Interactive Effects: When a DSM measure reduces the consumption of electricity such as a lighting measure in a building, this will often result in a decrease in cooling load during the cooling season, and an increase in heating load during the heating season. These effects are known as **interactive effects**. The impacts of these interactive effects will vary depending on the climate, and on the duration and severity of the heating and cooling seasons. The use of billing analysis when used with participant and non-participant samples, can address these interactive impacts for buildings using electricity for heating and cooling. Where natural gas or other fuels are used for space heating, this would require more elaborate sampling. Given the financial resources that FortisBC has available for DSM M&E studies, interactive effects will not be explicitly addressed.

M&E Study Sequencing: As the available information, and the inherent risks (uncertainty) in energy savings estimates vary over time, it is necessary to have several stages in the M&E plan of a demand-side management program. Pilot studies are generally conducted during and immediately after a pilot project, while process studies are generally conducted six to eighteen months following program launch and often include a preliminary market assessment to determine the progress of the changes in the market.

Market and impact studies are generally conducted anywhere from twenty-four to thirty-six months after program launch, when sufficient information is available, and then periodically at an interval of 2 to 3 years depending on criteria noted in Section 6 below. Initially, impact and market studies focus on savings per unit and hours-of-use, while later studies tend to focus on rated life (hours) of the technology, persistence issues (e.g., early removal, replacement when energy efficient technologies fails) and peak coincidence.

As programs continue to evolve, M&E efforts can build on previous experience and therefore place more emphasis on informal, timelier assessments based on a mix of techniques appropriate to the technology, the market, customer needs, the risks to FortisBC and the available information.

When an M&E study is to be undertaken, one of the pre-requisites is a quality assurance check that is typically carried out to ensure that the information required is complete and satisfactorily documented in the program files selected for analysis.

3.3 Data Sources

The following represent the type of the data sources used for M&E studies:

- program participants and non-participants;
- follow-up interviews with participants shortly after project installations (allows for the capture of "still fresh" time sensitive information)
- periodic customer end-use surveys (more frequent to measure market effects for assessing market transformation, or at a minimum prior to new CPR studies)
- trade allies involved in the distribution or installation of energy efficient measures (i.e. equipment or processes);
- knowledge sector stakeholders such as engineers and architects
- test results research, and federal, provincial and municipal statistical information;
- program designers and delivery staff; and
- management responsible for programs and results

3. M&E Plans for Enhanced and New DSM Programs

During the three-year period 2012 – 2014 when this M&E plan will be implemented, the 2012-2030 long-term DSM Plan calls for enhanced and new DSM programs to be developed and launched. These programs will require that specific M&E Plans be prepared for each program. The M&E plans will include the relevant baseline information (taken from the 2009 Residential and Business end-use surveys) and the capture of the relevant data during program implementation.

A comprehensive M&E plan for each DSM program will cover the following information to a greater or lesser extent depending on the scope and complexity of the program and resources available:

- A short description of the program, its objectives and expected impacts
- The theory and logic (influence tree) for the program
- The list of measures and technologies included in the program, and those technologies which will be included in the M&E studies
- Documentation of the issues to be researched and reported on in the M&E studies, the scope of the studies to be undertaken, and the metrics and other relevant data to be tracked

- A detailed listing of the M&E activities in support of the types of M&E studies being undertaken (process, market and impact), including monitoring, metering and verification efforts
- A presentation of how the comparison or non-participant group, if applicable, will be used in the analysis
- A description of how free-riders, market effects and program spill-over will be treated in the analysis
- Timelines for activities and M&E studies, and milestone reports
- Budget of internal resource requirements and $ costs (for outside services) for each M&E study

5. M&E Plan for 3 years 2012 through 2014

The following M&E activities are planned for the fiscal years 2012 through 2014. The sequence has been prioritized based on the magnitude of energy savings reported the cumulative expenditure to date, the level of perceived risk, and resources available for M&E activities as well as past studies undertaken.

This plan recognizes that the following M&E studies have been completed or are in the final stage of completion since the beginning of 2009:

- Commercial Lighting – January 2009
- Heat Pumps – March 2010
- Commercial New Building Improvements – February 2011 – being finalized

The plan also recognizes that M&E studies for the following programs are planned for completion in 2011.

- Commercial BIP (Retrofit)
- Residential Lighting
- Behavioural Program Baseline (Market Research)

The following table provides a summary of the cumulative savings by program from inception through 2010 and provides a guide to the need for comprehensive M&E studies.

	CUMULATIVE SAVINGS TO 2010
SECTOR/PROGRAM	**GWh/Year**
RESIDENTIAL	
Heat Pumps	**58.1**
New Homes	**13.2**
Residential Lighting	**27.2**
Homes Improvements	**11.3**
GENERAL SERVICE	

Lighting	**92.2**
Building Improvements(New)	**61.8**
Building Improvements(Retrofit)	**41.3**
INDUSTRIAL	
Industrial Efficiencies	**19.0**
Compressors	**14.4**

Based on the foregoing information here is the planned sequence of M&E studies for the period 2012 to 2014:

2012

Comprehensive Studies:

- Commercial Lighting (projects completed in the past three years accounted for accumulative run rate savings of 19.5 GW.h/year)
- Industrial Efficiency Study – QA review and process for projects completed up to and including December 2010 (33.4 GW.h/year since inception)

Mini Reviews:

- New Homes – mini review (13.2 GW.h/year since inception)
- Municipal Program – mini review (3.6 GW.h/year plan in 2011)
- Home Improvements (Building Envelope - in conjunction with LiveSmart BC)

2013

Comprehensive Studies:

- Heat Pumps projects to the end of 2011
- Commercial BIP (New) projects to the end of 2011.(savings planned 3 GW.h/year)

Mini Reviews:

- Residential Lighting – mini review
- Residential behavioural survey and mini-review
- Low Income program mini review

2014

Comprehensive Studies:

- Building Improvements (retrofit)

- New Homes comprehensive study

Mini Reviews:

- Industrial Efficiency—mini QA review
- Behavioural Evaluation based on the survey in 2013 and using the difference in the reported behaviours between the 2011 and the 2013 surveys. – mini assessment
- Commercial Lighting – mini review

6. Guiding Principles for M&E Studies

- M&E studies will be conducted when the savings reach 10 GW.h/year cumulative since inception or since the last M&E study.
- When a new program is introduced or when enhancements are made to an existing program, a mini review will be undertaken within a year of commencement where practical, to ensure that the program is performing as forecast. This will permit course correction as necessary.
- Major studies of large programs will be conducted approximately every third year if warranted, i.e. savings accumulated since the previous M&E study exceeds 10 GWH/year.
- When statistical analysis of billing records is uneconomic for the size of the program, then case studies are an option that will be utilized to improve estimated savings
- Resources are planned to conduct two comprehensive studies and three mini studies per year.
- The Home Improvements program is operated in conjunction with Live Smart BC and they handle the administration of the Program. FortisBC will coordinate the M&E studies for this initiative with BC Hydro when possible.
- When customers are eligible for multiple measures such as in the Home Improvements program, surveying for information will be bundled in order to improve efficiency and effectiveness, and avoid over-surveying of customers.